University of Southern Queensland

Faculty of Engineering and Surveying

Life Cycle Assessment (LCA) of Liquefied Natural Gas (LNG) and its environmental impact as a low carbon energy source

Dissertation submitted by

Paul Jonathan Barnett

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Abstract

A life cycle assessment is an environmental management methodology documented by the International Standards Organization (ISO2006) for researching the impact a product has on the environment. Liquefied natural gas is a product contributing to the emission of greenhouse gases such as carbon dioxide, methane and nitrous oxide. These emissions can be minimized by analysis of its source and adopting appropriate process technology throughout the product lifecycle.

Natural gas for many years was regarded as a volatile waste product within the oil and coal industries, and was subsequently vented into the atmosphere resulting in pollution. Natural gas is now accepted as a source of low carbon energy assisting the transition from heavy fuels to renewable energy. Liquefying the natural gas has proved to be an economic method for transporting this energy to the market place where pipeline infrastructure is unavailable.

Australia has large resources of natural gas in conventional off-shore wells and underground coal-seams. Demand for energy security has positioned Australia to capitalize on its natural resources and supply low carbon energy to fuel economic growth in Asia. The production of liquefied natural gas in Australia is forecast to grow above one hundred million tons per annum within the next five years, becoming the world's second largest supplier behind Qatar.

Natural gas has a calorific value of approximately 40 MJ/m^3, with greater than eighty five percent Methane content. Liquefied natural gas is produced by cooling natural gas to its boiling point of minus 161°C, becoming $1/600^{th}$ its original volume. It is stored in insulated tanks at normal atmospheric pressure before being loaded on-board ships and transported to market. Ships used to transport liquefied natural gas range in size between $135{,}000m^3$ and $265{,}000m^3$. Once delivered to market, liquefied natural gas is used for cryogenic storage and re-gasified for domestic gas supply, power generation and industrial manufacturing.

This study assesses the environmental impact of liquefied natural gas during liquefaction, shipping and re-gasification using a life cycle assessment approach. Greenhouse gas emissions are quantified in the form of carbon dioxide equivalent emissions and recommendations are made for process and technology improvements.

Liquefaction of natural gas produces emissions during the removal of carbon dioxide from inflow gas, fuel used in gas turbines compressors and fuel used by power generation turbines. Shipping liquefied natural gas generates emissions from fuel used by the ships engines and re-gasification generates emissions from fuel used to operate pumps and power turbines.

A thirty eight percent improvement in efficiency has been identified in the lifecycle of liquefied natural gas from Australia compared to global production, resulting in only six and a half grams of carbon dioxide equivalent emissions per mega Joule of energy delivered to Asian markets.

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Certification

I certify that the ideas, designs and experimental work, results, analyses and conclusions set out in this dissertation are entirely my own effort, except where otherwise indicated and acknowledged.

I further certify that the work is original and has not been previously submitted for assessment in any other course or institution, except where specifically stated.

Paul Jonathan Barnett
Student Number: D9613102

Signature

25 OCT 2010

Date

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Glossary of terms

Acid Gas	Natural Gas containing Carbon Dioxide or Hydrogen Sulphide which forms an acid compound when combined with water.
Boil Off Gas (BOG)	LNG is stored at its boiling point at normal atmospheric pressure. As LNG absorbs heat a small portion evaporates. BOG can be used as fuel for turbines or re-liquefied.
British Thermal Units (BTU)	A unit of heat widely used in the gas industry. Defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. Also described as a fixed 1055.056 Joules. Commonly used in multiples of one million Btu, abbreviated as MMBtu.
Calorie (Cal)	A calorie is no longer an SI unit of energy, but still widely used in Europe. Nominally described as the amount of heat required to raise one gram of water by one degree Celsius at one standard atmosphere. Now arbitrarily defined as 4.1868 Joules.
Carbon sequestration & storage (CSS)	The capture of carbon emissions to the atmosphere and storage in natural geological profile or depleted hydrocarbon fields.
Coal Bed Methane (CBM) or Coal Seam Gas (CSG)	Methane that can be recovered from coal seams by drilling wells into suitable coal seams and then reducing the pressure by pumping out water (usually saline) until methane is desorbed.
Condensate	A natural gas liquid with low vapour pressure produced from reservoir with high pressure and temperature. These very light hydrocarbons remain a liquid at normal pressure and temperature.
Cryogenics	The process of producing, maintaining and utilising very low temperatures (below -46ºC).
Calorific Value (CV)	Quantity of heat produced (e.g. MJ or MMBtu etc) by the complete combustion of a fuel.
Downstream	A term used to describe activities along the gas value chain. Downstream typically refers to liquefaction, shipping and re-gasification.

Dry Gas	An alternative name for lean gas. It does not always mean free of water.
Ethane	A gas with a molecular structure of two Carbon atoms and six hydrogen atom (C_2H_6). It boils at minus 84.4ºC and at normal temperature it is a dry colourless and odourless gas.
Flaring	Process of burning unwanted natural gas or oil. Due to government environmental regulation flaring only occurs as a safety mechanism of production or when the gas cannot be economically exploited or re-injected.
Free On Board (FOB)	Product sold (ownership transferred) onto a ship at the port of export.
Gas Turbine	A turbine propelled by the expansion of compressed air, heated by the combustion of a fuel such as natural gas. Widely used for power generation and refrigeration compression.
Hydrocarbon	An organic compound containing only elements hydrogen and carbon. Hydrocarbons exist as gases, liquids and solids. For example Methane, Ethane, Propane, Butane, Pentane, Hexane & Heptanes.
Joule (J)	The unit of energy in the SI system. Defined as one Newton metre. Currently the measure has only been adopted in Australia and New Zealand. For practical purposes mostly used in multiples of Mega Joules (MJ), Giga Joules (GJ), and Peta joule (PJ). 1.0551 GJ = 1 MMBtu.
Liquefied Natural Gas (LNG)	A natural gas which has been cooled to its boiling point of minus 161ºC at which it liquefies, reducing its volume 1/600. Containing >80% Methane, Ethane and Propane.
LNG Train	An independent gas liquefaction unit within a processing facility. A liquefaction facility may contain one or more trains each producing a designed output measured in million tons per annum (Mtpa) .
Liquid Petroleum Gas (LPG)	A hydrocarbon containing primarily Propane and Butane
Methane	A colourless, odourless flammable gas, lighter than air under normal conditions. Molecular structure containing one carbon atom and four hydrogen atoms (CH_4). Methane is the first member in the alkane (paraffin) series and is the primary constituent of natural gas. It liquefies at minus 161ºC.

Propane	The third member of the alkane (paraffin) group with a molecular structure of three carbon atoms and eight hydrogen atoms. It liquefies at minus 42ºC.
Re-gasification	The reconversion (warming) of LNG to a gas for pipeline distribution.
Upsteam	A term used to describe activities along the gas value chain. Upstream typically refers to exploration, development and production of gas.
Wobbe Index	A measure of the rate at which gas will deliver heat on combustion and hence of the compatibility of a gas with gas burning equipment.

CHAPTER 1 - INTRODUCTION

It is widely discussed by governments, scientists and environmentalist that the greatest contribution to be made to slow the pace of global warming is to reduce the use of carbon rich fossil fuels. It is commonly accepted that accelerating trends in global warming are related to the human demand for energy and subsequent release of carbon into the atmosphere. Dashwood (2010) stated that "rising greenhouse gas emissions poses a significant risk to society and ecosystems", and that "many emissions were energy related and it has taken decades for technological advancements to find low carbon energy - efficiency is the largest source of energy".

A submission to the Australian Energy White Paper by Pritchard (2009) suggested that while global energy supply will continue to be dominated by fossil fuels over several decades, a transition to zero and low carbon technologies would be required to reduce resultant greenhouse gas emissions. Liquefied natural gas is expected to provide this transition.

Oil and coal are the largest sources of energy used by humans around the globe. However they produce 1.4 to 1.75 times more greenhouse gas emissions than natural gas (Al-Sobhi et al 2009) on a lifecycle basis. This comparison is also supported by Okamura et al (2007) who has highlighted the increasing popularity of natural gas as a source of clean energy. Natural gas used to be considered as a waste product of the resources industry due to its relatively low calorific value despite its abundance within coal seam deposits and oil fields. Increasingly, natural gas is described as a transition fuel to wean the human race away from dependence on oil and coal.

Natural gas can be difficult to transport over long distances from its source to the consumer. While it is readily transported through pipelines, problems commonly arise when traversing multiple geographical boundaries, difficult terrain, geological instability, diverse political regimes and issues relating to energy security. Liquefied natural gas (LNG) has overcome these problems as a transport mechanism.

The LNG industry began in the early twentieth century when helium was produced from the liquefaction of gas. In 1959 the first international cargo of LNG was transported from the United States Gulf to the United Kingdom (UK). In 1964 commercial cargos of LNG began from Algeria to the UK, followed by LNG to Japan from Alaska in 1969. The first LNG plant in Asia began in 1972 followed by the Middle East in 1977. Global LNG trade by the year 2000 was 100 million tons (Mt) and in 2009 it reached 181 Mt (Gas Strategies 2010). In contrast, over the next 5 years Australia's planned production capacity of LNG is expected top 100 Mtpa alone.

As concerns grow over global environmental issues surrounding greenhouse gas emissions, attention has focused on what tools and techniques are available to prove the acceptability of natural gas as an alternative and transition energy, away from traditional fossil fuels (oil and coal) and towards renewable energies (solar, wind, thermal and wave). A life cycle assessment (LCA) is an accepted method to systematically quantify and assess environmental impacts during the life cycle of a product, process or activity. It can be described as a 'cradle to the grave' assessment, facilitated by the use of computers as a tool to assist model simulation.

Assessing the greenhouse gas emissions of liquefied natural gas is facilitated through a life cycle assessment. Emissions of interest are carbon dioxide, methane and nitrous oxide which are classed as greenhouse gases related to global warming. Chapter four discusses in detail the definition and calculations of greenhouse gas emissions.

Reductions in emissions through the use of liquefied natural gas have been reported in research conducted over the last ten years and further improvements are expected through advancements in technology. Tana (2010) stated that "LNG has an important role to play in delivering energy to China with 35% less greenhouse gas emissions than coal". Tana (2010) also advised that Queensland Gas Corporation (QGC) had reduced its original forecast emissions intensity by 27% through front end engineering design (FEED) by using aero-derivative gas turbine technology and low gas inflow temperatures in its liquefaction plant design for Curtis Island (QCLNG). England based BG Group is the owner of QGC and the QCLNG project, which obtained conditional environmental approval from the Australian Commonwealth government on 22nd October 2010 to develop one of the most efficient liquefaction facility in the world.

Life cycle assessments can be complex whilst attempting to analyze all elements of a product. The most recent LCA completed by Okamura et al (2007) on LNG, concluded that emissions were less than 11.93 grams of carbon dioxide equivalents per mega Joule of heat energy during liquefaction, transportation and re-gasification. Okamura et al (2007) also demonstrated emissions had reduced since 1997 and projected the feasibility of further reductions.

This study has researched LNG's product lifecycle within the induced liquid phase of liquefaction, shipping and re-gasification; assessing its environmental impact as a low carbon energy source. Chapter two provides a review of background literature, and chapters five, six and seven provides a summary of the emission results obtain from liquefaction, shipping and re-gasification of LNG.

CHAPTER 2 - LITERATURE REVIEW

2.1 What is liquefied natural gas

Liquefied Natural Gas (LNG) is an odorless, colorless liquid consisting of natural gas cooled to minus 161° Celsius, which is the temperature at which the primary species, methane liquefies. Upon liquefaction, the volume of natural gas reduces by approximately one six hundredth, making it ideal for bulk transport at atmospheric pressure as a boiling liquid in custom designed LNG ships (Gas Strategies 2010).

The chemical components of LNG are methane, ethane, propane and butanes. The calorific heating value of LNG as an energy source depends upon the quality of the source gas reserves and market demands. The quality of natural gas is commonly defined by its Wobbe index and gases are mixed to meet the specification of the market. The European gas markets require lean gas and the Asian gas markets require heavy gas; which impacts the design of the burner tips used in different countries. The calorific value of LNG is usually expressed in terms of energy per unit volume of gas. The calorific value of natural gas will differ according to its composition and ranges between 37.99 and 43.20 MJ/m^3.

Methane represents over 85% of the LNG composition producing 37.61 MJ/m^3, ethane produces 65.92 MJ/m^3, propane produces 93.85 MJ/m^3 and butanes produce 121.41 MJ/m^3 (Gas Strategies 2010). LNG is described as ‘lean’ or ‘heavy’ depending upon is composition of propane and butanes. Propane and butane are classed as a Liquid Petroleum Gas (LPG) representing less than 10% of LNG composition.

LNG is inconveniently described in different measures of quantity. Liquefaction and re-gasification plant capacities are described by mass in metric tons (t), storage and shipping capacities are described in volume as cubic metres of liquid (m^3) and market contracts as energy in millions of British thermal units (MMBtu), mega Watt hours (MWh), millions of Joules (MJ), thousands of calories (kCal) or numerous other units which deviate from standard international (SI) units.

LNG currently represents only 7% of the world natural gas supply. In 2009 the top ten exporters of LNG were Qatar, Indonesia, Algeria, Malaysia, Australia, Trinidad, Nigeria, Egypt, Oman and Brunei; representing approximately 90% of supply. Regionally, 30% of LNG is produced from the Atlantic Basin, 40% is produced from the Pacific Basin and 30% produced from the Middle East (Gas Strategies 2010).

Gas Strategies (2010) reported that the top ten LNG importers are Japan, Korea, Taiwan, Spain, France, Belgium, Turkey, Italy, United Kingdom (UK) and the United States of America (USA). The Asian region represents the largest of the importers. However LNG storage capacity is limited and seasonally constrained. Surplus LNG supply is readily accepted into the USA at Henry Hub market prices; however LNG liquefaction plants are commonly designed to match long term supply contracts.

LNG market prices are pegged to the global price of crude Oil in US dollars. Supply contacts are typically negotiated between producers and importers during construction planning of the liquefaction plant and are medium to long-term based on forecast supply and demand. For example, Japanese buyers prefer long-term LNG supply contracts (+15 years) and are expected to increase demand from 60 million tons per annum (Mtpa) in 2009 to 80 Mtpa by 2020 (Gas Strategies 2010). Increased demand in Japan is driven by ongoing problems with nuclear power reliability, strict government carbon emissions targets, limited capacity for domestic energy production and security of energy supply.

There are currently 17 liquefaction and export terminals in the world (two are in Australia) and 40 import and re-gasification terminal (25 of which are in Japan). Australia has an additional 10 new LNG plants firmly proposed of which several are currently under construction or awaiting final investment decision (FID) following federal government approval of environmental impact assessments.

A significant investment is required to establish a natural gas process chain including the LNG phase. The chain consists of the upstream well-head, liquefaction plant, shipping, and re-gasification plant. Table 2.1 illustrates an example of the gas self-consumption and capital investment cost in an 8 Mtpa LNG process chain. This means the liquefaction plant is designed to produce 8 Mtpa of LNG for shipping. In reality a liquefaction plant may consist of a number of production 'trains' to facilitate production management, scheduled maintenance shutdowns and ownership structures. In the case of Chevrons Australia Pty Ltd joint venture investment in the new Gorgon LNG plant on Barrow Island in North Western Australia, it is designed to produce 15 Mtpa using three 5 Mtpa trains.

	Upstream	**Liquefaction**	**Shipping**	**Re-gasification**	**Total**
Gas Use	Nil	10-14%	1.5-3.5%	1-2%	12.5 – 19.5%
Capital expenditure	$2-6bn	$6-10bn	$1-2.5bn	$1-1.5bn	$10-20bn
Unit cost ($/MMBtu)	$1-3	$3-4.5	$0.8-1.5	$0.4-0.8	$5.2-$9.8

Table 2.1:- Investment based on an 8 mtpa LNG process chain (Gas Strategies 2010).

To obtain a perspective of the LNG process, an LNG ship may have a carrying capacity of 140,000m^3 (approx 62,000t of LNG per voyage). If it transports LNG consisting of 30 Btu/m^3 at a market price of $8 USD/MMBtu, the market value of the shipment is $25.15M USD. Therefore, the 8 Mtpa LNG plant is generating annual revenues of $3.2bn USD (FOB), and will commercially break-even after 5 years operation, followed by 10 to 15 years of profitable production and shareholder returns.

The size of the liquefaction plant (Mtpa) and the number of process trains will depend upon the quantity and quality of the gas reserves, matched to supply contracts.

LNG projects require large gas resources to demonstrate economic feasibility. Initially a project will require a 2-4 year build-up phase to reach an optimal 15 year production plateau, followed by reducing production from tail gas and ultimate decommissioning of the gas field.

While liquefaction plants are primarily designed to cool natural gas for efficient transportation, natural gas from the well head is mixed with impurities such as water, carbon dioxide, hydrogen sulfide, mercaptans, mercury and condensates which must all be removed to ensure process efficiency and market quality LNG.

2.2 Liquefaction emissions

Carbon dioxide equivalent (CO_2-e) emissions are discharged during liquefaction, when natural gas is used to fuel gas turbines which power the plants and refrigeration compressors. Fuel consumption is dependent upon the efficiency and productive capacity of the liquefaction plant (Tamura et al 2001) and subsequently represent an area of further research.

The main types of greenhouse gas emissions in LNG liquefaction identified by Arteconi et al (2010) were:

- Fuel consumption for driving turbines and motors to operate equipment.
- Combustion of waste gases in flares.
- Gas losses from venting associated with pre-treatments, maintenance processes and losses from equipment and pipes.

CO_2-e emissions also occur during flare combustion, emissions of raw gas (leaks) and venting. During the liquefaction process, carbon dioxide (CO_2) is initially removed from natural gas using amines as a solvent. This regeneration process causes CO_2 and methane (CH_4) to be dissolved in small quantities (Tamura et al 2001). CH_4 is typically recovered and used as fuel for turbines, while CO_2 is released to the atmosphere as off-gas. Emissions from gas leaks also occur at liquefaction compressors, valves and flanges but are almost too small to measure and considered insignificant.

Each part of the liquefaction process has a role in purifying inflow natural gas prior to cooling and storage. There are a number of propriety equipment designs and processors from different companies who service the LNG industry. These technologies are described in chapter 4.

During liquefaction heavy hydrocarbons called condensates are separated from inflow natural gas. To calculate the proportional division of grams of carbon per mega Joule of heating energy (g-C/MJ), Tamura et al (2001) applied a balance equation described in table 2.2 below.

		Formula for proportional division (g-C/MJ)
Liquefaction	Fuel consumption	CO_2 from fuel consumption / (Condensate + LPG + LNG)
	Flare combustion	CO_2 from flare consumption / (Condensate + LPG + LNG)
	CH_4 from venting	CH_4 from venting / (Condensate + LPG + LNG)
CO_2 in input gas		CO_2 in raw gas / (Condensate + LPG + LNG)
Emissions		CO_2 + CH_4
Product		Condensates + LPG + LNG

Table 2.2:- Formula for calculating the proportional division of CO_2 emissions.

Studies on the LNG lifecycle completed by Tamura et al (2001) are summarized in table 2.3. Emissions intensity is expressed as CO_2-e per heating value of LNG. Tamura et al (2001) calculated that energy self-consumption during liquefaction was 8.8% compared with 10-14% historically reported. This efficiency improvement was a result of new technologies in co-generation systems, waste heat recovery, electricity recovery from pressurised gases and improvements in load factors. Anecdotally, at an Engineers Australia seminar in September 2010, Origin energy in Queensland Australia suggested a design requirement for self-consumption of only 6% for its coal seam gas (CSG) supply to Australia Pacific LNG (APLNG) on Curtis Island in Gladstone.

Energy self-consumption rate in liquefaction (%) = (fuel gas consumption in the liquefaction plant on a heat value basis x 100) / (gas input in the liquefaction plant on a heat value basis. However, consumption rates are correlated to reservoir and liquefaction facility design energy efficiency.

Tamura et al (2001) also calculated the weighted average concentration of CO_2-e in natural gas at the well head was 3.5%. This is lower than the 6-7% historically reported and is a reflection of gas quality.

In more recent years, the Australia LNG industry has planned the introduction of the most advanced liquefaction plants in the world at the Gorgon LNG plant. On Monday 11th October 2010 the 'West Australian' newspaper reported that Chevron Australia's managing director Roy Krzywosinski, plans to inject up to 4 million tons of carbon, 2.5 kilometres underground each year by 2015; once liquefaction is fully operational.

Gorgon LNG promises to be the first liquefaction plant to use carbon geo-sequestration technology to capture carbon dioxide. This technology is essential for Chevron Australia Pty Ltd to satisfy environmental approval conditions to process inflow gas with a CO_2 concentration of 16 mol %; of which 80% of the CO_2 is expected to be captured for storage and 20% of the CO_2 will be vented to the atmosphere.

In contrast, INPEX owned Ichthys LNG and Shell's Prelude floating LNG which also have high inflow gas CO_2 concentrations are expected to fully vented emissions. However emissions could be mitigated against carbon offsets through forestry plantations.

Chevron's carbon sequestration technology, when proven to be successful in the coming years, could have significant benefits for the broader energy industry including coal and diesel fueled power stations emissions reductions.

Stage of LNG Lifecycle	**Tamura et al 2001**	**Average (g-C/MJ)**	**Minimum (g-C/MJ)**	**Maximum (g-C/MJ)**
Liquefaction	CO2 from fuel consumption	1.43	1.30	1.57
	CO2 from flare combustion	0.09	0.00	0.18
	CH4 from venting	0.15	0.01	1.15
	CO2 in raw gas	0.47	0.01	0.77

Table 2.3:- Results of LCA of LNG CO_2 emissions during liquefaction based on 1997 data (Tamura et al 2001).

Stage of LNG Lifecycle	Okamura et al 2007	Average ($g\text{-}CO_2/MJ$)	Minimum ($g\text{-}CO_2/MJ$)	Maximum ($g\text{-}CO_2/MJ$)
Liquefaction	CO2 from fuel consumption	5.60	4.58	8.22
	CO2 from flare combustion	0.42	0.07	1.04
	CH4 from venting	0.47	0.00	1.76
	CO2 in raw gas	1.87	0.07	5.66

Table 2.4:- Results of LCA of LNG CO2 emissions during liquefaction based on 2003 data (Okamura et al 2007).

There is a difference between the liquefaction emissions reported by Tamura et al (2001) and Okamura et al (2007). While the results are the weighted averages of emissions from different source locations (inclusion of data from Qatar and Abu Dhabi in 2003); there is a difference in emissions measure from g-C/MJ to $g\text{-}CO_2/MJ$. This highlights the importance of defining the units of measurement relevant to a reporting standard.

Jaramillo et al (2006) assessment of LNG emissions was determined as a simple conversion of Tamura et al (2001) liquefaction emissions into the units of pounds of CO_2 per million BTU (lb CO_2/MMBtu), highlighting the numerous unit conventions adopted in the gas industry of different countries.

A standard measure of emissions has been adopted in this study of grams of carbon dioxide equivalents per mega Joule (g CO_2-e/MJ) and defined in chapter 4.

In another report by Arteconi et al (2010) it was assumed that gas flaring during the lifecycle of LNG accounted for 1% of the total emissions however, no evidence has been identified to validate the calculation.

Arteconi et al (2010) studied the lifecycle emissions of LNG as a fuel for vehicles in Europe compared to diesel. It was concluded that total emissions of LNG decreased linearly with the increase of liquefaction efficiency. Moreover, that LNG imported to Europe produced 10% less emissions than diesel, highlighting opportunities for further improvements in LNG liquefaction efficiency. Arteconi et al (2010) also recommended that a study of the emissions from LNG could be improved using a survey of data collected directly from an LNG production site, and this should be the objective of future studies.

In contrast to oil and coal which relies on mature technologies to produce useful energy, it is expected that further reductions in emissions from the LNG lifecycle can be achieved through a greater penetration of LNG fuel into the energy market (coupled with a reduction in reliance on energy from oil and coal), improved production efficiency in liquefaction plants, the development and introduction of new technology for carbon geo-sequestration, and the use of larger LNG transport ships (economies of scale).

Tamura et al (2001) and Okamura et al (2007) released high quality results on the analysis of greenhouse gas emissions from the LNG lifecycle. Their lifecycle range was between extraction of the natural gas from the well head, liquefaction and transport to final consumption (including plant manufacture and cryogenic use efficiencies). The LCA was focused on LNG supplied to Japan from a number of different countries. While the methodology was comprehensive it left open opportunities for the following research:-

- To assess of the proximity of Australian gas fields to Asian markets compared to producers in the Middle East and Atlantic Basins. Potentially Australia has a competitive advantage to supply the energy demands of the Asian markets at a lower carbon emission costs.
- The applications of carbon dioxide geo-sequestration technology at a liquefaction plant to reduce carbon dioxide emissions during flaring and venting. This would be particularly important in gas fields with high carbon dioxide concentrations but limited by suitable geological sites.
- The use of new processing technologies to reduce emissions and improve efficiency. Modern technology can also support process automation using microprocessor to operate complex operating systems and simulation models to lower costs and improve product quality.

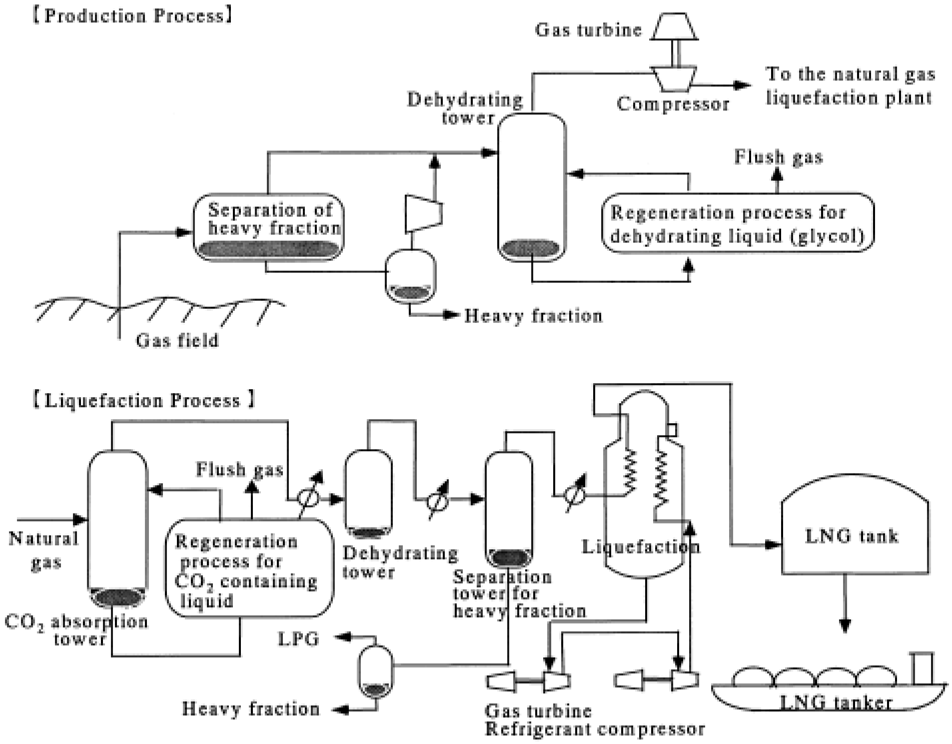

Figure 2.1:- Gas production and liquefaction process (Tamura et al 2001 page 305)

Figure 2.1 provides an illustration produced by Tamura et al (2001) describing the process flow of natural gas through production and liquefaction to storage and shipment in an LNG tanker. The liquefaction process is complex due to the removal of CO_2 and other impurities from the natural gas. CO_2 freezes to a solid if it remains in the gas during liquefaction, causing blockages and subsequent shutdown of trains for maintenance which results in further increased emissions.

2.4 Shipping emissions

LNG is transported to Asian markets in specially designed ships, which deliver their load to re-gasification terminals. The main type of CO_2-e emissions in LNG shipping is from fuel consumption on board the ship and LNG boil-off gas (CH_4). It is adequate to assumed that boil-off gases from the LNG being transported is either used as fuel to operating the ship or re-liquefied using on board plant (where installed).

Tamura et al (2001) completed studies on LNG ships travelling between Indonesia and Japan and estimated that CO_2-e emission intensity per ton of LNG transported was 2.4 g-C/t km; equivalent to 0.4 g-C/MJ. Estimates included the average amount of LNG loaded, amount of boil-off-gas (BOG), fuel consumed and cargo handling.
The emissions from LNG shipments relates to the volume of LNG transported and the distance travelled by the ship. LNG ship's fuel consumption can be obtained from Lloyd's of London Register of Shipping. Jaramillo et al (2006) estimated a comparable LNG transport emission range between 2.2 and 7.3 lb CO2/MMBTU and described the emissions from LNG shipping in equation 1.

$$EmissionFactor = \frac{(EF)\sum_x [\left(2 \times roundup\left(\frac{LNG_x}{TC}\right)\right) \times \frac{D_x}{TS} \times FX \times \frac{1}{24}]}{LNG_T}$$

Equation 1:- Jaramillo et al (2006) shipping emissions factor

In equation 1 the emissions factor is measured in lb CO_2/MMBtu, EF is the tanker emission factor of 3,200 kg CO_2/ ton of fuel consumed; 2 is the number of trips each tanker does for delivery of each load; LNGx is the amount of natural gas (in cubic feet) brought from each country; TC is the tanker capacity in cubic feet of natural gas (assumed to be 120,000 m^3 of LNG (1m^3 LNG = 21,537 ft^3 NG); Dx is the distance from each country; TS is the tanker speed of 14 knots; FC is a fuel consumption of 41 tons of fuel per day; and 24 is the number of hours in a day.

Jaramillo's et al (2006) formula was adopted (in part) for this study to calculate shipping emissions but modified into metric (SI units) to calculate grams of CO_2-e/MJ of LNG delivered, using researched average shipping distances, fuel usage, ship sizes and onboard technology.

It is apparent that LNG ships travelling between Australia and Asian markets will traverse a shorter distance than ships from the Middle East or Atlantic basin. Australian LNG can expect to produce lower emissions from transportation.

Item	Results
CO2 emissions intensity for transportation of 1t on LNG (g-CO2-e/(t km))	8.17
Weighted average transport distance (km)	6620
CO2 emissions intensity at LNG transportation stage (g-CO2-e/MJ)	1.97

Table 2.5:- Results of LNG transportation – stage analysis (Okamura et al 2007)

Okamura et al (2007) used the weighted average of LNG transported from the source country to Japan to calculate the CO_2-e emissions intensity in table 2.5, in a similar process to Jaramillo et al (2006). The difference in results is primarily dependent upon the distance to market, ship size and ship fuel use efficiency.

Okamura et al (2007) expected that an increase in the size of LNG ships would have a positive impact on transport efficiency and emission reductions. This may occur though economies of scale, assuming LNG receiving terminals have adequate storage facilities and port berthing facilities can handle large ships. It is also expected that LNG ships will reduce their use of heavy fuels and optimize the use of boil-off gas (BOG) from LNG for power. Alternatively LNG ships will require small liquefaction plants on board to reprocess BOG.

2.4 Re-gasification emissions

At the receiving terminal, CO_2-e emissions occur due to the electrical energy required to drive pumps used to transfer the LNG from the ship to storage facilities and re-gasification plant. Boil-off gases are considered to be recovered during re-gasification. It is generally assumed that re-gasification occurs in close proximity to the ship receiving terminal.

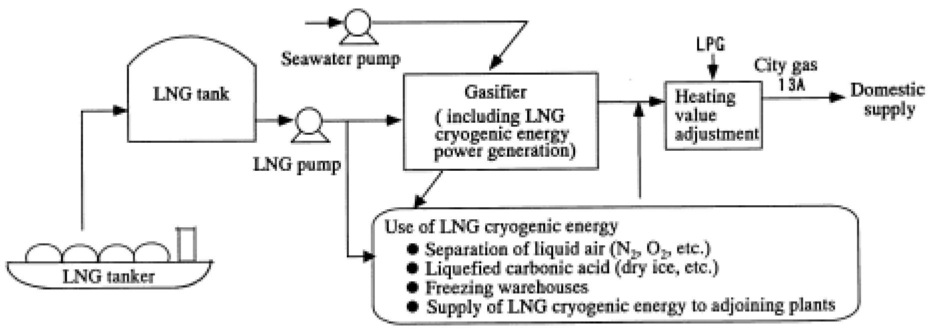

Figure 2.2:- LNG receiving and re-gasification terminal (Tamura et al 2001 page 310)

Figure 2.2 (Tamura et al 2001) illustrates the process flow of LNG from a ship to a re-gasifier prior to remixing the gas with LPG's to satisfy the required market Wobbe Index and distribution into the local pipeline network. It also illustrates the use of the LNG's cryogenic energy for cold storage and industrial processing.

It is feasible to leverage off the cryogenic benefits of LNG to operate cold storage facilities and further reduce CO_2 emissions, through mitigating the use of electricity to power refrigeration compressors. Okamura et al (2007) has completed reliable research that using cryogenic energy reduces CO_2 emissions intensity by 0.15 g-CO2-e/MJ.

Jaramillo et al (2006) calculated emissions from re-gasification of between 0.85 and 3.7 lb CO2/MMBtu; essentially adopting Tamura et al (2001) calculation of 0.1 g-C/MJ as a lower value and older industry values of 1.6 g CO2-e/MJ as the upper value.

Technological used in re-gasification has developed over time. Initially self consumption of natural gas was used to heat the LNG using burners and baffles, later electric drive pumps were used circulating sea water. Modern re-gasification facilities use the cryogenic benefits of LNG to cool the inflow air of power generation turbines and waste heat recovery to warm the LNG. This allows re-gasification to occur at modern facilities with zero emissions.

2.5 Summary

Carbon dioxide emissions from LNG liquefaction, transportation and re-gasification calculated by Tamura et al (2001) are 2.64g C/MJ. This is lower than previous industry estimates of approximately 5g C/MJ, reflecting better quality data and technological improvements in the LNG process. In contrast Okamura et al (2007) reported 10.33 g CO2-e/MJ. Okamura et al (2007) results do not demonstrate a higher emission, they reflect the atomic weight of carbon dioxide not elemental carbon used by Tamura et al (2001).

Okamura et al (2007) studied LNG supplied to Japan during 2003. The study is appropriate to the Australian LNG industry with a target market in Asia. Okamura et al (2007) reported life cycle CO_2-e emissions were between 0.6% and 0.9% lower in 2003 than in previous reports produced by Tamura et al (2001) on 1997 data. Okamura et al (2007) also predicted that emissions in 2010 would be between 1.1% and 1.2% lower than 2003 due to reduced shipping distances of LNG to Japan and efficiency improvements in liquefaction. Further reductions in potential emissions were also expected in the construction of new LNG plants being planned in Australia using new technologies.

CHAPTER 3 - METHODOLOGY

The aim of this project was to research natural gas within an induced liquid phase through liquefaction, shipping and re-gasification to assess its environmental impact as a low carbon energy source.

Previous studies have been completed on the emissions of liquefied natural gas (LNG) however these have not assessed the forecast growth of the Australian LNG industry, and its comparative emissions to other global producers supplying LNG to Asia.

A lifecycle assessment provides a methodical approach to understanding the impact LNG has on the environment through its greenhouse gas emissions. A lifecycle assessment (LCA) has been used to identify emissions in the form of carbon dioxide equivalents (CO_2-e), occurring during the phase where LNG is a liquid. The project quantifies system losses of CO_2-e to the atmosphere and identifies key area for process improvement.

This study was conducted in the following manner:

- Research existing and proposed liquefaction plants in Australia to identify technology and processes to analyse greenhouse gas emissions data.
- Research existing and proposed LNG shipping between Australian production facilities and Asian markets to determine ship capacities and average travel distances in order to calculate average greenhouse gas emissions.
- Research re-gasification processes at receiving terminals in Asia to calculate greenhouse gas emissions.
- Use a simple excel spreadsheet model to analyse the average greenhouse gas emissions in grams of carbon dioxide equivalents per mega Joule (g CO_2-e/MJ) of LNG delivered to market and draw comparisons with other studies.
- Discuss technology and process improvements for LNG production.

During design of the study specifications, consideration was made to the use of a commercially available life cycle assessment tool. Whilst there are a number of tools available the cost of purchasing the software and the time required to become proficient in their use could not be justified for this study. Microsoft Office base excel spreadsheet package provided a cost effective and simple analysis tool.

In this study a base average calorific value in mega Joules per cubic metre (MJ/m^3) was determined for natural gas (feed gas) entering a liquefaction plant. The raw data was obtained from public records of oil and gas companies such as Chevron Australia Pty Ltd, BG Group and industry analysts, Wood Mackenzie Research. Feed gas data provided carbon dioxide concentration (mol %) and gas quality in British thermal units per cubic foot (Btu/scf), which were converted into Standards International (SI) units.

Australian liquefaction plants (existing and proposed) use a combination of proprietary technologies and are required by government to assess their carbon dioxide equivalent emissions per ton of LNG produced annually (NGERA 2007). There are a number of complex variables considered by oil and gas companies in selecting liquefaction technology. These are described in detail within chapter 5. In this study each liquefaction plant in Australia was assessed comparatively using the greenhouse gas index (GI), which is the ratio of CO_2-e per ton of LNG produced annually. This index was then converted to liquefaction emissions as grams of CO_2-e/MJ of LNG produced at normalised (design) operation.

Sound evaluation of the environmental impacts of an LNG project requires an understanding of the unique characteristics of each facility design, in order to determine the optimal thermal efficiency and strongest economic boundaries. Yates (2002) suggests that different LNG technologies or plant designs can not be compared or benchmarked on thermal efficiency, unless the unique differences between projects are compensated. This study provides an overview of the processes and technology used in the industry.

During the front end engineering design (FEED) of a liquefaction plant the projected LNG off-take supply is presold under long term contracts. LNG buyers usually also invest as a minor shareholding of the plant ownership structure, and proceed to select shipping resources to be use for the collection of LNG from Australian during the life of the project.

The size of the ships used by LNG buyers will impact the design and construction of port berthing facilities. Once a ship size, on-board processing technology and destination port has been identified; the carbon dioxide equivalent emissions can be calculated. It is critical to identify the correct size and type of ship to be used by LNG buyer to ensure suitable calculation of emissions from the fuel usage. Chapter 6 discusses the calculation of the average CO_2-e emissions incurred during transportation of LNG from Australia to Asian markets.

LNG buyers collect and transport their product to port-side re-gasification facilities at import terminal. Energy used in pumping the LNG and technology used to heat the LNG (converting it back to a gas) is discussed in Chapter 7. The type of technology used during re-gasification will impact the energy use and resultant emissions.

An LNG life cycle assessment was completed by Tamura et al in 2001 using 1997 data and again by Okamura et al in 2007 using 2003 data. These internationally acclaimed studies have been reviewed for comparison; however different lifecycle parameters have been used. Figure 3.1 illustrates the boundaries of this lifecycle assessment of LNG within its liquid phase.

The rational of completing an LCA on only the liquid phase, is to focus attention on the three defined stages of LNG as a transport mechanism. These stages are illustrated in figure 3.1. This study excludes emissions from the up-stream well head, initial manufacture of infrastructure, final decommissioning of plant, liquefaction ramp-up and gas consumption by the end user. These potential sources of emissions are excluded to ensure the scope of study. There are opportunities for broader LCA research to be undertaken by industry technicians with greater access to commercially sensitive data.

A normalised LNG production state was assumed in this study for representation of an optimal (plateau) period of liquefaction. A normalised production state is also adopted by companies preparing environmental impact statements (EIS) for project approval submissions to state and commonwealth governments in Australia. As a result, greenhouse gas emissions during production ramp up and decommissioning are likely to be overstated.

The study by Tamura et al (2001) used a methodology based upon the International Standards Organisation (ISO) environmental management sector. As a reference standard ISO 14040:2006 and ISO 14044:2006 are used in this life cycle assessment of liquefied natural gas aimed at reducing the impact a product and production processes has on the environment. The LCA aims to drives process and technology efficiency to support the production of energy with low carbon emissions.

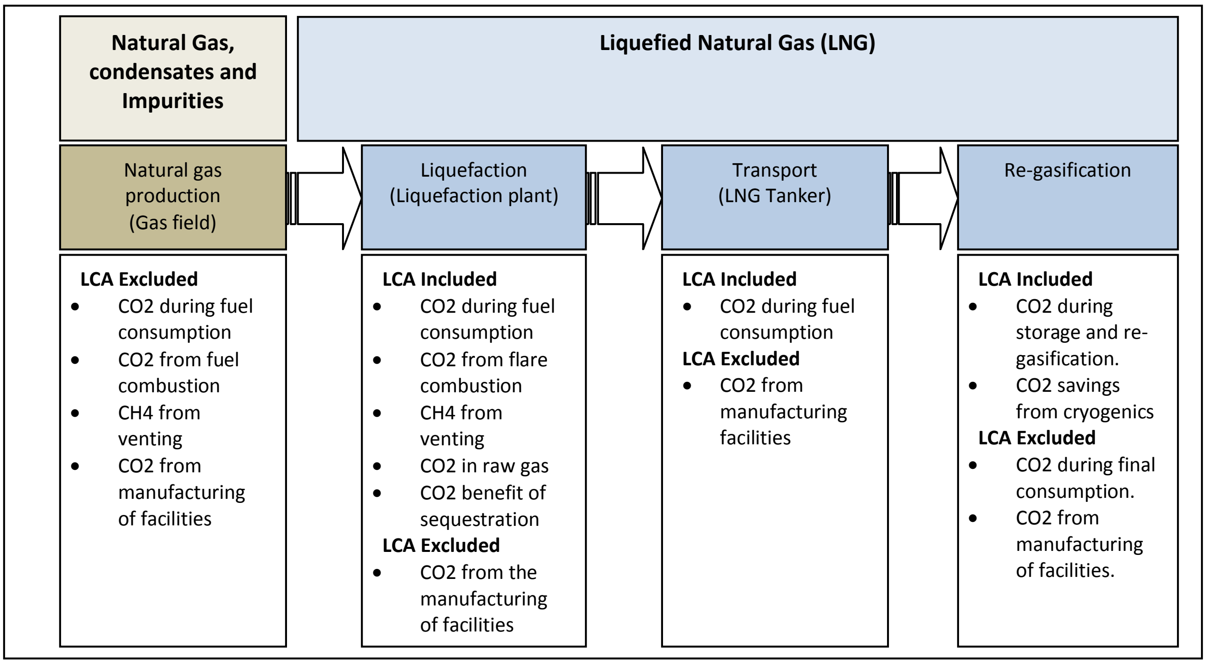

Figure 3.1:- Lifecycle CO_2 analysis of natural gas transported as LNG

This study of the lifecycle assessment of liquefied natural gas and its environmental impact as a low carbon energy source has required significant research. As a new industry for Australia much information has not been published in texts. A five day international LNG training course was attended with Gas Strategies (2010) in Singapore and Perth to study all parts of the LNG value chain from production to consumption. Subscriptions were taken with ‘Gas Matters’, the ‘Oil & Gas Journal’, Wood Mackenzie research data website; and a number of oil and gas technical conferences were attended, including the Society of Petroleum Engineers (SPE) Asia Pacific Oil & Gas Conference and Exhibition (APOGCE) in Brisbane, Queensland.

While employed in Asia a full appreciation of the costs and unreliability of energy supply and the resultant pollution of existing technologies inspired further study into Australian energy resource production. Development of an interest in LNG as a low carbon energy developed a deeper understanding of the technical and economic challenges faced by engineers to locate, extract and value add new energy sources.

Australia appears to have a natural competitive advantage in the export of lower carbon energy, which could reduce the use of less efficient energy sources such as coal and heavy oil.

CHAPTER 4 – GREENHOUSE GAS EMISSIONS

The Australian government has introduced the National Greenhouse and Energy Reporting Act 2007 (NGERA) to "provide for the reporting and dissemination of information related to greenhouse gas emissions, greenhouse gas projects and energy production consumption". Corporations operating in Australia must annually report their greenhouse gas emissions greater than 25,000 tons. Whilst the total emissions data reported by companies each year is publicly available, the assumptions and itemised details of their calculation are not available for analysis. It must therefore be assumed that emissions reported by corporations in Australia comply with the methodologies prescribed within the NGERA 2007 and suitable auditing has been undertaken.

As a result of the stringent environmental policies and legislation in Australia, engineers and managers need to assess a projects annual contribution to global warming (Aube 2001). This is achieved by calculating the greenhouse gas (GHG) or carbon dioxide equivalent emissions (CO_2-e) associated with energy use.

The Kyoto Protocol (ratified by Australia in 2007), describes six commonly reported greenhouse gas emissions. These are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluro-carbons (HFC), perfluro-carbons (PFC) and sulphur hexafluoride (SF_6). Hydrofluro-carbons, perfluro-carbons and sulphur hexafluoride are not a feature of LNG lifecycle emissions and are excluded from further investigation.

Emissions from methane and nitrous oxide have higher global warming potential than carbon dioxide and are converted to carbon dioxide equivalents (CO_2-e) using standard global warming potentials (GWP). The GWP of a gas is assessed by its impact on the environment over a 100 year period. Table 4.1 summaries the GWP's attributable to carbon dioxide, nitrous oxide and methane.

	CO_2	N_2O	CH_4
GWP	1	310	21

Table 4.1:- Global warming potentials of gas emissions

The calculation of CO_2-e is a relatively simple process however the steps involved in the process are time consuming and obtaining commercially sensitive data can be difficult. The calculation steps require the collection and evaluation of all fuel and electricity used or its projected use for the reporting period (Aube 2001). Depending upon the project design and efficiency; energy use is converted into a reference unit.

Table 4.2 summarises the emissions factors for typical fuels consumed as an energy source during liquefaction, shipping and re-gasification (Aube 2001 & Gas Strategies 2010). Depending upon the type and volume of fuel used the applicable GWP and emissions factors are applied to calculate emissions (g CO_2-e/MJ of LNG delivered to market).

	CO_2	N_2O	CH_4
Natural Gas	49.68 (t/TJ)	0.52 (kg/TJ)	1.1 (kg/TJ)
Diesel Oil	2830 (kg/m³)	0.013 (kg/m³)	0.006 (kg/m³)

Table 4.2:- Emission factors for fuel (Aube 2001)

The calculation of CO_2-e in this study of LNG requires the calculation of the sum total of emissions per ton of LNG produced at liquefaction plus the emissions per cubic metre of LNG transported to market, plus the emissions per mega Joule of LNG re-gasified. As a result, the reference units adopted for the study are grams of CO_2-e per mega Joule of LNG delivered to market (g CO_2-e/MJ).

	Calculation of t CO_2-e / t of fuel consumed
LNG	$37.23MJ/m^3 \div 0.000768m^3/t$ x $(1x49.68t/TJ + 310x0.52kg/TJ + 21x1.1kg/TJ)$ $= 2.4173t\ CO_2e/t$ LNG
Diesel Oil	$(1 \times 2830kg/m^3 + 310 \times 0.013kg/m^3 + 21 \times 0.006kg/m^3) \div 0.832t/m^3$ $= 3.4064t\ CO_2e/t$ diesel

Table 4.3:- Calculation of carbon dioxide equivalent emissions of LNG and diesel.

Using the GWP (table 4.1) and emissions factors (table 4.2) the CO_2-e emissions for LNG and Diesel are calculated in table 4.3. These values are used to calculate the emissions of fuel consumed during the LNG product lifecycle.

To provide perspective, natural gas can produce 37.23 MJ/m^3 compared to diesel at 38.68 MJ/l. However, when natural gas is converted to a liquid it stores potential energy of 48.48 GJ/t compared to 46.49 GJ/t for diesel. In terms of green house gas emissions, LNG provides 20.06 GJ/tCO_2-e compared to Diesel at 13.65 GJ/tCO_2-e. This means that LNG provides 31.95% more energy for the same greenhouse gas emissions.

LNG has become widely popular in Europe as a new fuel for ships, tugboats, trains, buses and trucks, potentially replacing diesel as a fuel. New engine design is allowing primary consumption of LNG and alternate consumption of diesel depending upon fuel supply access.

Wartsila (2010) has advised that engines using gas for operation provide greater environmental advantages over diesel. When engines operate in gas mode emissions are very low. NO_x emissions are 80% lower than standards set by the International Maritime Organisation (IMO), SO_x emissions are negligible and CO_2 emissions are 25% to 30% lower than diesel. A gas engines is cleaner, more reliable, highly efficient and operates at a lower decibel noise level than diesel.

The shipping industry is a good example of how global activity governed by international laws has implemented strict emissions standards. Wartsila (2010) is a multinational company providing new technology in equipment design or retro-fitting old equipment to ensure minimum greenhouse gas emissions. While advanced technology is available in Australia from Europe, the adoption rate of new technology is associated with local emissions standards and technology cost. Wartsila (2010) suggested their technology is not fully utilised in Australia as emissions standards are not as high as Europe.

CHAPTER 5 - LIQUEFACTION

5.1 Process overview

The process of liquefaction begins when feed gas from the upstream well head entering the liquefaction plant under pressure. Figure 5.1 illustrates the process flow of liquefaction. Initially heavy hydrocarbons (liquids) are removed from the feed gas and further treated in an acid gas recovery unit to remove carbon dioxide, hydrogen sulphide, mercaptans, water and mercury. The intensity of the feed gas treating process is dependent upon the inflow gas quality and concentration of impurities.

Carbon dioxide is either vented to the atmosphere, collected for geo-sequestration or used in industrial processing. Carbon dioxide (CO_2) must be removed to below 0.5 mol % to prevent plugging during the liquefaction processed caused by CO_2 freezing at a higher temperature than the targeted methane gas can become a liquid. Blockages cause by frozen CO_2 causes plant shutdown for cleaning which is expensive and time consuming, impacting productivity. Carbon dioxide and sulphur dioxide must also be removed from the inflow gas to prevent acid corrosion of the pipe networks.

Feed gas with high concentrations of carbon dioxide vented to the atmosphere will increase greenhouse gas emissions unless effectively captured and securely stored via geo-sequestration. Feed gas with low concentrations will incur a lower processing cost and low emissions.

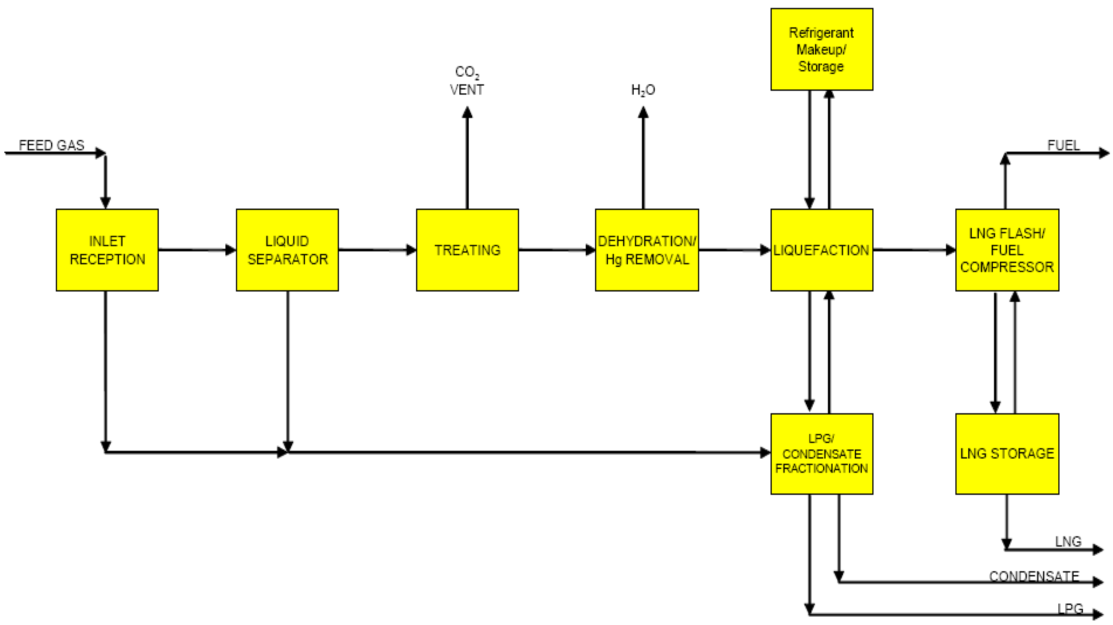

Figure 5.1:- Flow chart of a typical liquefaction process

After the feed gas has been treated in the acid gas recovery facility, it is dehydrated removing water and mercury which are also contaminants that impact the liquefaction process efficiency and end product quality.

Liquefaction occurs through a series of proprietary processes. The dry sweat gas is cooled by a stream of refrigerant separating off heavy hydrocarbons and leaving a targeted gas mixture consisting of primarily methane and less than 0.1 mol% of heavier hydrocarbons. Further cryogenic processing reduces the temperature of the gas to less than minus 161ºC, where it become completely liquefied and can be stored in specially designed insulated tanks prior to export by ship.

Heavier hydrocarbons of propane and butane separated during cooling are typically collected and exported as a Liquid Petroleum Gas (LPG) product. Any ethane separated during this process is reinjected for liquefaction with the methane.

5.2 Technology options for liquefaction

Technology selection for a liquefaction facility is undertaken during the initial feasibility stage of plant development and front end engineering design (FEED).

Factors influencing the technology selection include the facilities designed output capacity (Mtpa), refrigerant streaming processes to be used, compressor configuration, plant location and ambient conditions, plant availability, operational flexibility and economic factors including capital (CAPEX) and operational (OPEX) expenditure (Shukri 2004).

Until the development of the gas turbine, early LNG trains were steam driven. Modern facilities select a range of technology including steam turbines, industrial gas turbines, aero-derivative gas turbines and electric motors, to drive refrigeration compressors or combinations of the before mentioned. Each of these power plants incurs a different level of CO_2-e emission from fuel consumed and heat output.

The process of liquefaction alone typically consumes 10% to 16% of the inflow gas as fuel to generate electric power from gas turbines and to operate refrigeration compressors. The rate of use of gas as a fuel during liquefaction will depend upon the design production capacity, ambient operating temperatures, and access to alternative backup power sources from mains grid power or diesel generators. The plant also requires access to high quality water for cooling and steam or hot oil as a heating medium.

The LNG industry has developed several proprietary technologies for liquefaction and these are provided under licence to operators for the effective life of the plant. The principle of liquefaction involves matching the cooling/heating curves of the inflow process gas and the recycling refrigerant gases. This ensures optimal thermodynamic efficiency is achieved using less power per unit of LNG produced. It is the CO_2-e emissions per ton of LNG produced during liquefaction which is important in this study as it reflects the efficiency of the plant.

While a variety of technologies are used by the major gas companies for liquefaction, ultimate selection of technology is a trade-off of many factors; as liquefaction infrastructure accounts for between 30% and 40% of plant capital costs (Shukri 2004).

Equipment used during liquefaction includes power turbines to drive refrigerant compressors, heat exchanges used to cool and liquefy gas and exchange heat between refrigerants. Natural gas consist of a mix of gases which liquefy at different temperatures, therefore, to match the cooling/heating curve a number of refrigerant gasses are designed for use at high pressures to reduce equipment size and improve efficiency.

LNG drivers are predominantly industrial heavy duty gas turbines produced by General Electric (Frame 5 to 9). Table 5.2 outlines the power and efficiencies of different turbines. Larger and larger processing trains are pushing the current known design limits of compressor technology.

The composition of the recirculated refrigerant gas can be made from a pure gas or a mixture of gasses at each stage of cooling. This provides different elements of process control during liquefaction in line with the inflow gas quality.

The main liquefaction technologies used globally are the APCI propane pre-cooled mixed refrigerant process (MCR™), Phillips optimised cascade process, Black & Veatch PRICO™ process, Statoil/Linde mixed fluid cascade process (MFCP), Axens Liquefin™ process and Shell double mixed refrigerant process (DMR).

5.2.1 APCI propane pre-cooled mixed refrigerant process (MCR™)

This technology is simple for train capacities up to 5 Mtpa. It accounts for the majority of the LNG facilities used world wide. There are two main refrigerant cycles. The pre-cooling cycle uses propane, the liquefaction and sub-cooling cycle uses a mixed refrigerant consisting of nitrogen, methane, ethane and propane.

The pre-cooling cycle uses propane to cool the process gas to minus 40ºC and partially liquefy the mixed refrigerant. The cooling is achieved in an exchanger with propane refrigerant boiling and evaporating with process gas streaming through immersion tubes. A centrifugal compressor recovers the evaporated propane stream and compresses the vapour to be condensed against water or air and recycled. Pre-cooling compression will typically require a 40 MW gas turbine (Frame 6) plus helper motor or steam turbine. Due to the high molecular weight of propane a higher blade Mach number is required resulting in aerodynamic constraints (Shukri 2004), particularly on larger capacity trains.

In the mixed refrigerant cycle (Ethylene and Methane) the partially liquefied refrigerant is separated into vapour and liquid streams used to liquefy and sub-cool the process from minus 35ºC to minus 160ºC. This is achieved through a proprietary spiral wound main cryogenic heat exchanger. This exchanger consists of a bundle of two or three tubes arranged in a vertical shell with process gas and refrigerant entering the bottom flows upwards under pressure. As the process gases pass through the bundles it emerges liquefied at the top. The liquid mixed refrigerant is then extracted and flashed across a Joule Thompson valve (old technology) or hydraulic expander (new technology), flows downwards and evaporates, providing cooling. The vaporised mixed refrigerant stream is recovered via centrifugal or axial compressors.

Early plants used steam turbine drivers but typically now use a Frame 6 or Frame 7 combination for plant capacity between 3 and 3.3 Mtpa, Frame 7 for capacity to 4.7 Mtpa and higher capacities to 7.9 Mtpa will require Frame 7 gas turbines. APCI are using larger and larger gas turbines to reduce CAPEX in a single train configuration operating at 100% capacity for lower $/kW.

Modifications of this process used for large capacity trains (>6 Mtpa) in the APX-process, adds a third refrigerant cycle (nitrogen expander) to provide LNG sub-cooling outside the main cryogenic heat exchanger.

5.2.2 Phillips optimised cascade process

This process uses simple and reliable technology. It has been used for train capacities up to 3.3 Mtpa in Alaska, Trinidad and Egypt. It is also a popular choice of reliable technology selected for installation in Australia. Conoco Phillips established a joint venture with Bechtel Corporation (engineering) to project manage the design and manufacture of this technology under licence for LNG plants in Darwin, Karratha and Gladstone.

Some of the benefits of this process include parallel compressor trains avoiding capacity limitations, no helper turbine or large motor during start-up and higher CAPEX is offset by increased availability of between 95-96% with parallel train operations. In addition, the loss of one train does not cause plant shutdown and refrigerant/exchanger temperatures are not affected by one train trip enabling quick restart.

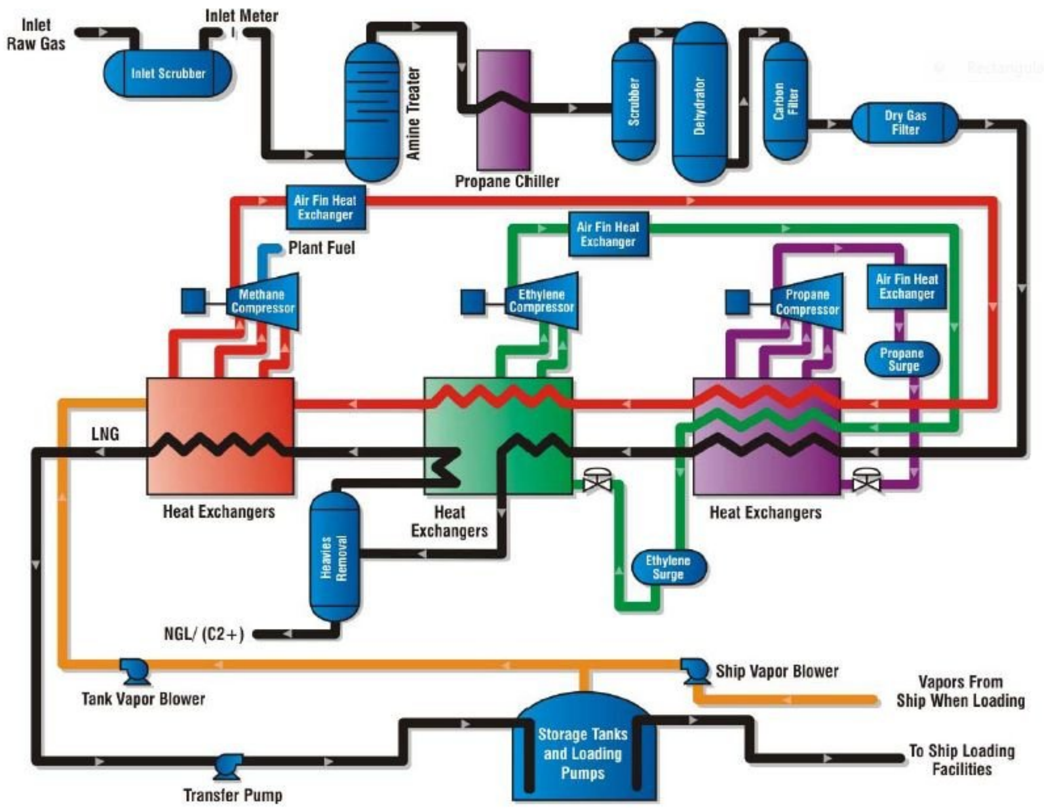

Figure 5.2:- Flow chart of the Phillips optimised cascade

Figure 5.2 illustrates the Phillips optimised cascade process. Refrigeration and liquefaction of the process gas is achieved in a cascade process using three pure component refrigerants (propane, ethane and methane), each at different pressure levels. This is achieved within a series of brazed aluminium vertical cold boxes. The refrigerants are circulated using centrifugal compressors. Each refrigerant has parallel compression trains and power is supplied through Frame 5 gas turbines (Shukri 2004).

Typically two 30 MW gas turbine (Frame 5) drivers will be used for the pre-cooling cycle, and two 30 MW gas turbines (Frame 5) used to power the mixed refrigerant cycle of each plant. The Phillips Optimised Cascade process uses two compressors per train operating at 50% capacity to achieve operating cost savings and high plant availability.

5.2.3 Black & Veatch PRICO™ process

This is a single mixed refrigerant process used on plant capacities up to 1.3 Mtpa. The mixed refrigerant is made up of nitrogen, methane, ethane, propane and iso-propane. The cooling and liquefaction is achieved at several pressure levels. The refrigerant is compressed and circulated using a single compression train typically using an axial compressor driven by steam turbines.

While Black & Veatch provide mid size liquefaction plants, drivers and exchanges are matched to output production capacity. For example an LM2500+ driver will offer capacity of 0.6 Mtpa LNG with a fuel use efficiency of 38.5% at 30°C ambient temperature.

5.2.4 Statoil/Linde mixed fluid cascade process (MFCP)

This process uses three mixed refrigerants to provide cooling and liquefaction. This technology is used for the Snohvit LNG facility in Norway. Snohvit LNG is reported as the most efficient plant in the world due to its cold environment and access to grid electricity mitigating the need for backup diesel powered generators (less CO_2-e emissions).

Following pre-cooling of the process gas with the first stage mixed refrigerant, liquefaction and sub-cooling occurs within a proprietary spiral wound heat exchanger manufactured by Linde. The refrigerants used are a selection of methane, ethane, propane and nitrogen.

The three refrigeration compression systems of this process can have separate drivers or be integrated to two strings of compression. A minimum of three Frame 6 or Frame 7 gas turbine or electric motors are required for compression drivers to process LNG greater than 4 Mtpa.

5.2.5 Axens Liquefin™ process

This is a dual mixed refrigerant process used by LNG plants producing up to 6 Mtpa. The first mixed refrigerant is used for pre-cooling, the second for liquefaction and sub-cooling. The refrigerants used are methane, ethane, propane, butane and nitrogen. Pre-cooling can reduce the temperature to minus 60ºC dependant upon the refrigerant mixture.

Two Frame 7 gas turbines are used in each train for main compression and two Frame 5 gas turbines for power generation. Higher capacities are possible using Frame 9 gas turbines, electric motors and steam turbines.

While it is similar to the APCI process, the propane compressor is replaced with mixed refrigerant for pre-cooling allowing more balanced flows, refrigeration loads and power between compressors; avoiding process design limitations associated with propane compressors.

5.2.6 Shell double mixed refrigerant process (DMR)

This is a dual mixed refrigerant process which has been used for train capacities averaging 4.8 Mtpa. The process configuration is similar to the propane pre-cooled mixed refrigerant process, with pre-cooling requiring a mixture of ethane and propane rather than pure propane. Pre-cooling is also completed using spiral wound exchangers supplied by Linde. Refrigerant compressors are driven by Frame 7 gas turbines and axial compressors are used during the cold refrigerant compression stages.

Shell DMR is similar to Axens but with twin parallel compressors trains for each process stream. Aero-derivative motors are used and the manufacture claims 4.5 to 5.5 Mtpa at lower cost.

5.3 Technology strengths and weaknesses

Table 5.1 summarises the suite of technology options, their strengths and weaknesses. Selection of the process technology is important to achieve optimal operating efficiency for the useful life of the plant and subsequently lower emissions in order to get more molecules of energy into the market place.

The different classes of turbines available for selection will depend upon the design output capacity of the LNG train. Table 5.2 lists the efficiency and power output of the primary types of turbines used for liquefaction.

New aero-derivative turbines have become a popular choice for mid size trains due to higher efficiency ratings, however larger capacity train require higher power output.

The current best practice LNG driver turbine technology used in Australia incorporates direct drive turbines to power refrigeration compressors with waste heat recovery units. This technology is supplied by ConocoPhilips to Woodside's North West Shelf LNG plant in Karratha.

This study has reviewed the technology selection descriptions of each liquefaction plant listed in appendix B and accepted the liquefaction owners' assessment of the greenhouse index (GI).

Technology selection	Strengths	Weaknesses
Spiral wound heat exchanger (SWHE)	Flexible operation	Proprietary / more expensive
Plate fin heat exchanger (PFHE)	Competitive vendors available Lower pressure drop and temperature differences	Requires careful design to ensure 2-phase flow distribution in multiple exchanger configuration
Axial compressors	High efficiency	Suitable only at high flow rates
Steam turbines	Several established vendors Use of mixed fuel High reliability >30 years High availability >3 yrs non stop Power output unaffected by ambient conditions	Old technology / High CAPEX Physically large with boilers, condensers, desalination and polishing plant. Overhaul time similar to large GT Complexity in steam auxiliaries
Industrial gas turbines	Proven low risk technology Efficient and cost effective Uncomplicated design Skid mounted Small footprint Lower NOx than Aero-derivative GT Range of size available	Less reliable/Strict maintenance cycle More complicated controls Fixed sizes and optimal speeds Low thermal efficiency High CO2 emissions Power output sensitive to ambient conditions
Aero-derivative gas turbines	Higher thermal efficiency than industrial gas turbine Smaller footprint than Industrial GT Short maintenance period Higher plant availability Free power for variable speed operations Helper motors / ST not required Range of sizes available	Higher NOx than Industrial GT Higher management of system due to higher operating pressures, temperature and design complexity Power output sensitive to ambient conditions Fuel quality is critical Limited LNG operating experience Higher risk technology
Combined Cycle turbines	50% extra power, 50% extra thermal efficiency and 50% less CO_2 emissions Allows optimisation of process ST for start-up and additional power Steam used elsewhere in process	High CAPEX / More civil works Increased complexity No favoured by LNG designers but higher consideration under a CO2 tax regime
Variable Speed Electric Motors	Made to suit allowing optimisation Higher availability than GT / ST Lower labour Reduce need for gearboxes Offsite power generation Lower CAPEX if using grid power Simple layout and reduced civil works	Most LNG plants in remote locations with limited access to grid power Limited high power experience Power has to be generated some where and emissions need to be accounted.
Mixed refrigerant process	Simpler compression systems Adjusting composition allows process matching	More complex operations
Pure component cascade process	Potentially higher availability with parallel compression	More equipment and complicated compression systems
Air cooling (compared to sea water cooling)	Lower cooling system CAPEX	Less efficient process Higher operating costs
Fluid medium heating (compared to steam)	Eliminates the need for steam generation and water treatment	Higher re-boiler costs
Larger train capacity	Lower specific costs (CAPEX/ton LNG)	Some equipment or processes may require further development

Table 5.1:- Technology selection parameters (Akhtar 2004 and Shukri et al 2004)

Turbine Type	Class	ISO Power (kW)	Heat Rate (kJ/kWh)	Efficiency (%)
Gas	Frame 5C	28340	12471	28.9
	Frame 5D	32580	12239	29.4
	Frame 5E	30000	9890	36.4
	Frame 6B	43534	10824	33.3
	Frame 7EA	86225	10923	33.0
	Frame 7FA	171700	9875	36.5
	Frame 9FA	255600	9759	36.9
	Siemens V94.2	159400	10498	34.3
	Siemens V94.3A	265900	9327	38.6
Aero-derivative	LM1600	14250	9932	36.2
	LM2500+	31364	8744	41.2
	LM6000	44742	8461	42.5
	RB211-24GT RT62	30387	9289	38.8
	Trent	52032	8409	42.8
Combined Cycle	LM1600PE	18591	7605	45
	LM2500PE	31048	7186	50
	LM2500+6STG	40912	6981	52
	LM6000PC	55007	6764	53
	LM6000PD Sprint	59142	6876	52
	RB211-24GT RT62	39760	7005	51.4
	Trent 50	64458	6780	53.1
	Trent 60	72268	7189	50.1

Table 5.2:- Power turbine specifications used in LNG Plant (Akhtar 2004)

There are not many turbine and compressor manufactures in the world who can supply the LNG industry. The equipment is typically supplied to operate over a design power range for optimal efficiency, in a similar manner a plumber would match the speed of a small water pump to the required flow rates.

Upon the selection of liquefaction process and technology, the calculation of emissions can be undertaken using manufactures efficiency ratings and adding up the components of fuel consumption along the train.

It should be noted at this point that liquefaction owners do not calculate emissions from selectively placed sensors distributed around the plant. Emissions are calculated from the sum of the fuel used during the liquefaction process, which relates to manufactures design specification. However, carbon dioxide sensors are located in the feed-gas network to ensure the optimal 'real-time' management of the acid gas recovery unit.

5.4 Emission sources

This study was primarily concerned with the process efficiency resulting in the energy consumed to produce LNG. The consumption of inflow gas, grid electricity or diesel as fuel during liquefaction will result in the release of green house gases measured in carbon dioxide equivalent emissions (CO_2-e). Up to the current limits of technology, the larger the power generation and refrigeration compressors the more efficient and cost effective they have become. However the selection of technology will depend initially upon the size of the available gas field (life span), quality of feed gas (CO_2 concentration) and LNG market demand (contracts values).

Appendix B summarises the specific data of the existing and proposed liquefaction plants in Australia leading to the calculation of average CO_2-e emissions per MJ of LNG delivered to market compared to prior studies and global best practice.

New LNG plants on the drawing boards or under construction aim to adopt best practice design and operation in terms of greenhouse gas emissions. Greenhouse gas emissions, reported as carbon dioxide equivalents (CO_2e) are measured in this study at normalized production conditions and benchmarked against available published data.

A review of the planned Gorgon LNG facility on Barrow Island and Wheatstone LNG facility in Karratha in West Australia reveal a number of key emission sources. Table 5.3 provides an emissions inventory for the proposed liquefaction plants, apportioning significance to the primary emission sources. The average GI of emissions of the two plants is 0.369, which is reflected in Appendix B.

Greenhouse gas emissions source	**Total CO2-e by source** (tons/yr)		**Average emissions**	**Percentage**
	Wheatstone (25Mtpa LNG)	**Gorgon** (15 Mtpa LNG)	(t emissions /Mt of LNG)	**(%)**
Gas Turbines – process	4,800,000	2,467,301	178,243	48.23
Venting	3,270,000	847,724	93,657	25.34
Gas Turbines – Electric power	900,000	2,153,294	89,776	24.29
Flaring (Pilot and events)	265,000	41,047	6,668	1.80
Fugitive	5,000	18,973	732	0.20
Heaters / Boilers	7,000	10,911	504	0.14
Total	**9,247,000**	**5,539,250**	**369,580**	**100%**

Table 5.3:- Projected CO2-e emissions inventory of Wheatstone and Gorgon liquefaction plants (Chevron 2010).

Important assumptions used by Chevron (2010) for Gorgon and Wheatstone LNG's CO_2-e emissions in calculating greenhouse gas emissions were:-

- LNG production will be available 340.4 stream days (8170 hours) per year for design capacity loaded Freight on Board (FOB) to ships.
- Gas turbines power generators will operate at 75% total power demand.
- All plant utilities, including flares, heaters, power generation plant and diesel standby equipment will be available 365 days per year.
- LNG production for Gorgon LNG is sources 65% from the Gorgon field and 35% from Jansz field.
- Twenty per cent of reservoir CO_2 is assumed to be vented.
- Flares remain on pilot.

In calculating emissions for Gorgon and Wheatstone, Chevron Australia Pty Ltd (2010) consulted the technical guidance of the National Greenhouse & Energy Reporting Regulations 2008 (NGER Regulations). Chevron also considered the National Greenhouse and Energy Reporting Act 2007 where emissions to the atmosphere occur as a direct result of emissions from LNG facilities. Chevron advised within their 2010 environmental impact statement that Gorgon LNG complies with the NGER requirements of transparency, comparability, accuracy and completeness. So it is with a confidence interval of 95% that their GI calculations can be relied upon.

Assessment of Gorgon LNG and Wheatstone LNG revealed that on average 48% of CO_2-e emissions occur during fuel consumed by gas process turbines used for refrigeration compression. Venting of acid gases account for 25% of emissions and fuel consumed by gas turbines used to generate electrical power accounts for 24%. This is a typical allocation for liquefaction plants. These three primary sources are the focus of further investigation in sections 5.4.1 – 5.4.3 to improve efficiency and reduce emissions.

Flaring and fugitive emissions are present, representing 2% of emissions and investigation for further efficiency is not warranted, given other primary sources. However, flaring represents a visual consumption of fuel and emissions and therefore attracts adverse political, social and environmental interest. While flaring remains an important safety feature of liquefaction plants, environmental regulations has resulted in the diversion of previously flared gases into return fuel lines feeding the power turbines.

Emissions from heaters and boilers will feature depending upon the liquefaction facility design and technology selection. Liquefaction plants processing high concentrations of feed gas CO_2 will receive efficiency benefits when using waste heat recovery units to supply thermal energy to the acid gas recovery unit, mitigating the fuel costs of operating heaters and boilers.

Technology provides efficiency over time. In 1998 the greenhouse gas index (GI) of the proposed Gorgon LNG plant was calculated at 0.89 tons of CO_2e emitted to the atmosphere for every ton of LNG shipped. Over time this has been reduced to 0.35 as a result of engineering decisions to replace an offshore gas processing platform with a sub-sea facility (0.04), changes in LNG technology over the last 10 years (0.23), provision of waste heat recovery units (WHRU's) on refrigeration gas turbines & removal of boilers as a heating source (0.05); and the injection of removed reservoir carbon dioxide into a confined subsurface reservoir (0.22).

It is openly discussed within the oil & gas industry that future incremental improvements in LNG technology can be achieved by increasing the size of the LNG processing trains to optimize production, using improved CO_2 removal medium in the AGRU's, using dry compressor & hydrocarbon pump seals and recovering flash gases and reusing it as fuel gas. Whilst the development of operational, start-up, shutdown and maintenance procedures aims to reduce the duration and frequency of CO_2-e emissions, once the plant is operational further energy optimization studies can be undertaken as required by the Commonwealth Energy Efficiency Opportunities Act 2006.

5.4.1 Refrigeration compressor gas turbines

Chevron (2010) has established that optimal LNG processing train design, incorporating direct drive gas turbines with throughput of 5Mtpa. This has been considered as best practice, representing a balance between capital costs, emissions intensity and operating risk profile.

Gas turbines are to be used by Chevron's (2010) in three LNG processing trains produce 44% of the overall CO_2e emissions estimated for normalized operations. These turbines drive the refrigeration compressors at the core of the LNG process.

Liquid expanders are also a feature of new LNG plants. Liquid expands replace the J-T valves contributing to a 6% increase in total LNG output resulting in lower emissions (Chiu et al 2009). Liquid expanders (cryogenic turbines) were originally applied to the Air Product Propane Pre-cooled Mixed refrigerant process. They are now used in the Linde Multiple Fluid Cascade and Phillips Optimised Cascade processes. In essence, cryogenic turbines expand gases from high to low pressure converting hydraulic energy to electrical energy, reducing the enthalpy of the liquefied gas for energy recovery (Chiu et al 2009) of between 1 and 2MW. Controls within an LNG plant allow the turbines to be interactively linked to manage LNG output. New generation expanders are being developed to recover energy within phase changes to further improve efficiency.

5.4.2 Acid gas removal process

Chemical amines are used as a solvent to absorb carbon dioxide concentration of inflow gas to the liquefaction plant. In all existing liquefaction plants around the world CO_2 removed in the acid gas recovery unit (AGRU) is vented to the atmosphere.

Operating the AGRU is an energy intensive process and new technology to improve conventional amide solvents, add membrane separators, or use cryogenics to remove CO_2 is being researched.

During acid gas recovery the CO_2 can be collected for geo-sequestration. Sequestration involves the long term storage of CO_2 within depleted gas fields or injection into a suitable geological profile. A significant number of studies are currently being undertaken to map CO_2 dispersion using different geological formations. The aim of this research is to understand the long term stability of stored carbon dioxide.

Chevron Australia Pty Ltd (2010) has Commonwealth government support and environmental approval to collect, inject and store CO_2 from feed gas supplied to its Gorgon LNG plant to be constructed on Barrow Island in West Australia. Chevron (2010) has projected a limited on CO_2 captured for sequestration to 80% of the inflow gas CO_2 concentration. 20% of the reservoir CO_2 will be vented to the atmosphere in a worst case scenario, due to operations ramp up, provisions for equipment failures and process inefficiencies.

5.4.3 Power generation gas turbines

Gas turbines are used to generate electrical power for the LNG plant to support infrastructure. At Gorgon LNG, 39% of the overall CO_2-e emissions estimated for normalized operations will occur from power generation. Given the remoteness of the facility on Barrow Island and the lack of access to the West Australian state electricity grid, the power generator selection must be reliable to avoid unplanned outages of any processing trains.

The required power demand of the Gorgon LNG processing plant is 416MW (Chevron 2010). Five open cycle industrial gas turbine each with 117.5 MW gross capacity will be installed to operate at partial load. In addition, power generator turbine will be fitted with a dry low NOx emissions control technology to further minimize CO_2-e emissions. This technology is employed in Europe under strict environmental legislation, however it is not required under existing Australian emissions standards.

A waste heat recovery unit (WHRU) attached to a gas turbine exhaust is new technology which can be used to provide heat for acid gas solvent regeneration, molecular sieve dehydrator regeneration and other plant heating needs; reducing fuel use and subsequent greenhouse gas emissions. The energy saved with this technology is equivalent to the fuel that would otherwise have been used to operate heaters or boilers. Chevron (2010) has designed its LNG processing trains to include WHRU's to absorb 640 MW of energy from the latent heat in the exhaust combustion gases of the turbines.

While most new LNG plants are using gas turbines for power generation and as drivers for refrigeration compressors, APLNG (Origin Energy and ConocoPhilips joint venture) is expected to use electric refrigeration compressors on Curtis Island in Gladstone. The electricity will be drawn from the existing power grid network. Origin Energy will use existing coal seam gas power generator on the Darling Downs to supply the grid with the additional power required in Gladstone. The advantage of this process selection is to leverage off the projects access to grid electricity to improve energy use efficiency.

5.5 Emission results

The existing and proposed LNG facilities have been analyzed nationally and benchmarked internationally to determine the comparative efficiency of the Australian LNG industry. Despite the high feed gas CO_2 concentration of some reservoirs and high average ambient operating temperatures, the average GI of Australian facilities will be amongst the most efficient in the world.

Benchmarking data was obtained from Yost & DiNapoli (2003), who assessed greenfield LNG projects in Oman, Nigeria, Qatar, Ras Laffan, Trinidad and Tobago. Yost & DiNapoli (2003) assessed each projects design on the basis that CO_2 emissions were a measure of LNG process efficiency and overall plant fuel efficiency. It was determined that an average GI of 0.35 was achieved based upon inflow gas quality of 1006 Btu/scf and 1.6 mol % CO_2 concentration for two trains producing 5.42 Mtpa of LNG. This extrapolates to emissions of 3.83 g CO_2-e/MJ.

The worlds most efficient LNG facility is Statoil's Snohvit LNG in Norway recording a GI of 0.22, extrapolating to 2.41 g CO_2-e/MJ. Snohvit was not included in the study undertaken by Yost & DiNapoli (2003). The reason for the low GI (high efficiency) is due to its geographic location at very low ambient temperature, waste heat recovery and reliable access to an electricity grid for standby power supply. Snohvit LNG uses the Statoil/Linde mixed fluid cascade process (MFCP).

The existing and proposed liquefaction plants in Australia were studied and a GI was obtained for each plant from publications issued by liquefaction plant owners. The GI's are listed in Appendix B for two existing facilities and eight planned facilities. The two existing facilities use conventional gas from offshore reserves in North West Australia. Of the eight planned facilities six will source conventional gas in North West Australia and two will source coal seam gas (CSG) from the inland Bowen and Surat Basins in Queensland, Australia.

To calculate the grams of CO_2-e emissions per MJ of LNG, the GI measured in tons of CO_2-e per ton of LNG is converted using the following formula into grams of CO_2-e/MJ.

$$\frac{g\ CO_2e}{MJ} = \frac{\left(\frac{t\ CO_2e}{t\ LNG} \times 1000\right)}{\left(\left(\left(\frac{Btu}{scf} \times \frac{35.31\ scf}{m^3}\right) \div \frac{947.8\ Btu}{MJ}\right) \times \frac{2.22m^3}{t}\right)}$$

Equation 2:- Conversion formula

To convert imperial gas quality (Btu/scf) into metric, there are 35.31 cubic feet per cubic metre. Converting British thermal units (Btu) into mega Joules (MJ) is a factor of 947.8 Btu per MJ; and 2.22 m^3 of LNG per ton (t).

The calculated liquefaction emissions are tabulated in Appendix B and illustrated in figure 5.3. The average of the Australian liquefaction plant emissions of 4.89g CO_2-e/MJ has been compared to the global benchmark of 3.83g CO_2-e/MJ and Okamura's 2007 study results of 8.36g CO_2-e/MJ.

Australian LNG plant efficiency are broadly compatible to the global benchmark, however the carbon dioxide concentrations of inflow gas to Ichthys LNG and Prelude LNG are high and will be vented to the atmosphere, skewing the country average efficiency. While these projects have not yet receive commonwealth government approval of their environmental impact statements. Ichthys is considering green abatements to offset future emissions and this has not been accounted for in this study. Globally benchmarked LNG facilities use less that 1 mol %, significantly reducing the energy required for AGRU's, resulting higher efficiency and low emissions.

Gorgon LNG also has high CO_2 concentrations of inflow gas. On average the CO_2 concentration is 14.2 mol % from two combine reservoirs. However, Gorgon LNG's emissions are expected to be only 3.97g CO_2-e/MJ due to its investment in carbon dioxide sequestration.

The molecular weight of CO_2 is 44 and methane (CH_4) is 16. Assuming that CH_4 is used as fuel gas, then combustion of 0.1Mt to liquefy 0.9Mt of gas to LNG will generate 0.275Mt of CO_2. Therefore the base ratio of CO_2 to LNG is a GI of 0.31. This is typical of the plateau of LNG production, however when considering the added inefficiencies of acid gas recovery units, the average lifetime efficiency can be expected to be roughly 0.4Mt of CO_2 per megaton of LNG produced. This level of efficiency is demonstrated by the majority of Australian LNG plants except for facilities using inflow gas with high CO_2 concentrations being vented to the atmosphere.

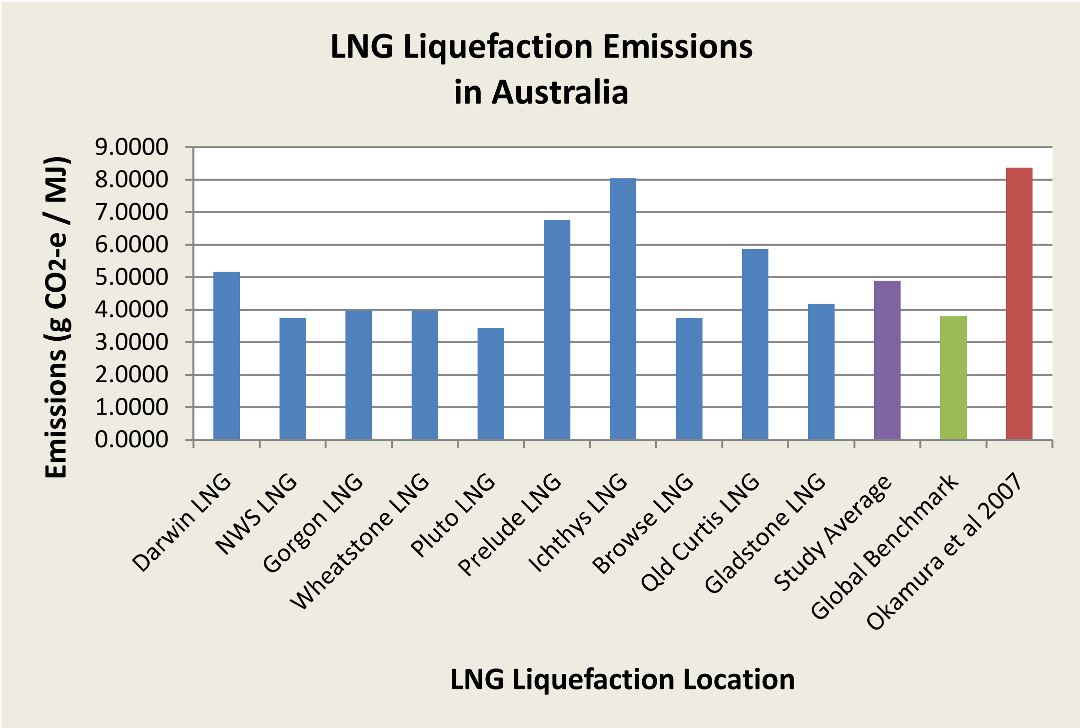

Figure 5.3:- LNG liquefaction emissions in Australia compared to global benchmark and previous studies.

Pluto LNG at Karratha has been calculated to be the most efficient liquefaction facility producing emissions of 3.43 g CO_2-e/MJ. While its inflow gas quality is similar to Wheatstone LNG, Pluto LNG will use Shells dual mixed refrigerant technology at an output capacity of 4.8Mtpa, compared to Wheatstone LNG's 25Mtpa using Phillips optimized cascade process. Wheatstone and Gorgon LNG's have the same projected emissions of 3.97 g CO_2-e/MJ, but construction will not be completed until 2015 and further technological advancements could aide efficiency. Pluto LNG is currently 95% completed and expected to produce first LNG by July 2011 followed by process assessment to optimise efficiency.

Compared to the 2007 study completed by Okamura using 2003 data, Australian LNG plants will be 42% more efficient. This is likely to be achieved through the use of waste heat recovery units, advanced amine solutions in acid gas recovery units, low average inflow gas carbon dioxide concentrations and larger productions capacities. In general Australian plants have selected new proprietary processing technology for superior efficiency.

CHAPTER 6 - SHIPPING

6.1 Process overview

Shipping emissions occurs during the consumption of fuel used to power the propulsion engine. For a long time LNG ships have retained the use of traditional steam turbine propulsion. The advantages of steam turbines are its low maintenance and ability to use a range of fuels from heavy oil to gas. However the disadvantage is high emissions and high fuel costs.

LNG contained on-board a ship is securely stored and does not result in direct emissions. Ships with fuel flexibility to use LNG boil-off gas are 40% more efficient than tradition heavy fuel ships according to Chiu et al (2009). Whist boil-off gas is suitable for use as fuel it interferes with the accounting of LNG supplied under contract to buyers. New generation ships include re-liquefaction plants to preserve the LNG supply shipment and use an independent fuel supply of LNG or diesel. As a matter of interest, LNG ships are never completely empty of LNG following supply delivery. Residual LNG is retained on-board to prevent distortion and structural damage resulting from extreme temperature changes whilst loading and unloading.

Figure 6.1:- Shipping routes from existing Australian LNG facilities to Asia (Wood Mackenzie maps 2010).

Australian LNG exports are characterised by long term supply contracts with buyers in Japan, South Korea, Taiwan, China and India. Figure 6.1 illustrates the geographical position of these markets to Australia and respective shipping routes.

In general, LNG exports will not be traded on a ‘spot’ market like the US Henry Hub. However if buyer engage a take-or-pay contract, LNG shipments could be diverted to alternative markets when buyer pay for a shipment they do not want delivered. This event has not been considered in the shipping emissions.

Advancements in technology have allowed the manufacture of larger vessels. The average ship size historically has been 137,000m³. Larger ships such as the 265,000m³ Q-Max ships used by Qatar LNG and improved port facilities has increase the average ship size to 145,000m³. The largest ship to be used in Australia will be 265,000m³ at the proposed Gladstone port, however most ship sizes will be less than 210,000m³. In order for Australia to accept larger LNG ships, loading facilities require engineering design for higher LNG flow capacity, mooring strength and adequate passageway (channel) freeboard.

Data from Wood Mackenzie (2010) was used in this study to assess ship types and fuel consumptions. This is represented in table 6.1 and records the assumptions used to determine the carbon dioxide equivalent emissions from transporting LNG from Australia to Asia using different size ships, propulsion and containment types. The 75,000m³ size ship was excluded from further analysis because it will not be represented in Australian LNG export.

Gross Cargo Capacity (m³)	**75,000**	**137,500**	**145,000**	**155,000**	**210,000**	**265,000**
Propulsion type	DFDE	Stream	Stream	DFDE	SSD	SSD
Containment type	Membrane	Self Supporting	Membrane	Membrane	Membrane	Membrane
Speed (knots)	17.5	19.5	19.5	19.5	19.5	19.5
Fuel oil consumption (t/day)	70	165	165	125	150	165
Natural boil-off gas (%/day)	0.125	0.125	0.125	0.125	0	0
Port turnaround time (days)	2.5	3	3	3	3.5	3.5
Fuel consumption in port (t/day)	15	35	35	25	30	35
Definitions:	DFDE: Dual fuel diesel electric SSD: Slow speed diesel and boil-off gas reliquefaction plants Steam: Drive turbines are stream operated					

Table 6.1:- LNG shipping data (Wood Mackenzie 2010)

6.2 Emissions results

Table 6.2 summarises the one way distance between the three Australian LNG export ports and five Asian import ports. An average distance has been calculated to determine the number of round trips a ship can achieve in a year and the number of ships required to deliver the gross annual LNG production.

A round supply route can been defined as ‘the loading time plus travel time to market plus unloading time plus return travel time’. During loading and unloading times the ship will consume diesel fuel in port for operational power. It is feasible for a ship to use land based power supply while in port however consumption through self generation was assumed, as fuel used in land based power generation could not be assessed. During travel time to market (fully laden) and return (un-laden) a constant speed was used depending upon the ship size and propulsion type.

Shipping Distances (km) from/to:	Japan (Kisarazu)	Korea (Incheon)	Taiwan (Talchung)	India (Dahej)	China (Hulyang)
Karratha, WA	3591	3536	2701	3764	2608
Darwin, NT	2932	3027	2326	4325	2328
Gladstone, Qld	3635	4025	3527	5924	3618
Average distance	**3386**	**3529**	**2851**	**4671**	**2851**
Hour/round trip (including port time)	335	343	305	432	329
Round trips per year	26	26	29	20	27
Gross LNG production (t)	101.2	101.2	101.2	101.2	101.2
Ships required for delivery	61	59	49	51	31

Table 6.2:- LNG Shipping distances and time per round trip between Australia and Asia,

Ship size (m^3)	137,000	145,000	155,000	210,000	265,000
Diesel Consumption (t/day)	35	35	25	30	35
t CO_2-e / t Diesel fuel	3.4064	3.4064	3.4064	3.4064	3.4064
LNG BOG consumption (t/day)	369.53	389.69	416.56	Nil	Nil
t CO_2-e / t LNG BOG	2.4173	2.4173	2.4173	2.4173	2.4173
Greenhouse Index (t CO_2-e/t LNG)	0.028779	0.027896	0.011376	0.010083	0.008859
Average inflow gas quality (Btu/scf)	1092.2	1092.2	1092.2	1092.2	1092.2
Average emissions (g CO_2-e/MJ of LNG delivered)	**1.5702**	**1.5220**	**0.6207**	**0.5501**	**0.4833**

Table 6.3:- Average CO2-e emissions per MJ delivered using different ship types.

Using the data from table 6.1 and 6.2 the average emissions were calculated. It was calculated in chapter 4, that diesel consumption will result in 3.4064 tons of CO_2-e emissions per ton, LNG boil-off consumption will result in 2.4173 tons of CO_2-e emissions per ton of LNG. Using an average shipping distance between Australia and Asian markets for each ship size the GI was determined (t CO_2-e / t LNG delivered).

Following calculation of the GI, the results were converted into g CO_2-e/MJ of LNG delivered using the average inflow gas quality of 1092.2 Btu/scf (refer Appendix B) and conversion formula discussed in chapter 5 (section 5.4).

Okamura et al 2007 completed a study of shipping emissions using 2003 data collected from global markets, determining that CO_2-e emissions were 1.97g/MJ. Figure 6.2 compares these results to the emissions for different size ships used between Australia and Asia.

The study average of shipping emissions for LNG delivered from Australia to Asia was 0.949g CO_2-e/MJ. This is 52% less that emissions reported by Okamura et al (2007). This significant difference is the combined effect of using larger ships to transport LNG to Asia and less travel distance. Australia is located closer to Asia than liquefaction plants in other countries and therefore less fuel is consumed during transportation.

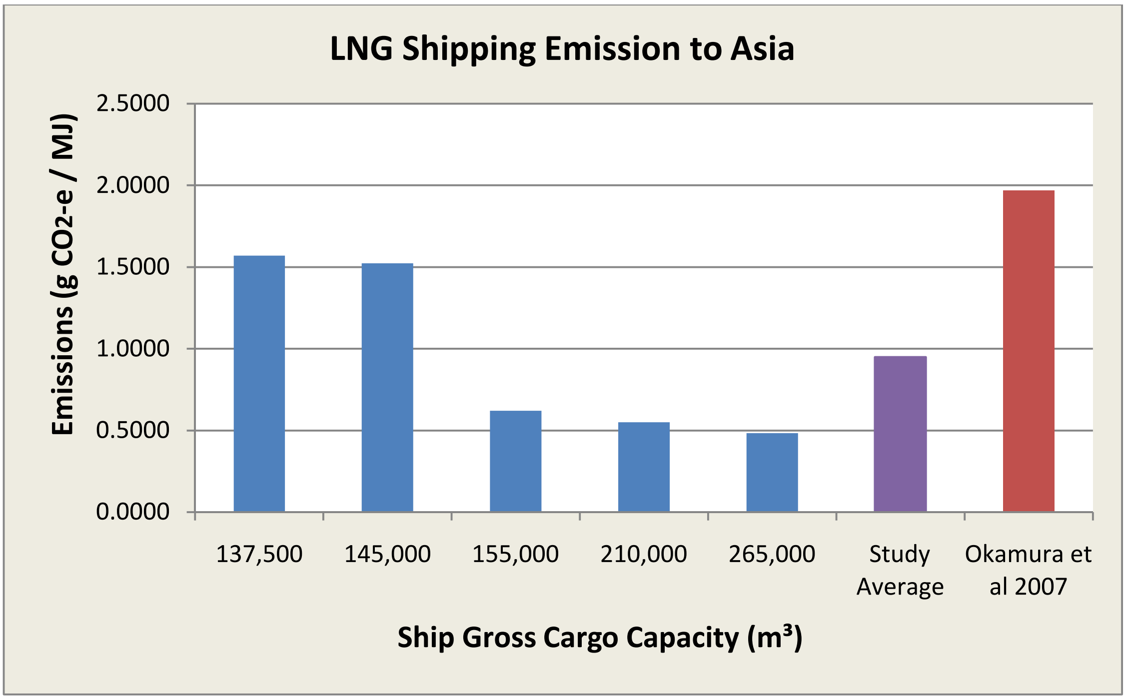

Figure 6.2:- Average shipping emissions of LNG from Australia to Asia

It was conservatively assessed that LNG buyers using 145,000m³ DFDE ships to transport LNG will result in higher emission than the study average at 1.52g CO_2-e/MJ and only 23% more efficient than results reported by Okamura et al 2007.

Due to Australia's proximity to Asian LNG markets, it is acknowledged that shipping emissions are less than global LNG producers. It is also acknowledged that larger sized ships using on-board re-liquefaction facilities can contribute to further lifecycle efficiencies.

CHAPTER 7 - REGASIFICATION

7.1 Process overview

Re-gasification of LNG delivered into a port in Asia occurs when natural gas is required for electrical power generation, gas mains distribution (heating and cooking) or industrial processing. LNG is re-gasified using heat to vaporise the cold liquid. Heat energy for re-gasification is obtained by self consumption of a percentage of gas, passing the LNG through seawater baffles or using waste heat recovery from power generation turbines.

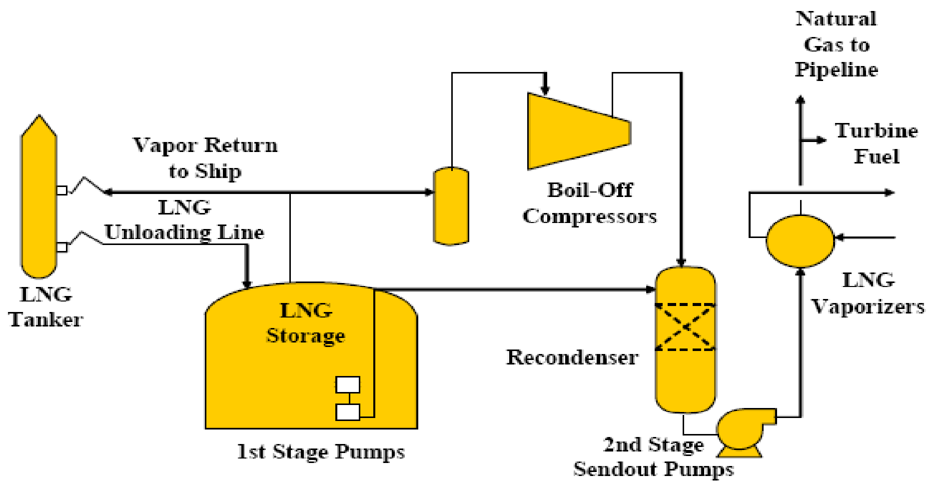

Figure 7.1:- Flowchart of re-gasification process (Black & Veatch 2010)

7.2 Emissions results

Okamura et al 2007 calculated re-gasification emission from the fuel used to pump sea water through baffles and included energy savings by using the cryogenic properties for cold storage. However, pumping sea water is less than ideal due to the ecological impact of low temperature water (less than 5°C) being recycled to the sea, the infrastructure costs to install large water pipes and pumping stations, and the consumption of fuel to operate these pumps.

Chiu et al (2009) amongst many technical advisors recommend the use of waste heat recovery from power generation turbines to warm the LNG. In addition cryogenic cooling of inflow air to the power turbines will improve operating efficiency of electric power production. Cryogenics can also be used for cold storage of commodities prior to re-gasification. The introduction of this improved technology and processes applied to new re-gasification plants can result in CO2-e emissions of less than 0.1g/MJ of energy delivered as LNG. This is a 58% reduction in emissions calculated by Okamura et al (2007), illustrated in Figure 7.2.

It is recommended that when re-gasification plants, power generation turbines and cryogenic storage facilities are co-located CO_2-e emissions could be reduced to zero. In Japan, LNG imports achieving a zero emissions, qualify the energy source to be trade in a special market reserved for renewal energies (hydropower and nuclear) or fossil fuels holding sufficient green abatements.

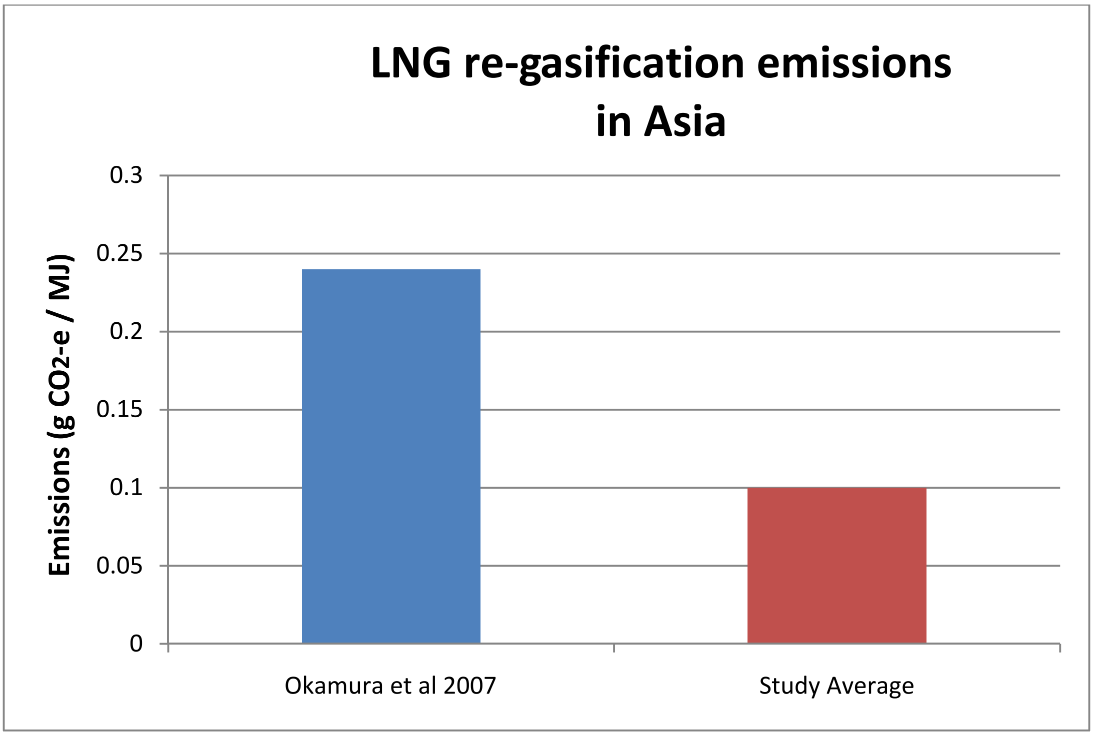

Figure 7.2:- LNG re-gasification emission in Asia

It is recommend that further studies are undertaken on the design and installation of new technology and processes for re-gasification. Adequate design could result in new facilities achieving zero emissions and provide operational cost savings to mitigate capital costs over the useful life of a facility.

It is worthy of a note that re-gasification is not a significant source of greenhouse gas emissions compared to liquefaction and shipping. Re-gasification has negligible impact on Australian emissions however it is a consideration for importing counties emissions inventory when compared to other fuel imports.

CHAPTER 8 - DISCUSSION RESULTS

This study of greenhouse gas emissions from LNG liquefaction, shipping and re-gasification has indicated that since 2003 (study by Okamura et al 2007) advanced technology, process improvement and close proximity to market Australian LNG has 38% less greenhouse gas emissions than other global suppliers.

Figure 8.1 illustrates the differences between this study and Okamura et al 2007. Liquefaction remains the highest component of energy use within the product lifecycle resulting in 75% of emissions. This emissions burden is first born into the Australian atmosphere and will impact on agreed Kyoto targets unless mitigated by a reduction in coal and oil usage or green abatements.

Re-gasification represents the lowest emissions component of the LNG lifecycle. Adequate technology and process management tools are available to achieve zero emissions at re-gasification when waste heat recovered from power generation turbines is used to heat LNG, and cryogenics is used to reduce third party energy production.

Efficiencies in LNG shipping can be achieved through the use of larger ships equipped with facilities to re-liquefy boil-off gas. Additional reductions in emissions could be achieved by using new technology to operate ships on one hundred percent LNG. Due to Australia's close proximity to Asian markets less emissions occur due to lower fuel consumption compared to other global LNG producers.

Liquefaction efficiency is first impacted by the carbon dioxide concentration of inflow gas followed by processing effort. 95% of liquefaction emissions occur due to fuel used by process refrigeration generators, acid gas processing and power generators.

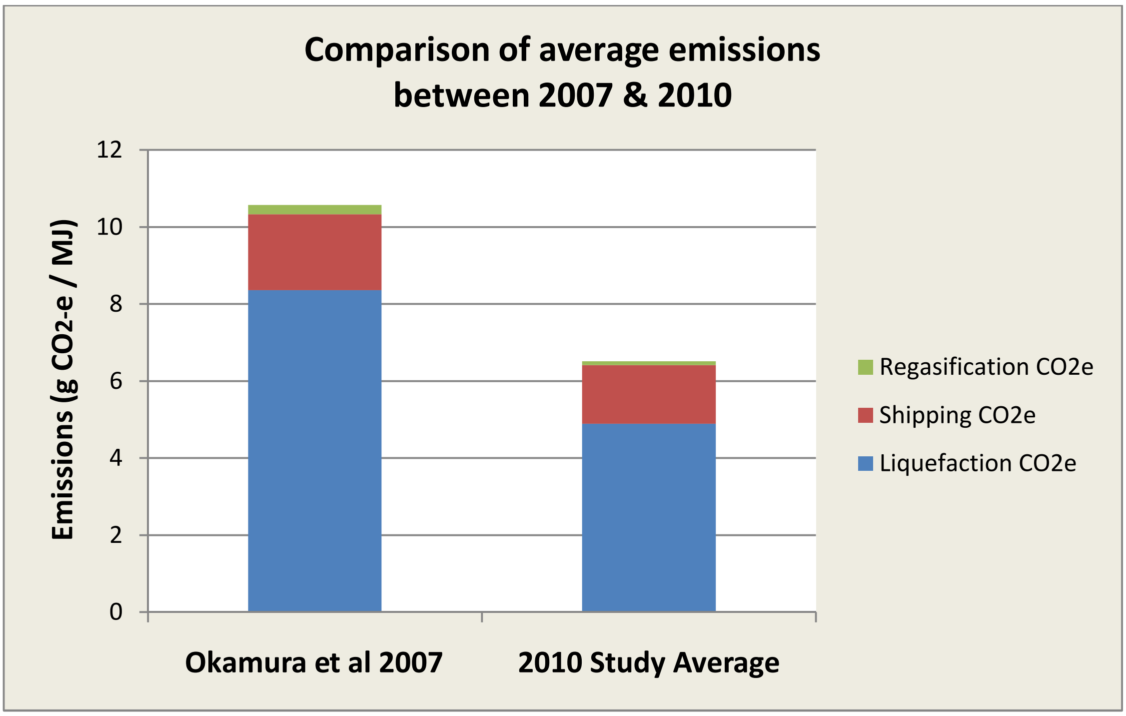

Figure 8.1:- Comparison between the results of 2007 and 2010 studies

Improving the energy efficiency of the LNG lifecycle does not cease at the design and construction of liquefaction plants, ships and re-gasification terminals. Ongoing monitoring and management of plant and process is critical for the life of projects.

Pending a future outcome of an emissions trading scheme in Australia, it is important for corporations to develop a greenhouse management plan, implement auditing and reporting of emissions, and undertake programs for continued efficiency improvements. The probability of a market or tax based emissions trading scheme is increasing. Government and industry are alert to the problems of greenhouse gas emissions and attention is focused on LNG reducing the environmental burden of consuming higher emission fuels such as coal and oil.

If emissions are fully costed into the economics of energy supply, efficiency will drive competitive advantage and technology will be a key feature of sustainability.

CHAPTER 9 - CONCLUSION

The road ahead for the LNG industry in Australia is viewed positively. New technology developments, process improvements including automated computer controlled real time simulators and a geographical advantage will contribute to the production of low emission energy to fuel the growth of Asia.

To optimise the benefits of LNG supporting the population growth pressures and energy security needs in Asia, it would be prudent to see a reduced reliance upon coal and oil. The benefits of using LNG over oil and coal as a source of energy has been widely studied and emissions reductions of between 30% and 40% are achievable.

LNG is viewed as a transitional energy between reducing reliance on heavy fuels and increasing the use of renewable energies (solar, wind, wave, hydropower, nuclear). However, technology and process improvements historically have taken generations to achieve. While technology and process improvements will increase energy use efficiency, reducing energy consumption in developed economies has a role in reducing global greenhouse gas emissions.

Significant discussions are underway to decide the future structure of emissions trading scheme and scientist are scaling up the industrialisation of carbon sequestration. Government and industry are challenged to decide on a price of carbon emissions. Potentially, the price of carbon will be linked to the cost of sequestration and this deserves further investigation.

Chevron Australia Pty Ltd has planned the development of the worlds largest carbon sequestration plant on Barrow Island in West Australia. If successful it will sequester 80% of the Gorgon LNG CO_2-e emissions becoming one of the worlds most efficient LNG facilities. It will also lead the world in sequestration technology which could be used by the resources industry to reduce emissions at coal fired power stations, oil refineries and other emission intensive facilities. Further investigation should be undertaken to ensure adequate legal and economic instruments are available to capitalise on this technology to be shared amongst polluters.

Failure is a motivator for invention. Whilst catastrophic failures have occurred in the oil and gas industry over time, having a profound impact on the environment; they are also a stimulus for technology and process improvement. Incremental technology and process improvement is likely to project Australia towards being a world class producer of liquefied natural gas.

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APPENDIX A – PROJECT SPECIFICATION

University of Southern Queensland

FACULTY OF ENGINEERING AND SURVEYING

ENG 4111/4112 Research Project
PROJECT SPECIFICATION

STUDENT: Paul Barnett

TOPIC: Life Cycle Assessment (LCA) of Liquefied Natural Gas (LNG) and its environmental impact as a low carbon source energy.

SUPERVISOR: Dr Guangnan Chen

SPONSORSHIP: Nil

PROJECT AIM: This project aims to research LNG between liquefaction and re-gasification and assess its environmental impact as a transport mechanism to supply low carbon energy.

PROGRAMME: Issue A / March 2010

1. Literature review of LNG chemistry and the engineered process chain between initial liquefaction (liquefaction train) and final re-gasification (re-gas plant), including storage and transport (shipping).
2. Research liquefaction, storage, transportation and re-gasification (LNG process); and identify system losses (Carbon Dioxide) which may impact the environment (point source pollution).
3. Choose an existing LCA modeling tool to assess the LNG process.
4. Suggest improvements that could be made to the design and operation of the LNG process, and discuss the feasibility and practicality of such improvements.

As time permits,

6. Discuss the environmental impacts of bi-products of the LNG process (eg Mercury, Sulphur Dioxide etc).
7. Discuss the political, economic and social impacts of LNG processing facilities.

AGREED

________ (Student) ________, ________ (Supervisors)

26/3/10 / / 19/4/10

APPENDIX B - LIQUEFACTION PLANT DATA IN AUSTRALIA

Facility state	Facility Operator & Location	Startup	Number of trains	LNG design production capacity (mmtpa)	Technology	LNG Quality Loaded (Btu/scf)	Max LNG Carrier Size (m^3)	Inflow Gas CO2 quantity	GI (t CO2e / t LNG)	Liquefaction emissions (gCO2e/MJ)
Existing	ConocoPhillips Darwin LNG in N.T	2006	1	3.7	Phillips Optim, Cascade	1075	150,000	6.0 mol %	0.46	5.17
Existing	Woodside NWS LNG at Karratha W.A.	1989	5	16.3	APCI	1127	148,000	2.5 mol %	0.35	3.76
Projected	Chevron Gorgon LNG on Barrow Is W.A	2014	3	15	APCI	1065	215,000	14.2 mol % (80% CSS)	0.35	3.97
Projected	Chevron Wheatstone LNG at Onslow W.A.	2015	6	25	Phillips Optim, Cascade	1127	215,000	<2.0 mol %	0.37	3.97
Projected	Woodside Pluto LNG in WA	2011	1	4.8	Shell Dual Mixed Refrigerant	1127	217,000	1.7 mol %	0.32	3.43
Projected (FLNG)	Shell Prelude LNG W.A.	2017	1	3.6	Shell Dual Mixed Refrigerant	1127	220,000	NA	0.63	6.76
Projected (FPSO)	INPEX Ichthys LNG N.T	2016	2	8.4	N/A	1127	220,000	17 mol %	0.25est	8.05
Projected	Woodside Browse LNG W.A.	2018	3	12	N/A	1127	150,000	NA	NA	3.76
Projected	BG Group LNG Qld Curtis LNG Gladstone	2014	2	8.5	Phillips Optim, Cascade	1010	266,000 (Q Max)	NA	0.26 (+ 0.23 pipelines)	5.87
Projected (CSG)	Santos Gladstone LNG in QLD	2014	1	3.6	Phillips Optim, Cascade	1010	160,000	NA	0.34 (+ 0.49 pipelines)	4.19
Average			3	10		1092	196,100		0.442	4.89
Benchmark	Oman/Nigeria/Qatar/Tobago	-	2	5.42	-	1106		1.6 mol %	0.35	3.83
Existing Overseas Best Practice	Statoil Snohvit LNG in Norway								0.22	2.41
	Okamura et al 2007 – Average g CO2e/MJ of LNG									8.36

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