The Australia Pacific LNG Project

Volume 4: LNG Facility

Chapter 14: Greenhouse Gases

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14. Greenhouse gases

14.1 Introduction

This chapter presents the key results of the technical report on the greenhouse gas (GHG) emissions assessment for the Project's liquefied natural gas (LNG) facility provided in Volume 5 Attachment 31. The technical report provides details of assumptions made, the GHG estimations performed and the GHG emissions projections for the LNG facility during construction, operations and decommissioning phases.

This chapter addresses the requirements outlined in the terms of reference for the Project's environmental impact statement (EIS). Specifically, this chapter:

- Quantifies the GHG emissions associated with the construction, operation and decommissioning of the project LNG facility
- Describes the methods by which GHG estimates were made
- Assesses immediate and potential mitigation GHG mitigation measures

This chapter outlines the scope of work and the GHG assessment boundary, followed by a brief overview of the GHG related legislative frameworks. This chapter then discusses the methodology used to quantify the GHG emissions, the sources of GHG emissions and the GHG emission projections. Subsequently, the potential impacts of the Project stemming from LNG facility GHG emissions are quantified and discussed.

This chapter identifies measures to minimise the Project GHG emissions from the LNG facility by addressing the major sources of GHG emissions within the appropriate boundary, and the immediate and potential mitigation steps to alleviate the impact are discussed. The mitigation actions are guided by Australia Pacific LNG's sustainability objectives.

A lifecycle GHG analysis was also performed that compares the GHG emissions associated with the combustion of LNG against that for coal and other fuels. The analysis estimates the GHG emissions that could be avoided by substituting GHG intensive fuels such as coal with natural gas derived from LNG. Finally, Australia Pacific LNG's future commitments to minimise the GHG emissions from the LNG facility are presented.

14.1.1 The Project

Natural gas is an abundant and low-polluting fuel; it plays a critical role in maintaining global energy security while the world phases out GHG intensive energy sources. For example, the Intergovernmental Panel on Climate Change (IPCC) has highlighted the importance of switching from coal based energy sources to natural gas based energy sources as an important GHG mitigation measure (IPCC 2001). Here, Australia Pacific LNG proposes to supply LNG as a low carbon transition fuel into the global energy market. LNG provides a less GHG intensive alternative to coal and other fossil fuels in the intermediate term, and is expected to be an invaluable companion to renewable energy sources in the future.

The LNG is produced by (1) extracting and processing coal seam gas (CSG) from Australia Pacific LNG's gas fields, (2) transporting the CSG to Australia Pacific LNG's LNG facility via a gas pipeline, and (3) converting the CSG into LNG for transport to the international energy market at the Project's LNG facility. The CSG is contained in reserves located in the Surat and Bowen basins (specifically, the Walloons Gas Fields Development area), is relatively abundant, and originates from a stable country with relatively small domestic energy needs. The Project thus has the added benefit of supplying a secure source of energy to meet international energy needs.

The Walloons gas fields will cover an area of approximately 570,000ha in Queensland's Darling Downs region. Australia Pacific LNG's development plan will include the drilling of approximately 10,000 wells over the Project's 30 year lifespan. Gas and water gathering systems will be developed to connect gas wells to gas processing facilities (GPFs) and water treatment facilities (WTFs). Associated infrastructure will include roads and access tracks, storage ponds, temporary accommodation facilities, communication infrastructures and other logistics support areas. A 450km underground gas pipeline will connect the gas fields with the LNG facility on Curtis Island.

Under the full development scenario, the LNG plant comprises four LNG trains with the capacity to produce and ship approximately 18 million tonnes per annum (Mtpa) of LNG. The associated wharf and material offloading facilities are to be located near Laird Point within the Curtis Island Industry Precinct of the Gladstone State Development Area. The LNG plant will utilise ConocoPhillips' Optimized Cascade® process for the CSG to LNG process.

14.1.2 Purpose

The purpose of this chapter is to describe the GHG emissions that are expected to arise from the LNG facility during the construction, commissioning, operations and decommissioning phases of the Project.

Of Australia Pacific LNG's 12 sustainability principles, key principles in relation to GHG emissions for the LNG facility are:

- Minimising adverse environmental impacts and enhancing environmental benefits associated with Australia Pacific LNG's activities, products or services; conserving, protecting, and enhancing where the opportunity exists, the biodiversity values and water resources in its operational areas
- Reducing the greenhouse gas intensity through the development of an energy source less carbon intensive than the world average for the majority of fuel providers for power generation; and implementing a greenhouse gas mitigation strategy for its operations to continuously seek opportunities to further reduce greenhouse gas emissions
- Identifying, assessing, managing, monitoring and reviewing risks to Australia Pacific LNG's workforce, its property, the environment and the communities affected by its activities.

Under these principles, the GHG emissions inventory is developed and the GHG mitigation measures assessed and quantified. Future GHG mitigation measures are also identified based on these sustainability principles.

14.1.3 Scope of work

The scope of work to assess GHG impacts associated with the LNG facility covers:

- Assessing the scope 1 (direct combustion) GHG emissions and relevant scope 3 (indirect) GHG emissions that are projected to arise from constructing, operating and decommissioning the LNG facility
- Assessing the GHG emissions that would arise from land clearing for the LNG facility
- Assessing the GHG mitigation measures included at the design phase of the Project

- Describing the GHG mitigation opportunities that may be suitable for future implementation.

Scope 1 GHG emissions arise from the direct combustion of fuels – in this case, diesel and CSG. Diesel is combusted in transportation and power-generation activities associated with the LNG facility. CSG is combusted in powering refrigeration and power generation turbines.

Scope 2 GHG emissions are primarily associated with imported electrical power. These GHG emissions are negligible because the activities occurring on Curtis Island are not connected to the Gladstone grid, and the LNG facility will not be importing power. In addition, the mainland facilities will only use a very small amount of power from the grid. Scope 2 GHG emissions are therefore estimated to be negligible and are not reported here. Given that the LNG facility will be powered by CSG, these GHG emissions are included as scope 1 GHG emissions in the GHG inventory.

Scope 3 GHG emissions cover the indirect GHG emissions that arise from Project activities. For example, diesel consumption is associated with both scope 1 and scope 3 GHG emissions. Scope 1 GHG emissions arise from the combustion of the fuel for transport and power generation. Scope 3 GHG emissions arise from the extraction, production and transportation of the diesel to the Project site.

This chapter also assesses the GHG mitigation measures that have been included at the design phase of the Project, and describes the GHG mitigation opportunities that may be suitable for future implementation but which are still being investigated.

Figure 14.1 gives an overview of how the various GHG emissions inventories that will be developed in this EIS sit within the overall Project GHG footprint. For the Project, three GHG emissions inventories are reported:

- A gas fields GHG inventory (refer Volume 2 Chapter 14)
- A gas pipeline GHG inventory (refer Volume 3 Chapter 14)
- An LNG facility GHG inventory (the subject of this chapter).

The GHG emissions from all relevant sources (and scopes) will be assessed for each inventory, and the impact of these GHG emissions is determined.

In order to compare LNG to other fuels, the overall GHG footprint associated with converting CSG to LNG, and consumption of the LNG, is used. To determine this footprint, sources of GHG emissions that are beyond Australia Pacific LNG's control but nonetheless contribute to the overall footprint are considered. In Figure 14.1 these sources include GHG emissions from other gas fields that supply CSG to the Project and GHG emissions associated with combusting natural gas by the final consumer. LNG shipping is assessed briefly in this study as a scope 3 GHG emission source for the LNG facility, These sources of GHGs are not assessed in detail in this EIS but they are included in relation to a lifecycle GHG emissions analysis for CSG to LNG, presented in Section 14.5.2.

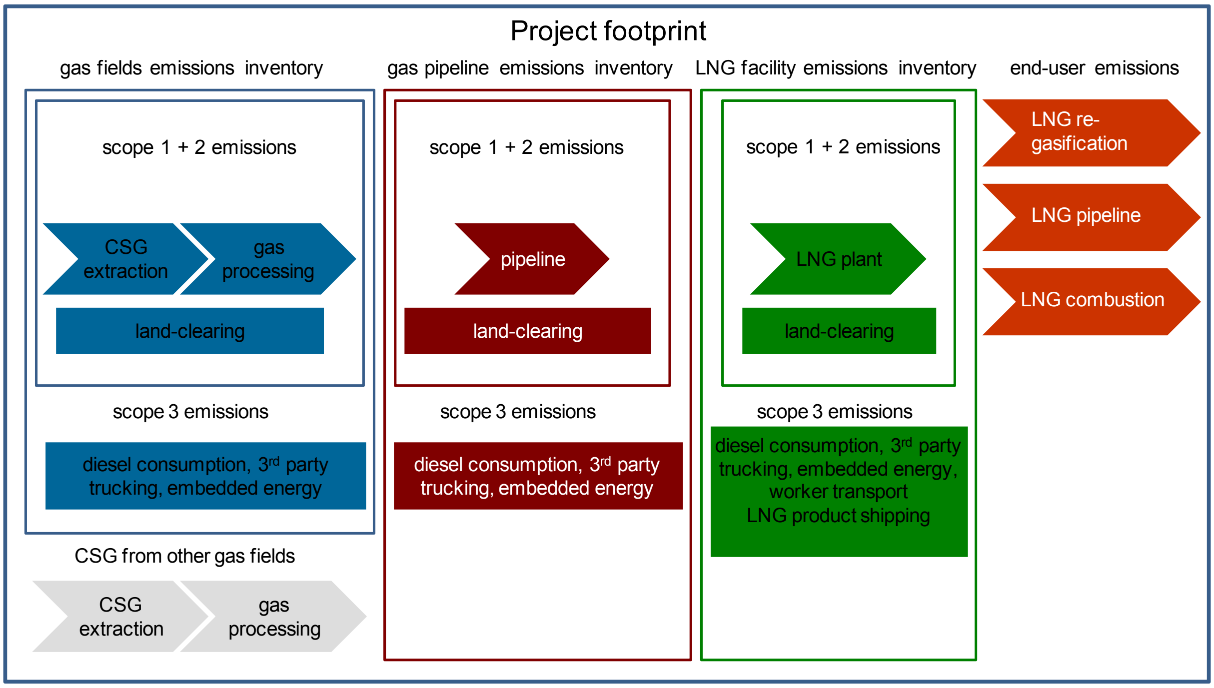

Figure 14.1 Overview of the Project's GHG footprint

14.1.4 Legislative framework

GHG emissions are covered by a number of legislative and policy requirements at both a State and Federal level, as well as international protocols to which Australia is signatory. These include:

- United Nations Framework Convention on Climate Change
- Kyoto Protocol, to which Australia is a signatory
- *Energy Efficiency Opportunities Act 2006*
- *National Greenhouse and Energy Reporting Act 2007*
- Queensland Greenhouse Strategy.

International policy

The Kyoto Protocol to the United Nations Framework Convention on Climate Change was signed in 1997 and ratified by Australia in December 2007. One of the aims of the Kyoto Protocol is to achieve the stabilisation of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system.

The Kyoto Protocol sets reduction targets on GHG emissions produced by Annex 1 countries, including Australia. Under the Kyoto Protocol, Australia has committed to reducing its GHG emissions to a level equivalent to 108% of 1990 levels by 2008–2012. For GHG emission reduction targets for the period beyond 2012, international negotiations remain in progress post the Copenhagen conference of parties.

Australian policy

The Australian Government's proposed carbon pollution reduction scheme (CPRS) is an emissions trading scheme in which GHG emissions would be capped, permits would be allocated up to the cap, and emissions permits would be traded. Liable entities would be required to obtain carbon pollution permits to acquit their GHG emissions liabilities. The CPRS is the Australian Government's central policy instrument for reducing the GHG emissions Australia produces. The Australian Government intends that the CPRS commences on 1 July 2011 however this is dependent on the passage of a number of Bills (Australian Government 2009) through the Senate.

The CPRS intends to encourage industry to reduce GHG emissions. The scheme will include a long-term GHG reduction target of 60% of 2000 levels by 2050 (Australian Government 2008). If the CPRS Bills are passed, the legislation may be different to what is proposed in the current CPRS Bills.

The Australian Government has set the following medium term 2020 GHG emission reduction target:

- An unconditional target of a 5% reduction below 2000 levels by 2020
- An conditional target of up to 15% reduction below 2000 levels by 2020 in the context of a global agreement under which all major developing economies commit to substantially restrain emissions and advanced economies take on reductions comparable to Australia or
- A conditional target of 25% reduction below 2000 levels by 2020 if Australia is a party to a comprehensive agreement which is capable of stabilising atmospheric concentrations of GHG at around 450 parts per million of CO_2-e or lower (Australian Government 2008; Department of Climate Change (DCC) 2009c).

The proposed CPRS includes measures designed to reduce the immediate impact of the price of carbon on emission intensive trade exposed (EITE) industries. LNG production has been identified as an EITE industry; consequently, the assistance is directly relevant to the Project. The initial assistance depends on the GHG emissions intensity per million dollars of revenue. The GHG emissions intensity of the LNG industry is between 1,000-2,000t CO_2-e/$m revenue [$CO_2$ equivalent emissions per million dollars of revenue] (Petroleum Exporters Society of Australia 2009), suggesting assistance would cover 66% of GHG emissions.

Energy Efficiency Opportunities Act

The *Energy Efficiency Opportunities Act 2006* was introduced by the Department of Resources, Energy and Tourism (DRET). It requires significant energy users, consuming over 0.5PJpa of energy, to take part in a transparent process of energy efficiency assessment and reporting.

The program's requirements are set out in the legislation, which came into effect on 1 July 2006. Participants in the program are required to assess their energy use and report publicly on cost effective opportunities to improve energy efficiency. In particular, corporations must report publicly on opportunities with a financial payback period of less than four years. Australia Pacific LNG joint venture partners Origin Energy and ConocoPhillips have been reporting under the energy efficiencies opportunities scheme since 2006 and 2007 respectively, so both partners in Australia Pacific LNG are familiar with the scheme's requirements.

National Greenhouse and Energy Reporting Act

The *National Greenhouse and Energy Reporting Act 2007* (NGER Act) establishes a national framework for Australian corporations to report GHG emissions, and energy consumed and produced from 1 July 2008. The NGER Act and supporting systems have been designed to provide a robust database for the proposed CPRS.

From 1 July 2008, corporations are required to report if they:

- Control facilities that emit 25Kt or more of GHG CO_2-e, or produce or consume 100 terajoules or more of energy or
- Their corporate group emits 125Kt CO_2-e, or produces or consumes 500 terajoules or more of energy.

Lower thresholds for corporate groups will be phased in by 2010-11. The final thresholds will be 50Kt CO_2-e or 200 terajoules of energy produced or consumed for a corporate group. Companies must register by 31 August and report by 31 October following the financial year in which they meet a threshold. A report must be submitted every year once registered even in those years where the threshold is not triggered. Origin and ConocoPhillips have both recently made their first reports under the *National Greenhouse and Energy Reporting Act 2007*, and so both partners in Australia Pacific LNG are familiar with the Act's requirements.

Queensland policy and initiatives

The Queensland Government's ClimateSmart 2050 strategy (2007) outlines key long-term climate change targets. The Queensland Government has agreed to the national target of achieving a 60% reduction in national GHG emissions by 2050, compared with 2000 levels. This will involve cuts in GHG emissions of more than 30Mt CO2-e over 10 years and save the Queensland economy about $80 million each year (Queensland Government 2007).

To help achieve this target, the Queensland Government has developed the Queensland gas scheme, where Queensland electricity retailers and large users of electricity are required to source at least 13% of their electricity from gas-fired generators.

The gas scheme is aimed at reducing Queensland's emission intensity from 0.917t CO_2-e/MWh (2000-2001 levels) to 0.794t CO_2-e/MWh by 2011-2012. The 13% target under this scheme has been increased to 15% by 2010 with the provision to increase it to 18% by 2020.

In 2008 the Queensland Government commenced a review of Queensland's climate change strategies in response to national and international developments in climate change science and policy. In August 2009, the Queensland Government released ClimateQ: toward a greener Queensland.

This strategy consolidates and updates the policy approach outlined in ClimateSmart 2050 and Queensland's ClimateSmart Adaptation Plan 2007-12. The revised strategy presents investments and policies to ensure Queensland remains at the forefront of the national climate change response (Queensland Government 2009).

Australia Pacific LNG policy and position on climate change

Australia Pacific LNG recognises that climate change poses significant risks and opportunities to its business. Australia Pacific LNG will be pro-active in building a business that will be well positioned in a low carbon economy. Origin's and ConocoPhillips' established corporate strategies on climate change will underpin Australia Pacific LNG's response to the challenges of climate change.

Origin has long recognised the need to address the global issues of climate change and has built a business that is well positioned in a more carbon constrained regulatory, social and investment environment. Origin has a strong portfolio of natural gas reserves in Australia and New Zealand and invests in renewable energy sources including wind, solar and geothermal. Origin has developed a series of retail offerings, such as GreenPower, to encourage customer participation in GHG reductions.

Origin has engaged strongly in the development of government policy in relation to mitigating GHG emissions and reducing the impacts of climate change. This includes contributions to the Garnaut Review (Garnaut 2008), the CPRS and other government processes, and participation in the media and public debate. Origin has also taken significant measures to understand and reduce its carbon footprint.

ConocoPhillips fully supports mandatory national frameworks to address GHG emissions. It has joined the United States Climate Action Partnership, a business environmental leadership group dedicated to the quick enactment of strong legislation to require significant reductions of GHG emissions.

With operations around the globe ConocoPhillips seeks to encourage external policy measures at the international level that deliver the following principles:

- Slow, stop and ultimately reverse the rate of growth in global GHG emissions
- Establish a value for carbon emissions, which is transparent and relatively stable and sufficient to drive the changed behaviours necessary to achieve targeted emissions reductions
- Develop and deploy innovative technology to help avoid or mitigate GHG emissions at all stages of the product's life
- Ensure energy efficiency is implemented at all stages of the product's life
- Recognise consumer preference for reduced GHG-intensive consumption, and work towards meeting these expectations
- Deploy carbon capture and storage as a practical near term solution if technically and economically feasible
- Develop processes that are less energy and material intensive
- Build price of carbon into base case business evaluations
- Ensure energy and materials efficiency is part of the project development/value improvement processes.

The Project will use the commitment and technical strengths of both of its joint venture partners to develop and implement a GHG management plan that includes GHG mitigation measures, monitoring, reporting, and assessment of business specific actions.

14.2 Methodology

The GHG inventory for the LNG facility is based on the accounting and reporting principles of the GHG protocol (the Protocol) (World Business Council for Sustainable Development and the World Resource Institute 2004) and various GHG estimation methodologies. The Protocol is an internationally accepted accounting and reporting standard for corporate GHG emissions. The methodology in the Protocol is consistent with the methodology in the National Greenhouse Accounts Factors (DCC 2009a).

14.2.1 GHG accounting and reporting principles

The guiding principles of the Protocol for compiling an inventory of GHG data are relevance, completeness, consistency, transparency and accuracy. The Protocol separates GHG producing activities according to the related scope:

- Scope 1 GHG emissions are produced directly from combustion, fugitive and vented sources that are within the Project boundary
- Scope 2 GHG emissions arise from generating purchased electricity, heat and steam. This energy is generated outside of the LNG facility's boundary and is transmitted to the site
- Scope 3 GHG emissions refer to emissions related to the activities of the Project but arising outside the reporting boundary. For example, transport of liquefied natural gas to international markets and transport of materials, equipment and consumables to the project site. Scope 3 GHG emissions are also associated with the extraction, production and transportation of imported fuels consumed for project activities.

Scope 1 GHG emissions

The method for estimating scope 1 GHG emissions is to estimate each activity's annual data, such as volumes of CSG and diesel consumed, and fugitive gas releases. This data is then multiplied by the appropriate GHG emissions factor (refer Table 14.1) to convert the activity data into a GHG emission in units of tonnes CO_2-e. For the power generation and refrigeration turbines, vendor GHG emissions data were used.

Table 14.1 Default GHG emissions factors

	GHG emission factors			Unit	Source of emission factor
Source	**CO_2**	**CH_4**	**N_2O**		
Flare operation	2.8	0.14	0.03	tonnes/tonnes production	API compendium table 4.7
Hot oil heater	50.6	0.02	0.3	kg CO_2-e/GJ	AP 42 Table 1.4-2
Diesel engine emissions (>600HP)	70.9	0.07	0.06	kg CO_2-e/GJ	AP 42 Table 3.3.1; table 3.4-1 for CO_2 and CH_4 API compendium table-C10 for N_2O
Diesel engine emissions (<600HP)	70.9	0.07	0.3	kg CO_2-e/GJ	AP 42 table 3.3.1; table 3.4-1 for CO_2 and CH_4 API compendium table-C10 for N_2O
Fugitive CSG emissions	Refer table B11 of the API compendium				

Scope 2 GHG emissions

The assumption for this study is that no grid electricity will be purchased for activities on Curtis Island and that electricity for onsite construction and operations will be generated by gas turbines that use CSG or by diesel generators. Although there will be a small support facility on the mainland the LNG facility's power consumption and associated scope 2 GHG emissions will be negligible.

Scope 3 GHG emissions

For scope 3 GHG emissions, such as those for materials transported from sources that are beyond the Project's boundary the methodology is the same as that used for scope 1 GHG emissions. For trucking GHG emissions the total number of kilometres travelled by a vehicle is multiplied by the fuel efficiency of the vehicle. This will yield the volume of fuels consumed by each form of transport. The quantity of fuel is multiplied by the energy content of the fuel and the GHG emissions factor as for scope 1 GHG emissions.

For purchased fuels for use in onsite transport or diesel generators there are scope 3 GHG emissions associated with the extraction, production and transport of the fuels. To account for these GHG emissions the energy content and the scope 3 GHG emissions factor for diesel are used (refer Table 14.2).

Table 14.2 Default GHG emissions factors used to estimate scope 3 GHG emissions

Fuel combusted	Scope 1 emission factor kg CO2-e/GJ	Scope 3 emission factor kg CO2-e/GJ	Energy content GJ/kL
Diesel emissions (transport)	69.9	5.3	38.6
Petrol emissions (transport)	67.4	5.3	34.2
Fuel oil emissions (transport)	73.6	5.3	39.7
Diesel emissions (stationary)	69.5	5.3	38.6

The scope of the GHG assessment is to estimate an annual and a project lifetime inventory of GHG emissions for the LNG facility. This is restricted to the construction, operations and subsequent decommissioning of the LNG facility. GHG emissions due to LNG shipping is not within Australia Pacific LNG's organisational boundary and is considered as a scope 3 GHG emissions. Combustion of LNG is considered to be part of the end user's GHG emissions inventory.

Listed in the following sections are the sources of GHG emissions from the Project's construction, operations and subsequent decommissioning phases.

14.2.2 GHG emissions from construction and decommissioning

Construction activities are assumed to cover excavation, equipment hauling, and civil works such as land clearing which are scope 1 GHG emissions for the Project. Relevant scope 3 GHG emissions arise from worker transport, shipment of materials and equipment to the project site, embedded energy in construction materials, waste sent to landfill.

Various types of construction equipment will be used from the inception of site works until start-up and commissioning of the LNG facility. Construction will occur for a period of approximately four years and nine months for trains 1 and 2 in years 2011 to 2015. Construction of trains 3 and 4 is assumed to begin in 2017 and also last for four years and nine months. This will incur around 30% less GHG emissions because much of the common infrastructure will be in place when construction of trains 3 and 4 commence.

Decommissioning refers to site closure and removal of buildings and infrastructure. Decommissioning GHG emissions are scope 1 GHG emissions. However, due to uncertainties about the activities, these have not been estimated in detail. They are assumed to be the same as the construction phase GHG emissions as similar equipment and activities will be required.

Diesel and gasoline combustion for on-site transport and earth moving

Scope 1 GHG emissions will arise from the direct combustion of diesel by on-site transport associated with equipment hauling. A combination of diesel and petrol fuelled vehicles will be used for on-site personnel transport.

Diesel is expected to be consumed by excavation and earth moving machinery.

Scope 3 GHG emissions are associated with diesel and gasoline combustion which result from extraction, production and transportation of these fuels to the Project site.

Diesel combustion for power generation

The primary fuel used for stationary energy generation purposes will be diesel; generators are likely to operate intermittently during operations and full time during construction. This source is considered minimal when compared to other GHG sources.

Land clearing

The recent EIS for the Gladstone LNG project includes an assessment of GHGs from land clearing (GLNG 2009a). Gladstone LNG determined an emission factor for the GHGs associated with land clearing on Curtis Island to range between 96 and 159t CO_2-e/hectare cleared. So, for the purposes of this assessment, a conservative figure of 200t CO_2-e/hectare cleared is used.

The same emission factor has been assumed for this study as the type of vegetation cleared for the Australia Pacific LNG facility is assumed to be the same as that cleared for Gladstone LNG's LNG facility given the close proximity of the facilities.

To determine the GHGs from land clearing the land clearance in hectares is multiplied by the assumed emission factor. Land clearance data can be found in Volume 4 Chapter 8.

Fuel combustion for transport of materials and equipment

Scope 3 GHG emissions arise from third party trucking from off-site locations to the Project site. It is expected that diesel will be the primary fuel combusted by truck transport. Fuel oil will be consumed by barge in transporting equipment and machinery from Auckland Point to Laird Point.

Transport of materials and equipment by truck over the construction phases have been studied in Volume 4 Chapter 17. GHG emissions estimates are based on this data.

Fuel combustion for transport of workers

Scope 3 GHG emissions will arise from commuters using petrol vehicles to drive from the surrounding area to Auckland Point. Fuel oil will be consumed by ferry in transporting workers from Auckland Point to Laird Point.

Transport of workers by car and ferry over the construction phases have been studied in Volume 4 Chapter 17. GHG emissions estimates are based on this data.

Fuel combustion for shipping of materials and equipment

Scope 3 GHG emissions arise from the shipping of materials and equipment from overseas ports to the project site. Ships are expected to consume fuel oil.

Materials such as pipe lengths (imported from Asia), electrical items, insulation, fuels, concrete, and steel are considered as part of this chapter. Most of these materials and equipment will be trucked from Brisbane to Auckland Point, and then transported by barge to Laird Point. The steel pipe sections will be delivered direct by ship from Asia to the material offloading facility on Curtis Island. Structural steel may be shipped from China and other South East Asian countries.

Modular units for the LNG facility infrastructure will most likely be shipped from the Philippines and Thailand to the material offloading facility on Curtis Island. Materials used in the modular units will be shipped to the Philippines and Thailand for assembly, from ports that include the USA, Europe, the Far East, India and Turkey.

Embedded energy related emissions

To estimate the scope 3 GHG emissions associated with the embedded energy in construction materials, the tonnes of steel, concrete, insulation and copper cable were obtained for the construction of four trains. To determine the associated GHG emissions, the tonnes of materials were multiplied by the embedded emission factors (kg CO_2-e/kg) from Hammond and Jones (2008). These factors do not include transport of the materials.

Waste disposal

Scope 3 GHG emissions arise from waste sent to landfill. Waste will be generated during the construction phase of the Project. This waste is being exported to an offsite landfill waste facility, so the direct GHG emissions generated are the responsibility of the waste facility owner.

Waste from construction materials and site personnel are included in this assessment. The waste streams include general construction and decommissioning waste, food and domestic waste, paper, plastics, glass, and metals.

14.2.3 Operations

Normal operations refer to the day-to-day running of the plant to produce LNG. These production processes will operate on a continual basis and include stationary emission sources that combust CSG, and liquefy and refrigerate CSG. Because these activities emit methane or its combustion products and impurities directly to the atmosphere, these activities are classified as scope 1 GHG emissions.

CSG combustion for power generation and gas processing

Scope 1 GHG emissions arise from the combustion of CSG consumed by the various power generation and liquefaction equipment.

A total of 24 GE LM2500+G4 gas turbines are required to drive the compressors for the operation of four-trains (i.e. six for each train). These turbines are powered by CSG and are used to drive the ConocoPhillips' Optimized Cascade® process to refrigerate and liquefy the CSG. Because of the energy intensive nature of the gas compression/refrigeration process, it is expected to be the largest source of GHG emissions for the LNG facility.

The number, type and rating of gas turbines for power generation depends on the optimisation of power requirements, turbine operating conditions, project phasing, reliability, GHG emissions and capital/operating costs. While the optimisation process is ongoing, the current base case (used for this GHG assessment) is that 12 (+ 1 spare) Solar Titan 130 power generator sets, rated at 15MW are required for generating power for the four-train operations. These turbines are fuelled by CSG. Alternative designs including the increase of the number of turbines to 14 are currently being considered during the front end engineering design phase of the Project.

For the LM2500+G4 gas turbines and Titan-130 turbines, data on the carbon dioxide and methane emissions were supplied by the vendor.

Although the primary heat source is waste heat recovered from the process drive exhausts, hot oil heaters are used to support the heating requirements of a number of process streams. These supplementary heaters are primarily for start-up purposes, but to achieve this function the heaters must be kept running at low rates and hot at all times. This results in scope 1 GHG emissions due to CSG combustion.

Diesel consumption is used intermittently for pumping water and back-up power generation and other general support, emergency and back-up services.

Gas venting

Scope 1 GHG emissions arise from the venting of the various process gases. Each train is assumed to have an acid gas removal unit (AGRU) which uses an amine to reduce the carbon dioxide concentration in the CSG to a low level, thus preventing blockages due to frozen carbon dioxide further in the LNG process. The carbon dioxide is absorbed into the amine, and the amine solution is regenerated with the carbon dioxide sent to an acid gas vent. Carbon dioxide is thus vented directly to the atmosphere.

The nitrogen rejection unit removes nitrogen impurity from the feed gas. When this nitrogen is removed, oxidised and vented, small quantities of CO_2 are released to the atmosphere.

Fugitive gas emissions

Scope 1 GHG emissions arise from the fugitive releases of methane from valves, flanges, seals and connectors are associated with processing the CSG. Surveys undertaken by ConocoPhillips at its Darwin LNG facility have demonstrated that fugitive GHG emissions from a modern LNG facility are very small, as shown in Section 14.4.

It should be noted that no fugitive GHG emissions are predicted to arise from the LNG storage tanks or from the ship loading systems. The combined vapours from the LNG tanks and the ship loading systems are compressed by the boil-off gas compressors and returned to the refrigeration system, or flared.

Flaring emissions

Scope 1 GHG emissions arise from the flaring of the various process gases. To deal with process upsets, outside of the predicted normal parameters, some flaring of waste CSG or LNG may be required where this cannot be captured or retained within the process. These upsets are usually relatively short in duration. The sources of GHGs associated with flaring that have been assessed include:

- Marine flare, which is located near the LNG ship loading area. It handles surplus LNG vapours during the loading of LNG onto the ship that cannot otherwise be recycled into the process. This flare operates only under upset conditions when the boil-off gas compressors are not functional, or the capacity is exceeded. During ship loading, flaring is not normally expected as the boil-off gas will either be reliquefied into the storage tanks, returned to the process or utilised as fuel gas for power generation. Occasionally a hot ship may be required to be cooled down prior to accepting LNG. This activity can result in flaring but this is not a normal occurrence
- Dry gas flare, which combusts liquid and vapour cryogenic hydrocarbons, releasing carbon dioxide and small quantities of methane
- Wet gas flare, which combusts warm hydrocarbon streams, releasing carbon dioxide and small quantities of methane.

Diesel combustion for power generation

Diesel will be consumed for back-up power generation and other general support, emergency and back-up services.

Transport of employees and materials and equipment

Scope 3 GHG emissions arise from the transport of consumables such as refrigerant materials, diesel, chemicals and other miscellaneous materials throughout the Project lifetime. Diesel fuelled trucks are expected to transport these goods to and from the Project site.

Scope 3 GHG emissions also arise from worker transport. It is expected that all workers will commute from the Gladstone area by private car to Auckland Point, where a ferry will transport them to Curtis Island. The assumption that each worker will commute by car is considered conservative as buses may be used. If so, this would reduce the emissions on a per person basis. However, bus transport for workers has not been assessed. Traffic movements due to worker transport are covered in detail in Volume 4 Chapter 17.

The general approach used to estimate the GHG emissions was to estimate the quantity of fuel consumed by each form of transport using the distances travelled and vehicle fuel efficiencies. From the quantity of fuel consumed, the emissions can be estimated using the emission factors in Table 14.2.

Transport of liquefied natural gas

Scope 3 GHG emissions arise from shipping the product LNG. It is expected that the product will be shipped to Japan. The GHG emissions estimate includes the ship's return journey from Japan to Curtis Island. The ship is assumed to have a capacity of 142,000m^3 (a small ship which is assumed to be conservative) and will use 100t per day of the LNG cargo's boil-off gas as fuel (Heede 2006). Some vessels may use bunker fuel, but for this EIS it is assumed that ships only use LNG as fuel. Such an assumption is considered to be reasonable as use of bunker fuel would serve to only slightly increase the Scope 3 GHG emissions over those assessed here.

The general approach used to estimate the GHG emissions was to estimate the quantity of fuel consumed from the distances travelled by the LNG ships and the estimated fuel consumption rates (Heede 2006). From the quantity of fuel consumed, the emissions can be estimated using the emission factors in Table 14.2.

14.2.4 Decommissioning

Decommissioning refers to site closure and removal of buildings and infrastructure. Decommissioning GHG emissions are scope 1 GHG emissions. Due to uncertainties about the activities, these have not been estimated in detail. They are assumed to be the same as the construction phase GHG emissions as similar equipment and activities will be required.

14.3 GHG emissions methodology

GHG emissions factors for estimating the quantities of GHGs are usually expressed in terms of the quantity of a GHG per unit of energy consumed (kg CO_2-e/GJ), or per unit of mass such as tonnes CO_2-e/tonnes gas flared. The example of diesel combustion shows how the GHG emissions factors are applied. The volume of diesel combusted in kilolitres is multiplied by the fuel's energy content factor in GJ/kL to give the energy content of the diesel consumed. The energy content of the fuel is then converted to a GHG emission in carbon dioxide equivalents by multiplying it by the GHG emission factor (kg CO_2-e/GJ). For GHG emissions from gas flaring, the tonnes of GHG emissions are estimated based on the tonnes of liquefied natural gas produced.

For the LM2500 + G4 gas turbines and Titan-130 turbines, data on the carbon dioxide and methane emissions were supplied by the vendor. Where vendor data was not available, default emission factors given in the United States Environmental Protection Agency (US-EPA) AP 42 tables (US-EPA 1998) and the American Petroleum Institute Compendium (API Compendium) (API 2004) were used as shown in Table 14.1. Data for fugitive methane emissions from gas processing equipment were estimated using methodologies in the API Compendium (API 2004).

Scope 1 emission factors for combustion of all liquid and gaseous fuels, and vented and flared CSG were sourced from the AP 42 or the API Compendium. These are provided in Table 14.1. The API Compendium factors were preferred for flaring GHG emissions as emissions factors for all three GHGs are provided. The API Compendium (Table C10) also provides specific nitrous oxide (N_2O) factors for the various diesel engines, which are not provided by the AP 42 emission factors.

For operational flaring, the AP 42 factors are slightly higher than the National Greenhouse Accounts (NGA) factors for all three gases. For the hot oil heater, the carbon dioxide factor in AP 42 is 1% lower than the NGA factors and the methane and nitrous oxide emissions also lower in AP 42.

For diesel combustion the AP 42 factor for carbon dioxide is higher by 2.5% for large and small diesel fired engines and the methane factors are slightly lower than NGA factors. Nitrous oxide emission factors were sourced from the API Compendium (2004). The GHG emission factor depends on the capacity of the engine. The NGA factors give a nitrous oxide factor of 0.2kg CO_2-e/GJ for all diesel fired engines compared with 0.06 and 0.3 for the large (>600HP) and small diesel (<600HP) engines in the API Compendium. Again, the differences between the methane and nitrous oxide emission factors are small and will not materially change the overall emissions from these combustion sources as the most significant GHG is carbon dioxide.

In spite of the minor differences, the AP 42 factors used in this assessment are consistent with the NGA factors within the accuracy of this GHG assessment.

Scope 1 and 3 GHG emissions factors for the consumption of liquid fuels were sourced from the NGA factors (DCC 2009a) and are presented in Table 14.2.

Other GHG emissions may be associated with the LNG facility, such as sulphur hexafluoride, which is used for electrical switchgear, and hydrofluorocarbons, which are commonly used for air conditioning. These gases are not required in large quantities, and their emissions are very small as the gases are stored in sealed vessels. Therefore these gases will not contribute significantly to the project GHG emissions inventory.

Scope 3 embedded energy related emission factors

The GHG emissions related to the energy embedded in the major material components required to construct the LNG facility were assessed in this study. The materials considered were structural steel, concrete, copper cabling and pipe and equipment insulation. The emissions factors were obtained from Hammond and Jones (2008) and are given in Table 14.3. GHG emissions from materials transport are not included in these embedded energy emission factors. The embedded GHG emissions for each material are estimated by multiplying the mass of each material by the embedded GHG emission factors.

Table 14.3 GHG factors for embedded energy related emissions

Material	kg CO_2-e/kg
Galvanised steel	2.70
Concrete	0.13
Copper cable	3.83
Pipe and equipment insulation	1.35

14.3.1 Limitations

The GHG emissions estimated using the default factors method is an estimate of the likely emissions to arise from a source. In most cases, the emissions factors are an average of all available data of acceptable quality. Furthermore, these factors are generally assumed to be representative of the long-term averages for all facilities with a particular source of GHG emissions. Actual emissions estimates will be required for compliance with the *National Greenhouse and Energy Reporting Act 2007,* giving a more accurate GHG emissions inventory during each year of the Project.

14.4 Existing environment

This section details the Queensland, Australian and global GHG emission inventories in order to ascertain the potential impact of the project LNG facility's GHG emissions inventory.

Data from the United Nations Framework Convention on Climate Change (UNFCCC) estimates that aggregate GHG emissions from Annex I countries[1] in 2007 were 18,112 million tonnes CO_2-e excluding land use, land use change and forestry (UNFCCC 2009).

The emissions from Annex I countries including land use, land use change and forestry were 16,547 million tonnes CO_2-e. For non-Annex I countries[1], the aggregate emissions in 1994 (the latest year in which these estimates were compiled) were 11,700 million tonnes CO_2-e, excluding land use, land use change and forestry and 11,900 million tonnes CO_2-e, including land use, land use change and forestry (UNFCCC 2005).

The total GHG emissions from Annex I and non-Annex I countries are estimated to be 29,812 million tonnes CO_2-e (excluding land use, land use change and forestry) and 28,447 million tonnes CO_2-e (including land use, land use change and forestry).

Australia's net GHG emissions across all sectors in 2007 were reported to be 597 million tonnes CO_2-e (DCC 2009b). The energy sector was the largest source of emissions at 408 million tonnes CO_2-e or 68.3% of net GHG emissions. This indicates Australia's emissions are currently about 2% of global emissions.

The GHG emissions in Queensland for 2007 accounted for 182 million tonnes CO_2-e (DCC 2009b) or represent approximately 30% of Australia's emissions.

1 Annex I Parties include the industrialised countries that were members of the OECD (Organisation for Economic Co-operation and Development) in 1992, plus countries with economies in transition including the Russian Federation, the Baltic States, and several Central and Eastern European States. Non-Annex I countries are mostly developing nations.

14.5 Projected GHG emissions

GHG emissions have been estimated on an annual basis for the major scope 1 GHG emissions for the LNG facility. Emissions have also been assessed over the life of the Project, which is assumed to end in 2045. This includes all relevant scope 1 and scope 3 emission sources.

The GHG assessment for the LNG facility covers GHG emitting activities during the construction, operation, expansion and decommissioning stages of the Project. Production from each LNG train will be staged according to the development of the Project's gas wells. Decommissioning GHG emissions have not been estimated in detail but are assumed to be the same as the total construction phase GHG emissions.

It should be noted that all data reported in this section is generally aggregated GHG emissions in terms of CO_2-e. Emission factors for methane and nitrous oxide outlined in Table 14.1 show that emission of these gases usually accounts for less than 1% of total emissions from the major emissions sources such as power and refrigeration turbines and the hot oil heater. For this reason, methane and nitrous oxide emissions are not explicitly shown individually but their emissions are included in the GHG emissions estimates reported here.

14.5.1 Modelling results

Scope 1 GHG emissions

Figure 14.2 shows the scope 1 GHG emissions for operating the LNG facility over the Project lifetime. It is assumed that train 1 begins operation in 2015 and train 2 begins in 2016. After a second period of construction, train 3 is assumed to begin operations in 2019 and train 4 in 2020. The figure shows how the emissions increase over time with the scheduled deployment of the trains. It is estimated that from 2020, when all four trains should be operational, the LNG facility will produce approximately 5.5 million tonnes of CO_2-e per annum. The construction, land-clearing and decommissioning GHG emissions are relatively small and are not shown in Figure 14.2. These emissions are instead shown in Table 14.4. The figure below also shows a sudden stop in production. This is not likely to occur in reality but will occur as a ramp down over time. Such a ramp down is so far in the future that it is not considered meaningful to show this any other way than as a sudden stop at this stage.

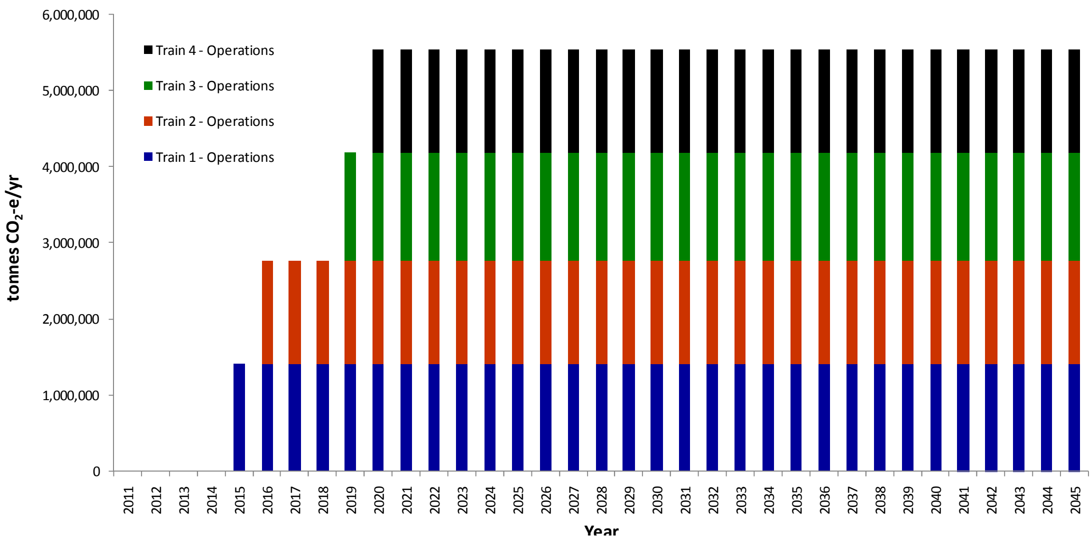

Figure 14.2 Scope 1 GHG emissions for the LNG facility, during operations

Table 14.4 Total scope 1 GHG emissions from constructing, operating and decommissioning four LNG trains over the Project lifetime

Phase	Projected duration (years)	Projected total emissions (t CO_2-e)
Construction (four-trains)		
Transport – diesel consumption	4.75	50,000
Transport – petrol consumption	4.75	5,000
Stationary energy – diesel consumption	4.75	5,000
Land clearing	1.00	30,000
Total		**90,000**
Operations (four-trains)		
Stationary combustion (CSG)	30.00	140,000,000
Stationary combustion (diesel)	30.00	4,000
Vented emissions	30.00	25,000,000
Flaring emissions	30.00	3,700,000
Fugitive emissions	30.00	440,000
Total		**169,144,000**
Decommissioning (four-trains)		**60,000**
Approximate total		**169,300,000**

A detailed breakdown of the scope 1 GHG emissions is presented on a per annum basis in Table 14.5. The GHG data is based on a typical year during peak LNG production (i.e. four-train operations).

Clearly, the largest contribution to the GHG footprint for the LNG facility arises from the CSG powered refrigeration compressor turbines. Power generation turbines also make a significant contribution to the GHG inventory, as does venting of CO_2 from the AGRU.

As stated previously, the power generation system configuration is an optimisation of power requirements, site operating conditions, project phasing, reliability, GHG emissions and capital/operating costs. While this optimisation is ongoing, the current base case described in Section 14.2.3 has been utilised. The final configuration will result in similar GHG emissions. The emissions from CO_2 venting are a conservative estimate. This assumes a feed gas composition of 1.0% CO_2 even though the most likely CO_2 concentration in the feed gas may be a fraction of this.

Table 14.5 Estimated annual scope 1 GHG emissions for the Australia Pacific LNG facility during operations[2]

Process area	Train 1 4.5Mtpa ($t\ CO_2$-e/yr)	Trains 1 and 2 9 Mtpa ($t\ CO_2$-e/yr)	Trains 1 to 3 13.5Mtpa ($t\ CO_2$-e/yr)	Trains1 to 4 18Mtpa ($t\ CO_2$-e/yr)
Oil heating	17,500	35,000	52,500	70,000
Refrigeration compressor turbines	890,000	1,780,000	2,670,000	3,560,000
LNG facility power	100,000	200,000	300,000	400,000
Additional power for ship at berth	130,000	260,000	390,000	520,000
Diesel generators	100	200	300	400
Acid gas (CO_2) vent – 1% CO_2	145,000	290,000	435,000	580,000
Methane in nitrogen purge	60,000	120,000	180,000	240,000
Fugitive methane emissions from processing equipment	4,000	8,000	12,000	16,000
Flaring	60,000	60,000	120,000	120,000
Approximate total	**1,400,000**	**2,800,000**	**4,200,000**	**5,500,000**
Intensity (t CO_2-e/tonnes LNG produced)	**0.31**	**0.31**	**0.31**	**0.31**

[2] GHG emissions for the commissioning phase have been included through conservative assumptions made in the operations phase GHG emissions

Flaring will be required during commissioning of each LNG train, so a brief increase in GHG emissions results in the first year that each new train is brought on-line. Such short term increases in GHG emissions do not appear in the emission profile in Figure 14.2 because the data provided assumes a full year of production and hence a full year of GHG emissions for the first year an LNG train is commissioned. The GHG emissions from flaring during commissioning will be relatively small compared with the GHG emissions from the annual operations of the LNG train. GHG emissions from flaring during LNG train commissioning are not quantified due to variability in the commissioning outcomes.

Table 14.4 shows the total scope 1 GHG emissions from construction and operation of the LNG facility over the life of the Project, as well as providing an estimate for decommissioning. Production is assumed to begin in 2015 and end in 2045.

The LNG facility requires land clearing of approximately 156ha (refer Volume 4 Chapter 8 for further details). Therefore, the estimated land clearing equates to approximately 30,000 tonnes CO_2-e based on an emission factor of 200 tonnes CO_2-e/hectare. Land clearing occurs only during the construction phase of the Project (assuming four-trains). This assessment of GHG emissions from land clearing is a conservative approach, as no allowance has been made for GHG reductions due to land rehabilitation as part of the decommissioning phase.

Scope 3 GHG emissions estimates

Table 14.6 shows estimates of the scope 3 GHG emissions from transport over the Project lifetime, during construction, operation and decommissioning. Emissions from the embedded energy of construction materials are also included here. Accommodation facility construction activities include employees travelling by ferry to Laird Point; importing modular sections from overseas ports via ship, and transporting material, equipment and consumables. Further information on these scope 3 GHG emission activities can be found in Volume 4 Chapter 17.

Scope 3 GHG emissions from consuming diesel fuel for construction are included. It is assumed that the same emissions will arise from decommissioning the accommodation facility. The LNG facility construction emissions include scope 3 GHG emissions from worker transport, materials and equipment transport and waste to landfill emissions. Note that waste from decommissioning the LNG facility will likely consist primarily of steel, concrete, copper wire and glass fibre insulation, which are mostly recyclable. Any wastes sent to landfill or recycled, would not release GHGs in any appreciable amount and hence the GHG emission factors are zero (DCC 2009a). Therefore GHG emissions from decommissioning waste would be negligible and are not assessed in detail.

Scope 3 GHG emissions for operations of the LNG facility include worker, materials, equipment and consumables transport. Embedded energy emissions are included for structural steel, concrete, copper wire and cable, equipment insulation, and pipe insulation used for constructing four LNG trains.

Scope 3 GHG emissions for the annual shipping of LNG to an overseas customer were estimated to be 2 million tonnes CO2-e per annum. The ships consume a portion of the LNG for power. Some vessels may use bunker fuel, but for this EIS it was assumed that the ships only use LNG as fuel. Such an assumption is considered to be reasonable as bunker fuel would serve to only slightly increase scope 3 GHG emissions over those assessed here.

Table 14.6 Scope 3 GHG emissions for construction, operation and decommissioning over the Project lifetime

Scope 3 GHG emissions source	Tonnes CO_2-e
Accommodation facility construction and decommissioning	100,000
LNG facility construction	300,000
LNG facility operations	50,000
Embedded energy emissions	800,000
Approximate total	**1,250,000**

Details on the estimation of emissions from product shipping can be obtained from the GHG assessment Technical Report in Volume 5 Attachment 31.

14.5.2 Comparison of lifecycle GHG emissions for LNG, coal and other fuels

This section presents a lifecycle GHG analysis that compares the GHG emissions associated with the production and use of LNG with coal and other fuels. For LNG, the GHG emissions across the LNG lifecycle (that is, the GHG footprint) are considered, which is illustrated by Figure 14.1. The GHG footprint consists of the Project GHG inventories developed for this EIS which include the gas fields, the gas pipeline, and the LNG facility GHG inventories. Other sources of GHG emissions that are associated with the LNG lifecycle but are beyond Australia Pacific LNG's control include supply of CSG from other gas fields, LNG product transport, external processing such as LNG re-gasification, natural gas transport and product consumption (here assumed to be for power generation). These are not part of the Project GHG inventories for this EIS but they are considered here as part of the GHG footprint.

In 2023, the Project's gas fields will produce a forecast maximum of 633PJpa, with projected scope 1 GHG emissions totalling 3.3Mt CO_2-e/yr. At maximum LNG output, the Project requires additional CSG from other fields, with a forecast contribution of 462PJpa of CSG in 2023. These non-Project fields will produce additional scope 1 GHG emissions totalling approximately 2.4Mt CO_2-e/yr. The contribution from the Project gas pipeline is relatively insignificant at approximately 5,000t CO_2-e/yr. Refer to the GHG assessment for the gas fields in Volume 2 Chapter 14 and the gas pipeline in Volume 3 Chapter 14 for additional information.

The LNG facility is estimated to produce approximately 5.5 Mt CO_2-e/yr at maximum production.

Table 14.7 details the GHG emissions from sources within the Project and those sources not controlled by Australia Pacific LNG but which make up the GHG footprint. These GHG emissions occur during full LNG production.

The overall GHG emissions intensity of the Project during peak production is estimated to be approximately 0.63 tonnes CO_2-e/tonne LNG. Of this, the LNG facility accounts for approximately 0.31 tonnes CO_2-e/tonne liquefied natural gas, while the gas fields (including other gas fields) and the gas pipeline accounts for approximately 0.32 tonnes CO_2-e/tonne LNG.

Table 14.7 Breakdown of the Project's GHG footprint in 2023

Emissions source	Emissions ($Mt\ CO_2$-e/yr)	GHG intensity t CO_2-e/GJ delivered
Project gas fields (scope 1)	3.3	0.003
Project gas pipeline (scope 1)	0.005	0
Project LNG plant (scope 1)	5.5	0.006
Total Project GHGs (scope 1)	**8.8**	**0.009**
Other gas fields (scope 1)	2.4	0.002
Total GHGs to produce 18 Mtpa LNG	**11.2**	**0.011**
LNG shipping	2.0	0.002
LNG re-gasification and natural gas pipeline emissions	3.6	0.004
End user combustion of 18 Mtpa LNG	51.6	0.051
Total GHG footprint emissions for 18 Mtpa	**68.4**	**0.068**

Table 14.8 presents a GHG emission intensity comparison between lifecycle GHG emissions for LNG, coal, and other fuels. The total GHG emissions related to the LNG extraction and processing activities within Australia are 11.2Mt CO_2-e/yr (refer Table 14.7). Table 14.8 shows that (1) GHG emissions from the extraction, processing and product transport for LNG are higher than for coal, and (2) GHG emissions from the external processing and power generation activities for LNG are significantly lower than for coal. Overall, the coal delivery and power generation activities produce 43% more GHG emissions than LNG per GJ of energy delivered. Diesel and fuel oil produce approximately 10-15% more GHG emissions than LNG.

Table 14.8 Comparison of GHG emission intensities between LNG, coal and other fuels

<table>
<tr><th rowspan="2">Activity</th><th colspan="4">Emissions intensity (t CO_2-e/GJ)</th></tr>
<tr><th>Coal</th><th>Diesel</th><th>Fuel oil</th><th>LNG</th></tr>
<tr><td>Extraction and processing activities in Australia</td><td>0.004</td><td rowspan="2">0.005*</td><td rowspan="2">0.005*</td><td>0.011</td></tr>
<tr><td>Product transport - international activities</td><td>0.003</td><td>0.002</td></tr>
<tr><td>External processing and combustion</td><td>0.090</td><td>0.070</td><td>0.073</td><td>0.055</td></tr>
<tr><td>Total</td><td>0.097</td><td>0.075</td><td>0.078</td><td>0.068</td></tr>
</table>

Data sources: Pace Global Energy Services (2009), WorleyParsons (2008) and the DCC (2009b).
*Note that extraction and transport emissions for diesel and fuel oil are summed together and presented as a single line item.

One of the main uses for fuels like LNG and coal is for power generation. The analysis carried out above neglects the efficiencies associated with specific power generating technologies. Table 14.9 shows the GHG emission intensities on an electricity production (MWh) basis for LNG combusted in a combined-cycle gas turbine (CCGT) plant compared with a variety of coal fired power plants. This analysis accounts for the power generation efficiencies of each type of power plant.

Table 14.9 Comparison of LNG and coal GHG emission intensities for power generation

Activity	Emissions intensity (t CO_2-e/MWh)			
	Coal sub-critical	Coal super-critical	Coal ultra super-critical	LNG CCGT
Extraction and processing activities in Australia	0.04	0.03	0.03	0.08
Product transport - international activities	0.03	0.02	0.02	0.01
External processing and power generation activities	0.95	0.71	0.67	0.39
Total	1.02	0.76	0.72	0.48
GHG emissions compared to LNG CCGT	112%	57%	50%	-

Data sources: Pace Global Energy Services (2009), WorleyParsons (2008) and the DCC (2009b).

On this basis, LNG combustion in a CCGT is a substantially lower GHG emission generation option with coal combustion in a sub-critical power plant producing 112% more GHG emissions. The more advanced coal fired generation such as super-critical and ultra super-critical power plants still produce 57% and 50% more GHG emissions, respectively, than LNG combusted in a CCGT. This clearly shows that LNG can be a key fuel in assisting international efforts in the transition to a low carbon economy.

14.5.3 Explanation of results

Figure 14.3 gives a detailed breakdown of the GHG emissions for each activity summed for the project lifetime. The data in the figure refers to four-train operations, while Table 14.4 provides a detailed summary of the emissions from each source.

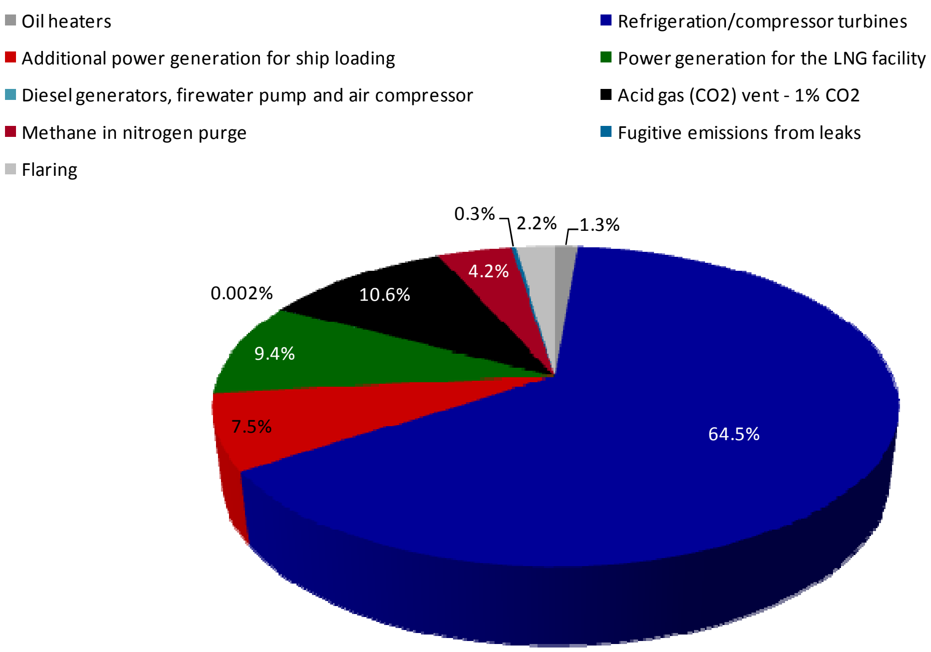

Figure 14.3 Scope 1 GHG emissions for the LNG facility across the Project lifetime

Figure 14.3 shows that the projected GHG emissions profile for the Project is dominated by the combustion of CSG for powering the refrigeration compressor turbines. This represents 64.5% of the inventory. GHG emissions from consuming CSG for power generation comprise 16.9% of the inventory, which includes power consumption for ship loading. Meanwhile, carbon dioxide released from the acid gas vent is 10.6% of the inventory. This vented CO_2 emissions estimate is based on a feed gas composition of 1.0% even though the most likely CO_2 concentration in the feed gas will be a fraction of this.

Of lesser importance are methane releases from the nitrogen rejection unit (4.2%), maintenance flaring during operations (2.2%) and oil heater emissions (1.3%). Emissions due to fugitive methane releases from processing equipment and consumption of diesel for backup power generation are relatively insignificant at 0.3% and 0.002% respectively.

Figure 14.4 shows the detailed breakdown of the scope 3 GHG emissions over the Project lifetime, while Table 14.6 provides a summary of the emissions for each source. Included in Figure 14.4 are the GHG emissions from LNG product shipping.

The largest contribution to the scope 3 GHG emissions is from the LNG product shipping at approximately 64%. Of the scope 3 GHG emissions, embedded energy related GHG emissions represent approximately 22%, worker transport represents approximately 7.5% and shipping of modular sections by ship/barge represents 3%.

Scope 3 GHG emissions from the consumption of liquid fuels, transport of materials, equipment and consumables by trucks and waste to landfill emissions represent approximately 3.4% of scope 3 GHG emissions.

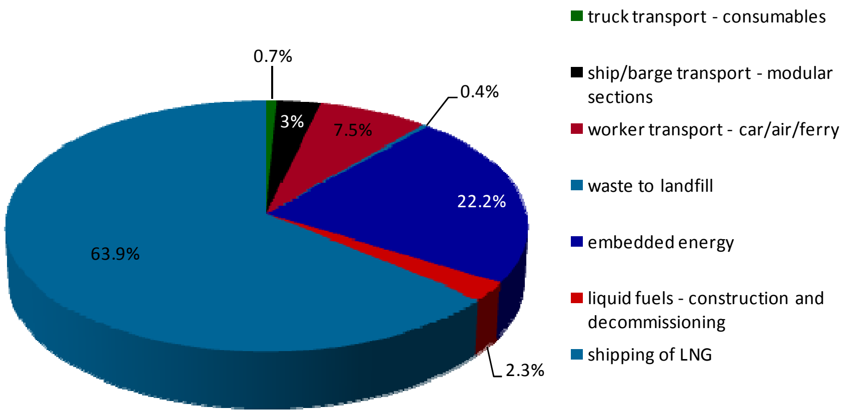

Figure 14.4 Scope 3 GHG emissions for the LNG facility across the Project lifetime

Figure 14.5 shows the detailed breakdown of the combined scope 1 and scope 3 GHG emissions over the Project lifetime. The largest contribution to the GHG inventory was scope 1 GHG emissions from stationary combustion of CSG (power generation and compressor turbines, and the hot oil heater). These sources contribute around 81% of the total emissions. Vented emissions from the acid gas removal unit and the nitrogen rejection unit represent approximately 14% of emissions. Scope 3 GHG emissions from product LNG shipping contribute 1.2% of the emissions and other scope 3 GHG emissions (these are the sum of all scope 3 GHG emissions in Figure 14.4 except LNG shipping) contribute 0.7% in total. GHG emissions from the stationary combustion of diesel contribute only 0.002%.

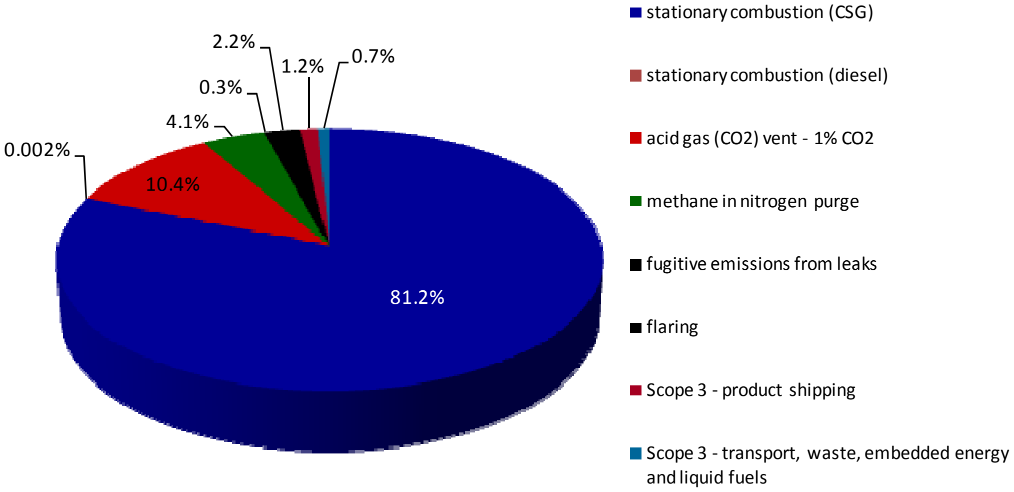

Figure 14.5 Scope 1 and 3 GHG emissions for the LNG facility across the Project lifetime

14.6 Project's potential impact on the existing environment

This section details the Queensland, Australian and global GHG emission inventories to ascertain the potential impact of the GHG emissions arising from the Project's LNG facility. The scope 1 GHG emissions during peak LNG production from the LNG facility are 5.5Mt CO_2-e. To gain a meaningful perspective on the Project's impact, this section also shows the GHG emissions across the entire Project, encompassing the gas fields, the gas pipeline, and the LNG facility (and excluding the GHG emissions from the other gas fields, which are not part of this Project). This is illustrated in Figure 14.1. These GHG emissions total approximately 8.8Mt CO_2-e (see Table 14.7). Table 14.10 shows the maximum impact of Project GHG annual emissions in the context of Queensland, Australia and global annual GHG emissions (from Section 14.4)

Table 14.10 The maximum impact of Project scope 1 GHG annual emissions in 2023

	Annual GHG emissions (Mt CO_2-e)	% contribution from LNG facility	% contribution from Project	% contribution on a lifecycle GHG basis
Queensland	182	3.02	4.84	N/A
Australia	597	0.92	1.48	N/A
Global	29,000	0.02	0.03	-0.28

The above analysis assumes that 18Mtpa LNG, or approximately 1,000PJpa of energy, is produced, exported and combusted. On this basis, the combustion of 1,000PJpa of natural gas in a CCGT releases approximately 71Mt CO_2-e per year. Combusting 1,000PJpa of coal in a sub-critical coal fired power plant releases approximately 151Mt CO_2-e per year and an ultra super-critical coal fired power plant releases 106Mt CO_2-e per year. Thus, the end-use of the Project's LNG output could avoid the emission of between 35 and 80Mt CO_2-e of GHG emissions per year. The avoided emissions from substituting these coal fired power generation technologies with natural gas fired CCGT technology is equivalent to reducing Australia's 2007 GHG emissions by between 5.9% and 13.4%, which compensates the GHG emissions across the LNG production chain. On a global scale, GHG emissions could be reduced by between 0.12% and 0.28%.

Over the lifetime of the Project, substituting LNG for coal could avoid between 960 and 2,200Mt CO_2-e of GHG emissions depending on the coal fired generation technology used.

14.7 Mitigation and management

Australia Pacific LNG has an objective to reduce the GHG intensity of its production processes. Australia Pacific LNG has performed an analysis of the various technologies and processes to improve the energy efficiency of the LNG facility and reduce the GHG emissions. The liquefaction/refrigeration process is highly energy intensive and is therefore a key area where energy efficiency improvements has and will continue to be focused.

The liquefaction technology used in this project is the ConocoPhillips' Optimized Cascade® process, which is a well proven technology for processing LNG. The process is currently used at the Darwin LNG facility, which is operated by ConocoPhillips. Santos/Petronas also propose to use this process for their Gladstone LNG project (GLNG 2009), while BG Group proposes to use it for their Queensland Curtis LNG (QGC 2009) CSG to LNG development in Gladstone. This popularity is primarily due to its efficiency and operational flexibility.

14.7.1 Incorporated mitigation measures

The key mitigation measures that have been included in the design of the Project are:

- Efficient refrigeration turbines
- Waste heat utilisation
- Vapour recovery to reduce flaring of fugitive GHG emissions and leaks.

Australia Pacific LNG has identified that GE LM2500+G4 aero-derivative gas turbines are among the most fuel efficient turbines available. The aero-derivative turbines use less CSG to generate the same quantity of power.

The application of the aero-derivative turbines results in approximately 25% less GHG emissions (ConocoPhillips 2009) compared with industrial Frame 5D turbines which have been commonly used in LNG facilities around the world. It is estimated that on a per train per annum basis, the aero-derivative turbines could reduce the total scope 1 GHG emissions by approximately 225,000 tonnes CO_2-e.

Aero-derivative turbines are currently in use at some LNG facilities such as Darwin LNG, where Australia Pacific LNG has gained experience with the technology through ConocoPhillips. This energy efficient technology represents international leading practice and will be implemented at the Project's LNG facility.

A second key mitigation measure is installing waste heat recovery units on the gas turbine exhaust stacks, instead of gas-fired boilers. The waste heat will be used to heat the hot oil system and the dehydration system regeneration gas for two of the refrigeration gas turbines. Engineering estimates suggest this could reduce GHG emissions by around 63,000 tonnes CO_2-e per train per annum (ConocoPhillips 2009).

The third key mitigation measure identified is installing boil-off gas compression facilities to recover vapours generated from the LNG tanks and LNG export vessels during LNG loading. The recovery of gas during the ship loading process reduces GHG emissions associated with flaring this stream, and conserves CSG. The estimated greenhouse gas savings are approximately 100,000 tonnes CO_2-e per train per year.

These GHG mitigation measures have been quantified in Table 14.11 and are shown in Figure 14.6.

Table 14.11 Mitigation actions quantified on a four-train per annum basis

Mitigation option	GHG emission baseline	GHG emissions mitigation	
	t CO_2-e/yr	t CO_2-e/yr	%
Reference case	7,100,000	-	-
Aero-derivative turbines	6,200,000	900,000	13
Waste heat recovery	5,950,000	250,000	3
Vapour recovery	5,500,000	400,000	5
Final emissions baseline	5,500,000	-	-
Total GHG reductions		**1,550,000**	**21**

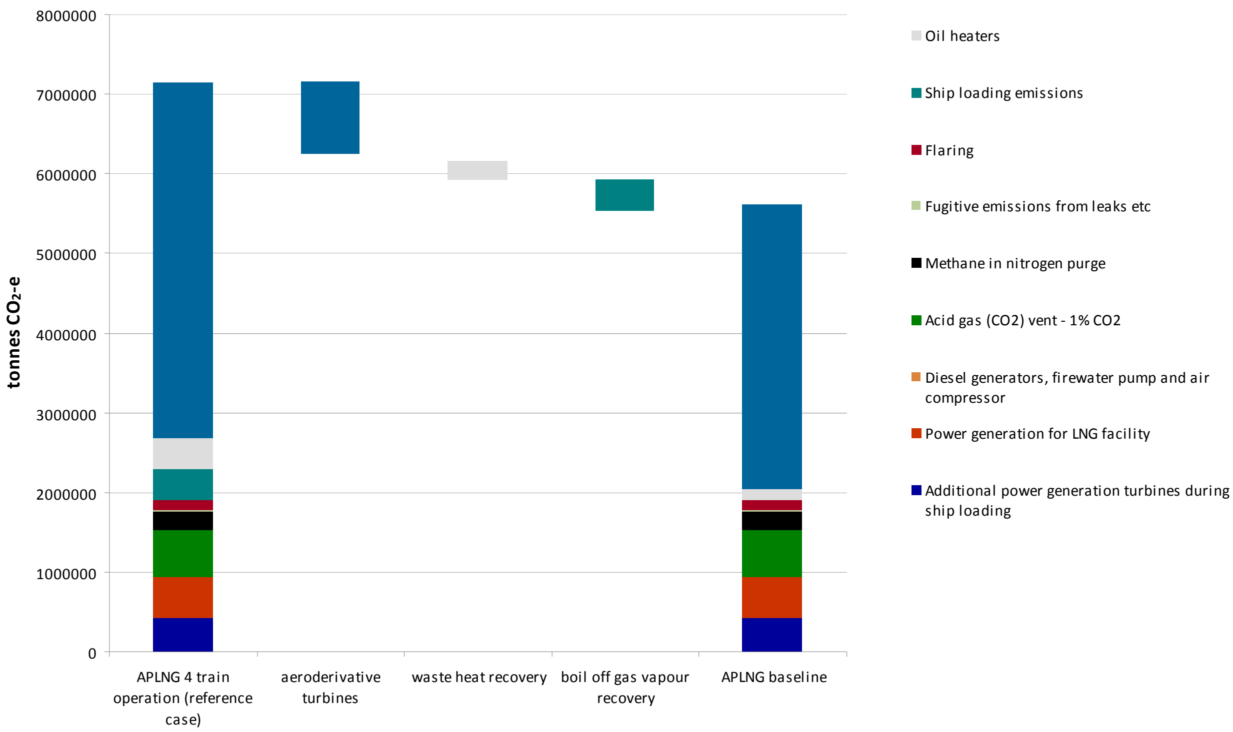

Figure 14.6 GHG emissions reductions associated with the mitigation measures implemented at the LNG facility

Over a 30 year period, these mitigation measures could save around 46 million tonnes CO_2-e.

Australia Pacific LNG has also assessed industry leading practice for GHG mitigation in flaring. As a result, Australia Pacific LNG proposes to use a ground flare similar to that currently used at ConocoPhillips' Darwin LNG facility. This type of flare burns more cleanly than the conventional elevated pipe flare and this results in fewer GHG emissions overall.

Using a ground flare rather than an elevated flare is estimated to reduce LNG facility GHG emissions by approximately 10% per annum. A comparison of ground and elevated flaring GHG emissions is covered in more detail in Volume 5 Attachment 31. The reductions in GHG emissions have not been included in Figure 14.6 because of significant uncertainties associated with the different flaring methods.

An opportunity was identified to reduce methane emissions associated with the nitrogen rejection unit. An assessment of industry leading practice was made and a thermal oxidiser will be used. The thermal oxidiser will convert the methane to carbon dioxide thus reducing GHG emissions, as the global warming potential of methane is 21 times that of carbon dioxide. The challenge is that additional fuel is often required to make the oxidiser function, so the net GHG benefits will be reviewed as part of the ongoing assessment.

14.7.2 Further mitigation measures

Various other design and operational features will be assessed and may be employed with the objective of minimising GHG emissions. These include:

- Using heat exchangers (additional to recovery of heat from the gas turbine exhaust stacks)
- Using inlet air-cooling to turbine inlets instead of water cooling
- Using activated methyldiethanolamine (a-MDEA) as the amine for CO_2 removal, instead of available alternatives
- Directing flash gas from the amine unit to either the fuel gas system or the flare
- Flaring waste streams from the nitrogen rejection unit instead of venting
- Insulating hot and cold equipment and piping
- Selecting paint colours and equipment finishes to reduce heat transfer to cold equipment and piping
- Washing gas turbines with water to maintain high efficiency
- Developing procedures to start-up, shutdown and maintain equipment
- Implementing process control, shutdown and metering systems
- Designing plant layout to more efficiently move the streams through the process
- Implementing continuous circulation of liquefied natural gas through the loading lines to keep them cold
- Assessing high efficiency equipment specifications such as compressors, pumps and air-coolers
- Considering GHG emissions as part of the power generation system selection
- Carrying out fugitive GHG emissions surveys
- Using energy efficient building design
- Using a revised design of the nitrogen rejection unit which reduces the methane concentration in the nitrogen reject stream
- Installing a thermal oxidiser on the AGRU.

Installing carbon capture ready technology is another alternative, but there are no feasible reservoirs for CO_2 storage currently available.

In addition to these design features metering and sampling systems will also be compliant with the *National Greenhouse and Energy Reporting Act 2007.*

Benchmarking against other LNG facilities

Through an analysis of the key LNG processes including compression, power generation and process heating, a number of mitigation measures were identified that reduce total GHG by around 21% over the reference case. These reductions contribute to achieving Australia Pacific LNG's objective to reduce the GHG intensity of its LNG production process.

The GHG emissions intensities of the reference case and the current design of the LNG facility are shown in Figure 14.7. The figure also shows a number of Australian and international LNG facilities, some of which are in operation. Other LNG proponents such as Queensland Curtis LNG, Gladstone LNG (Santos/PETRONAS joint venture) and Gladstone LNG – Fisherman's Landing, are at the design stage. It should be noted that the Darwin LNG, Egyptian LNG and Atlantic LNG currently operate with ConocoPhillips' Optimized Cascade® process. Both Queensland Curtis LNG and Gladstone LNG have adopted this technology in their current LNG facility designs.

The Australia Pacific LNG project has adopted ConocoPhillips' Optimized Cascade® process technology. Figure 14.7 shows that the current design of the Project's LNG facility is amongst the least GHG intensive projects in the world.

However, comparisons with Darwin LNG should be explained further. Darwin LNG has an intensity of approximately 0.46 tonnes CO2-e/tonne LNG produced. This is partly because the feed gas used by Darwin LNG contains approximately 6% CO2, compared with 1.0% CO2 assumed for the feed gas to be used for the Project.

Shell's Prelude project (Shell 2009), which uses floating LNG technology, has the ability to process gas in situ over an offshore gas field. The 3.6Mtpa facility generates approximately 2.3 million tonnes CO2-e per annum, with an overall intensity of 0.64 tonnes CO2-e/tonne LNG production. From this, approximately 0.3 tonnes CO2-e/tonne LNG is for the LNG facility and the remainder is vented reservoir CO2. Caution should also be used in making a direct comparison with the overall GHG emissions intensity for the Prelude development because it has 9% CO2 in the feed gas.

From Figure 14.7, the Queensland Curtis LNG project has a lower GHG intensity than the Project. However, the EIS for the Queensland Curtis LNG project (QGC 2009) reports gas field GHG emissions for a two train capacity and GHG emissions for a three train LNG facility. It is therefore not clear whether the full GHG inventory has been reported. For the Project, GHG emissions from the gas field and LNG facility are reported on the basis of a full four train capacity.

Comparisons between the Gladstone LNG project and the Project cannot be made as the Gladstone LNG EIS (Gladstone LNG Pty Ltd 2008) does not specify power generation and desalination requirements, the CO_2 content of the feed gas or the frequency and volumes of gas flared.

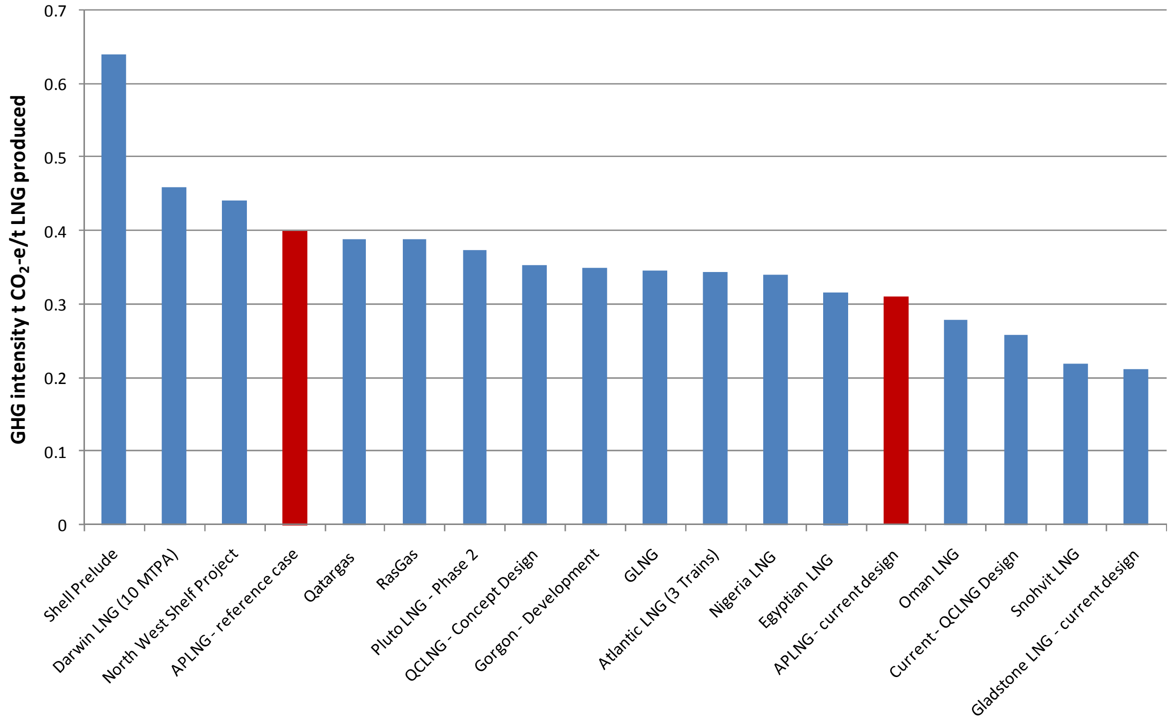

Figure 14.7 GHG intensities of various Australian and international LNG facilities[3]

14.8 Conclusions

14.8.1 Assessment outcomes

An analysis was performed to identify the key sustainability principles and the potential impacts of the LNG facility in terms of the GHG emissions on third parties, property and the environment in general.

Table 14.12 summarises the key potential risks, the mitigation actions to reduce the impact of the risk, and the residual risk. The residual risk is categorised as either negligible, low, medium, high, or very high. A full description of the risk assessment methodology is given in Volume 1 Chapter 4.

[3] Notes: the GHG intensity data for the Queensland Curtis LNG project is based on a two train gas field operations to supply a three train LNG facility. The Gladstone LNG EIS does not specify power generation and desalination requirements, the CO_2 content of the feed gas or the frequency and volumes of gas flared.

Table 14.12 Summary of environmental values, sustainability principles, potential impacts and mitigation measures

Environmental values	Sustainability principles	Potential impacts	Possible causes	Mitigation and management measures	Residual risk level
Reduce the risk of the impacts of climate change Improve health and wellbeing of people	Minimising adverse environmental impacts and enhancing environmental benefits associated with Australia Pacific LNG's activities, products or services; conserving, protecting, and enhancing where the opportunity exists, the biodiversity values and water resources in its operational areas Identifying, assessing, managing, monitoring and reviewing risks to Australia Pacific LNG's workforce, its property, the environment and the communities affected by its activities.	GHG emissions to the atmosphere; potential long term climate change impacts	Operation of construction machinery and transport equipment hauling	Optimise transport logistics to reduce energy consumption, and use fuel efficient vehicles and machinery where practicable	Low
			Operation of gas liquefaction facilities (power generation and refrigeration turbines)	Use high efficiency turbines that produce lower GHG emissions Install waste heat recovery units to meet the process heat requirements of the LNG facility	Low
			Flaring and venting CSG during maintenance and process upsets	Reduce flaring by capturing liquefied natural gas boil off gases from normal ship loading using boil-off gas compressors Develop and implement plans for preventative maintenance and operational efficiencies to reduce flaring	Low
			Transportation of people, construction materials and liquefied natural gas	Optimise transport logistics to reduce energy consumption and use fuel efficient ships	Negligible
			Embedded energy in materials	Consider less energy intensive construction materials during design phase of the Project	Low
Reduce the risk of the impacts of climate change	Reducing greenhouse gas intensity through the development of an	GHG emissions to the atmosphere; potential long term climate change	GHG emissions from LNG facility processes and other indirect	Develop and implement a GHG management plan to monitor and assess GHG emissions from the	Low

Environmental values	Sustainability principles	Potential impacts	Possible causes	Mitigation and management measures	Residual risk level
Improve health and wellbeing of people	energy source less carbon intensive than the world average for the majority of fuel providers for power generation; and implementing a greenhouse gas mitigation strategy for our operations that continuously seeks opportunities to further reduce greenhouse gas emissions	impacts	emissions such as third party and worker transportation	Project. Use this plan to define and execute actions to reduce GHG emissions	
Reduce the risk of the impacts of climate change Improve health and wellbeing of people	Minimising adverse environmental impacts and enhancing environmental benefits associated with Australia Pacific LNG's activities, products or services; conserving, protecting, and enhancing where the opportunity exists, the biodiversity values and water resources in its operational areas Identifying, assessing, managing, monitoring and reviewing risks to Australia Pacific LNG's	Land clearing releases CO_2 and reduces CO_2 uptake	Land clearing for construction of project infrastructure	Progressively rehabilitate cleared areas as described in Volume 4 Chapter 8 Develop biodiversity offset strategy which will generate GHG offsets	Low

Environmental values	Sustainability principles	Potential impacts	Possible causes	Mitigation and management measures	Residual risk level
	workforce, its property, the environment and the communities affected by its activities.				

14.8.2 Commitments

Australia Pacific LNG will:

- Contribute to reducing global GHG intensity by producing LNG which can substitute for higher GHG intensive fuels
- Develop ongoing processes for reducing energy consumption and GHG emissions
- Use high efficiency aero-derivative drivers for refrigerant compressors
- Install waste heat recovery units to meet the process heat requirements of the LNG facility
- Reduce operational flaring and venting by:
  - Recovering LNG boil-off gas vapours during ship loading
  - Developing a leak detection program
  - Developing a strategy to minimise plant shutdowns
- Develop a GHG management plan, taking into account biodiversity offsets.

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