Energies **2012**, *5*, 872-897; doi:10.3390/en5040872

OPEN ACCESS

energies

ISSN 1996-1073

www.mdpi.com/journal/energies

Article

Life Cycle Greenhouse Gas Emissions from Electricity Generation: A Comparative Analysis of Australian Energy Sources

Paul E. Hardisty [1,2,*], Tom S. Clark [3] and Robert G. Hynes [4]

[1] Global Director, EcoNomics™ & Sustainability, WorleyParsons/Level 7, 250 St Georges Terrace, Perth 6000, Western Australia, Australia

[2] Visiting Professor, Department of Civil and Environmental Engineering, Imperial College, London/Exhibition Road, South Kensington, London SW7 2AZ, UK

[3] Principal Consultant (Carbon and Sustainability Consulting) WorleyParsons/Level 7, 250 St Georges Terrace, Perth 6000 Western Australia, Australia; E-Mail: tom.clark@worleyparsons.com

[4] Principal Consultant (Carbon and Sustainability Consulting), WorleyParsons/Level 10, 141 Walker Street, North Sydney 2000, New South Wales, Australia; E-Mail: rob.hynes@worleyparsons.com

* Author to whom correspondence should be addressed; E-Mail: paul.hardisty@worleyparsons.com; Tel.: +61-8-6263-7111; Fax: +61-8-9278-8110.

Received: 10 November 2011; in revised form: 12 March 2012 / Accepted: 15 March 2012 / Published: 26 March 2012

Abstract: Electricity generation is one of the major contributors to global greenhouse gas emissions. Transitioning the World's energy economy to a lower carbon future will require significant investment in a variety of cleaner technologies, including renewables and nuclear power. In the short term, improving the efficiency of fossil fuel combustion in energy generation can provide an important contribution. Availability of life cycle GHG intensity data will allow decision-makers to move away from overly simplistic assertions about the relative merits of certain fuels, and focus on the complete picture, especially the critical roles of technology selection and application of best practice. This analysis compares the life-cycle greenhouse gas (GHG) intensities per megawatt-hour (MWh) of electricity produced for a range of Australian and other energy sources, including coal, conventional liquefied natural gas (LNG), coal seam gas LNG, nuclear and renewables, for the Australian export market. When Australian fossil fuels are exported to China, life cycle greenhouse gas emission intensity in electricity production depends to a significant degree on the technology used in combustion. LNG in general is less GHG intensive than black coal, but the gap is smaller for gas combusted in open cycle gas turbine plant (OCGT) and for LNG derived from coal seam gas (CSG). On average, conventional LNG burned in a conventional OCGT plant is approximately 38% less GHG intensive over its life cycle than black coal burned in a sub-critical plant, per MWh of electricity produced. However, if OCGT LNG combustion is compared to the most efficient new ultra-supercritical coal power, the GHG intensity gap narrows considerably. Coal seam gas LNG is approximately 13–20% more GHG intensive across its life cycle, on a like-for like basis, than conventional LNG. Upstream fugitive emissions from CSG (assuming best practice gas extraction techniques) do not materially alter the life cycle GHG intensity rankings, such is the dominance of end-use combustion, but application of the most recent estimates of the 20-year global warming potential (GWP) increases the contribution of fugitives considerably if best practice fugitives management is not assumed. However, if methane leakage approaches the elevated levels recently reported in some US gas fields (circa 4% of gas production) and assuming a 20-year methane GWP, the GHG intensity of CSG-LNG generation is on a par with sub-critical coal-fired generation. The importance of applying best practice to fugitives management in Australia's emerging natural gas industry is evident. When exported to China for electricity production, LNG was found to be 22–36 times more GHG intensive than wind and concentrated solar thermal (CST) power and 13–21 times more GHG intensive than nuclear power which, even in the post-Fukushima world, continues to be a key option for global GHG reduction.

Keywords: greenhouse gas; coal seam gas; renewable energy; CO_2 emissions; LNG

---

1. Introduction

Providing the benefits of electricity to hundreds of millions of people around the World is a key challenge of this century. In the International Energy Agency's World Energy Outlook 2010, global energy demand was expected to rise 1.4% per year on average to 2035, assuming no change in current business-as-usual energy policy [1]. In 2010, actual global energy use jumped by 5.6%, the largest single year increase since 1973 [2]. The current global energy mix remains heavily weighted towards conventional fossil fuels. Coal's share of global energy consumption was 29.6%, the highest since 1970. By 2030, it is expected that World energy consumption will rise from just under 12 btoe (billions of tonnes of oil equivalent) to over 16 btoe, with much of this growth occurring in non-OECD countries, particularly China and India [3].

In line with the rapid growth in energy consumption, and reflecting the current heavy dependence on fossil fuels, global anthropogenic greenhouse gas emissions grew by 5.9% in 2010, the steepest single year increase since 1972. In 2009, worldwide fossil fuel consumption subsidies amounted to $ 312 bn, with oil products and natural gas the largest recipients, at $ 126 bn and $ 85 bn respectively [1].

Such trends are at a time when scientists, economists and government leaders around the world have recognized the need to significantly lower emissions and stabilize atmospheric CO_2 levels to avoid the worst predicted effects of climate change. To this end, the Australian government has introduced legislation which will put a price on carbon emissions by 2012, partially internalizing what heretofore has been an externality for Australians. In doing so, Australia is following in the footsteps of the European Union, Norway, several American states and Canadian provinces, all of whom are applying some mechanism to provide an economic incentive to reduce emissions. As a major exporter of fossil fuels, notably LNG and coal, and one of the highest per capita users of fossil fuels, including brown coal, Australia faces significant challenges both in pricing carbon, and in understanding the effects of such pricing on export markets. Meeting rising power demand while simultaneously driving down global emissions of the greenhouse gases which drive anthropogenic global warming will require clear, accurate information on the relative emissions intensities of power generation options.

A variety of studies are available in the literature, which examine the life-cycle emissions of various fuel types [4–7]. Recent studies in the Australian context have focused on exports to Asia of Northwest Shelf gas (conventional gas), coal seam gas (CSG), and Australian black coal [8–10]. These studies have concluded generally that LNG has lower overall lifecycle GHG emissions than coal, when power generation technologies of similar efficiency or application are compared (e.g., gas from LNG burned in open cycle generation produces 35% less emissions than sub-critical coal-fired technology, for instance). Open cycle gas-fired technology for Australian Northwest Shelf gas LNG produced 41% fewer emissions than the worst (sub-critical) coal technology [8]. Open cycle gas technology, using LNG from CSG, produced 27% and 5% fewer GHG emissions over its life cycle than sub-critical and ultra-supercritical coal fired technology, respectively, burning Australian black coal [9]. CSG was found to be more GHG intensive than conventional Northwest shelf gas, on a like-for-like basis, but this CSG study [9] did not consider upstream fugitive emissions in any detail.

The US Environmental Protection Agency (USEPA) has estimated that worldwide leakage and venting of natural gas (methane) would reach 95 billion m^3 in 2010 [11]. Other recent work from the USA has estimated that fugitive emissions could add as much as 3–6% to the total life cycle emissions for shale gas [12]. This and other work suggests that with application of best practice, fugitive emissions can be significantly reduced. Other work has examined the life cycle GHG emissions of nuclear power and various renewable energy sources [13,14]. None of the existing studies in the Australian context have examined and compared the life cycle GHG emissions of a wider range of power sources such as export fossil fuels, domestic gas, nuclear and renewables.

2. Approach

This study is based on a review of original source data from public submissions in Australia, available studies in the literature, and the authors' experience. This study focuses on the Australian context, which, as discussed below, differs from the American situation in a number of respects. While in the US gas is used predominantly for heating [12], when Australian gas is exported as LNG, electricity production is the primary use. On this basis, when comparing energy sources, GHG emissions in this paper are estimated and compared based on the functional unit of MWh of electricity sent out from a power station (after efficiency losses). The analysis is an attributional life cycle assessment, based on static, current emissions, and thus is inherently limited in assessing future emissions, especially the impact of innovation and other system changes. For policy making, consequential LCAs involving dynamic modelling can be useful.

In deriving GHG emissions estimates, the Greenhouse Gas Protocol of the World Business Council for Sustainable Development and the World Resource Institute was followed [15]. The Australian Government's National Greenhouse and Energy Reporting methodology is consistent with the Protocol [16]. Estimates were developed following the Australian Government's National Greenhouse and Energy Reporting (NGER) (Measurement) Determination [16]. In the case of fugitives from natural gas operations, latest available studies in the peer-reviewed literature were used to supplement the American Petroleum Institute guidelines (the API Compendium) [17].

All emissions are converted to carbon dioxide equivalents (CO_2-e) as specified under the Kyoto Protocol accounting provisions to produce comparable measures of global warming potential (GWP). The GWP factors used are those specified in the Australian NGA Factors (carbon dioxide 1, methane 21 (over 100 years) and nitrous oxide 310) [18]. The values adopted by the Australian Government are based on IPCC 1995 values [19].

GWPs relative to carbon dioxide change with time as gases decay. The latest estimates for the GWP of methane over 20 years are between 72 [20] and 105 [21]. To provide a conservative view, this study also examines the effect of fugitives using the higher, most recent 20 year GWP of Shindell *et al*. [21].

2.1. General Assumptions

In developing GHG life cycle emissions estimates for a comparative analysis, certain key assumptions are required to normalize the data. For export scenarios, China is assumed to be the destination for comparison, although in practice both Australian LNG and black coal have multiple destinations. There is some piping of gas to individual power stations but, for comparability, power stations are assumed to be at or near the port and pumping energy use is not material.

For the base comparison, emissions from existing technologies are assumed to apply for the comparison, including best practice for GHG mitigation. A normal range of combustion technologies for gas combustion and power generation has been assumed. These technologies are internationally similar for power generation although the mix of types and relative efficiencies (and greenhouse emissions) will vary from country to country. For gas combustion, estimates have been made for open cycle gas turbine (OCGT, average efficiency 39%) and combined cycle gas turbine power plant (CCGT, average efficiency 53%). In practice there is wide variation in efficiencies around these figures. For coal combustion, estimates have been made for sub-critical (average efficiency 31%), supercritical (average efficiency 33%) and ultra-supercritical (average efficiency 41%) pulverized fuel power plant. Again, in practice there is wide variation in efficiencies around these figures.

The timeline for comparison spans from the present, considering technologies currently applied or going on-stream, while considering average emissions over the life of a project. For LNG, CSG and coal projects this is typically up to 30 years. While there may be some technology changes over this time, especially improvements in end-use combustion efficiency, the technologies for both industries are generally well established and most GHG emissions can be readily estimated based on activity levels and other factors.

Estimates include emissions from construction, emissions embedded in materials, production, transport, and from combustion. Fugitive emissions across the life-cycle are also included. When considering the life cycle emissions for renewable and nuclear energy, the vast majority of emissions are related to construction and embedded in materials. Embedded emissions in non-Australian project capital equipment were not included on the grounds of immateriality [22].

2.2. Assumptions for Black Coal

Source data from publicly available submissions varied in terms of inclusion of emissions types. While all included diesel use, fugitives and explosives and many use grid power, reporting of other emissions varied. Industry averages were developed from the cases available and included in the base case. Atypical emissions such as gas flaring from underground mines were not included.

There are general differences between open cut and deep (underground) mines, especially in levels of fugitives, relative use of diesel and electricity and, for some underground mines, use of gas for power generation. The analysis reflects these differences, and provides a range of emission intensities. The base case assumes coal from large open cut mines which dominate the export industry. It is assumed that 100% of the gas content of fugitives released is methane.

Spontaneous combustion may occur in stockpiles and release greenhouse gas emissions and estimates are made based on data from environmental impact statements (EIS), and have been included in this analysis. However, there is no accepted international or Australian methodology for estimating this type of emission. Other sources of emissions which have not been included, on the basis of immateriality, include land clearance and offsets from rehabilitation, and waste gas draining and gas flaring from underground mines. For pulverized fuel combustion, the shipped coal is pulverized to the required specification. Power use in crushing mills is part of the internal power use of a power station and is reflected in overall efficiency figures. Pulverization is assumed to take up to 2% of output, and feed pumps and other systems another 2%.

2.3. Assumptions for All Natural Gas

This analysis considered natural gas exported as LNG from both conventional Northwest Shelf gas and CSG. As noted above, for simplification, it was assumed that the power station at the receiving country is close to port, requiring minimal energy for transmission. Loss of LNG product occurs in shipping (1.5% loss of LNG product cargo as shipping fuel) and in re-gasification (2.7% lost in fueling re-gasification heaters). Where an LNG plant processes condensate and domestic gas, GHG emissions for LNG exports are apportioned. For the LNG base case, production of 10 Mtpa (a 3 train LNG plant) is assumed.

2.4. Assumptions for Coal Seam Gas

For coal seam gas scenarios, the study considers GHG emissions from the exploration phase, including coreholes and operation of pilot wells, construction and operation of production wells, gas gathering lines, gas compressors and gas dehydration equipment. The base case assumes zero venting in gas field development and operations (*i.e.*, all fugitive emissions are flared). At present, the CSG industry is nascent in Australia, and there is little operational data to support this assumption. However, most CSG proponents have stated in their EIS that zero venting will be part of normal operating practice. Therefore, this is taken as the base case. Scenarios are then considered for various levels of gas field leakage and venting to illustrate the implications of not applying best practice. Assumptions for LNG production and shipping are as for conventional gas.

3. Life Cycle Emissions

3.1. Australian Black Coal for Export

Australia is the world's largest exporter of black coal. The industry boasts a diversity of mine types (surface, open cut and high wall), sizes, ownership (major and independents), operational conditions and product types. In addition to the existing industry, a large number of new and mine expansion projects are proposed in both New South Wales and Queensland in response to rising prices and world demand for coal, especially from China. GHG emissions sources for each stage of the mining operation are summarized in Table 1.

Table 1. Australian black coal: GHG emissions sources.

Operation	Emissions sources
Extraction and processing • Open cut mining operations • Deep mining operations • Preparation plant for all mines includes crushing, screening, sizing, washing, blending and loading onto trucks and conveyors	• Use of diesel for generators (used for plant and equipment) and vehicles • Use of grid electricity for some mines (scope 2 or indirect emissions) • Fugitives (more significant for 'gassy' underground mines) • Use of explosives • Slow oxidation • Spontaneous combustion • Construction emissions • Embedded emissions in materials and fuel
Transport Most coal is transported by rail to port where it is transferred to bulk carriers. Rail shipment distance range from less than 20 km to around 400 km and may be on dedicated or shared systems.	Use of diesel for locomotives (or electricity for electrified railways), electricity in port handling, fuel for ships.
Combustion The most common modern type of power plant in all export and domestic markets is pulverized coal power plant where the coal is pulverized in the receiving power station. Various combustion technologies are commonly employed, including sub-, super and ultra-super critical with various efficiencies in electricity sent out.	The main life cycle emissions arise from the use of coal in power generation, including internal use of power in pulverization and other plant systems (which contributes to efficiency losses).

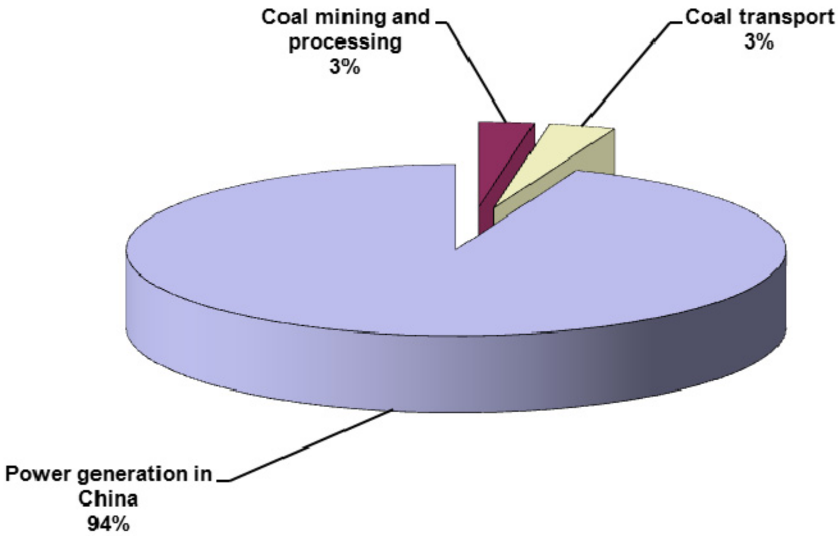
To date, there has been relatively little data available specific to GHG emissions from export of Australian coal. There are extensive project forecast EIS data in Australia, but little publicly available data for existing operations. GHG emissions estimates have been developed from existing information from 6 underground and 9 open cut mines of which some examples are listed in the references [23–27]. The coal mines were selected on the basis of EIS availability, and to reflect a range of mine types, location, and status. These data were combined with existing studies to develop emission estimate ranges.

Base case estimates for GHG life cycle emissions for Australian black coal for export to China are provided in Table 2, broken down by activity. Figure 1 shows the percentage contribution to overall emissions from production, transport and power generation stages of the life-cycle.

Table 2. Base case life cycle GHG emissions-black coal.

Activity	**GHG emissions intensity**				
	Base case (t CO_2-e/t product coal)	%	Sub-critical power generation 33% efficiency (t CO_2-e/MWh)	Super-critical power generation 41% efficiency (t CO_2-e/MWh)	Ultra super-critical power generation 43% efficiency (t CO_2-e/MWh)
MINING					
Mine fugitives	0.0375	1.47	0.0152	0.0122	0.0116
Mine diesel use	0.0114	0.40	0.0046	0.0037	0.0035
Explosives	0.00025	0.01	0.0001	0.0001	0.0001
Slow oxidation	0.00018	0.01	0.0001	0.0001	0.0001
Power consumption	0.0157	0.62	0.0063	0.0051	0.0049
Spontaneous combustion	0.00185	0.07	0.0007	0.0006	0.0006
Scope 3 fuel and electricity	0.0029	0.11	0.0012	0.0009	0.0009
TRANSPORT					
Rail operations	0.00205	0.08	0.0008	0.0007	0.0006
Port handling	0.00161	0.06	0.0007	0.0005	0.0005
Shipping	0.0791	3.11	0.0320	0.0257	0.0245
END USE					
Combustion	2.388	94.02	0.9647	0.7765	0.7403
TOTAL all sources	2.540	100	1.026	0.826	0.788
Range Min			0.75	0.61	0.58
Max			1.56	1.26	1.20

Figure 1. Percentage contribution to life cycle GHG emissions: black coal.



The majority of life cycle GHG emissions occur in end use combustion (94%). Extraction and processing in Australia account for only a small component (2.7%). Of extraction and processing activities, fugitive emissions (1.5%) are the largest single contributor, followed by use of fuel and power (1.2%).

3.2. Conventional LNG for Export

Australian conventional natural gas is almost entirely sourced from large offshore wells, complemented by extensive transmission and distribution systems. Much of this infrastructure has been in place for more than a decade. The life cycle GHG emissions of Australian Northwest Shelf conventional gas are already well established. Raw gas composition varies according to location, but typically includes CO_2 and other impurities. GHG emissions sources are summarized in Table 3.

Data for this analysis were drawn from public submissions of EIS documents from a variety of Northwest Shelf LNG projects, and LCA reports based on information from planned and operational plants in Western Australia. Data from the Karratha Gas plant, using gas from the NR2 field (with lower than average CO_2 content in feed gas at around 2%), were used to estimate life cycle emissions as 0.60 and 0.44 t CO_2-e/MWh for OCGT and CCGT respectively, and total emissions intensity of 3.12 t CO_2-e/t LNG [8]. An LCA for the proposed Scarborough LNG project, assuming shipment of LNG to California, included detailed calculation of shipping emissions which have been used in subsequent studies. The average total emissions intensity (including combustion) was estimated at 3.88 t CO_2-e/t LNG (based on 6.3 Mt of LNG delivered) [28]. A recent literature review [29] of LNG liquefaction, transport, and regasification found average emissions intensities 0.006 t CO_2-e per GJ for these stages of the life cycle. Table 4 compares emissions intensities for various existing and proposed liquefaction plants in Australia, and shows that the GHG intensity of LNG depends in part on the CO_2 content of the feed gas. The significant number of proposed LNG projects reflects Australia's emergence as one of the world's major LNG exporters.

Table 3. Australian conventional LNG: Operations and GHG emissions sources.

Operations	Emissions sources
Extraction and upstream processing	
• Exploration and test drilling • Gas/water separation, condensate separation, dehydration, compression and other initial processing on offshore platforms • Stripping of CO_2 and other impurities from raw gas • Pipeline transmission to the onshore processing plant	• Operating gas turbines and standby diesel generators power • Flaring or venting gas for safety and during maintenance • Leaks • Emissions from vessels and helicopters • Construction related GHG emissions-transport vessels, diesel generators, helicopters • Embedded emissions in materials and fuel
LNG Facility	
• Gas treatment to remove impurities, including removal of nitrogen and carbon dioxide • Depending on the plant, some of the gas may be processed for local industrial and domestic use, and transmitted via pipeline • Depending on the plant, processing of condensate for export. Life cycle emission estimates for LNG include apportionment for the export component	• Gas turbines for power generation and liquefaction (largest component of GHG emissions from an LNG plant) • Vented CO_2 from acid gas removal, flared and un-burnt methane from flares and thermal oxidizers • Fugitives from flanges and other leaks (typically small and closely monitored for safety reasons) • Flaring during ship loading (systems are designed to capture boil off gas for use as fuel by the ship) • Construction emissions (diesel generators, plant and vehicles and construction vessels) • Embedded emissions in materials and fuel
Transport	
The LNG is transported by ship	• Combustion of fuel by the ship • Leaks (for safety reasons leaks from shipboard LNG tanks are typically closely monitored and very small)
Regasification and combustion	
At or near the destination port the LNG is re-gasified and transmitted by pipeline to the receiving power plant When used for power generation the gas is burned in a combined cycle or open cycle gas turbine plant (base case assumption)	• Energy (gas use) for regasification • Emissions from combustion in the power station

Table 4. GHG emissions from Western Australia LNG plants (after Barnett, 2010 [29]).

Plant	E/P *	Trains	Inflow CO_2 (mol%)	T CO_2-e/t LNG	G CO_2-e/MJ
Darwin LNG	E	1	6	0.46	5.17
NWS Karratha	E	5	2.5	0.35	3.76
Gorgon LNG	P	3	14.2 (80% CCS)	0.35	3.97
Wheatstone LNG	P	6	<2	0.37	3.97
Pluto LNG	P	1	1.7	0.32	3.43
Prelude LNG	P	1	NA	0.63	6.76
Ichthys LNG	P	2	17	0.25 (estimate)	8.05
Browse LNG	P	3	12		3.76
Average				0.442	4.89

* E = existing, P = proposed.

Recent US-based studies have found a similar range of intensities. PACE [30] estimated life cycle GHG emissions from imported LNG, accounting for natural gas extraction, liquefaction, shipping, regasification and pipeline transport. The intensity was 0.74 t CO_2-e/t LNG. Jaramillo [31] calculated emissions intensities in the range of 0.69 to 1.68 t CO_2-e/t LNG for the same production and transportation segments.

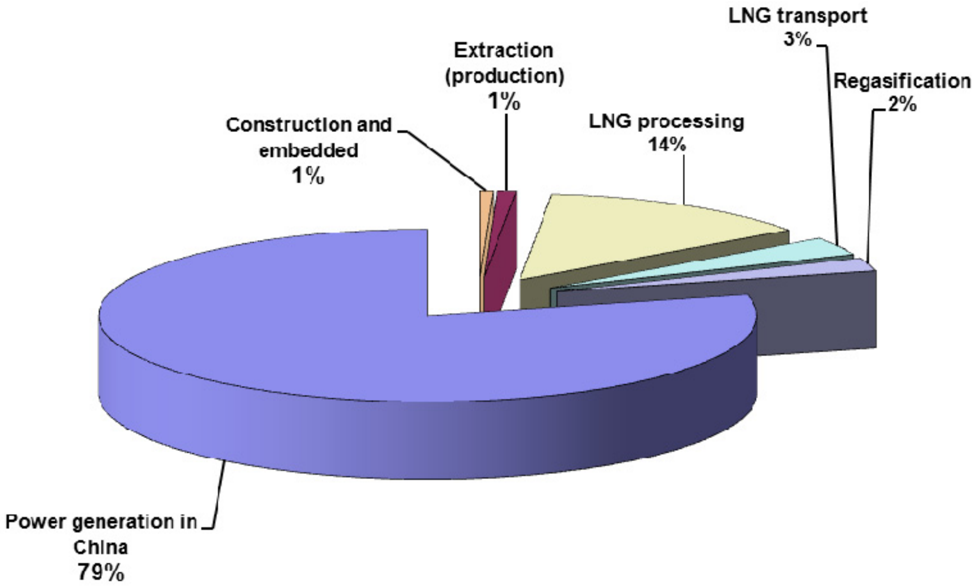
Based on the available data, a base-case for GHG emissions for a typical or "average" Australian LNG export project into China is shown in Table 5 for each stage of the life cycle. The base case uses an average Northwest Shelf CO_2 feed gas content, and includes construction and embedded emissions. Combustion in open cycle and combined cycle power-plant scenarios are provided. The ranges in the averages are due mostly to variation in the thermal efficiency of power plants.

Table 5. Conventional LNG life cycle GHG emission-base case.

Life cycle operation	Emissions Intensity			
	t CO_2-e/t LNG		t CO_2-e/MWh	
		%	OCGT	CCGT
Assumed average efficiency (%)			41	53
Construction and embedded	0.02-est	0.6	0.003	0.002
Extraction (production)	0.03	0.9	0.005	0.003
LNG processing	0.44	13.6	0.065	0.047
Transport	0.11	3.4	0.03	0.02
Regasification	0.08	2.4	0.02	0.01
Power generation in China	2.54	78.6	0.52	0.36
Totals	3.23	100	0.65	0.45
Ranges Min			0.53	0.39
Max			0.71	0.54

The majority of GHG emissions occur in end-use combustion (79%), but extraction and processing in Australia accounts for a significant component (15%), as shown in Figure 2, below.

Figure 2. Percentage contribution to life cycle GHG emissions: conventional LNG.



3.3. Coal Seam Gas to LNG for Export

Australian coal seam gas exported from Queensland to China as LNG is used as a reference case. Recent studies have shown that CSG-LNG was less GHG intensive than coal across its life cycle for most end-use combustion scenarios [9,10], based on data from two available EIS reports submitted by project proponents, considering early design proposals and assumed best practice in emissions management, including zero venting and minimal fugitive emissions from leakage (0.1% of production). The CSG industry in Australia is in the early stages of development and data for CSG projects and potential upstream GHG emissions remain limited, largely based on forecasts rather than measured data. The present study considers these GHG emissions in more depth, incorporating more recent information and experience.

Application of best practice will dictate minimization of fugitive methane emissions. Under a carbon pricing scheme, fugitive methane emissions could lead to significant financial liability for operators. Nevertheless, standard operating practices may require occasional gas venting. Sources of GHG emissions are summarized in Table 6 (emissions from LNG plant, transport, regasification and combustion operations are identical to those described in Table 4, above).

Table 6. Australian CSG/LNG: Operations and GHG emissions sources.

Operations	Emissions sources
Extraction and upstream processing	
• Exploration (including test drilling and core sampling) • Drilling of test, pilot, and production wells • Hydraulic fracturing, if required • Gas/water separators capture the gas for collection via pipelines to processing plant where the gas is treated (including dehydration) and compressed for transmission • High pressure transmission pipeline to the LNG plant • Water treatment for reuse or aquifer recharge	• In exploration, use of diesel for drill rigs, and vehicles • During construction and operation GHG emissions arise from vehicles and machinery, diesel generators, land clearing and embedded emissions in materials and fuel • Flaring and venting from pilot wells, production well completion and work-over • Flaring and venting from gas gathering and processing, including compression and dehydration • Power for compressors and other systems, including water treatment units
LNG Facility	
Similar to conventional gas but no condensate production-See Table 3	Similar to conventional gas but raw gas CO_2 content is lower
Transport	
As for conventional LNG-see Table 3	
Regasification and combustion	
As for conventional gas-see Table 3	

Fugitive emissions and leaks of methane in CSG production may be unintentional or due to process upsets. The large number of wells required for CSG extraction at scale (between 6000 and 10,000 wells for a large scale CSG development in Queensland), and associated gas handling equipment, pipe work and connections, provide additional potential for GHG emissions. Although fugitives may be a small percentage of total production, the GHG impacts are magnified, since, as noted above, methane's global warming potential is 21 times that of CO_2 over a 100-year period [19], and between 72 to 105 times over a 20-year period. Managing these potential sources of GHG emissions is an important consideration for CSG operators. Upstream fugitive emissions from existing CSG operations are dominated by compressor station venting, field and compression fuel gas consumption, pilot and production well venting, leaks from connections and equipment throughout the gathering system, entrained CH_4 in water production, and system upsets and blowdowns [32]. In estimating fugitive emissions for the CSG-LNG reference case, it is assumed that the current regulatory requirements for fugitive emissions in Queensland are being met, including a "no venting" requirement. A recent government review of 2715 CSG well heads found only five had "reportable" leaks [33]. Avoiding methane venting is already recognized internationally as best practice [34]. However, recent studies from the USA have indicated the potential for significant venting of fugitives if best practice is not followed [12].

There are no current Australian-specific guidelines for estimating natural gas fugitives. Australia's current NGER Technical Guidelines specify using the US API Compendium [17], which may be considered out of date. Emissions factors for equipment used in the US may not be applicable to proposed projects in Australia. The US EPA has, over the past 15 years, monitored fugitives from the US gas industry, and established the Star Program to work with industry on fugitive emissions reduction. The US EPA conducted a major investigation into fugitives from the US natural gas industry in 1997 and found average losses of 1.4 ± 0.5% from production, transmission and storage [35]. In 2010 it produced an update, announcing upward revisions of these estimates in some cases and new estimates for well completion and work-over (9175 Mcf methane/work-over or completion). The Star program in the USA and similar programs in Canada have shown that methane emissions can be significantly reduced by applying best practice technology and management methods. Some of the main approaches are summarized in Table 7. Unburnt methane from flaring is not expected to be a large source of GHGs as ground flares burn with an efficiency of at least 99.5% and conventional elevated flares burn with an efficiency of 98% [36]. The Australian CSG industry, still in relative infancy, has a golden opportunity to learn from the North American gas experience, and move now to embed best practice in design, construction and operation of CSG projects and associated infrastructure.

Table 7. Methane fugitive emissions mitigation measures.

Emissions sources	Mitigation
Venting from pilot wells, well completions and workovers	• Capturing the gas and connecting to supply lines • Capturing gas entrained in produced water • Flaring where the gas cannot be used • Maximizing combustion efficiency of flaring • Minimizing time periods for any necessary venting
Venting from compressor stations and pneumatic devices; Some equipment, e.g., pneumatic devices, are specifically designed to vent gas when use in gas systems although it appears that their use will be minimal in Queensland as these devices will run on compressed air.	• Use of grid powered instead of gas powered compressor stations • Flaring wherever possible • Avoiding cold vents • Avoiding pneumatic devices using gas
Leaks	• High integrity equipment • Construction, installation and testing to high standards • Leak detection programs, including remote sensing
Environmental management	Implementing methane emissions minimization as part of implementing environmental management plans including: • Assessment of risks and impacts • Objectives, targets, plans and KPIs • Training and awareness, including sub-contractors • Procedures, including incident management • Monitoring • Auditing, reporting and corrective action

An estimate of upstream fugitive emissions for the Queensland reference case was developed based on the most recent available data from operating CSG fields [37]. Projected peak upstream GHG emissions were estimated at 2.8 Mt CO_2-e, assuming 4500 wells required for the 10 Mtpa reference case.

The base case estimate is based on a typical large coal seam gas development, as described in a number of EIS reports (e.g., [32,37,38]). The base case assumes preparation of 500 core holes for exploration, 300 pilot wells and 6000 production wells. Each production well is assumed to have a lifetime of 15 years, with 1 well completion and 8 workover activities over this lifetime. The development includes a transmission pipeline and LNG plant capable of producing 10 Mtpa of LNG. The GHG emissions for the CSG-LNG lifecycle base case are shown in Table 8, on the basis that no gas in the flare streams are vented and using a 100-year methane global warming potential.

Table 8. GHG emissions for CSG-LNG reference case, at maximum production.

Source of emissions	GHGs (t CO_2-e pa)
Core holes-construction	56,600
Pilot Wells-construction + operations	122,100
CSG Fields-construction	278,600
CSG Pipeline- construction	61,300
LNG Plant-construction	173,100
CSG Fields-operations	4,081,000
CSG Pipeline-operations	5000
LNG Plant-operations	3,526,000
LNG shipment	937,000
LNG re-gasification	758,300
Combustion of LNG	30,065,000
Total life cycle emission	Approx. 40,063,000

Figure 3. Breakdown of life cycle GHG emissions from CSG-LNG Reference Case.

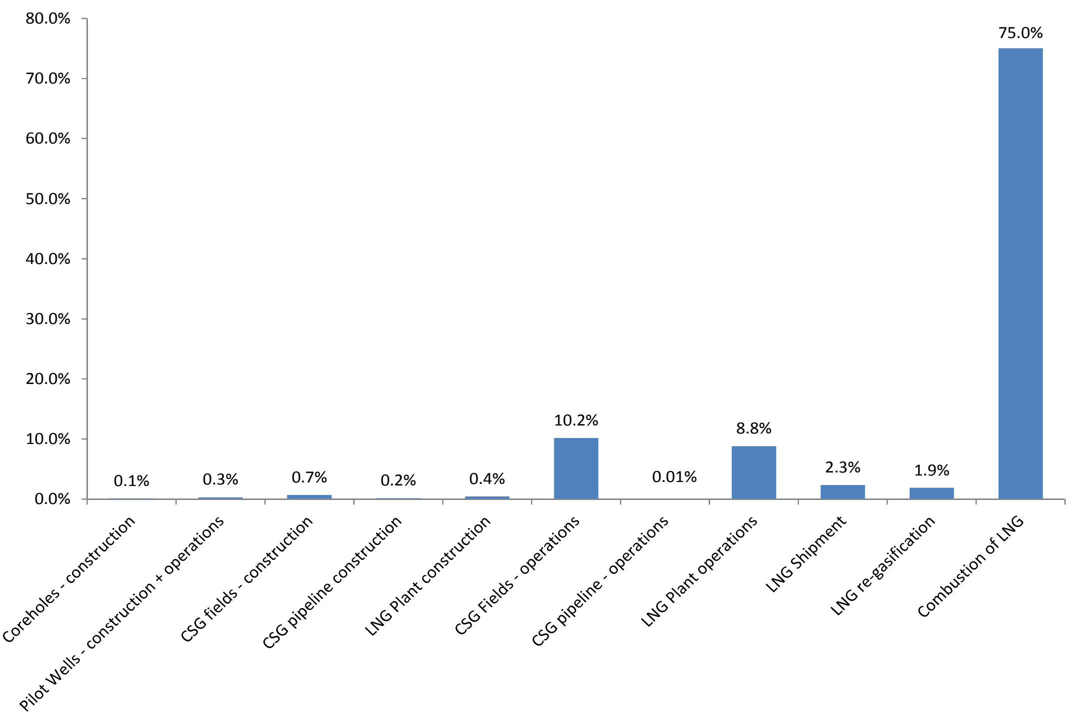


Table 8 shows that total upstream annual emissions for the reference facility amount to 4.1 Mt CO_2-e, approximately 10% of the total lifecycle GHG emissions of approximately 40 Mt CO_2-e. Upstream fugitive emissions, as defined by the API Compendium (2009) [17], accounted for 0.73 Mt CO_2-e per annum of this total. The largest source of fugitive emissions is from screw and centrifugal compressors. LNG plant operations account for 9% of emissions, with 0.53 Mt CO_2-e per annum arising from fugitive methane emissions. As found in previous studies, end-use combustion emissions overwhelmingly dominate the lifecycle GHG emissions of all types of LNG (Figure 3).

Table 9 shows the GHG emission intensity per tonne of CSG-LNG product and per MWh of power sent out for the base case (0% venting; 100-year methane GWP).

Table 9. Base case life cycle GHG emission intensities for CSG-LNG.

Source of emissions	T CO_2-e pa/GJ	T CO_2-e pa/t LNG	%	OCGT 39% efficiency t CO_2-e/MWh	CCGT 53% efficiency t CO_2-e/MWh
Core holes-construction	0.0001	0.006	0.1	0.001	0.001
Pilot Wells-construction + operations	0.0002	0.012	0.3	0.002	0.001
CSG Fields-construction	0.0005	0.028	0.7	0.004	0.003
CSG Pipeline-construction	0.0001	0.006	0.2	0.001	0.001
LNG Plant-construction	0.0003	0.017	0.4	0.003	0.002
CSG Fields-operations	0.0069	0.408	10.2	0.063	0.047
CSG Pipeline-operations	0.00001	0.001	0.01	0.0001	0.0001
LNG Plant-operations	0.0059	0.353	8.8	0.055	0.040
LNG Shipment	0.0016	0.095	2.3	0.015	0.011
LNG Re-gasification	0.0013	0.077	1.9	0.012	0.009
Combustion of LNG	0.0525	3.138	75.0	0.578	0.425
Total	0.069	4.140	100.0	0.733	0.540

The results in Table 9 compare well with other recent lifecycle GHG emissions studies [9] and Jiang *et al*. [39] for Marcellus shale gas. Jiang *et al*. [39] considered pre-production, production, processing, transmission, distribution and combustion stages and reported overall lifecycle GHG emissions were 0.068 tonnes/GJ, which is in good agreement with the value of 0.069 tonnes/GJ found in this study. End-use combustion accounted for 75% of lifecycle GHG emissions, with the GHG intensity for electricity sent out from a CCGT power plant ranging from 0.48 to 0.56 t CO_2-e/MWh, also in broad agreement with the present study.

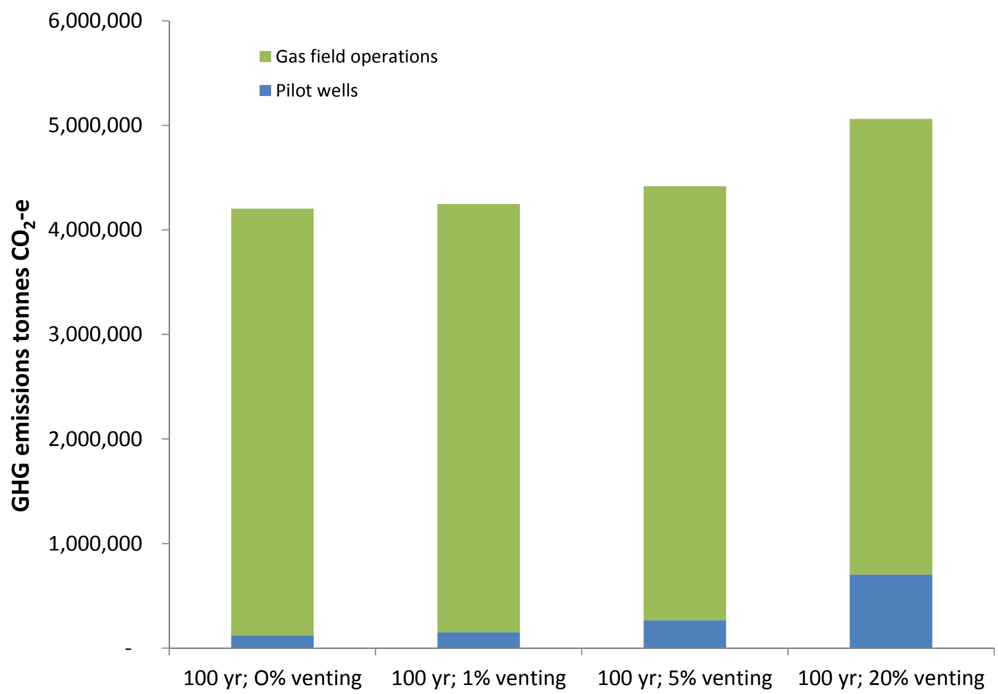
The results of the present study also compare well with NETL [40] data for average gas-fired generation based on unconventional gas (0.53 t CO_2-e/MWh) for a 100-year methane GWP.

It should be noted that Howarth *et al*. [41] state that the emissions from transmission, storage and distribution reported in Jiang *et al*. [39] and NETL [40] are 38% and 50% less than those reported by the US EPA [42]. Howarth *et al*. [41] suggest that this is due to the overestimation of the lifetime gas production from a well, which underestimates the GHG emissions per unit of energy available from gas production. This will have an impact on these two lifecycle GHG emission studies, but the extent of the impacts has not been evaluated here because there is currently very little experience in Australia on the anticipated CSG well life.

Although deliberate gas venting is not strictly permitted in Queensland, there are nevertheless instances where venting has and will continue to occur, such as during emergencies and shutdowns for maintenance. In order to estimate the impact of venting, a number of scenarios were considered in which a percentage of the flare streams were instead vented. Three scenarios were considered, assuming 1%, 5% and 20% of flare streams from pilot wells and production wells are vented. Estimates of annual volumes of gas flared were developed from data in operators' environmental impact statements [37], and included pilot well flaring (2.7 million m^3/year per well), and work-over activities (42,500 m^3/work-over).

Figure 4 shows that GHG emissions during pilot well operations are particularly sensitive to venting of flare stream gas. The base case uses the 100-year methane GWP and 0% venting. A scenario with 1% venting leads to a 24% rise in GHGs from this segment. In terms of CSG field operations, venting of flare streams is less sensitive in terms of overall segment GHG emissions, as these are dominated by combustion of fuel gas in gas engines and compressors. Only a high value of 20% venting leads to a significant change in CSG field GHG emissions (an approximate 7% rise).

Figure 4. Impact of venting scenarios on gas field emissions.



In terms of overall lifecycle GHG emissions, only the 20% venting scenario leads to a significant (>2%) change, corresponding to a rise in GHG intensity to 0.55 t CO_2-e/MWh (based on CCGT technology). In the hypothetical situation where all flared gas is vented, the GHG intensity rises to 0.59 t CO_2-e/MWh for a 100-year methane GWP.

A fourth scenario considers the recent results of a sampling campaign in the Denver-Julesberg Fossil Fuel Basin in the United States by Pétron *et al.* [43]. Various estimates were made of the methane emissions from flashing and venting activities by oil and gas operations in northeastern

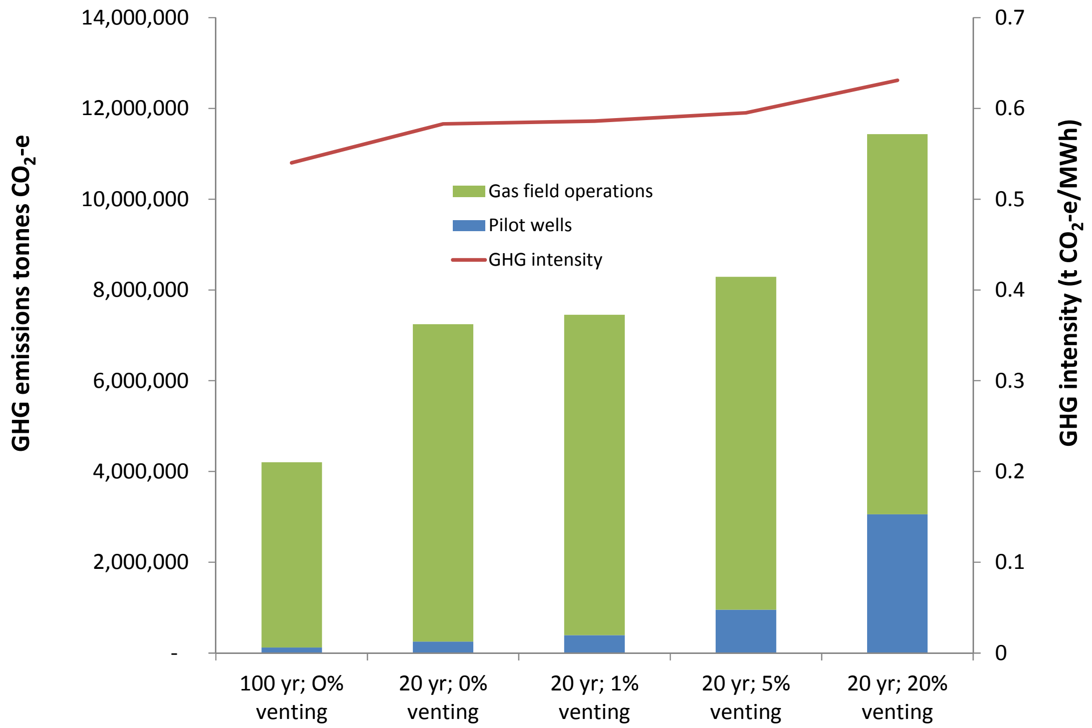
Colorado. Bottom-up estimates show that 1.68% of the total natural gas produced in 2008 was vented. Top-down scenarios give a range 3.1% up to 4.0% (minimum range of 2.3% up to 3.8% and a maximum range of 4.5% up to 7.7%). In this study we take the average of all top down estimates from Pétron [43] *et al*., giving 4.38% of all gas production being vented. Although the study of Pétron [43] *et al*. includes both gas and oil production emissions, no attempt is made here to separate these emission sources. Given that the Denver-Julesberg data represent a field which is several decades old, this clearly represents a worst case scenario when applied to the emerging Australian CSG industry. Nevertheless, it does illustrate what could occur in future if leading practice is not adopted and GHG abatement measures are not incorporated across the industry.

To calculate the impact of the 4.38% loss of CSG as fugitive emissions, the upstream CSG production emissions were also increased commensurately by 4.38% to ensure the same amount of CSG reaches the LNG production facility. This loss of CSG as fugitive emissions results in an additional 8.6 Mt CO_2-e emissions per annum compared with the base case and a 100-year methane GWP. Compared to Figure 3, the emissions from the CSG fields rise from 10% of total lifecycle emissions to 26%, and end-use combustion emissions drop from 75% to 62%. The GHG intensity also rises to 0.64 t CO_2-e/MWh for CCGT technology and 0.87 t CO_2-e/MWh for OCGT technology. In this scenario, the lifecycle GHG emissions for OCGT electricity generation are higher than for supercritical and ultra-supercritical coal fired generation.

Figure 5 shows the impact of changing the methane GWP from the 100-year value of 21 to the 20-year value of 105 [21] on vented emissions. For CSG, the present study finds that the change in methane GWP has an impact on pilot well and gas production well segment emissions. Given the significant volume of gas flared at the pilot well stage (since pilot wells are generally not linked to a gas-gathering pipeline network), any fraction of the gas stream that is vented, instead of being flared, will have an impact on overall GHG emissions. Natural gas venting and leaks from the LNG plant are well-defined and factored into the base case emissions scenario, although a jump in emissions of 0.8 Mt CO_2-e emissions per annum accompanies the increase in methane GWP. For the CSG fields, gas that is vented instead of flared at compressor stations, well completions and workovers, and routine and emergency venting make large contributions to segment GHG emissions. The impact of these releases is amplified by the high 20-year methane GWP.

Figure 5 reflects the large impact of the increase in the methane GWP in pilot well GHGs due to the relatively large amounts of gas flared (of the order of 3 million m^3 of gas is flared per pilot well). For production wells, industry proponents estimate that a total of 25,470 m^3 of CSG are released per well during completions and workovers over a lifetime of 15 years (based on data in [37]: 14,150 m^3 flared per day for 3 days during workovers).

Figure 5. Impact of a 20-year methane GWP on upstream GHG emissions and lifecycle emissions intensity for CSG.



In response to the increased methane GWP, the overall lifecycle GHG emissions increase by between 9.6% (3.8 Mt CO_2-e per annum) for 0% flared gas being vented and up to 20% (8 Mt CO_2-e per annum) for 20% of the flare gas being vented. Similarly, the GHG intensity for the CSG/LNG lifecycle rises from 0.54 to 0.63 t CO_2-e/MWh sent out, based on CCGT technology. When the fugitive emissions for coal mining are assessed using the 20-year methane GWP, the GHG intensities also increase, ranging from 0.834 (ultra-supercritical), 0.875 (super-critical) and 1.087 t CO_2-e/MWh (sub-critical). On this basis, the GHG intensity of gas-fired generation is still below the life cycle GHG emissions for all coal-fired generation technologies.

As a comparison, the NETL [40] predicts an intensity of 0.69 t CO_2-e/MWh for average natural gas baseload generation fuelled by shale gas, assuming a 20-year methane GWP of 72. The present study predicts an intensity of 0.63 based on a much higher methane GWP. The variations in the two GHG intensities may be a result of the differences in methane venting volumes for Australian CSG and US shale gas from completions, workovers, and liquid unloading events. Also, gas distribution and storage losses are not a significant part of the Australian CSG/LNG lifecycle as most of the Australian CSG will be converted to LNG for overseas export.

Considering the worst case scenario of 4.38% of total upstream production being vented (based on 10 Mtpa of CSG output), and the 20-year methane GWP, results in an additional 41 Mt CO_2-e of emissions per annum. Under this worst case scenario, the GHG intensity of generation using CCGT technology is approximately 1.07 t CO_2-e/MWh sent out, which is higher than ultra-supercritical and super-critical coal-fired generation technology, and nearly the same as sub-critical coal-fired generation when assessed with a 20-year methane GWP.

High losses of CSG through leaks and venting are considered unlikely, as this represents a substantial loss in revenue, a potential safety hazard for the industry, and in Australia, an ongoing significant carbon tax liability. Nevertheless, the results of this analysis indicate the need for the Australian CSG industry to improve monitoring of methane releases and to adopt best practice technology and systems to reduce leaks and venting emissions, particularly during workovers and well completions. Howarth *et al*. [12] provide a brief review of methane abatement technologies. According to the US General Accountability Office (GAO) [44], "green" technologies are capable of reducing methane emissions by 40%. This includes reducing liquid unloading related emissions with automated plunger lifts and using flash tank separators or vapour recovery units to reduce dehydrator emissions. Reduced emissions completions technologies can reduce emissions from flowbacks during workovers and completions, but this requires gas gathering pipelines to be in place prior to completions. This may not be possible for pilot wells and gas fields under development. Compressor leaks may be reduced by using dry seals and increasing frequency of maintenance and monitoring. Table 7 (above) provides a summary of emissions reduction methods.

From the lifecycle analysis of CSG/LNG, it was apparent that methane releases from liquid unloading, well completion and workover events (whether flared or vented), are potential, yet uncertain, sources of GHG emissions. When compared to the data available in relation to shale gas GHG emissions from the US EPA, it is evident that emissions from these sources require further research in the Australian context. The possibility of methane dissolution and migration in groundwater and subsequent release to atmosphere via improperly abandoned wells or other geological pathways also exists. One study on the Marcellus Shale in the USA found evidence of elevated levels of dissolved methane in groundwater (19.2 mg/L on average), compared to natural background levels (1.1 mg/L), in proximity to gas wells [45]. Given the concentrations reported, the potential for dissolved concentrations of methane in groundwater de-gassing to atmosphere to have a meaningful impact on the overall GHG life-cycle appear small. However, at present, very little research on this migration mechanism and the potential for atmospheric release has been completed, especially in the Australian context.

4. Life Cycle GHG Emissions Comparison

Using the emissions intensity estimates developed above, GHG emissions of various energy sources were compared in the Australian context for export to China. The base case comparison is between conventional LNG, CSG-LNG and black coal when exported from Australia to China for power generation.

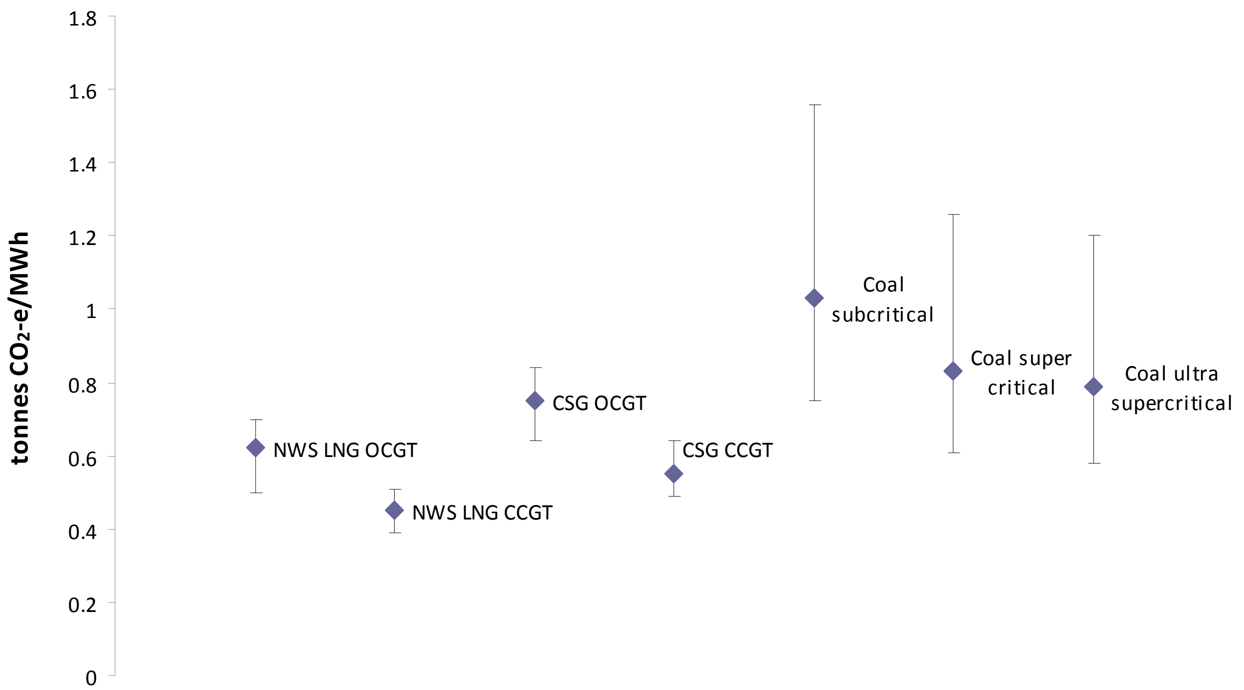
4.1. Base Comparison—Australian Export

Table 10 summarizes base case life cycle GHG emissions intensity in electrical power generation in China, for Australian conventional gas, coal seam gas and black coal. Estimates are provided for OCGT and CCGT gas combustion, and for sub-, super-, and ultrasuper-critical coal combustion. The ranges in intensities largely reflect variations in thermal efficiencies in end-use combustion. The base case for CSG/LNG assumes zero venting and leakage losses of 0.1% of production, as discussed above. These findings are provided graphically in Figure 6, including ranges from all life cycle-emissions sources.

Table 10. GHG intensities-base case (t CO_2-e/MWh).

Operation	Conventional gas		Coal seam gas		Black coal		
	OCGT	CCGT	OCGT	CCGT	Sub-critical	Super-critical	Ultrasuper-critical
Assumed average efficiency (%)	39	53	39	53	33	41	43
Extraction and processing	0.09	0.07	0.12	0.10	0.03	0.02	0.02
Transport	0.02	0.01	0.02	0.01	0.03	0.03	0.03
Processing and power generation in China	0.54	0.37	0.59	0.43	0.97	0.78	0.74
Totals	0.65	0.45	0.73	0.54	1.03	0.83	0.79
Ranges Min	0.50	0.39	0.64	0.49	0.75	0.61	0.58
Max	0.70	0.51	0.84	0.64	1.56	1.26	1.20
T CO_2-e/t product	3.23	3.23	4.14	4.14	2.54	2.54	2.54

Figure 6. Base case GHG intensities and ranges.



The results show that for all exported fossil fuels, end-use combustion dominates GHG emissions, accounting for 94% of the total in the case of coal, 82% for conventional LNG, and 75% for CSG/LNG. For most combustion technologies, coal is more GHG intensive than LNG. However CSG-LNG is 17–21% more GHG intensive than conventional LNG, largely as a result of higher energy use in upstream production (when zero venting is assumed). Conventional LNG re-gasified and burnt in CCGT power plants is least GHG intensive, and black coal burnt in a subcritical power plant is the most GHG intensive of the scenarios. The gap between coal and LNG narrows considerably with higher efficiency coal technologies and when ranges are considered, to the extent that CSG-LNG burned in low efficiency power plants is slightly more GHG intensive than the most efficient coal combustion technology.

4.2. Renewable and Nuclear Energy

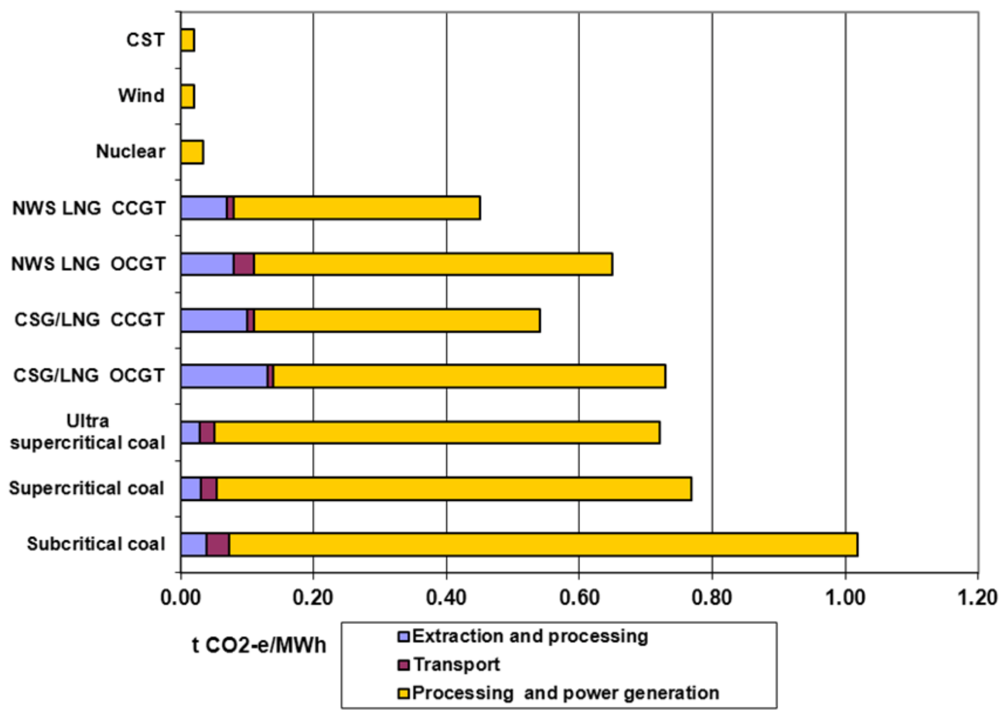
Renewable and nuclear energy sources provide an alternative basis for comparison of GHG emissions intensities (Table 11). Renewable energy sources (wind, solar, wave and geothermal) produce no GHG emissions in electricity generation, and the GHG intensity is derived from fuel use for construction and ancillary purposes, and embedded emissions in infrastructure and consumables. Wind and concentrated solar thermal (CST) show similar life cycle emissions. Life cycle GHG emissions for nuclear energy depend on the grade of fuel and processing required and how reprocessing power is sourced. Figure 7 illustrates the significantly higher life cycle GHG emissions of exported Australian fossil fuels compared to solar, wind and nuclear when used for power generation in China.

Table 11. GHG emission intensities for renewable and nuclear energy-base case.

	Emissions intensity t CO_2-e/MWh	Range (from literature review) t CO_2-e/MWh
Wind	0.021 [13]	0.013–0.040 [13]
Solar Photovoltaic	0.106 [13]	0.053–0.217 [13]
Concentrated Solar Thermal	0.020 [46]	Central tower 0.0202 [46] Parabolic trough 0.0196[46]
Hydro	0.015 [13]	0.006–0.044 [13]
Nuclear-current technologies	0.034 [47]	0.01–0.13 [13]

Note: The emissions intensities stated here have been derived from the specific LCA studies referenced and from associated literature reviews of LCA studies conducted internationally. For the purposes of the comparison in this study the figures are applicable to power generation in China.

Figure 7. Life cycle GHG emissions intensities for Australian fossil fuel exports, and selected renewables and nuclear, base case.



4.3. Displacement of Coal by Gas

Recent Australian studies have examined the theoretical GHG emissions reductions that could occur if LNG is exported to China and other Asian destinations [8–10]. Depending on the assumptions around generation technology, and assuming full displacement, natural gas exported as LNG was found generally to offer a potential overall global GHG emissions savings. However, the assumption that LNG exported to China, or any other Asian destination, would result in a coal-fired power station being taken off-line and replaced by a gas-fired power station is problematic [9]. The International Energy Agency has recently suggested that while this type of direct displacement is likely in the USA, it is unlikely that LNG will displace coal in Asia. Rather LNG is more likely to add to overall capacity in an expanding energy market [48]. Using the base case estimates from this study, if CCGT combustion technology fueled by natural gas derived from conventional LNG displaced an old subcritical coal-fired power station, 0.58 t CO_2-e/MWh of emissions would be avoided (0.49 t CO_2-e for CSG/LNG). This represents the best average case for displacement by Australian LNG. If natural gas-fired OCGT displaced an ultra-supercritical coal plant, however, the savings would drop to 0.14 and 0.06 t CO_2-e/MWh for conventional and CSG derived LNG, respectively, again assuming base cases.

Currently, coal is relatively cheap compared to gas. However, renewables and nuclear power are more expensive than gas. Under current market conditions, therefore, displacement of renewables by imported LNG in China is also a possible scenario. If LNG-fired conventional OCGT technology were to displace wind or concentrated solar thermal power in China, an overall increase in emissions of 0.63 t CO_2-e/MWh would be experienced, rising to 0.71 t CO_2-e/MWh for CSG/LNG. If global GHG savings are to be claimed as a key driver for LNG development, detailed economic research and modelling should be undertaken to determine the markets and conditions under which real benefits are generated.

5. Conclusion

This analysis brings together the most recent data available from energy producers and studies available in the literature to produce an average comparison of the lifecycle GHG intensities per MWh of electricity sent out, for a range of Australian and other energy sources. When Australian fossil fuels are exported to China, lifecycle greenhouse gas emission intensity in electricity production depends to a significant degree on the technology used in combustion. In general, natural gas exported as LNG is less GHG intensive than black coal but the gap is smaller for OCGT plant and for CSG.

On average, conventional LNG burned in a conventional OCGT plant is approximately 38% less GHG intensive over its life cycle than black coal burned in a sub-critical plant, per MWh of electricity produced. However, if OCGT combustion is compared to the most efficient new ultra-supercritical coal-fired power, the gap narrows considerably. Coal seam gas LNG is approximately 13–20% more GHG intensive across its life cycle, on a like-for-like basis, than conventional LNG, and thus compares less favorably to coal than conventional LNG under all technology combinations. Upstream fugitive emissions from CSG in the Australian context were found to be uncertain because of a lack of data. Nevertheless, fugitive methane emissions are potentially manageable by applying best practice technologies.

In modelling the GHG emissions for a typical CSG-LNG development, it was assumed that between 1% and 20% of the flare stream gas was vented. Combined with the latest estimate for the 20-year GWP for methane, these vented emissions significantly added to the overall GHG footprint. However, the lifecycle GHG intensity rankings did not materially change, such is the dominance of end-use combustion. The exception to this is if the worst case scenario of 4.38% of all production is released as leaks and vented emissions (based on recent US studies). Here, the GHG intensity of electricity generation using CCGT technology based on CSG/LNG is approximately 1.07 t CO_2-e/MWh sent out, which is higher than ultra-supercritical and super-critical coal-fired generation technology, and nearly the same as sub-critical coal-fired generation when assessed with a 20-year methane GWP.

The implications for regulators and the emerging Australian CSG industry are that best practice applied to design, construction and operation of projects can significantly reduce emissions (particularly fugitives), lower financial liabilities under the carbon tax, and help make CSG a less GHG-intensive fuel option.

When exported for electricity production, LNG was found to be 22 to 36 times more GHG intensive than wind and concentrated solar thermal (CST) power and 13–21 times more GHG intensive than nuclear power. Transitioning the world's energy economy to a lower carbon future will require significant investment in a variety of cleaner technologies, including renewables and nuclear power. In the short term, improving the efficiency of fossil fuel combustion in energy generation can provide an important contribution.

Availability of life cycle GHG intensity data will allow decision-makers to move away from overly simplistic assertions about the relative merits of certain fuels, and focus on the complete picture, especially the critical roles of energy policy, technology selection and application of best practice.

References

1. IEA (International Energy Agency). *World Energy Outlook*; 2010; IEA: Paris, France, November 2010.
2. BP. *Statistical Review of World Energy*; 2010; BP: London, UK, 2011.
3. BP. *BP Energy Outlook*; 2010; BP: London, UK, 2011.
4. Hondo, H. Life cycle GHG emission analysis of power generation systems: Japanese case. *Energy* **2005**, *30*, 2024–2056.
5. Weisser, D. A guide to life cycle greenhouse gas (GHG) emissions for electricity supply technologies. *Energy* **2007**, *32*, 1543–1559.
6. Dones, R.; Heck, T.; Hirschberg, S. Greenhouse gas emissions for energy systems: Comparison and overview. *Energy* **2004**, 27–95.
7. Tamura, I.; Tanaka, T.; Kagajo, T.; Hwabara, S.; Yoshioka, T.; Nagata, T.; Kurahashi, K. Life cycle CO_2 analysis of LNG and city gas. *Appl. Energy* **2001**, *68*, 301–319.

8. WorleyParsons. *Greenhouse Gas Emissions Study of Australian LNG*. Available online: http://www.woodside.com.au/Our-Approach/Climate-Change/Pages/Benefits-of-LNG (accessed on 12 September 2011)
9. WorleyParsons. *Greenhouse Gas Emissions Study of Australian CSG to LNG*; Technical Report for the Association of Petroleum Producers and Explorers of Australia (APPEA); APPEA: Sydney, Australia, 2011.
10. *Coal Seam Gas and Greenhouse Emissions-Comparing the Lifecycle Emissions for CSG/LNG* vs. *Coal*; Technical Report for Citi Global Markets; Institute for Sustainable Futures: Sydney, Australia, 2011.
11. US EPA. *Global Anthropogenic Non-*CO_2 *Greenhouse Gas Emissions*: *1990–2020*; US Environmental Protection Agency: Washington, DC, USA, 2006.
12. Howarth, R.W.; Santoro, R.; Ingraffea, A. Methane and the greenhouse-gas footprint of natural gas from shale formations. *Clim. Change* **2011**, *106*, 679–690.
13. Lenzen, M. Life cycle energy and greenhouse gas emissions of nuclear energy: A review. *Energy Convers. Manag.* **2008**, *49*, 2178–2199.
14. Raadal, H.L.; Gagnon, L.; Modahl, I.S.; Hanssen, O.J. Life cycle greenhouse gas (GHG) emissions from the generation of wind and hydro power. *Renew. Sustain. Energy Rev.* **2011**, *15*, 3417–3422.
15. World Business Council for Sustainable Development and the World Resource Institute. *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard*; World Business Council for Sustainable Development and the World Resource Institute: Washington, DC, USA, 2004.
16. Australian Government, Department of Climate Change and Energy Efficiency. *The National Greenhouse and Energy Reporting (Measurement) Determination*; Commonwealth of Australia: Sydney, Australia, 2010.
17. American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*. Available online: http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf (accessed on 15 March 2009).
18. Australian Government, Department of Climate Change and Energy Efficiency. *National Greenhouse and Energy Reporting System Measurement Technical Guidelines*; Australian Government: Canberra, Australia, 2010.
19. Intergovernmental Panel on Climate Change. *IPCC Second Assessment, Climate Change*. Available online: http://www.ipcc.ch/pdf/climate-changes-1995/ipcc-2nd-assessment/2nd-assessment-en.pdf (accessed on 15 September 2011).
20. Intergovernmental Panel on Climate Change. *IPCC Fourth Assessment Report (AR4)*, 2007. Working Group 1, The Physical Science Basis. Available online: http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html. (accessed on 3 November 2011).
21. Shindell, D.T.; Faluvegi, G.; Koch, D.M.; Schmidt, G.A.; Unger, N.; Bauer, S.E. Improved attribution of climate forcing to emission. *Science* **2009**, *326*, 716–718.
22. Frischenknect, R.; Althaus, H.-J.; Bauer, C.; Doka, G.; Heck, T.; Jungbluth, N.; Kellenberger, D.; Nemecek, T. The environmental relevance of capital goods in life cycle assessments of products and services. *Int. J. LCA* **2007**, doi:http://dx.doi.org/10.1065/lca2007.02.308

23. Ulan Coal. Ulan Coal Continued Operations Project. *Energy and Greenhouse Assessment*. Available online: http://www.ulancoal.com.au/EN/OperatingApprovals/Volume%20Six/Appendix14.pdf (accessed on 3 November 2011).
24. Vale Australia. Ellensfield Coal Mine Project, Environmental Impact Statement. *Greenhouse Gas Assessment*. Available online: http://www.ap.urscorp.com/Projects/EllensfieldEIS/_pdf/Appendix_I2_Greenhouse_Gas_Assessment.pdf (accessed on 3 November 2011).
25. WACJV. Wallarah 2 Coal Project. *Air Quality Assessment*. Available online: http://www.wallarah.com.au/air.html (accessed on 3 November 2011).
26. Xstrata Coal, Cumnock No 1 Pty. Cumnock Colliery, Environmental Impact Statement. *Greenhouse Gas and Energy Assessment*. Available online: http://www.xstrataravensworth.com.au/EN/Publications/EAs/Cumnock_WPP_EA_Main_text_DA_123–05–01_M1.pdf (accessed on 3 November 2011).
27. New Hope Coal. New Acland Stage 3 Expansion, Environmental Impact Statement, Chapter 10. *Greenhouse gases and Climate Change*. Available online: http://www.newhopecoal.com.au/media/6181/chapter10greenhousegasesfinaldone.pdf (accessed on 3 November 2011).
28. Heede, R. LNG Supply Chain Greenhouse Gas Emissions for the Cabrillo Deepwater Port: Natural Gas from Australia to California, Climate Mitigation Services. Available online: http://www.edcnet.org/pdf/Heede_06_LNG_GHG_Anlys.pdf (accessed on 3 November 2011).
29. Barnett, P.J. *Life Cycle Assessment of Liquefied Natural Gas and Its Environmental Impact as a Low Carbon Energy Source*; University of Southern Queensland: Queensland, Australia, 2010. Available online: http://eprints.usq.edu.au/18409/1/Barnett_2010.pdf (accessed on 3 November 2011).
30. Pace Global Energy Services. *Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results.* Available online: http://www.lngfacts.org/resources/LCA_Assumptions_LNG_and_Coal_Feb09.pdf (accessed on 3 November 2011).
31. Jaramillo, P. A Life Cycle Comparison of Coal and Natural Gas for Electricity, Generation and the Production of Transportation Fuels. Ph.D. Thesis, Carnegie Mellon University, Pittsburgh, PA, USA, May 2008. Available online: http://wpweb2.tepper.cmu.edu/ceic/theses/Paulina_Jaramillo_PhD_Thesis.pdf (accessed on 3 November 2011).
32. Arrow Energy Limited. Environmental Management Plan for Authority to Prospect 683, May 2010. Available online: http://www.arrowenergy.com.au/icms_docs/72619_EM_Plan_ATP_683.pdf (accessed on 3 November 2011).
33. Queensland Government, Department of Employment, Economic Development and Innovation. Coal Seam Gas Well Head Safety Program—Final Report, 2011. Available online: http://mines.industry.qld.gov.au/assets/petroleum-pdf/Coal-Seam-Gas-Well-Head-Safety-Program-Inspection-Report-2011.pdf (accessed on 3 November 2011).
34. IEA. *World Energy Outlook 2011*, *The Golden Age of Gas*; International Energy Agency: Paris, France, 2011.
35. Harrison, M.R.; Shires, T.M.; Wessels, J.K.; Cowgill, R.M. *Methane Emissions from the Natural Gas Industry*; Technical Report for Environmental Protection Agency; USEPA: Washington, DC, USA, 1996.

36. Australia Pacific LNG. Environmental Impact Statement, 2010. Available online: http://www.aplng.com.au/our-eis (accessed on 3 November 2011).
37. Queensland Curtis LNG Project Draft and Supplementary EIS, 2010. Available online: http://www.qgc.com.au/01_cms/details.asp?ID=427 (accessed on 3 November 2011).
38. GLNG. GLNG Project Environmental Impact Statement. Available online: http://www.glng.com.au/Content.aspx?p=90 (accessed on 29 February 2011).
39. Jiang, M.; Griffin, W.M.; Hendrickson, C.; Jaramillo, P.; van Briesen, J.; Venkatesh, A. Life cycle greenhouse gas emissions of Marcellus shale gas. *Environ. Res. Lett.* **2011**, *6*, doi:10.1088/1748-9326/6/3/034014.
40. National Energy Technology Laboratory (NETL). Life cycle Greenhouse Gas Analysis of Natural Gas Extraction and Delivery in the United States. Available online: http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=386) accessed on 29 February 2011).
41. Howarth, R.W.; Santoro, R.; Ingraffea, A. Venting and leaking of methane from shale gas development: response to Cathles. *Clim. Change* 2012, DOI 10.1007/s10584–012–0401–0.
42. *US EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009*; U.S. Environmental Protection Agency: Washington, DC, USA, April 2011. Available online: http://epa.gov/climatechange/emissions/usinventoryreport.html (accessed on 13 September 2011)
43. Pétron, G.; Frost, G.; Miller, B.R.; Hirsch, A.I.; Montzka, S.A.; Karion, A.; Trainer, M.; Sweeney, C.; Andrews, A.E.; Miller, L.; Kofler, J.; Bar-Ilan, A.; Dlugokencky, E.J.; Patrick, L.; Moore, J.C.T.; Ryerson, T.B.; Siso, C.; Kolodzey, W.; Lang, P.M.; Conway, T.; Novelli, P.; Masarie, K.; Hall, B.; Guenther, D.; Kitzis, D.; Miller, J.; Welsh, D.; Wolfe, D.; Neff, W.; Tans, P. Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study. *J. Geophys. Res.* **2012**, *117*, doi:10.1029/2011JD016360.
44. GAO. Federal oil and gas leases: opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases. GAO-11-34 U.S. General Accountability Office: Washington, DC, USA, October 2010. Available online: http://www.gao.gov/new.items/d1134.pdf (accessed on 13 September 2011)
45. Osborn, S.T.; Vengosh, A.; Warner, N.R.; Jackson, R.B. Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. *Proc. Natl. Acad. Sci. USA* **2011**, *108*, 8172–8176.
46. Varun, I.K.B.; Prakash, R. LCA of renewable energy for electricity generation systems—A review. *Renew. Sustain. Energy Rev*. **2009**, *13*, 1067–1073.
47. Norgate, T.; Haque, N.; Koltun, P.; Tharumarajah, R. Environmental sustainability of nuclear power: Greenhouse gas status. In *Proceedings of Presentation of Study Results to AusIMM International Uranium Conference*, Perth, Australia, June 8–9 2011.
48. IEA. *World Energy Outlook 2011*; International Energy Agency: Paris, France, 2011.