Gorgon Gas Development and Jansz Feed Gas Pipeline

Greenhouse Gas Abatement Program

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TERMINOLOGY, DEFINITIONS AND ABBREVIATIONS

Terms, definitions and abbreviations used in this document are listed below. These align with the terms, definitions and abbreviations defined in Schedule 2 of the Western Australian Gorgon Gas Development Ministerial Implementation Statement No. 800 (Statement No. 800).

ABU	Australasia Business Unit
AFAT	Average Feed Composition, Average Ambient Temperature
AGRU	Acid Gas Removal Unit
ALARP	As Low As Reasonably Practicable Defined as a level of risk that is not intolerable, and cannot be reduced further without the expenditure of costs that are grossly disproportionate to the benefit gained.
a-MDEA	Activated Methyl Di-ethanol Amine
APCI	Air Products and Chemicals Incorporated
APPEA	Australian Petroleum Production and Exploration Association
ARI	Assessment on Referral Information (for the proposed Jansz Feed Gas Pipeline dated September 2007) as amended or supplemented from time to time.
BOG	Boil-off Gas; vapours produced as a result of heat input and pressure variations that occur in association with LNG storage and loading operations.
BTEX	Benzene, toluene, ethylbenzene and xylene aromatic hydrocarbon compounds present in petroleum.
Carbon Dioxide (CO_2) Injection System	The mechanical components required to be constructed to enable the injection of reservoir carbon dioxide, including but not limited to compressors, pipelines and wells.
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
Construction	Construction includes any Proposal-related (or action-related) construction and commissioning activities within the Terrestrial and Marine Disturbance Footprints, excluding investigatory works such as, but not limited to, geotechnical, geophysical, biological and cultural heritage surveys, baseline monitoring surveys and technology trials.

Cth	Commonwealth of Australia
DCC	Commonwealth Department of Climate Change
DEA	Di-ethanol Amine
DEC	Western Australian Department of Environment and Conservation
DEWHA	Commonwealth Department of the Environment, Water, Heritage and the Arts
DLN	Dry Low NO_x
DomGas	Domestic Gas
EIS/ERMP	Environmental Impact Statement/Environmental Review and Management Programme (for the Proposed Gorgon Gas Development dated September 2005) as amended or supplemented from time to time.
EP Act	Western Australian *Environmental Protection Act 1986*
EPA	Western Australian Environmental Protection Authority
EPBC Reference: 2005/2184	Commonwealth Ministerial Approval (for the Jansz Feed Gas Pipeline) as amended or replaced from time to time.
EPBC Act	Commonwealth *Environment Protection and Biodiversity Conservation Act 1999*
EPBC Reference: 2003/1294	Commonwealth Ministerial Approval (for the Gorgon Gas Development) as amended or replaced from time to time.
EPBC Reference: 2008/4178	Commonwealth Ministerial Approval (for the Revised Gorgon Gas Development) as amended or replaced from time to time.
EPCM	Engineering, Procurement and Construction Management
FEED	Front End Engineering Design
FOB	Freight On Board
GHG	Greenhouse Gas
GI	Greenhouse Gas Intensity
Gorgon Gas Development	The Gorgon Gas Development as approved under Statement No. 800 and EPBC Reference: 2003/1294 and 2008/4178 as amended or replaced from time to time.
Greenfield	An undeveloped property or resource

Greenhouse Gases	Components of the atmosphere that contribute to the greenhouse effect. These include the six commonly reported GHGs under the Kyoto Protocol – methane (CH_4), carbon dioxide (CO_2), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF_6).
GT	Gas Turbine
GTG	Gas Turbine Generator
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
ha	Hectare
HES	Health, Environment and Safety
HFC	Hydrofluorocarbon
HIPPS	High Integrity Pressure Protection System
HVAC	Heating, Ventilation and Air Conditioning
Hydrocarbons	A large class of organic compounds composed of hydrogen and carbon. Crude oil, natural gas, and natural gas condensate are all mixtures of various hydrocarbons.
Isentropic	Where the entropy of a system remains constant.
ISO	International Organization for Standardization
Jansz Feed Gas Pipeline	The Jansz Feed Gas Pipeline as approved in Statement No. 769 and EPBC Reference: 2005/2184 as amended or replaced from time to time.
JT	Joule-Thomson
km	Kilometre
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MCHE	Main Cryogenic Heat Exchanger
MEA	Mono-Ethanol Amine
MEG	Mono-ethylene Glycol
MOF	Materials Offloading Facility

Mole %	The ratio of the number of moles of one substance to the total number of moles in a mixture of substances, all multiplied by 100 (to express the number on a percentage basis).
MR	Mixed Refrigerant
MTPA	Million Tonnes Per Annum
MW	Megawatt
N_2O	Nitrous Oxide
NGA	National Greenhouse Accounts
NGER	National Greenhouse and Energy Reporting
NMVOC	Non-Methane Volatile Organic Compounds
NO_x	Nitrogen Oxides (NO and NO_2)
NPI	National Pollutant Inventory; an Australian pollution database of emissions managed by the Australian Government on behalf of the Australian States and Territories.
OE	Chevron Operational Excellence
OEMS	Chevron Operational Excellence Management System
Operations (Gorgon Gas Development)	In relation to Statement No. 800 for the respective LNG trains, this is the period from the date on which the Gorgon Joint Venturers issue a notice of acceptance of work under the Engineering, Procurement and Construction Management (EPCM) contract, or equivalent contract entered into in respect of that LNG train of the Gas Treatment Plant; until the date on which the Gorgon Joint Venturers commence decommissioning of that LNG train.
p.a.	Per Annum; yearly
PER	Public Environmental Review for the Gorgon Gas Development Revised and Expanded Proposal dated September 2008, as amended or supplemented from time to time.
PFC	Perfluorocarbon
PGPA	Policy, Government and Public Affairs
Pig	Pipeline inspection gauge; a tool that is sent down a pipeline and propelled by the pressure of the product in the pipeline, or another fluid (usually during commissioning).
PM	Particulate Matter

Practicable	For the purposes of Statement No. 800 means reasonably practicable having regard to, among other things, local conditions and circumstances (including costs) and to the current state of technical knowledge.
SF_6	Sulfur Hexafluoride
Slug Catcher	A unit in the gas refinery or petroleum industry in which slugs at the outlet of pipelines are collected or 'caught'. A slug is a large quantity of gas or liquid that exits the pipeline.
SO_x	Sulfur Oxides
Statement No. 748	Western Australian Ministerial Implementation Statement No. 748 (for the Gorgon Gas Development) as amended from time to time [superseded by Statement No. 800].
Statement No. 769	Western Australian Ministerial Implementation Statement No. 769 (for the Jansz Feed Gas Pipeline) as amended from time to time.
Statement No. 800	Western Australian Ministerial Implementation Statement No. 800 (for the Gorgon Gas Development) as amended from time to time.
TJ	Terajoule
VOC	Volatile Organic Compounds; organic chemical compounds that have high enough vapour pressures under normal conditions to vaporise and enter the atmosphere.
WA	Western Australia
WAPET	West Australian Petroleum Pty Ltd
WAPET Landing	Proper name referring to the site of the barge landing existing on the east coast of Barrow Island prior to the date of Statement No. 800.
Wellhead	The surface termination of a wellbore that incorporates systems to provide pressure control, suspension of casing strings and provide sealing functionality for oil wells.
WHRU	Waste Heat Recovery Unit

1.0 INTRODUCTION

1.1 Proponent

Chevron Australia Pty Ltd (Chevron Australia) is the proponent and the person taking the action for the Gorgon Gas Development on behalf of the following companies (collectively known as the Gorgon Joint Venturers):

- Chevron Australia Pty Ltd
- Chevron (TAPL) Pty Ltd
- Shell Development (Australia) Proprietary Limited
- Mobil Australia Resources Company Pty Limited

pursuant to Statement No. 800 and EPBC Reference: 2003/1294 and 2008/4178.

Chevron Australia is also the proponent for the Jansz Feed Gas Pipeline on behalf of the Gorgon Joint Venturers, pursuant to Statement No. 769, and will apply to be the person taking the action for the Jansz Feed Gas Pipeline, as approved under EPBC Reference: 2005/2184. (Note: If the Commonwealth Minister refuses Chevron Australia's application to become the person taking the action for the Jansz Feed Gas Pipeline, this Program will be reviewed).

1.2 Project

Chevron Australia proposes to develop the gas reserves of the Greater Gorgon Area (Figure 1.1).

Subsea gathering systems and subsea pipelines will be installed to deliver feed gas from the Gorgon and Jansz–Io gas fields to the west coast of Barrow Island. The feed gas pipeline system will be buried as it traverses from the west coast to the east coast of the Island where the system will tie in to the Gas Treatment Plant located at Town Point. The Gas Treatment Plant will comprise Liquefied Natural Gas (LNG) trains capable of producing a nominal capacity of five Million Tonnes Per Annum (MTPA) per train. The Gas Treatment Plant will also produce condensate and domestic gas. Carbon dioxide (CO_2), which occurs naturally in the feed gas, will be separated during the production process. As part of the Gorgon Gas Development, Chevron Australia will inject the separated CO_2 into deep formations below Barrow Island. The LNG and condensate will be loaded from a dedicated jetty offshore from Town Point and then transported by dedicated carriers to international markets. Gas for domestic use will be exported by a pipeline from Town Point to the domestic gas collection and distribution network on the mainland (Figure 1.2).

1.3 Location

The Gorgon gas field is located approximately 130 km and the Jansz–Io field approximately 200 km off the north-west coast of Western Australia. Barrow Island is located off the Pilbara coast 85 km north-north-east of the town of Onslow and 140 km west of Karratha. The Island is approximately 25 km long and 10 km wide and covers 23 567 ha. It is the largest of a group of islands, including the Montebello and Lowendal Islands.

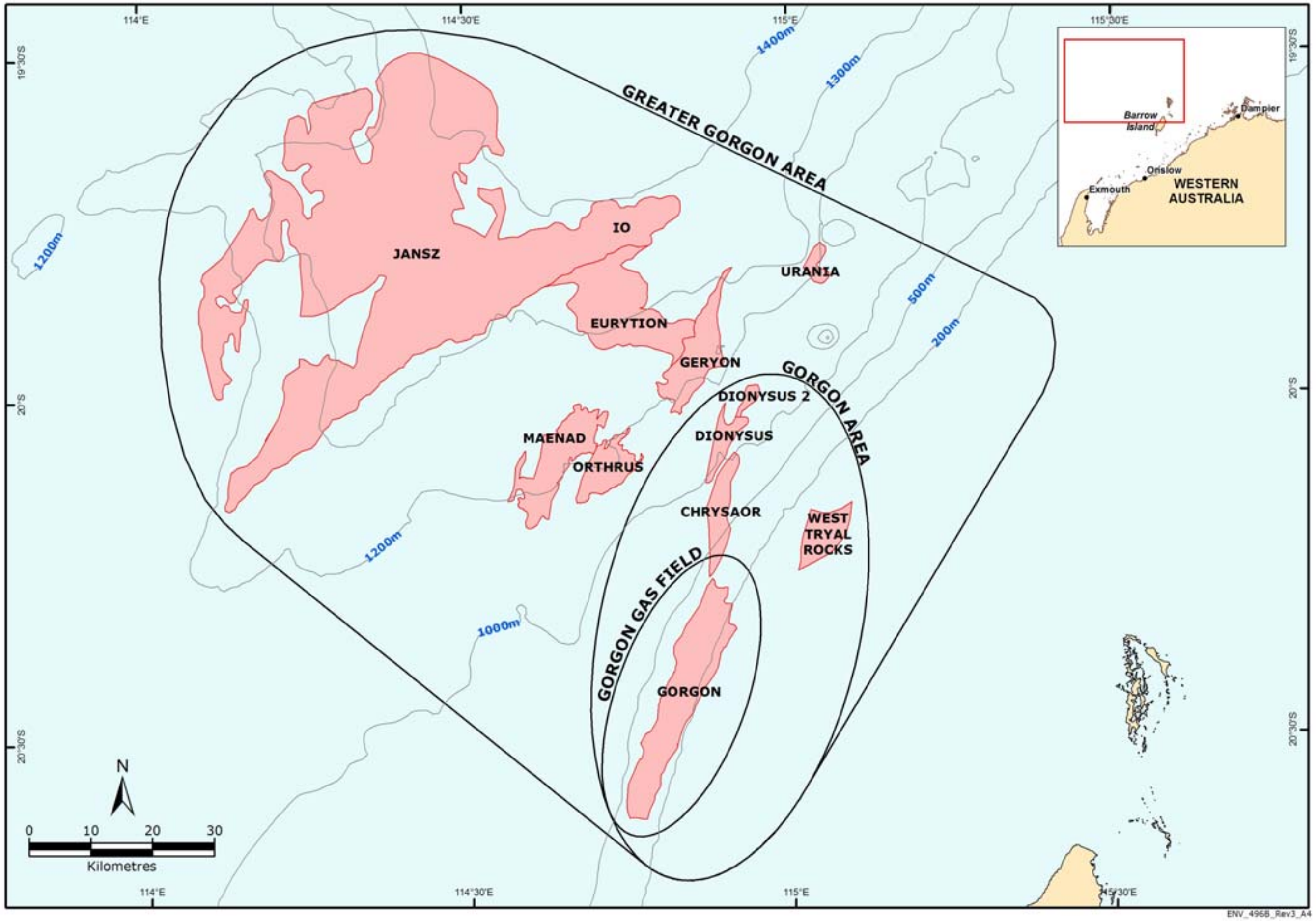

Figure 1.1: Location of the Greater Gorgon Area

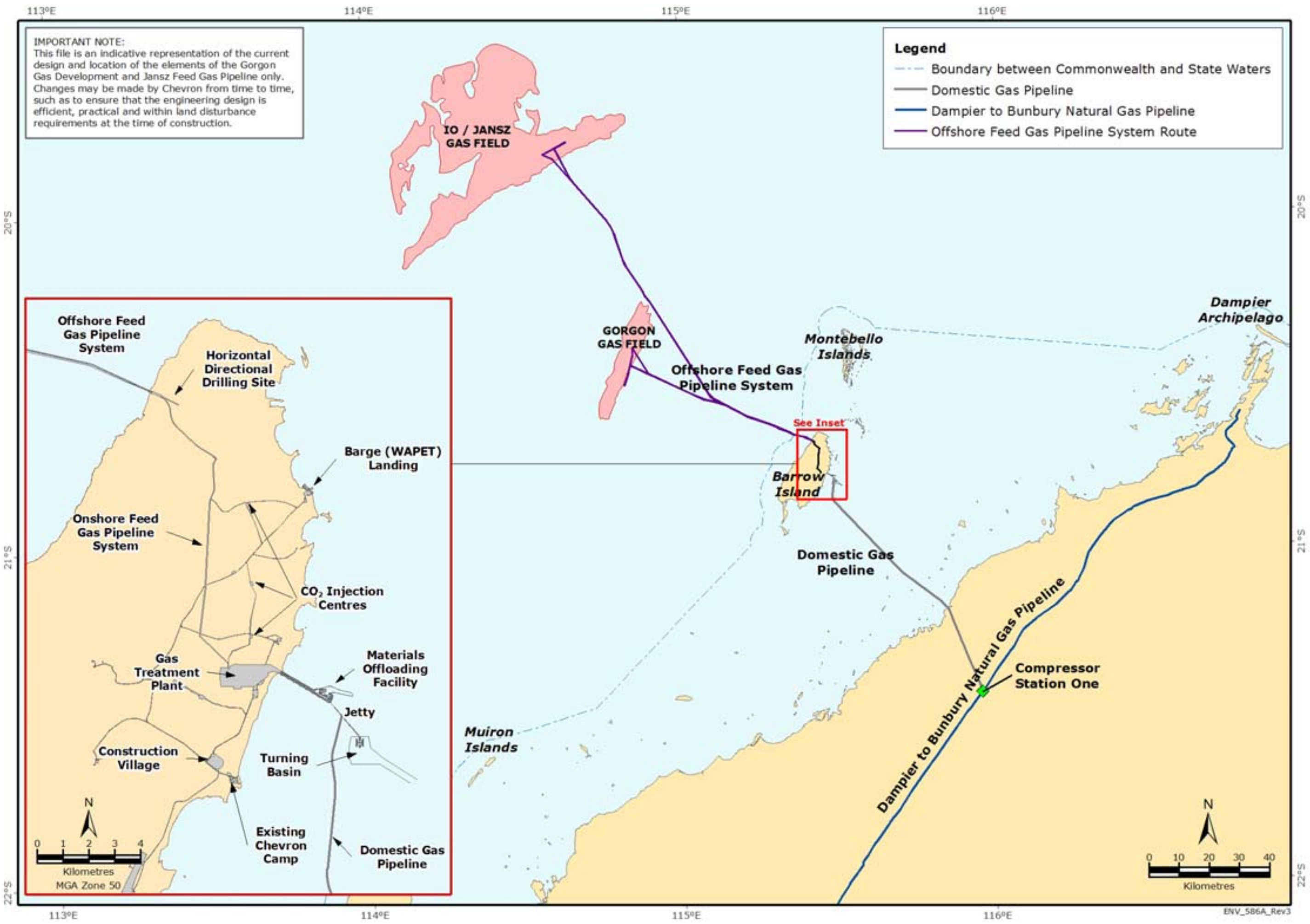

Figure 1.2: Location of the Gorgon Gas Development and Jansz Feed Gas Pipeline

1.4 Approvals

The initial Gorgon Gas Development was assessed through an Environmental Impact Statement/Environmental Review and Management Programme (EIS/ERMP) assessment process (Chevron Australia 2005; Chevron Australia 2006).

The initial Gorgon Gas Development was approved by the Western Australian State Minister for the Environment on 6 September 2007 by way of Ministerial Implementation Statement No. 748 (Statement No. 748) and the Commonwealth Minister for the Environment and Water Resources on 3 October 2007 (EPBC Reference: 2003/1294).

In May 2008, under section 45C of the Western Australian Environmental Protection Act 1986 (EP Act), the Environmental Protection Authority (EPA) approved some minor changes to the Gorgon Gas Development that it considered 'not to result in a significant, detrimental, environmental effect in addition to, or different from, the effect of the original proposal' (EPA 2008). The approved changes are:

- excavation of a berthing pocket at the Barge (WAPET) Landing facility
- installation of additional communications facilities (microwave communications towers)
- relocation of the seawater intake
- modification to the seismic monitoring program.

In September 2008, Chevron Australia sought both State and Commonwealth approval through a Public Environment Review (PER) assessment process (Chevron Australia 2008) for the Revised and Expanded Gorgon Gas Development to make some changes to 'Key Proposal Characteristics' of the initial Gorgon Gas Development, as outlined below:

- addition of a five MTPA LNG train, increasing the number of LNG trains from two to three
- expansion of the CO_2 Injection System, increasing the number of injection wells and surface drill locations
- extension of the causeway and the Materials Offloading Facility (MOF) into deeper water.

The Revised and Expanded Gorgon Gas Development was approved by the Western Australian State Minister for the Environment on 10 August 2009 by way of Ministerial Implementation Statement No. 800 (Statement No. 800). Statement No. 800 also superseded Statement No. 748 as the approval for the initial Gorgon Gas Development. Statement No. 800 therefore provides approval for both the initial Gorgon Gas Development and the Revised and Expanded Gorgon Gas Development, which together are known as the Gorgon Gas Development.

On 26 August 2009, the Commonwealth Minister for the Environment, Heritage and the Arts issued approval for the Revised and Expanded Gorgon Gas Development (EPBC Reference: 2008/4178) and varied the conditions for the initial Gorgon Gas Development (EPBC Reference: 2003/1294).

The Jansz Feed Gas Pipeline was assessed via Environmental Impact Statement/Assessment on Referral Information (ARI) and EPBC Referral assessment processes (Mobil Australia 2005; Mobil Australia 2006).

The Jansz Feed Gas Pipeline was approved by the Western Australian State Minister for the Environment on 28 May 2008 by way of Ministerial Implementation Statement No. 769

(Statement No. 769) and the Commonwealth Minister for the Environment and Water Resources on 22 March 2006 (EPBC Reference: 2005/2184).

This Program covers the Gorgon Gas Development as approved under Statement No. 800 and as approved by EPBC Reference: 2003/1294 and EPBC Reference: 2008/4178.

In respect of the Carbon Dioxide Seismic Baseline Survey Works Program, which comprises the only works approved under Statement No. 748 before it was superseded, and under EPBC Reference: 2003/1294 before the Minister approved a variation to it on 26 August 2009, note that under Condition 1A.1 of Ministerial Statement No. 800 and Condition 1.4 of EPBC Reference: 2003/1294 and 2008/4178 this Program is authorised to continue for six months subject to the existing approved plans, reports, programs and systems for the Program, and the works under the Program are not the subject of this Program.

1.5 Purpose of this Program

1.5.1 Legislative Requirements

1.5.1.1 State Ministerial Conditions

This Program is required under Condition 27.1 of Statement No. 800, which is quoted below:

> *"Prior to commencement of construction of the Gas Treatment Plant, the Proponent shall prepare and submit to the Minister a Greenhouse Gas Abatement Program (the Program) that meets the objectives set out in Condition 27.2 and the requirements set out in Condition 27.2, as determined by the Minister."*

Condition 26 of Statement No. 800 is only relevant to the objectives for the Greenhouse Gas Abatement Program to the extent that it outlines the performance parameters of the reservoir carbon dioxide injection system, which are discussed in this Program; however, most of the requirements of Condition 26 are outside the scope of the Program and will be addressed in a separate document.

1.5.2 Objectives

The objectives of this Program, as stated in Condition 27.2 of Statement No. 800, are to:

i. *Demonstrate that currently applied best practice in terms of greenhouse gas emissions have been adopted in the design and operation of the Gas Treatment Plant. The greenhouse gas emissions per tonne of LNG produced should be normalised to the standard conditions and benchmarked against publicly available data for other national and overseas LNG processing facilities*
ii. *Periodically review and where practicable, adopt advances in technology and operational processes aimed at reducing greenhouse gas emissions per tonne of LNG produced.*

1.5.3 Requirements

The requirements this Program, as stated in Condition 27 of Statement No. 800, are listed in Table 1.1.

Table 1.1: Requirements of this Program

Ministerial Document	Condition No.	Requirement	Section Reference in this Program
Statement No. 800	27.2(i)	Demonstrate that currently applied best practice in terms of greenhouse gas emissions have been adopted in the design and operation of the Gas Treatment Plant.	Section 4.0
Statement No. 800	27.2(i)	The greenhouse gas emissions per tonne of LNG produced should be normalised to the standard conditions and benchmarked against publicly available data for other national and overseas LNG processing facilities.	Section 3.3.3.1
Statement No. 800	27.2(ii)	Periodically review and where practicable, adopt advances in technology and operational processes aimed at reducing greenhouse gas emissions per tonne of LNG produced.	Section 6.3
Statement No. 800	27.3	The Proponent shall implement the Program.	Section 5.0

1.5.4 Scope

In line with the requirements of Condition 27 of Statement No. 800, the facilities scope of the Greenhouse Gas (GHG) Abatement Program includes the GHG emission sources arising from the start-up and commissioning, and operation of the Gorgon Gas Development Gas Treatment Plant on Barrow Island, as defined in Schedule 1, 'Summary of Key Proposal Characteristics' of Statement No. 800.

The facilities in the scope for the GHG Abatement Program include:

- LNG Trains: 3 × 5 MTPA (nominal)
- LNG Tanks: 2 × 180 000 m^3 (nominal)
- Condensate tanks: 4 × 35 000 m^3 (nominal)
- Gas Processing Drivers: 6 × 80 MW (nominal) fitted with dry low NO_x (DLN) burners
- Power Generation: 5 × 116 MW (nominal) gas turbines fitted with DLN burners
- Flare design: ground flare for the main plant flare; boil off gas (BOG) flare in LNG storage and loading area

The following Gorgon Gas Development activities will be included in this Program, as per the intent of Condition 27 of Statement No. 800:

- design of the Gas Treatment Plant as pertaining to the objectives of the GHG Abatement Program
- start-up and commissioning of the Gas Treatment Plant, including the progressive start-up and commissioning of LNG trains 1 to 3
- operation of the Gas Treatment Plant.

Greenhouse gases, in the scope for this Program, include the six commonly reported GHGs under the Kyoto Protocol, namely methane (CH_4), carbon dioxide (CO_2), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF_6).

Emissions of atmospheric pollutants and air toxics, such as nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), particulate matter (PM), non-methane volatile organic compounds (NMVOC) and hydrogen sulfide (H_2S) and benzene, toluene, ethyl-benzene and xylene (BTEX), respectively are outside the scope of the GHG Abatement Program and are dealt with in the Air Quality Management Plan required under Condition 29 of Statement No. 800 (Chevron Australia 2009).

The GHG Abatement Program also lists Gorgon Gas Development-specific best practice measures to reduce GHG emissions from the Gas Treatment Plant.

1.5.5 Hierarchy of Documentation

This Program will be implemented for the Gorgon Gas Development via the Chevron Australasia Business Unit (ABU) Operational Excellence Management System (OEMS). The OEMS is the standardised approach that applies across the ABU in order to continuously improve the management of safety, health, environment, reliability and efficiency to achieve world-class performance. Implementation of the OEMS enables the Chevron ABU to integrate its Operational Excellence (OE) objectives, processes, procedures, values, and behaviours into the daily operations of Chevron Australia personnel and contractors working under Chevron Australia's supervision. The OEMS is designed to be consistent with and, in some respects, go beyond ISO 14001-2004 (Environmental Management Systems – Requirements with Guidance for Use) (Standards Australia/Standards New Zealand 2004).

Figure 1.3 provides an overview of the overall hierarchy of environmental management documentation within which this Program exists. Further details on environmental documentation for the Gorgon Gas Development are provided in Section 5.1 of this Program.

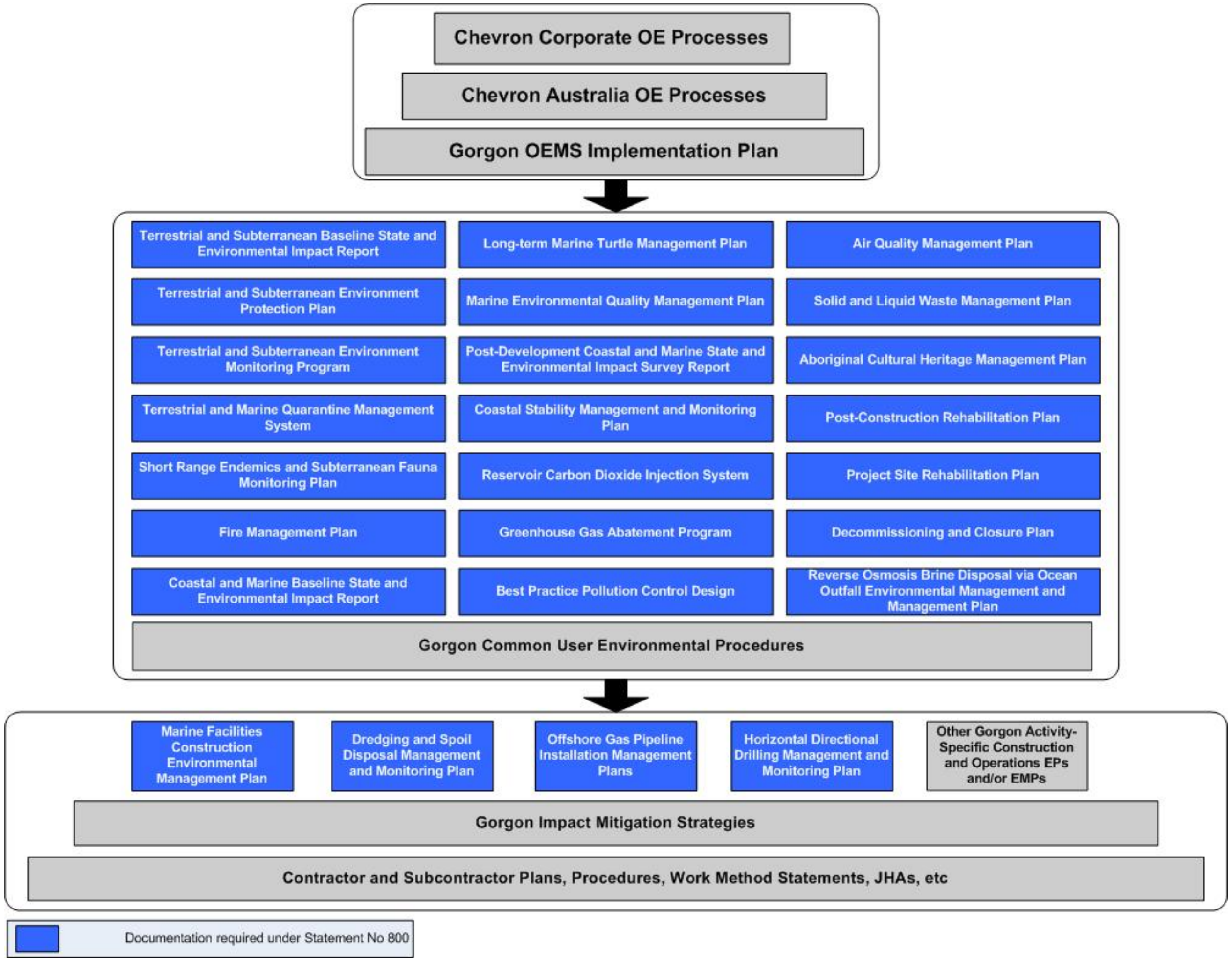

Figure 1.3: Hierarchy of Gorgon Gas Development Environmental Documentation

1.5.6 Stakeholder Consultation

Consultation with stakeholders has been undertaken by Chevron Australia on a regular basis throughout the development of environmental impact assessment management documentation for the Gorgon Gas Development. This has included engagement with the community, government departments, industry operators and contractors to Chevron Australia via planning workshops, risk assessments, meetings, teleconferences, and the PER and EIS/ERMP formal approval processes.

This document has been prepared with input from the Western Australian Department of Environment and Conservation (DEC). The DEC reviewed draft revisions of this Program and their comments have been incorporated or otherwise resolved.

The process for development, review and approval of this Program is shown in Figure 1.4.

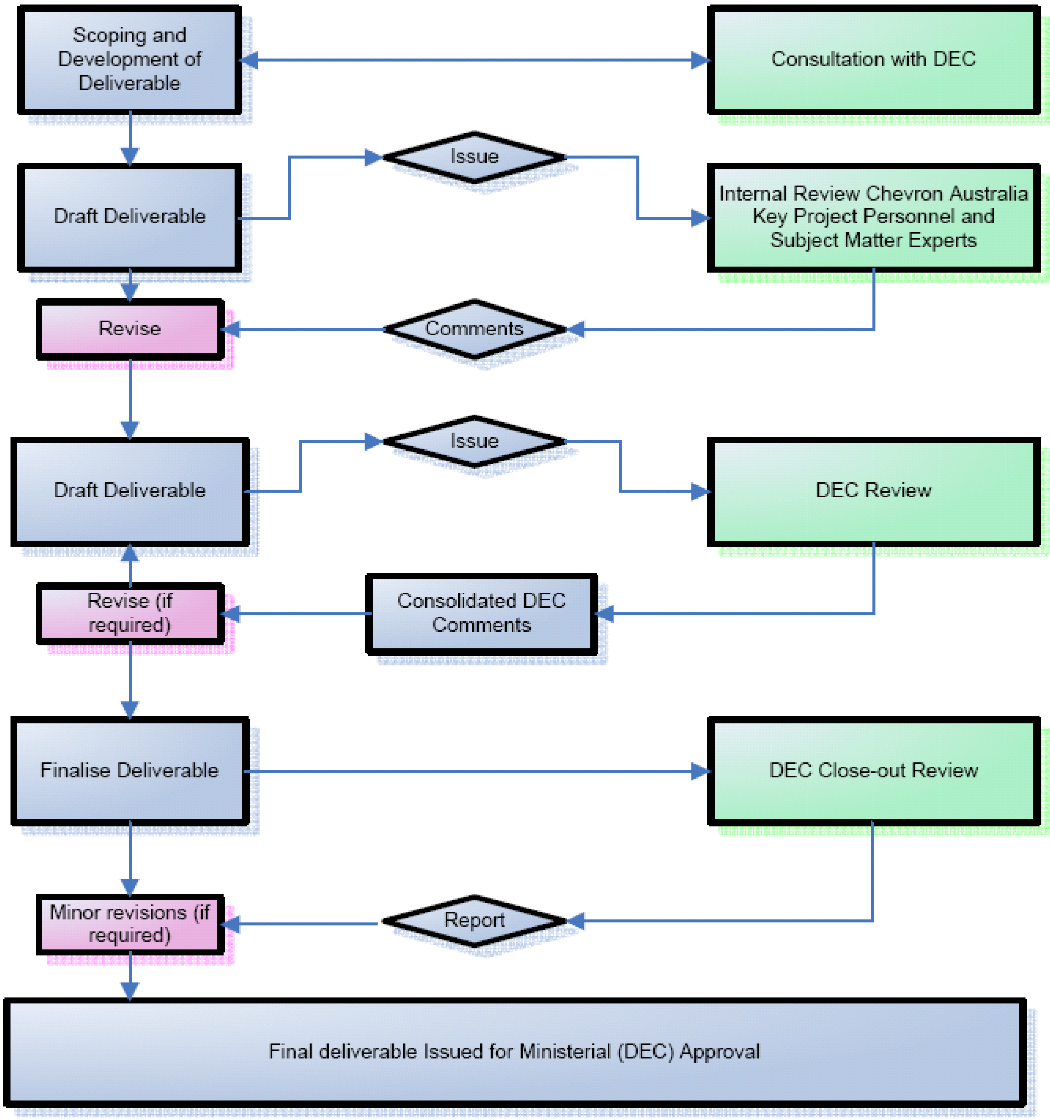

Figure 1.4: Deliverable Development, Review and Approval Flowchart

1.5.7 Public Availability

This Program will be made public as and when determined by the Minister, under Condition 35 of Statement No. 800.

2.0 GAS TREATMENT PLANT OVERVIEW

2.1 Gas Treatment Plant Processing Facilities

As approved under Statement No. 800, the Gorgon Gas Treatment Plant comprises the main processing units described in the following sections and depicted in Figure 2.1.

2.1.1 Inlet Processing, MEG Regeneration and Condensate Stabilisation

The Gorgon and Jansz feed gas arrives at dedicated Gorgon and Jansz inlet processing facilities (slug catchers), designed to segregate the incoming fluids into three separate phases (gas, condensate and aqueous phase) and provide steady flow rates to the downstream units. The reduced pressure gas phase is combined and sent to the Acid Gas Removal Units (AGRUs). A side stream of gas downstream of the Jansz slug catcher is sent to the Domestic Gas (DomGas) Plant for processing and export.

The aqueous phase is sent to the Mono-ethylene Glycol (MEG) Regeneration unit, designed to regenerate the rich (water-saturated) MEG (MEG is used to inhibit hydrate formation in the pipelines) by removing water and salts from a slipstream of the reconcentrated MEG to meet lean MEG specifications. Recovered lean MEG is sent back to the Gorgon and Jansz production wellheads via dedicated MEG utility pipelines.

The condensate stream is sent to Condensate Stabilisation, where further stripping of the light hydrocarbon components is undertaken to produce a stabilised condensate stream, which is combined with the condensate from the LNG Train Fractionation Unit prior to storage and export.

2.1.2 Acid Gas Removal and Carbon Dioxide Compression

The commingled Gorgon and Jansz gas phase streams from the slug catchers and the condensate stabilisation unit are routed to the AGRU for carbon dioxide (CO_2) and hydrogen sulfide (H_2S) (collectively termed 'acid gas') removal from the natural gas using a proprietary activated Methyl Di-ethanol Amine (a-MDEA) technology. Acid gas must be removed from the natural gas to prevent it from freezing out at low temperatures in the cryogenic sections of the plant and to meet the LNG product CO_2 and sulfur specifications.

Each AGRU is designed to process 33% of the combined Gorgon and Jansz gas stream. The AGRUs consist of two subsystems:

- an Absorber System, designed to remove carbon dioxide (CO_2) and hydrogen sulfide (H_2S) from the natural gas by absorption in an activated Methyl Di-Ethanol Amine (a-MDEA) solvent
- a Regenerator System, designed to regenerate the a-MDEA solvent for re-use by separating it from the acid gas components, removed from the natural gas in the Absorption System (see Figure 2.2).

The removed acid gas, containing 99.7 mole % of CO_2 and minor residual amounts of volatile organic compounds (VOCs) and H_2S, is compressed in the CO_2 Injection System and injected into the subsurface Dupuy Formation, or vented in the event of a compression and injection system failure.

The CO_2 Injection System consists of 2 x 50% CO_2 Injection units (A and B) dedicated to each AGRU (see Figure 2.2). Failure of any critical equipment inside each injection unit is likely to result in the immediate shutdown of that unit and local acid gas venting. The second CO_2 injection unit is expected to be able to operate normally during this time.

Maintenance on the critical equipment in the shutdown unit is not expected to adversely affect the operation of the second unit, i.e. it is intended that equipment failure in one unit will result in acid gas venting from that unit only, allowing 50% of the acid gas stream processed through the affected AGRU train to continue to be injected.

The CO_2 injection facilities, downstream of the CO_2 injection units, are not part of the Gas Treatment Plant, but are described here for information.

The compressed acid gas will be injected via eight or nine CO_2 injection wells, drilled directionally from three or four CO_2 drill centres. An above-ground CO_2 pipeline will run from the CO_2 compressors on the north side of the Gas Treatment Plant to these drill centres.

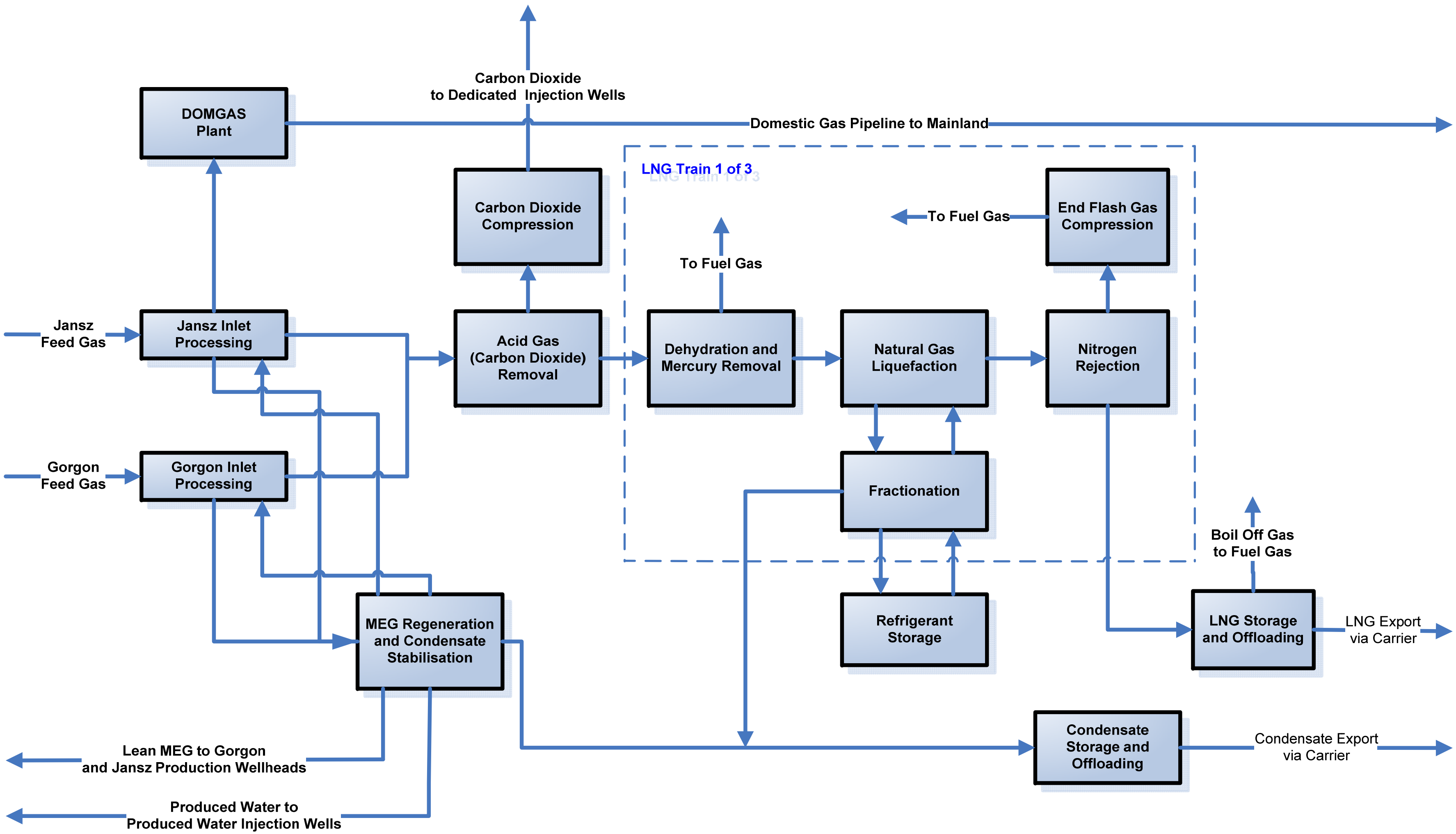

Figure 2.1: Gorgon Gas Treatment Plant Block Flow Diagram

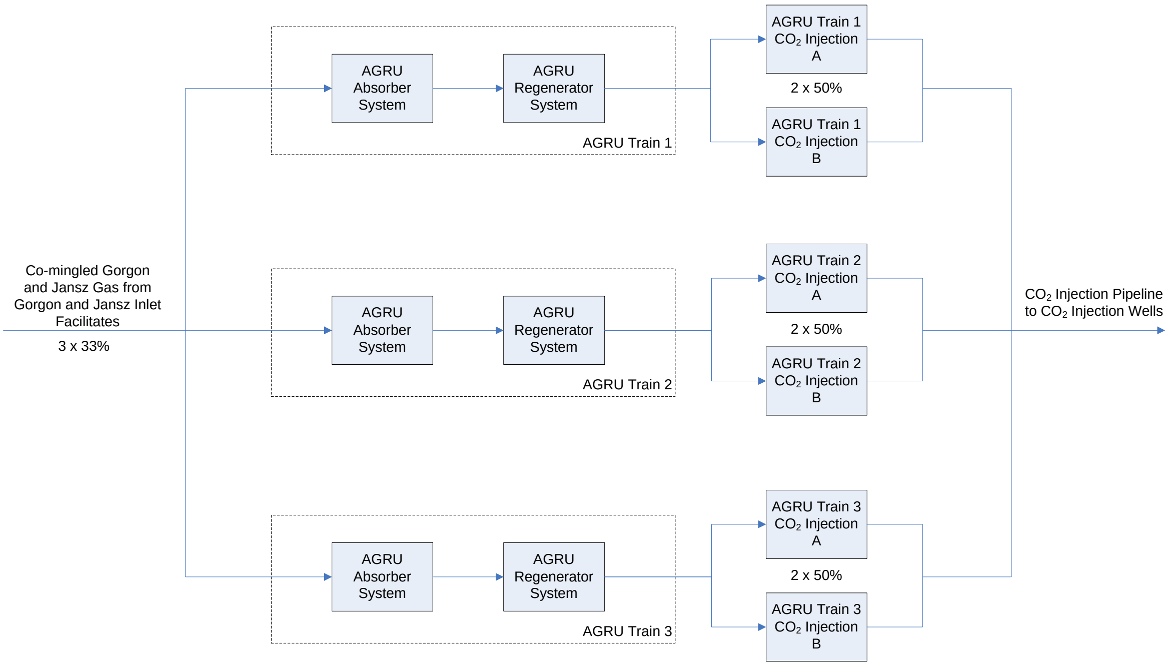

Figure 2.2: Acid Gas Removal and CO_2 Injection System Block Flow Diagram

2.1.3 Dehydration and Mercury Removal

The purpose of the Dehydration Unit is to remove water from the treated hydrocarbon gas leaving the AGRUs. The treated gas is then dried in a molecular sieve to remove the final traces of water and to prevent hydrate formation in the Liquefaction Unit which could cause blockages of lines and equipment.

The purpose of the Mercury Removal Unit is to remove trace quantities of mercury present in the feed gas to the Liquefaction Unit to prevent corrosion of the heat exchanger tubes in the Main Cryogenic Heat Exchanger (MCHE). Mercury adsorbers with non-regenerable packed beds and adsorber after filters will be provided to ensure adequate removal of trace quantities of mercury.

2.1.4 Liquefaction, Fractionation and Refrigerant Make Up

Before the dry treated gas from the mercury adsorber units can be liquefied, heavy hydrocarbons, which can otherwise freeze out in the liquefied natural gas, need to be removed. For this purpose, the dry treated gas is pre-cooled and fed to the Scrub Column which removes heavy hydrocarbons and aromatics to comply with LNG product specifications and to prevent freezing at cryogenic temperatures in the MCHE; and recovers ethane and propane from the natural gas allowing sufficient refrigerant make up to be produced in the Fractionation Unit. The cooling medium is ambient air.

Liquefaction is the main component of the LNG train; it chills the natural gas to a temperature at which LNG can be produced using large gas turbines and a series of cryogenic heat exchangers. The liquefaction process is the Air Products and Chemicals Incorporated (APCI) Split–MR™ Propane Pre-Cooled Mixed Refrigerant (MR) Process (see Figure 2.3). Each LNG train has refrigeration compressors driven by Frame 7 gas turbines. The APCI 5 MTPA Refrigeration Cycle is illustrated in Figure 2.3.

2.1.5 Nitrogen Removal and End Flash Gas Compression

Liquefied natural gas is further cooled in the Nitrogen Column Reboiler and subsequently flashed off in the top of the Nitrogen Rejection Column. The LNG product separates in the Nitrogen Rejection Column bottom and is pumped to the LNG Storage Tanks. End flash gas is routed to a multistage End Flash Gas Compressor, which compresses it to the pressure required for the high-pressure fuel gas system.

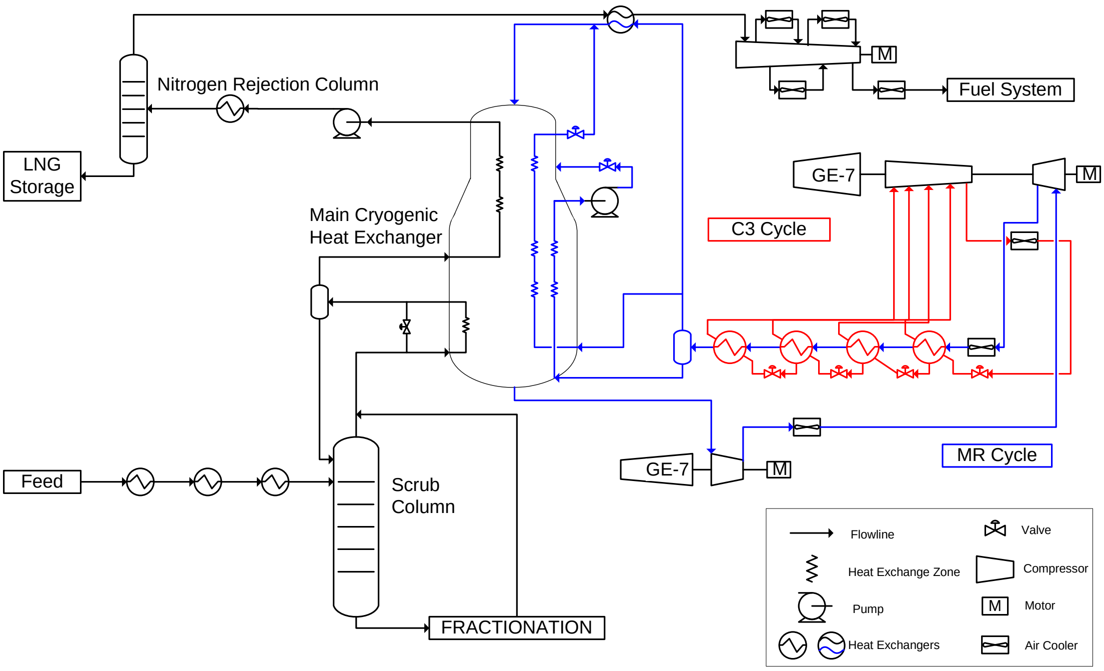

Figure 2.3: APCI 5 MTPA Refrigeration Cycle

Legend:

GE-7	*Frame 7 Process Gas Turbines, driving the Refrigeration Compressors*
C3 Cycle	*Propane Refrigerant Cycle*
MR Cycle	*Mixed Refrigerant Cycle*
M	*Refrigerant Compressor Helper Motor*

2.1.6 LNG and Condensate Storage and Loading

The purpose of the LNG Storage and Loading unit is to provide adequate storage and loading facilities to allow continuous production of LNG at the designed production rates and to enable intermittent exports by LNG carriers. The two LNG Storage tanks are full containment tanks with a net capacity of 180 000 m^3 each. Boil off gas (BOG) from the LNG storage tanks is collected, compressed and returned to the high-pressure fuel gas system inside the LNG trains.

The LNG Jetty, located approximately 4 km offshore from the Gas Treatment Plant at Town Point, has two LNG Carrier Berths, each equipped with four loading arms, i.e. two liquid loading arms, one hybrid (liquid and vapour), and one vapour return arm. The BOG generated during LNG loading of LNG carriers is routed back down the jetty via the vapour return arm and the vapour return line and compressed and recycled as feed gas to the Dehydration and Mercury Removal Units inside the LNG trains. A BOG (marine) flare is provided for the safe disposal of BOG in the event of BOG compressor failure and warm LNG carrier de-inerting.

The purpose of the Condensate Storage and Loading Unit is to provide adequate storage and loading facilities to allow continuous production of condensate at the design capacity of the Gas Treatment Plant and to enable intermittent exports by condensate tankers. The four condensate storage tanks will be emptied by periodic loading of condensate tankers through a load out line that runs along the jetty and terminates at the loading platform at two 50% condensate loading arms.

2.1.7 Domestic Gas (DomGas Unit)

The DomGas Unit will be designed for 300 terajoules of sales gas per day (TJ/d), derived from Jansz feed gas. The unit uses Mono-ethylene glycol (MEG)/Joule-Thomson (JT) processing to meet pipeline moisture and hydrocarbon dewpoint specifications. Domestic gas will be exported via a dedicated pipeline to the mainland where it will tie in to the Dampier to Bunbury Natural Gas Pipeline.

2.2 Ancillary Systems and Facilities

The main ancillary systems and facilities associated with the Gas Treatment Plant include the following:

2.2.1 Fuel Gas and Recycle Gas Systems

The purpose of the Fuel Gas and Recycle Gas systems is to reliably provide fuel gas to users throughout the Gas Treatment Plant, and to return low-pressure gas, unsuitable for use as fuel, to the process for treating. The unit consists of multiple systems:

- high-pressure fuel gas system in each LNG train to supply the refrigerant gas turbines
- high-pressure fuel gas system in the Utilities area to supply the gas turbines for power generation
- high-pressure fuel gas is let down to separate low-pressure fuel gas headers to supply the heating medium heaters and the pilots and purge gas for the flare systems
- a Recycle Gas system compresses flash gas from the AGRUs back to the process units for further treatment.

2.2.2 Power Generation

The Gorgon Gas Development power generation system will generate power for electrical consumers in the Gas Treatment Plant and other electrical consumers (e.g. administration area and construction village, etc.). The estimated total electrical power load for all electrical consumers is 416 MW (with contingency).

Electrical power is provided by five Frame 9 gas turbine generators (N+1 operating philosophy), running continuously and sharing the load, between 80 and 100 MW each, under normal operating conditions. The maximum power output of the power generation plant under average feed composition/average ambient temperature (AFAT) operating conditions is 550 MW (fouled condition) with all five gas turbines running.

2.2.3 Heating Medium System

The Heating Medium System is a pressurised, closed-loop hot demineralised water recirculating system. Heat is recovered from the available waste heat from gas turbine exhausts in the Waste Heat Recovery Units (WHRUs) and sent to various heat consumers around the Gas Treatment Plant, including inlet gas heating, AGRU reboilers, MEG regeneration package, etc.

2.2.4 Pressure Relief/Liquids Disposal, Flare and Vent Systems

The design of the flare system is based on segregation of wet (containing water or water vapour), heavy hydrocarbons and light, dry (water-free), potentially cold hydrocarbons so that hydrate formation, freezing or condensation will not restrict the operation of any system.

Three separate systems are provided for this purpose: wet flare, dry flare and the BOG flare.

The design basis for the Gas Treatment Plant specifies no routine flaring during normal operations other than flare pilots and purged gas (Chevron Australia 2008a).

The wet and dry gas flare systems are each comprised of a collection header system for vapours and a collection header system for liquids, a knock out drum and a staged ground flare. No liquid burners are installed. The BOG flare system consists of two 100% low-pressure flares (one operational, one spare) located in the vicinity of the LNG Storage Tanks.

The design basis for the Gas Treatment Plant specifies no routine hydrocarbon venting and there are no routine vents provided on hydrocarbon process streams (Chevron Australia 2008a). Acid gas (carbon dioxide) venting will occur in the event of failure of the carbon dioxide compression or injection system. The availability of the carbon dioxide compression and injection system, which is capable of disposing by underground injection 100% of the volume of reservoir carbon dioxide to be removed during routine processing operations, is expected to be greater than 80%, expressed as a five-year rolling average.

3.0 GREENHOUSE GAS EMISSIONS AND INTENSITY

3.1 GHG Emissions Estimation Methodology

The Gorgon Gas Development's GHG emissions inventory has been calculated using a methodology consistent with the technical guidance provided under the National Greenhouse and Energy Reporting Regulations 2008 (NGER Regulations), specifically the National Greenhouse and Energy Reporting (Measurement) Technical Guidelines (Department of Climate Change [DCC] 2009) and the National Greenhouse Accounts (NGA) Factors (DCC 2008).

The proposed Gas Treatment Plant facilities are considered to be a Scope 1 activity for GHG reporting purposes under the *National Greenhouse and Energy Reporting Act 2007* (Cth). A Scope 1 activity is one in which GHG emissions to the atmosphere occur as a direct result of the activity, or series of activities, including ancillary activities that constitute a facility.

The methodology employed in compiling the Gorgon Gas Development's GHG emissions inventory complies with Method 2, which is defined in the National Greenhouse and Energy Reporting (Measurement) Technical Guidelines (DCC 2009) as a 'facility-specific method using industry sampling and Australian or international standards listed in the Determination or equivalent for analysis of fuels and raw materials at facility level'. Salient features of Method 2, as applied to the Gorgon Gas Development's GHG emissions inventory, include:

- Fuel composition and relevant fuel qualities (e.g. heating value), estimated as part of engineering and design are used to calculate fuel specific emission factors using the methods prescribed in the existing Generator Efficiency Standards (Department of the Environment, Water, Heritage and the Arts [DEWHA] 2006).
- As fuel consumption, composition and energy values continue to change as a result of detailed engineering work, fuel consumption quantities and emission factors will also continue to be fine-tuned to reflect these changes.

During start-up and commissioning, and the operations phase of the Gas Treatment Plant, some sources of GHG emissions are to be calculated using Method 3 (based on direct measurement of fuel composition and energy values), where applicable.

In addition, the GHG emissions inventory complies with the following key NGER requirements (in National Greenhouse and Energy Reporting (Measurement) Technical Guidelines [DCC 2009]):

- Transparency: All emissions calculations have been documented and can be verified against the facilities design.
- Comparability: Emissions estimates per source have been recalculated using Method 1 emission factors (national industry average factors as listed in the NGA Factors workbook [DCC 2008]) and both estimates compare very well (i.e. difference less than 2%).
- Accuracy: Accuracy has been improved by using Method 2 over Method 1 and will continue to be improved through detailed design as greater design definition and equipment vendor information become available. Accuracy against true values will be monitored and verified in operations to achieve the 95% confidence level required in the NGER Regulations.
- Completeness: Emission sources have been identified using hazard identification and design data, as well as industry benchmarking using the Australian Petroleum Production and Exploration Association (APPEA) GHG Emissions Reporting Survey

(APPEA 2005) and the National Pollutant Inventory (NPI) Emission Estimation Technique Manual for Oil and Gas Exploration and Production (DEWHA 2005).

3.2 Gorgon Gas Development GHG Emissions Inventory

3.2.1 Start-up and Commissioning GHG Emissions Inventory

The GHG emissions inventory for the start-up and commissioning of the Gas Treatment Plant will be estimated from the start-up and commissioning sequence and schedule documents, which are still under development. A number of key start-up and commissioning decisions are still pending resolution and could significantly influence the duration of hydrocarbon gas venting and flaring and acid gas venting activities, which are expected to dominate the total GHG emissions for the duration of the Gas Treatment Plant start-up and commissioning activities. It is intended to employ reasonably practicable measures to reduce GHG emissions from start-up and commissioning activities to as low as reasonably practicable (ALARP).

The Gas Treatment Plant start-up and commissioning GHG emissions inventory will be provided to the Western Australian Department of Environment and Conservation (DEC) as part of the Commissioning Plan intended to be produced as an Addendum to the Works Approval Application under Part V of the Western Australian *Environmental Protection Act 1986* (EP Act).

3.2.2 Operations Phase GHG Emissions Inventory

The preliminary operations phase GHG emissions inventory was prepared early in Front End Engineering Design (FEED) phase of the Gorgon Gas Development and will be subject to refinement during the detailed design phase. As such, it currently represents only an approximation of the expected actual annual GHG emissions inventory during steady-state operations of the 3 × 5 MTPA Gas Treatment Plant.

A refined GHG emissions inventory will be provided to the DEC towards the end of detailed design phase as part of the Gas Treatment Plant application for an operating licence under Part V of the EP Act (WA).

The preliminary Gas Treatment Plant GHG emissions inventory for steady-state operations is presented in Table 3.1. This inventory is reflective of a typical production year, with all three LNG trains commissioned and operating under steady-state conditions.

Furthermore, the following assumptions underpin the GHG estimates provided in this inventory:

- LNG production availability is 8170 hours (340.4 stream days) per calendar year (Chevron Australia 2008b), corresponding to an annual average LNG production of 15.59 MTPA Freight on Board (FOB). This is the assumed production availability of the refrigeration compressor gas turbines as well.
- All power generation gas turbine generators are operated at 75.4% part load (corresponding to 416 MW total Gas Treatment Plant power demand without contingency) in an N+1 operating mode, whereby one turbine provides a spinning reserve.
- Gas Treatment Plant utilities, including flares, heaters, and power generation plant and diesel consuming safety equipment on stand-by, are required to be available 365 days per calendar year. This has been reflected in the GHG emissions estimates for these emission sources.
- LNG production is sourced 65% from the Gorgon field and 35% from the Jansz field.

- Domestic gas production is sourced exclusively from the Jansz field (see Figure 2.1).
- Twenty per cent of removed reservoir CO_2 is assumed to be vented due to the periodic unavailability of the CO_2 injection system.
- One of the two Heating Medium Heaters is maintained on cold stand-by (pilot flame only) during normal operations; the other is offline.

No perfluorocarbons (PFCs) are planned to be used in the Gas Treatment Plant. Hydrofluorocarbons (HFCs) will be used in the heating ventilation and air conditioning (HVAC) systems and sulfur hexafluoride (SF_6) will be used in some electrical switch gear. However, both these uses are for closed systems, and so emissions of these substances could potentially occur only under non-routine or emergency conditions. Operating and maintenance procedures for HVAC systems will aim to prevent loss of hydrofluorocarbons during refrigerant change out.

Table 3.1: Preliminary Gas Treatment Plant Operations GHG Emissions Inventory

GREENHOUSE GAS EMISSION SOURCE		TOTAL ANNUAL EMISSION ESTIMATES [TONNES]				Total CO_2e by source
	Fuel / Emission Type	CO_2	CH_4	N_2O	Total CO_2e	
Heating Medium Heaters						
Start-up and Occasional Use (F-4101A/F-4101B)	Fuel gas (4426)	700	0.00001	0.004	701	
Cold stand-by (F-4101A or F-4101B)	Fuel gas (4426)	10190	0.00	0.06	10,210	**10,911**
Routine Flaring						
Dry Gas Flare Pilot & Purge Gas	Fuel gas (4441/2)	2198	4	0.00002	2,283	
Wet Gas Flare Pilot & Purge Gas	Fuel gas (4441/2)	1686	3	0.00002	1,750	
BOG Gas Flare Pilot & Purge Gas	Fuel gas (4441/2)	1487	3	0.00002	1,544	**5,577**
Planned and Unplanned Non-Routine Flaring						
Dry Gas Unplanned Non-Routine Flaring	Dry hydrocarbon gas	12825	0	0.0002	12,825	
Wet Gas Unplanned Non-Routine Flaring	Wet hydrocarbon gas	2897	4	0.00003	2,981	
BOG Planned Non-Routine Flaring	Inert gas / BOG	3611	6	0.00004	3,735	
BOG Unplanned Non-Routine Flaring	BOG	15333	28	0.0002	15,929	**35,470**
Process Gas Turbines						
LP MR Compressor Gas Turbine Driver (1KT-1510)	Fuel gas (4434)	393465	698	10	411,217	
LP MR Compressor Gas Turbine Driver (2KT-1510)	Fuel gas (4434)	393465	698	10	411,217	
LP MR Compressor Gas Turbine Driver (3KT-1510)	Fuel gas (4434)	393465	698	10	411,217	
PR Compressor Gas Turbine Driver (1KT-1530)	Fuel gas (4435)	393465	698	10	411,217	
PR Compressor Gas Turbine Driver (2KT-1530)	Fuel gas (4435)	393465	698	10	411,217	
PR Compressor Gas Turbine Driver (3KT-1530)	Fuel gas (4435)	393465	698	10	411,217	**2,467,301**
Power Generation Turbines						
Gas Turbine Generator Package (GT-4001)	Fuel gas (4440)	411734	741	11	430,659	
Gas Turbine Generator Package (GT-4002)	Fuel gas (4440)	411734	741	11	430,659	
Gas Turbine Generator Package (GT-4003)	Fuel gas (4440)	411734	741	11	430,659	
Gas Turbine Generator Package (GT-4004)	Fuel gas (4440)	411734	741	11	430,659	
Gas Turbine Generator Package (GT-4005)	Fuel gas (4440)	411734	741	11	430,659	**2,153,294**
Acid Gas Venting						
Unplanned Acid Gas Venting at AGRUs	Acid gas	840119	362	0	847,724	**847,724**
Other						
Fugitive Emissions from the Gas Treatment Plant	Hydrocarbon gas	0	903	0	18,973	**18,973**
TOTAL		**5,310,504**	**9,203**	**114**	**5,539,250**	**5,539,250**

Note: Fugitive emissions of CO_2 from the AGRU and CO_2 injection systems within the Gas Treatment Plant have been included in the Acid Gas Venting estimate.

3.2.3 Discussion of Major GHG Emissions Sources

Figure 3.1 shows a breakdown of the relative contribution of the major GHG emissions sources to the overall Gorgon Gas Development GHG emissions inventory.

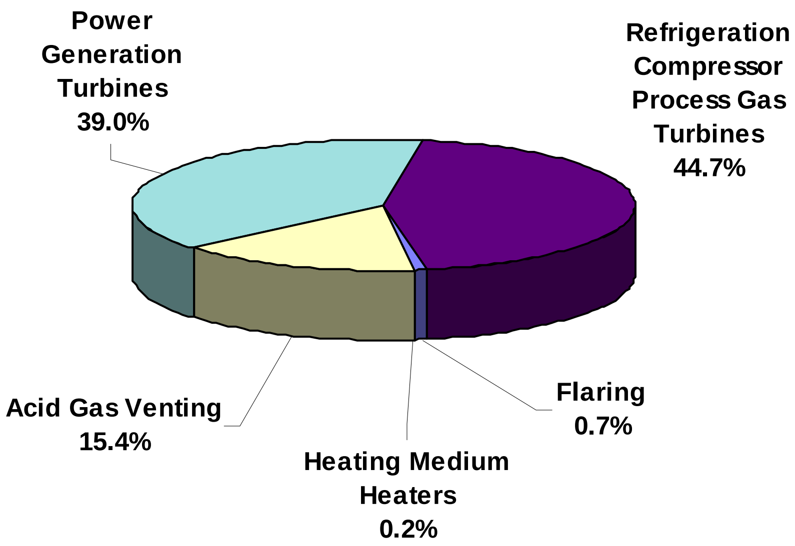

Figure 3.1: Gorgon Operations Major GHG Emission Sources

Figure 3.1 indicates that Refrigeration Compressor Process Gas Turbines (GTs), Power Generation Gas Turbine Generators (GTGs), as well as acid gas venting, collectively contribute approximately 99% of the total GHG emissions associated with the Gas Treatment Plant operations. These major contributors are discussed in the following sections.

3.2.3.1 Refrigeration Compressor Gas Turbines

The gas turbines to be used in the three LNG processing trains account for approximately 44% of the overall GHG emissions estimated for steady-state operations of the Gas Treatment Plant. These gas turbines drive the refrigeration compressors at the core of the LNG process.

Liquefied natural gas processing train design, incorporating direct drive gas turbines with an LNG throughput of approximately 5 MTPA, represents established best practice in LNG plant design, offering optimum balance between capital cost, GHG emissions intensity and operability risk profile.

The gas turbines in the LNG processing trains will be fitted with WHRUs to recover additional energy from the latent heat in the exhaust combustion gases from the turbines. This recovered energy stream will be used within the Gas Treatment Plant to provide processing heat required for the regeneration of the CO_2 removal solvent (a-MDEA), regeneration of the hydrate inhibitor (MEG) and feed gas pre-heating and fractionation. In addition to providing approximately 450 MW of mechanical energy, 640 MW of process heat will be provided from the WHRUs fitted to the exhausts of the gas processing drivers. Each gas processing driver turbine will be fitted with dry low NO_x (DLN) emissions control technology.

3.2.3.2 Power Generation Gas Turbine Generators

GHG emissions from the gas turbines used to generate electrical power for the Gas Treatment Plant and its support infrastructure represents approximately 39% of the overall GHG emissions estimated for steady-state operations.

Extensive studies have been undertaken to identify and evaluate options for alternative power generation (Chevron Australia 2009a). These studies considered a range of open cycle and combined cycle options, as well as options for inlet cooling and water and steam injection. The options were evaluated using criteria such as:

- safety and operability risks
- capital and operating cost
- availability and reliability
- fuel consumption and resulting GHG emissions
- land area (footprint) and water requirements
- integration with the Gas Treatment Plant waste heat recovery system.

Given the remoteness of the proposed Gas Treatment Plant on Barrow Island and lack of access to the State's electricity grid, the Gorgon Gas Development's power generation configuration must be highly reliable to avoid unplanned outages of the LNG processing trains. The LNG processing trains operate most efficiently when running at full capacity over long time periods. An unreliable electrical power supply would result in the LNG processing trains operating at lower than peak efficiency, or in the worst case, having to be shut down. LNG trips or full train shutdowns would result in a large increase in GHG emissions as part of or the entire gas inventory within the Gas Treatment Plant would have to be flared.

Total power demand for operations comprises 384 MW for LNG processing trains and inlet facilities, 12 MW for domestic gas processing, and 20 MW for Gorgon Gas Development and Jansz Feed Gas Pipeline infrastructure electricity consumption.

Power generation studies have concluded that the most appropriate configuration for the required generation of approximately 416 MW of electrical demand is to employ five open cycle industrial gas turbines each with approximately 117.5 MW (gross) and 110.5 MW (site rated) capacity operated at partial load. Having each turbine operating at partial load enables the operating turbines to quickly take up the load if one turbine should go offline, thereby maintaining a stable electrical supply to the LNG processing trains and avoiding LNG process upsets that might result in increased and potentially long duration flaring events.

Each of the power generation turbines is proposed to be fitted with dry low NO_x (DLN) emissions control technology.

3.2.3.3 Acid Gas Venting

Under routine operations, all reservoir CO_2 removed from the incoming gas stream is intended to be injected into the Dupuy Formation. The injection of reservoir CO_2 and associated impurities (collectively known as acid gas) will reduce GHG emissions attributable to the Gorgon Gas Development by approximately 3.4 million CO_2e tonnes per annum. However, venting of the reservoir CO_2 will be required during periods of facility or injection system maintenance, unplanned downtime and in the event of unforeseen reservoir or injection well constraints.

Design features aimed at increasing the reliability of the CO_2 injection system include:

- provision of 2 × 50% CO_2 injection compressors per CO_2 injection train – to allow continued injection of 50% of the acid gas stream and venting of the residual 50% of the acid gas stream if one 50% CO_2 compressor is offline
- above-ground CO_2 injection pipeline – to facilitate external pipeline integrity maintenance inspections
- provision of pig launching and receiving facilities – to allow intelligent and maintenance pigging of the CO_2 injection pipeline
- provision of three to four CO_2 drill centres and nine to ten directionally drilled CO_2 injection wells – to allow different regions of the Dupuy reservoir to be accessed
- provision of pressure management facilities for the Dupuy reservoir and production of Dupuy Formation water to the surface – to avoid Dupuy Formation pressure build up and facilitate the CO_2 injection process.

Based on these design features, it is anticipated that the amount of reservoir CO_2 vented in any particular 12-month period will be less than 200 000 tonnes CO_2e; however, there is the potential for a higher level of venting, particularly in the event of unexpected injection well failure or an unexpected subsurface outcome. As a consequence, the reference case for GHG emissions used in this document assumes approximately 850 000 tonnes (or 20% of the reservoir CO_2 available for injection) will be vented annually. This represents a worst-case operational outcome which is anticipated to be improved upon during detailed design and with the development of operational experience.

The anticipated volumes of reservoir CO_2 that will be vented and the volumes anticipated to be injected are identified in Table 3.2. Volumes vented are expected to decline over time as the facility and CO_2 injection operations are optimised.

Table 3.2: Volumes of Acid Gas Anticipated to be Vented and Injected

Percentage of Acid Gas (Reservoir CO_2)	Operations Year 1	Operations Years 2–5	Operations Year 6+	Long-term Performance Target
Percentage of Acid Gas injected into the Dupuy Formation	60–90% p.a. (2.52–3.78 MTPA)	70–95% p.a. (2.94–3.99 MTPA)	80–97% p.a. (3.36–3.99 MTPA)	95% p.a. (3.99 MTPA)
Acid Gas vented due to scheduled maintenance and unplanned facilities downtime	5–15% p.a. (0.21–0.63 MTPA)	5–10% p.a. (0.21–0.42 MTPA)	3–5% p.a. (0.13–0.21 MTPA)	3% p.a. (0.13 MTPA)
Acid Gas vented due to unforeseen reservoir constraints (including well injectivity failure)	0–25% p.a. (0–1.05 MTPA)	0–20% p.a. (0–0.84MTPA)	0–15% p.a. (0–0.63 MTPA)	2% p.a. (0.08 MTPA)

Note: As the concentration of CO_2 varies in different parts of the Gorgon Gas Field, these figures represent the anticipated maximum annual CO_2 production rate of 4.2 MTPA (Chevron Australia 2008c).

3.2.3.4 Further GHG Emissions Reduction Options

The discussion of the Gorgon Gas Development's major GHG emissions contributors indicates that only acid gas venting realistically offers a potential for considerable future GHG emissions reductions during operations.

3.3 GHG Intensity Benchmarking

3.3.1 Gas Treatment Plant GHG Intensity

The GHG intensity (GI) of the Gas Treatment Plant can be expressed as the mass of GHG (tonne CO_2e) emitted per tonne of LNG produced. Therefore, identification of GHG emissions associated with LNG production only is required. This approach is consistent with the standard industry method for calculating and benchmarking GI for LNG production facilities, as these facilities are often supplied with gas produced by offshore gas production and processing platforms, which also produce other liquid hydrocarbon products, including oil and condensate, propane and butane, etc.

GHG emissions associated with production of these liquid hydrocarbons, or the compression and transport of the natural gas from the offshore (or onshore) facility to the onshore LNG facilities should be excluded from the LNG facilities GI calculation. GHG emissions from these sources can significantly skew results and make the benchmarking process difficult due to the large variety in the processes and emissions involved in feed gas production, processing and transportation to the LNG production facilities.

Therefore, the steady-state operations GHG emissions inventory, presented in Table 3.1, can be split between LNG processing (defined as all components of the Gas Treatment Plant as presented in Figure 2.1, except the DomGas unit), DomGas processing, and associated terrestrial infrastructure on the basis of the electrical power consumed by these components, as follows:

- Gas Treatment Plant load schedule (Chevron Australia 2008d) is 416 MW without contingency.
- Electrical power load allocated to DomGas Processing is 12 MW (Chevron Australia 2008d).
- Electrical power load allocated to the Gorgon Gas Development and Jansz Feed Gas Pipeline's infrastructure electricity consumption is 20 MW (Chevron Australia 2008d). Major electricity consumers within this infrastructure include the Administration Area and the Construction Village.

The contribution of each component to the preliminary Gas Treatment Plant operations GHG emission inventory is presented in Table 3.3. Individual contribution sources have been rounded up.

Table 3.3: Allocation of the Operations GHG Emissions Inventory between LNG and DomGas Production and Project Infrastructure Electricity Consumption

Emissions Source	LNG Production [CO_2e Tonnes per annum]	DomGas Production [CO_2e Tonnes per annum]	Project Infrastructure Electricity Consumption [CO_2e Tonnes per annum]
Process Gas Turbines	2 467 000	Nil	Nil
Power Generation GTG	1 987 000	62 110	103 500
Fired Heaters	10 910	Minor	Nil
Flare – Events	35 470	Minor	Nil
Flare – Pilots	5580	Minor	Nil
Fugitive Emissions	18 970	Minor	Nil
Acid Gas Venting	847 700	Minor	Nil
Total	**5 374 000**	**62 110**	**103 500**

The Gorgon LNG processing facilities GI is thus calculated for 5 374 000 tonnes of CO_2e produced from the LNG trains only (see Table 3.3) and an annual average LNG production of approximately 15.59 MTPA FOB LNG based on 340.4 stream days per year (Chevron Australia 2008b).

$$GI = \frac{M_{GHG}}{M_{LNGproduced}} \text{ (tonnes } CO_2\text{e/tonne LNG produced)}$$

$$GI = \frac{5,374,000}{15,590,000} = 0.35 \text{ (tonnes } CO_2\text{e/tonne LNG produced)}$$

3.3.2 Improvements in GHG Intensity

Early design concepts for the development of the Gorgon gas field incorporated a gas processing platform located offshore in the vicinity of the gas field, with the LNG processing facility on the Burrup Peninsula. This design concept formed the basis of the 1998 Greenhouse Challenge Cooperative Agreement between the Gorgon Joint Venture Participants (JVPs) and the Australian Greenhouse Office (West Australian Petroleum [WAPET] 1998). The GI improvements identified below compare the current design to that used as the basis of the 1998 Cooperative Agreement.

The GI of the Gorgon Gas Development as stated in the 1998 Cooperative Agreement was 0.89 tonnes of CO_2e emitted to the atmosphere for every tonne of LNG to be shipped. As the 1998 Cooperative Agreement did not include gas for domestic consumption, only emissions related to the processing and production of LNG were considered.

Engineering decisions that have resulted in significant improvements in GI compared to the 1998 design case include:

- replacement of the offshore gas processing platform with a subsea development
- changes in LNG process technology
- provision of waste heat recovery on the refrigeration gas turbines resulting in significant reduction in the use of supplementary heaters and removal of boilers to provide heating for process needs
- significant reduction in GHG emissions by injecting removed reservoir carbon dioxide into the Dupuy Formation.

Figure 3.2 shows the contribution to improved GI from each of these areas.

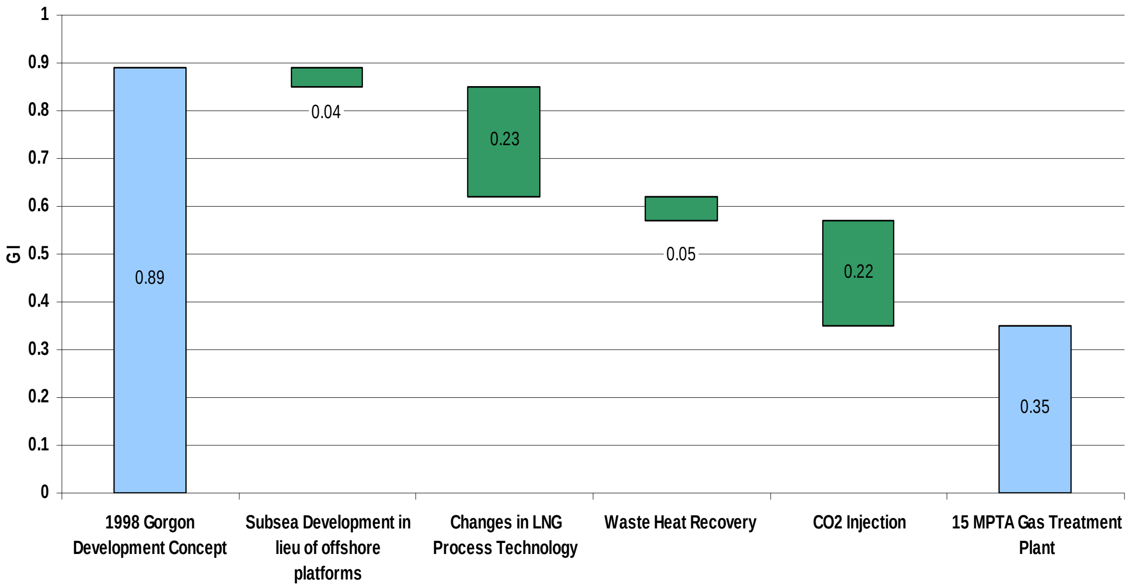

Figure 3.2: GI Improvements from the 1998 Gorgon Development Concept

The selection of Barrow Island as the preferred site for the gas processing facilities has enabled the use of subsea technology rather than platform-based offshore gas processing. The offshore gas production platform in the 1998 design accounted for approximately 600 000 tonnes of CO_2e emissions per year. By eliminating the offshore gas production platform and using a subsea gas production system, the GI of the Gorgon Gas Development has been improved by 0.04 tonnes of CO_2e per tonne of LNG to be produced.

LNG process technology has evolved significantly over the last ten years driven by the use of larger, more efficient plants and changes in technology used to remove carbon dioxide from the natural gas stream. A range of design areas have been studied for incremental improvements in GI and have been included in the current Gorgon Gas Development design, including:

- increasing the size of the LNG process trains to the maximum practicable for the selected LNG technology
- using a-MDEA as the CO_2 removal medium in the acid gas removal units
- using dry compressor and hydrocarbon pump seals
- recovering flash gas from the nitrogen removal column and re-using it as fuel gas (see Figure 2.1).

These technology improvements have resulted in a GI improvement of 0.23 tonnes of CO_2e per tonne of LNG to be produced, compared to the 1998 LNG process technology.

The design concept, upon which the Greenhouse Challenge Cooperative Agreement was based, included the use of direct fired heaters/boilers. These boilers accounted for approximately 520 000 tonnes of CO_2e emissions per annum. Studies into the better capture and application of waste heat recovered from the process gas turbines have resulted in the restricted use of process heaters (e.g. periods of plant start-up or failure of a WHRU). Improved waste heat recovery has resulted in a GI improvement of 0.05 tonnes of CO_2e per tonne LNG produced versus the 1998 Gas Treatment Plant design.

The Gorgon JVPs conducted studies on further GHG emissions reductions beyond those available through improved plant design, such as the subsurface injection of separated reservoir carbon dioxide. GHG offsets such as forestry or land rehabilitation planting or purchasing GHG credits were also considered. As a result of these studies, the Gorgon JVPs have elected to make a significant reduction in the Gorgon Gas Development's GHG emissions by injecting the reservoir carbon dioxide removed during the gas processing operations into the Dupuy Formation. For the 15 MTPA Gas Treatment Plant, it is estimated that a minimum of 3.4 MTPA of reservoir carbon dioxide will be injected into the Dupuy Formation, which imparts a further GI improvement of 0.22 tonnes of CO_2e per tonne LNG produced versus the 1998 development concept.

Table 3.4 summarises several technology options considered during the preliminary design phase of the Gorgon Gas Development that had the potential to further reduce GHG emissions but which were not adopted. As was the case for all GHG emissions abatement options considered, these options were assessed on a combination of cost effectiveness, operability, technology, health, safety and environmental risks. The primary reason for not adopting many of the options was the high cost of implementation for a relatively low reduction in GHG emissions. By way of illustration, while the capital costs associated with the injection of separated reservoir carbon dioxide is high, the volume of carbon dioxide disposed of is also very large. This relationship can be expressed as a capital cost per annual mass of CO_2e abated. For the carbon dioxide injection approach this metric results in a figure of AU$250/tonne of CO_2e abated. Many options that were rejected had a capital cost of annual CO_2e abated of around AU$1500/tonne. This highlights that these options are not competitive GHG emissions mitigation options when compared to the subsurface injection of separated reservoir carbon dioxide.

Table 3.4: List of Other GHG Emissions Abatement Options Considered

Design Option	Offset in GHG Emissions [tonnes CO_2e p.a.]	Evaluation Comments
Use of alternative LNG technology rather than APCI	100 000	Emissions improvement is only a claim as the alternative technology remains unproven. Significant operability, asset and Health, Environment and Safety (HES) risk with being the first application of new technology.
Electric drive LNG compressors rather than direct drive compressors	300 000	Use of electric drive LNG compressors is relatively untested and carries higher technology risks and increased plot space requirement.
Combined cycle electrical power generation	900 000	Combined cycle power generation would increase operating cost, complexity and required plot space and potentially reduce plant reliability. Lack of readily available water supply on Barrow Island.
Aero-derivative gas turbines for electrical power generation	280 000	Increased operating costs and larger plot space requirements
Power recovery turbines on liquid stream pressure let downs	Small	Rejected due to cost and operational complexity.
Air insulation on high voltage equipment	Small	Rejected due to increase in plot space required over gas-insulated switch gear.

3.3.3 Industry Benchmarking

Benchmark GI data available to enable the comparison of the GI of the Gorgon Gas Development with other LNG projects are limited, as industry competitors' data are not widely published.

The data that are publicly available are restricted to the intensity of LNG processing. The volume of GHG emissions emitted to the atmosphere for each tonne of LNG produced provides a recognised benchmark by which to assess the GI of an LNG production facility. However, this metric is not a direct reflection of the thermal efficiency of an LNG production facility as it is influenced by:

- the composition of the incoming gas stream, particularly the concentration of reservoir carbon dioxide and nitrogen, as well as the level of non-methane hydrocarbons (e.g. ethane, propane, butanes and pentanes)
- the ambient temperature in which the Gas Treatment Plant operates
- the energy used to inject reservoir carbon dioxide, if it is to be injected (note only the Snohvit Project and the proposed Gorgon Gas Development involve separated reservoir carbon dioxide injection operations)
- the degree to which GHG emissions from associated terrestrial infrastructure have been included in the calculations.

The calculated (predicted) GI for the 3 × 5 MTPA Gorgon Gas Development Gas Treatment Plant is 0.35 tonnes of CO_2e per tonne LNG produced. This intensity includes all emissions related to the production of the natural gas from the offshore fields, the energy required to inject 3.4 million tonnes of reservoir carbon dioxide per annum and the volume of reservoir carbon dioxide that is vented rather than injected. As such, it represents the GI of the overall LNG component of the proposed Gorgon Gas Development.

The predicted GI data from the Gorgon Gas Development are presented in Figure 3.3 and compared to equivalent predicted data from:

- Woodside – North West Shelf Project (i.e. Karratha's Onshore Gas Plant LNG Trains 1 to 4)
- ConocoPhillips – LNG Plant in Darwin, Australia
- Statoil – Snohvit LNG Plant, Hammerfest, Norway
- Oman LNG – LNG Plant at Qalhat, Oman
- Nigeria LNG – LNG Plant at Bonny Island, Nigeria
- RasGas – LNG Plant at Ras Laffan, Qatar
- Qatargas – LNG Plant at Ras Laffan, Qatar
- Woodside – Pluto LNG Project, North West Shelf, Western Australia
- Atlantic LNG – LNG Plant at Point Fortin, Trinidad and Tobago
- Santos – LNG Plant from Coal Seam Gas, Gladstone, Queensland, Australia.

The GI for LNG production from the North West Shelf Project has improved from 0.59 to 0.49 tonnes of CO_2e per tonne LNG for the initial three processing trains (Woodside Energy 2004). This was due to process improvements and de-bottlenecking the process trains once commissioned. The recently commissioned LNG Trains 4 and 5 are reported to have an intensity of 0.345 tonnes of CO_2e per tonne LNG reflecting improvements related to the increased size of the process trains (Woodside Energy 2004). This gives the current North West Shelf LNG Project a GI of 0.44 tonnes of CO_2e per tonne LNG (based on production from Trains 1, 2, 3 and 4). The feed gas supplying the North West Shelf LNG facility includes approximately 2.5% reservoir carbon dioxide which, once removed from the gas stream, is vented to the atmosphere and is included in the reported GI value. The benchmark numbers discussed above exclude GHG emissions from the offshore gas production platforms required to feed the gas into the Karratha Onshore Gas Plant.

ConocoPhillips commissioned a single LNG train plant (nameplate capacity of 3.7 MTPA) at Wickham Point, Darwin in 2006, which processes gas from the Bayu–Undan gas condensate field in the Timor Sea. ConocoPhillips estimates that the Darwin LNG facility will have a GI of 0.46 tonnes of CO_2e per tonne of LNG produced (ConocoPhillips Australia 2002). The feed gas supplying the Darwin LNG facility includes approximately 6% reservoir carbon dioxide which, once removed from the gas stream, will be vented to atmosphere and is included in the calculation of the Darwin LNG Project's GI. The GI discussed above excludes the GHG emissions from the offshore gas processing platform required to produce and compress the feed gas for transportation over 500 km to the mainland.

The Santos Gladstone LNG Project, Queensland, Australia recently published data on their Gladstone Coal Seam Gas LNG Plant GI intensity (URS Corporation 2009). The reported GI for the Gladstone 10 MTPA LNG Project of 0.347 CO_2e tonnes per tonne of LNG produced is based on GHG emissions from the LNG Facility only and does not include the GHG emissions from feed gas production and transportation to the LNG Facility. Coal seam gas production, collection and compression will result in another 3.5 million tonnes CO_2e per annum related to fuel consumption in process equipment, fugitive emissions and flaring and venting.

The recently approved Pluto Project, operated by Woodside, has reported a GI of 0.3 tonnes CO_2e per tonne LNG produced. The feed gas to the Pluto LNG plant is expected to contain up to 2 mole % CO_2, which, after removal, will be vented to atmosphere. The vented CO_2 gas will contribute up to 17% of the GHG emissions from the Project, the rest of which will be due to the power generation plant and the refrigeration process turbines.

The Norwegian petroleum company, Statoil, operates the Snohvit LNG facility near the town of Hammerfest in northern Norway. The Snohvit Project is comprised of an offshore subsea production system, an onshore LNG production facility and facilitates the reinjection of separated reservoir carbon dioxide. The feed gas supplying the Snohvit Project includes approximately 8% carbon dioxide. The data published for Snohvit are based on the assumption that all reservoir CO_2 will be injected into the subsurface.

In 2003, the Oil and Gas Journal published benchmark data on five greenfield LNG projects: Oman LNG, Nigeria LNG, RasGas, Qatargas, and Atlantic LNG (Yost and DiNapoli 2003). These LNG facilities had all been commissioned as greenfield projects in the preceding ten years and as such represent current design practice. The reservoir carbon dioxide content in the feed gas supplying these projects is:

- Oman LNG – 1.0 mole %
- Nigeria LNG – 1.8 mole %
- RasGas – 2.3 mole %
- Qatargas – 2.1 mole %
- Atlantic LNG – 0.8 mole %.

In comparison, the reservoir carbon dioxide content in the Gorgon feed gas is expected to be approximately 14 mole %, while the reservoir carbon dioxide content in the Jansz feed gas is estimated to be up to 0.9 mole % (Chevron Australia 2008b).

The venting of the reservoir CO_2 from these projects is included in the GI calculation.

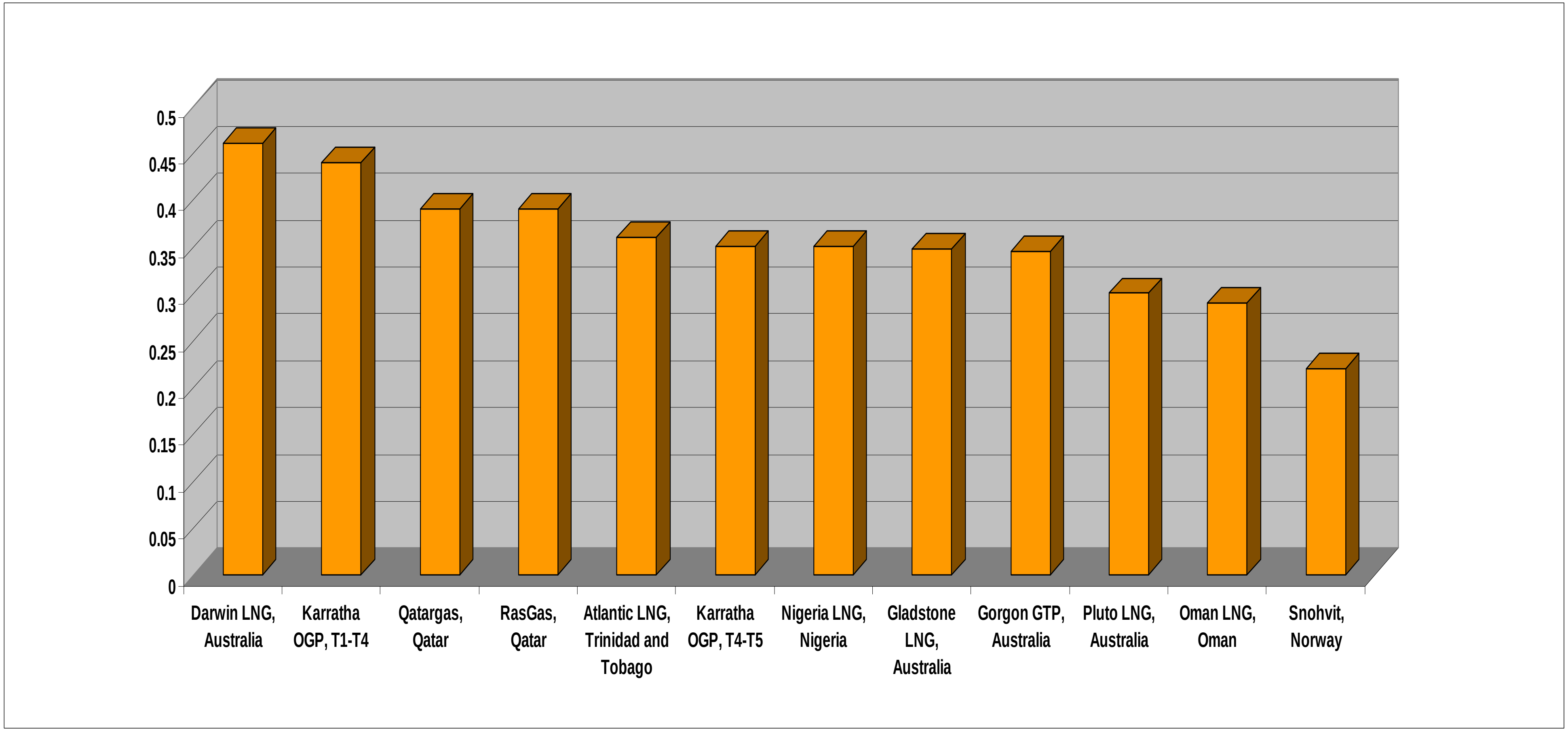

Figure 3.3: Gorgon Benchmarked Greenhouse Gas Intensity

3.3.3.1 Gas Treatment Plant GI Normalisation to Standard Conditions

As shown in the benchmarking data presented in Section 3.3.3, Oman LNG and Snohvit have appreciably better GI than the Gorgon Gas Development Gas Treatment Plant. To illustrate the influence of the reservoir carbon dioxide content in the feed gas and ambient temperature on the Gas Treatment Plant GI and in response to the Statement No. 800 Condition 27.2(i) requirement, the GHG emissions from the Gas Treatment Plant have been normalised and benchmarked against the Oman and Snohvit LNG Plants' GI data.

In comparison to Oman LNG, the Gorgon Gas Development Gas Treatment Plant must remove a greater proportion of reservoir CO_2 from the incoming feed gas. The electrical power required to operate the larger Gorgon Gas Development Gas Treatment Plant acid gas removal units is estimated at 15 MW. The increased heat load associated with the larger AGRUs has not been considered in this comparison as it is supplied by the WHRU. The 15 MTPA Gas Treatment Plant operations GHG emissions inventory includes approximately 850 000 CO_2e tonnes per year of reservoir CO_2 that is assumed to be vented and an allocation of 485 000 tonnes of CO_2e per year from the power generation plant GHG emissions, required to meet an 85 MW power demand to operate the CO_2 injection system. If the Gorgon feed gas had the same gas composition as the feed gas for Oman LNG, the benchmarked GI for Gorgon would reduce to 0.25 tonnes CO_2e per tonne LNG. A calculation enabling the Gorgon Gas Development Gas Treatment Plant GI to be benchmarked to the GI of the Oman LNG Plant is provided in Table 3.5.

Table 3.5: Normalised Benchmark Comparison to Oman LNG

	Tonnes CO_2e per tonne LNG
Gorgon Gas Development Gas Treatment Plant GI, equivalent to 14.2 mole % of CO_2 in Gorgon feed gas	0.345
Less power to AGRUs	0.006
Less reservoir CO_2 vented	0.054
Less power to run CO_2 compressors	0.031
Resultant Gorgon Gas Development Gas Treatment Plant GI, equivalent to 1.0 mole % of CO_2 in Gorgon feed gas	0.25
Oman LNG Facility GI	0.28

Notes:

- *Above calculations do not include the reduction in process heat associated with CO_2 removal from the gas stream. Process heat required for CO_2 removal in the AGRUs is provided from the waste heat recovery system. If the savings in GHG emissions, equivalent to the lesser process heat requirements to extract CO_2 from the feed gas in the Gas Treatment Plant AGRUs are considered, then the Gorgon Gas Development Gas Treatment Plant GI is expected to be reduced even further.*
- *The Oman LNG Plant GI includes GHG emissions equivalent to venting of the 1% (mole) CO_2 content in feed gas, hence if the Oman LNG Plant GI is further normalised to exclude those emissions, its GI will move closer to the normalised Gorgon Gas Treatment Plant GI.*

The Snohvit LNG Plant operates at less than a third (4.1 MTPA LNG) of the gas processing capacity of the Gorgon Gas Development Gas Treatment Plant but shares a similar approach to the management of GHG emissions. Both developments are based around a subsea gas production system and a GHG reduction philosophy of subsurface injection of reservoir CO_2.

Since the GI of the Snohvit LNG Plant assumes that all reservoir CO_2 will be injected, a similar assumption has been made for the Gorgon Gas Development Gas Treatment Plant reservoir CO_2 removed in the AGRUs, thus reducing the Gas Treatment Plant's overall GHG emissions inventory by approximately 850 000 CO_2e tonnes.

The climate in which Snohvit operates is very different from that of the Gorgon Gas Development, as it is located above the Arctic Circle. Average temperatures in the area are approximately 0 °C compared to the design case for the Gorgon Gas Development Gas Treatment Plant of 26 °C. The colder ambient temperatures result in both the process gas turbines and the LNG process working more efficiently. For every one degree reduction in ambient operating temperature, LNG process capacity increases by approximately 0.6%. Assuming the same Gas Treatment Plant configuration, if the Gorgon Gas Development was operating in a similar climate to Snohvit, annual LNG production would lift from 15.59 MTPA to 18.02 MTPA. This alone would improve the benchmarked GI by 0.046 tonne CO_2e per tonne LNG.

A calculation enabling the Gorgon Gas Development Gas Treatment Plant GI to be benchmarked to that of Snohvit is provided in Table 3.6.

Table 3.6: Normalised Benchmark Comparison to Snohvit LNG

	Tonnes CO_2e per tonne LNG
Gorgon Gas Development Gas Treatment Plant GI	0.345
Less efficiency improvement due to lower ambient operating temperature	0.046
Less reservoir CO_2 vented	0.054
Resultant Gorgon Gas Development Gas Treatment Plant GI, with no acid gas venting and operations in cold ambient conditions	0.25
Snohvit LNG Facility GI	0.22

3.3.3.2 Conclusions

The benchmarking of the Gorgon Gas Development Gas Treatment Plant to other similar facilities both nationally and internationally indicates that despite the high feed gas CO_2 content and high average ambient temperature, the GI of the Gas Treatment Plant is still one of the best, both nationally and internationally. This is a testament to the appropriate balance being achieved between GHG considerations, capital cost and HES and operability risk profile.

The normalising and benchmarking of the Gorgon Gas Development Gas Treatment Plant GI to the world's best in terms of GI LNG facilities, indicates that the design of the Gas Treatment Plant has successfully managed to integrate a number of best practices, which are listed and discussed in Section 4.0.

4.0 BEST PRACTICES IN GHG EMISSIONS MANAGEMENT

4.1 Integrating GHG Considerations in Design and Operations

The Gorgon JVPs have recognised GHG emissions as a key environmental aspect and have fully integrated GHG considerations in the design and planning for the start-up and commissioning and operations phases of the Gorgon Gas Treatment Plant through these management measures:

- ♦ The Environmental Basis of Design (Chevron Australia 2008a) sets a number of design and environmental performance requirements on design and operational aspects linked to GHG emissions-generating activities and equipment, including flaring, venting, fugitive emissions, etc. In addition to those requirements and in selection of equipment, the Environmental Basis of Design requires demonstration of ALARP and a cost–benefit assessment to be conducted over a range of possible costs per tonne of CO_2e emitted.
- ♦ Cost–benefit assessments, including costs of CO_2e emitted, have been conducted to select the configuration of the Gas Treatment Plant power generation plant.
- ♦ Procurement strategies include requirements for major equipment vendors to provide environmental performance information for their equipment, including GHG emissions, which becomes a consideration in the vendor and/or equipment selection process.
- ♦ The ABU Hazardous Materials Management Process (Chevron Australia 2006a) requires assessment of the hazardous properties of chemicals, including their Global Warming Potential (GWP) and selection and approval for purchase and use of those chemicals that are least hazardous to the environment.
- ♦ The Management of Change Process (Chevron Australia 2008e) requires identification of environmental aspects associated with the change and assessment of environmental impacts using a risk-based approach. This also includes GHG considerations.

Sections 4.2 and 4.3 list specific best practice measures for GHG emissions minimisation in design, and measures planned to be implemented in the Gas Treatment Plant start-up and commissioning and the operations phases. These measures are aimed at reducing the total net GHG emissions and GHG emissions per unit of LNG produced from the Gorgon Gas Development.

4.2 Best Practice in Gas Treatment Plant Design

Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include:

- ♦ The injection of reservoir carbon dioxide recovered from the AGRUs into a confined subsurface reservoir (Dupuy Formation) below Barrow Island. Reservoir CO_2 is intended to be vented only in the event of injection system maintenance or unplanned downtime, or in the event of an unforeseen reservoir performance or injection well constraint.
- ♦ No routine flaring of hydrocarbons. Routine flaring is defined as the continuous flaring of process hydrocarbon gas beyond that required for the safe operation of the flare system (i.e. flare pilots and purge gas) and plant (e.g. small flows from equipment purges which are not practicable to collect during normal production operations).
- ♦ No routine venting of hydrocarbons. Minor quantities of hydrocarbons may be vented only under non-routine operating conditions such as prior to maintenance activities, process or equipment trips, etc.
- ♦ The end flash gas from the nitrogen rejection unit will be used as fuel gas. Prior to use as fuel, the low temperatures in this gas (-160 °C) are used to cool mixed refrigerant and

reinjection liquefied petroleum gas (LPG) components, thus recovering 'cold energy' from this stream. This reduces the amount of power required to produce a unit of LNG by approximately 2%, reducing overall GHG emissions from the mechanical drive turbines by an equivalent amount for a given amount of LNG production.

- Use of tandem dry gas seals for process compressors and power generation machinery in the plant, including small compressors in minor services.
- Subsea development approach for the Gorgon and Jansz gas fields, thus eliminating the need for an offshore production and compression platform.
- Use of a waste heat recovery system on the refrigeration compressor gas turbines to recover thermal energy from the gas turbine exhaust gases, significantly reducing the need to use heaters/boilers to meet process heat demand during routine production operations.
- Use of activated MDEA (a-MDEA) as the preferred amine for acid gas removal from the feed gas. Activated MDEA uses significantly less energy for CO_2 removal than competing amines such as Mono-ethanol Amine (MEA) or Di-ethanol Amine (DEA). The use of a-MDEA means that electrical energy is saved from a smaller circulation rate, as well as thermal energy from a lower heat of desorption and less circulation.
- The process chosen by the Gorgon Gas Development to produce LNG is the Split Mixed Refrigerant (MR) technology developed by APCI (see Section 2.1.4). This best-in-class process, first employed at the RasGas LNG Plant in 2003, uses all available power from two primary drivers by splitting the MR compression duty onto the two drivers. This provides the optimal refrigeration split, and achieves a best-in-class process efficiency and decreased GHG intensity.
- Use of LNG and MR expanders to produce an isentropic pressure drop for the LNG and refrigerant fluids, reducing the amount of lost work in the process relative to using an expansion valve. This reduces the amount of power required to produce a unit of LNG by approximately 3%, thereby reducing overall GHG emissions from the mechanical drive turbines by an equivalent amount for the same amount of LNG production.
- The Gorgon Gas Development will use a recycle compressor to recover flash gas from the nitrogen rejection system and recycle it to the feed gas (see Section 2.1.5). Most plants recover this flash vapour to the low-pressure fuel system. Since the flash gas is CO_2-rich, fuel gas consumers using this fuel gas source emit more CO_2 than those using normal plant fuel gas. Therefore, the Gorgon Gas Development use of the flash gas recycle compressor and plant configuration provides a significant reduction in GHG emissions.
- The Gorgon Gas Development will use a stabiliser overhead compressor to compress hydrocarbon-containing vapour from the stabiliser into the feed gas, preventing the flaring of this gas.
- Vapours from MEG flash and distillation processes will be recovered via compression and/or will be condensed. The MEG flash vapour compressor will send vapours (largely CO_2) to the suction of the CO_2 injection compressors, where they will be injected into the Dupuy Formation. Other vapours will be sent to the produced water injection wells after condensing.
- Low and medium voltage motor specifications for use on the Gas Treatment Plant include a requirement for a high efficiency motor design.
- Recover and re-use LNG BOG generated during ship loading operations by compressing it to the front end of the Gas Treatment Plant via a BOG recycle compressor.
- Recover BOG from the LNG storage tanks during normal LNG holding mode by using redundant BOG compressors. This gas will be sent to fuel, where it displaces an

equivalent amount of fuel that would otherwise be sourced from the feed gas. The BOG recycle compressor provides sparing for the BOG compressor when not engaged in LNG loading operations (i.e. in LNG holding mode only). This reduces the potential for flaring in the event that the BOG compressor fails during normal LNG holding mode.

- It is intended that under normal operations the LNG loading lines will be maintained in a cold state between LNG carrier loadings. While this strategy increases the overall heat leak into the LNG lines, it decreases the amount of vapour generated during loading operations, which would otherwise require flaring during peak cool-down operations or a slow and inefficient loading operation. Either of these options would result in an increase in GHG emissions.
- Any vapour generated in the refrigerant storage vessels will be sent to a LNG storage tank rather than directed to flare.
- Large motors for process compressors, and many of the motors used for fin fan coolers, will be fitted with adjustable speed drives. This will allow plant operators to match the motor duty to the process requirements without wasting energy.
- Use of a High Integrity Pressure Protection System (HIPPS) to prevent plant equipment trips and increased flaring due to high flow/high pressure in the feed gas system.
- Control valves have been specified as low fugitive emission type, with a maximum allowable process fluid leakage. Since control valve leaks are responsible for the majority of fugitive process fluid emissions in the plant, and the Gas Treatment Plant process emissions are largely methane, this is expected to provide a significant reduction in GHG emissions in the order of several thousand tonnes of methane annually.
- Development of a shutdown philosophy, based on block in and hold pressure, and depressurisation only in events where and when required for safety of personnel and/or asset protection. The refrigerant compressors will be partially depressurised to restart.
- Consideration, including reserving plot space, for the potential future installation of WHRUs, which could be used for further cogeneration and/or combined cycle power generation, if practicable.
- Specified reductions to lighting in the Gas Treatment Plant both to conserve energy and to reduce environmental impact on Island fauna. These changes will include reduced lighting intensity, switched or timed lighting in most areas, changing from area lighting to task-specific lighting where practicable, and other modifications.
- Installation of a pressure-controlled line from the MCHE shell side to the End Flash Gas Compressor suction, so that tube leaks in the MCHE will be routed to fuel gas usage instead of being flared.

4.3 Best Practice in Gas Treatment Plant Commissioning and Operations

A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant start-up and commissioning and operations phases. These actions include, but are not limited to:

- Developing start-up, commissioning and operating procedures that aim to reduce the duration and frequency of hydrocarbon flaring and venting and/or acid gas venting.
- Developing operational, start-up, shutdown and maintenance procedures with the objective of reducing GHG emissions during normal operations and planned maintenance shutdowns.
- Developing marine operational procedures to reduce flaring associated with 'warm' LNG carrier de-inerting operations.

- Once the Gorgon Gas Treatment Plant is operational, undertaking Energy Optimisation Studies in line with requirements in Chevron Australia's OEMS and in line with the obligations under the *Energy Efficiency Opportunities Act 2006* (Cth).
- Continuing to periodically review and where practicable, adopt advances in technology and operational processes aimed at reducing GHG emissions per tonne of LNG produced.

5.0 IMPLEMENTATION

5.1 Environmental Management Documentation

5.1.1 Overview

Figure 1.3 in Section 1.5.5 of this Program shows the hierarchy of environmental management documentation within which this Program exists. The following sections describe each level of documentation in greater detail.

5.1.2 Chevron ABU OE Documentation

As part of the Chevron ABU the Gorgon Gas Development is governed by the requirements of the ABU OEMS, within which a number of OE Processes exist. The Gorgon Gas Development will implement internally those OE Processes (and supporting OE Procedures) that apply to the Gorgon Gas Development activities where they are appropriate and reasonably practicable.

The key ABU OE Processes taken into account during the development of this Program, with a description of the intent of the Process, are:

- **Environmental, Social and Health Impact Assessment Process** (Chevron Australia 2009b): Process for addressing potentially significant environmental, social and health impacts of projects under consideration.
- **HES Risk Management Process** (Chevron Australia 2007): Process for identifying, assessing and managing HES, operability, efficiency and reliability risks related to the Gorgon Gas Development.
- **Environmental Stewardship Process** (Chevron Corporation 2007): Applies during the Operations Phase of the Gorgon Gas Development. Process for ensuring all environmental aspects are identified, regulatory compliance is achieved, environmental management programs are maintained, continuous improvement in performance is achieved, and alignment with ISO 14001-2004 (Standards Australia/Standards New Zealand 2004) is achieved.
- **Hazardous Materials Management Process** (Chevron Australia 2006a): Process for managing and communicating chemical and physical hazards to the workforce.
- **Management of Change Process** (Chevron Australia 2008e): Process for assessing and managing risks stemming from permanent or temporary changes to prevent incidents.
- **Contractor HES Management Process** (Chevron Australia 2008f): Process for defining the critical roles, responsibilities and requirements to effectively manage contractors involved with the Gorgon Gas Development.
- **Competency, Training and Assessment Process** (Chevron Australia 2006b): Process for ensuring that the workforce has the skills and knowledge to perform their jobs in an incident-free manner, and in compliance with applicable laws and regulations.
- **Incident Reporting and Investigation Process** (Chevron Australia 2008g): Process for reporting and investigating incidents (including near misses) to reduce or eliminate root causes and prevent future incidents.
- **Emergency Management Process** (Chevron Australia 2007a): Process for providing organisational structures, management processes and tools necessary to respond to emergencies and to prevent or mitigate emergency and/or crisis situations.

- **Compliance Assurance Process** (Chevron Australia 2006c): Process for ensuring that all HES and OE-related legal and policy requirements are recognised, implemented and periodically audited for compliance.

5.1.3 Gorgon Gas Development Documentation

5.1.3.1 Ministerial Plans and Reports

In addition to this Program, a number of other plans and reports have been (or will be) developed for the Gorgon Gas Development that are required under State and/or Commonwealth Ministerial Conditions (refer to Figure 1.3). These documents address the requirements of specific Conditions and provide standards for environmental performance for the Gorgon Gas Development.

5.2 Training and Inductions

All personnel (including contractors and subcontractors) are required to attend environmental inductions and training relevant to their role on the Gorgon Gas Development. Training and induction programs facilitate the understanding personnel have of their environmental responsibilities, and increase their awareness of the management and protection measures required to reduce potential impacts on the environment.

Chevron Australia has prepared the ABU Competency, Training and Assessment Process (Chevron Australia 2006b) to deal with the identification and assessment of required competencies for environmental roles and which it internally requires its employees, contractors, etc. to comply with.

Environmental training and competency requirements for personnel, including contractors and subcontractors, are maintained in a Gorgon Gas Development HES training matrix.

6.0 AUDITING, REPORTING, AND REVIEW

6.1 Auditing

6.1.1 Internal Auditing

Chevron Australia has prepared the internal Compliance Assurance ASBU – Standardized OE Process (Chevron Australia 2006c) to manage compliance, and which it internally requires its employees, contractors, etc. to comply with. This Process will also be applied to assess compliance of the Gorgon Gas Development against the requirements of Statement No. 800 where this is appropriate and reasonably practicable.

An internal Audit Schedule has been developed and will be maintained for the Gorgon Gas Development (with input from the Engineering, Procurement and Construction Management [EPCM] Contractors) that includes audits of the Development's environmental performance and compliance with the Ministerial Conditions. A record of all internal audits and the audit outcomes is maintained. Actions arising from internal audits are tracked until their close-out.

Any document that is required to be implemented under this Program will be made available to the relevant DEC auditor.

6.1.2 External Auditing

Audits and/or inspections undertaken by external regulators will be facilitated via the Gorgon Gas Development Regulatory Approvals and Compliance Team. The findings of external regulatory audits will be recorded and actions and/or recommendations will be addressed and tracked. Chevron Australia may also undertake independent external auditing during the Gorgon Gas Development.

6.2 Reporting

6.2.1 Compliance Reporting

Condition 4 of Statement No. 800 requires Chevron Australia to submit a Compliance Assessment Report annually to address the previous 12-month period. An audit table is provided in Appendix B to assist with auditing for compliance with this Program for Statement No. 800.

6.2.2 Environmental Performance Reporting

Environmental performance reporting obligations for the GHG Abatement Program arise from the requirements of Condition 5 of Statement No. 800, which call for an annual Environmental Performance Report to be submitted to the Minister covering the following topics of relevance to the GHG Abatement Program, quoting:

- *Data on greenhouse gas emissions intensity (defined as greenhouse gas emissions per tonne of LNG produced) averaged over one year and describe the methodology used*
- *Trend of annually averaged greenhouse gas emissions intensity and explain the reasons for any change*
- *The actual energy efficiency of gas turbines in the Gas Treatment Plant.*

Further, Condition 5 of Statement No. 800 requires that every five years from the date of the first annual Environmental Performance Report, Chevron Australia submits an Environmental Performance Report for the preceding five-year period, which covers in addition to the annual GHG Program reporting requirements listed above, recent advances in technology and/ or operational processes for LNG processing facilities and justification for the adoption or otherwise of these recent advances in technology and/ or operational processes (Items 10iii and 10iv in Schedule 3 of Statement No. 800 respectively).

6.2.3 Routine Internal Reporting

The Gorgon Gas Development will use a number of routine internal reporting formats to effectively implement the requirements of this Program. Routine reporting is likely to include daily, weekly and/or monthly HES reports for specific scopes of work on the Development. These reports include information on a number of relevant environmental aspects, such as details of environmental incidents (if any), environmental statistics and records, records of environmental audits and inspections undertaken, status of environmental monitoring programs, tracking of environmental performance against performance indicators, targets and criteria, etc.

6.3 Review of this Program

Chevron Australia is committed to conducting activities in an environmentally responsible manner and aims to implement best practice environmental management as part of a program of continuous improvement. This commitment to continuous improvement means Chevron Australia will review this Program every five years and more often as required (e.g. in response to new information).

These five-yearly reviews will examine advances in technology and/or operational processes aimed at reducing the GI of the Gas Treatment Plant, and consider adoption of those technologies that offer a practicable way of reducing GHG emissions per tonne of LNG produced as per the requirement of Condition 27.2(ii) of Statement No. 800.

Reviews will also address matters such as the overall design and effectiveness of the Program, progress in environmental performance, changes in business conditions, and any relevant emerging environmental issues.

If the Plan no longer meets the aims, objectives or requirements of the Plan, if works are not appropriately covered by the Plan, or measures are identified to improve the Plan, Chevron Australia may submit an amendment or addendum to the Plan to the Minister for approval under Condition 36 of Statement No. 800.

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APPENDIX A: GORGON PROJECT GREENHOUSE GAS MANAGEMENT STRATEGY

Chevron

Gorgon Project Greenhouse Gas Management Strategy

The Gorgon Project Greenhouse Gas Management Strategy for a Barrow Island development is to:

- Demonstrate via lifecycle analysis that a Gorgon gas development and LNG export results in a net reduction in global greenhouse gas emissions relative to other fossil fuel alternatives.
- Design the production facilities to incorporate current best practices in thermal efficiency and greenhouse emission control where practicable.
- Develop a project to re-inject removed reservoir CO_2 into the Barrow Island Dupuy saline reservoir, unless it is technically infeasible or cost prohibitive. This will involve:
  - Pursuing a stepwise process to develop a reservoir CO_2 re-injection project, demonstrate technical feasibility and ensure costs to the project are not excessive.
  - Selling treated gas to meet domestic gas customer requirements and re-inject the removed reservoir CO_2.
  - Commencing re-injection as soon as practicable after the processing facilities commissioning and start-up process.
  - Implementing re-injection of reservoir CO_2 by installing a single train of injection equipment, sized for the full volume of reservoir CO2.
- Investigate potential synergies with existing Barrow Island operations and implement measures that minimise greenhouse emissions and enable full use of associated gas production where practicable.
- Pursue projects and opportunities which provide net conservation benefits and enhance greenhouse gas removal from the atmosphere.
- Continue existing funding for greenhouse gas related research and development projects such as CRC's and technological research.
- Review options for funding additional value-added research and development or demonstration projects.
- Pursue potential opportunities for external sale or use of separated reservoir CO_2 as a chemical feedstock or enhanced oil recovery agent.
- Develop a contingency plan that could provide a partial offset for reservoir CO_2 if a sequestration project proves infeasible. Options may include:
  - Maturing alternative re-injection sites that could be developed in the future such as a depleted gas reservoir.
  - Creation of emission reductions or offsets external to the Gorgon gas development.
  - Sequestration opportunities such as forestry.
  - Additional research funding.
- Meet the commitments within the LNG Action Agenda including the revision of the existing Gorgon Greenhouse Challenge Cooperative Agreement.
- Continue to advocate increased use of gas based fuels, in preference to more carbon intensive options, to reduce greenhouse emissions.
- Participate constructively in the development of greenhouse policy at both the State and Commonwealth level.

Colin Beckett

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General Manager, Greater Gorgon Area

Operated by **Chevron Australia**
in joint venture with

ExxonMobil

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APPENDIX B: COMPLIANCE REPORTING TABLE

Action No.	Key Action	Timing
3.2.1	The GHG emissions inventory for the start-up and commissioning of the Gas Treatment Plant will be estimated from the start-up and commissioning sequence and schedule documents, which are still under development.	Design
3.2.1	The Gas Treatment Plant start-up and commissioning GHG emissions inventory will be provided to the Western Australian Department of Environment and Conservation (DEC) as part of the Commissioning Plan intended to be produced as an Addendum to the Works Approval Application under Part V of the Western Australian Environmental Protection Act 1986 (EP Act).	Design
3.2.2	The preliminary operations phase GHG emissions inventory was prepared early in Front End Engineering Design phase of the Gorgon Gas Development and will be subject to refinement during the detailed design phase.	Design
3.2.2	A refined GHG emissions inventory will be provided to the DEC towards the end of detailed design phase as part of the Gas Treatment Plant application for an operating licence under Part V of the EP Act (WA).	Design and Construction
3.2.2	Operating and maintenance procedures for heating ventilation and air conditioning systems will aim to prevent loss of hydrofluorocarbons during refrigerant change out.	Design and Operations
3.2.3.1	The gas turbines in the LNG processing trains will be fitted with Waste Heat Recovery Units to recover additional energy from the latent heat in the exhaust combustion gases from the turbines.	Design
3.2.3.1	Each gas processing driver turbine will be fitted with dry low NO_x emissions control technology.	Design
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ The injection of reservoir carbon dioxide recovered from the Acid Gas Removal Units into a confined subsurface reservoir (Dupuy Formation) below Barrow Island. Reservoir CO2 is intended to be vented only in the event of injection system maintenance or unplanned downtime, or in the event of an unforeseen reservoir performance or injection well constraint.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include ♦ No routine flaring of hydrocarbons. Routine flaring is defined as the continuous flaring of process hydrocarbon gas beyond that required for the safe operation of the flare system (i.e. flare pilots and purge gas) and plant (e.g. small flows from equipment purges which are not practicable to collect during normal production operations).	Design and Operations

Action No.	Key Action	Timing
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ No routine venting of hydrocarbons. Minor quantities of hydrocarbons may be vented only under non-routine operating conditions such as prior to maintenance activities, process or equipment trips, etc.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ The end flash gas from the nitrogen rejection unit will be used as fuel gas. Prior to use as fuel, the low temperatures in this gas (-160 °C) are used to cool mixed refrigerant and reinjection liquefied petroleum gas (LPG) components, thus recovering “cold energy” from this stream. This reduces the amount of power required to produce a unit of LNG by approximately 2%, reducing overall GHG emissions from the mechanical drive turbines by an equivalent amount for a given amount of LNG production.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Use of tandem dry gas seals for process compressors and power generation machinery in the plant, including small compressors in minor services.	Design
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Subsea development approach for the Gorgon and Jansz gas fields, thus eliminating the need for an offshore production and compression platform.	Design
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Use of a waste heat recovery system on the refrigeration compressor gas turbines to recover thermal energy from the gas turbine exhaust gases, significantly reducing the need to use heaters/boilers to meet process heat demand during routine production operations.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Use of activated MDEA (a-MDEA) as the preferred amine for acid gas removal from the feed gas.	Design
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ The process chosen by the Gorgon Gas Development to produce LNG is the Split Mixed Refrigerant (MR) technology developed by APCI	Design

Action No.	Key Action	Timing
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Use of LNG and MR expanders to produce an isentropic pressure drop for the LNG and refrigerant fluids, reducing the amount of lost work in the process relative to using an expansion valve.	Design
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ The Gorgon Gas Development will use a recycle compressor to recover flash gas from the nitrogen rejection system and recycle it to the feed gas	Design
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ The Gorgon Gas Development will use a stabiliser overhead compressor to compress hydrocarbon-containing vapour from the stabiliser into the feed gas, preventing the flaring of this gas.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Vapours from MEG flash and distillation processes will be recovered via compression and/or will be condensed. The MEG flash vapour compressor will send vapours (largely CO_2) to the suction of the CO_2 injection compressors, where they will be injected into the Dupuy Formation. Other vapours will be sent to the produced water injection wells after condensing.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Low and medium voltage motor specifications for use on the Gas Treatment Plant include a requirement for a high efficiency motor design.	Design
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Recover BOG from the LNG storage tanks during normal LNG holding mode by using redundant BOG compressors. This gas will be sent to fuel, where it displaces an equivalent amount of fuel that would otherwise be sourced from the feed gas. The BOG recycle compressor provides sparing for the BOG compressor when not engaged in LNG loading operations (i.e. in LNG holding mode only). This reduces the potential for flaring in the event that the BOG compressor fails during normal LNG holding mode.	Design and Operations

Action No.	Key Action	Timing
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ It is intended that under normal operations the LNG loading lines will be maintained in a cold state between LNG carrier loadings. While this strategy increases the overall heat leak into the LNG lines, it decreases the amount of vapour generated during loading operations, which would otherwise require flaring during peak cool-down operations or a slow and inefficient loading operation. Either of these options would result in an increase in GHG emissions.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ • Any vapour generated in the refrigerant storage vessels will be sent to a LNG storage tank rather than directed to flare.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Large motors for process compressors, and many of the motors used for fin fan coolers, will be fitted with adjustable speed drives. This will allow plant operators to match the motor duty to the process requirements without wasting energy	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Use of a High Integrity Pressure Protection System to prevent plant equipment trips and increased flaring due to high flow/high pressure in the feed gas system.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Control valves have been specified as low fugitive emission type, with a maximum allowable process fluid leakage.	Design
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Development of a shutdown philosophy, based on block in and hold pressure, and depressurisation only in events where and when required for safety of personnel and/or asset protection. The refrigerant compressors will be partially depressurised to restart.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Consideration, including reserving plot space, for the potential future installation of Waste Heat Recovery Units, which could be used for further cogeneration and/or combined cycle power generation, if practicable.	Design and Operations

Action No.	Key Action	Timing
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ • Specified reductions to lighting in the Gas Treatment Plant both to conserve energy and to reduce environmental impact on Island fauna. These changes will include reduced lighting intensity, switched or timed lighting in most areas, changing from area lighting to task-specific lighting where practicable, and other modifications.	Design and Operations
4.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in design. These include: ♦ Installation of a pressure-controlled line from the Main Cryogenic Heat Exchanger shell side to the End Flash Gas Compressor suction, so that tube leaks in the Main Cryogenic Heat Exchanger will be routed to fuel gas usage instead of being flared.	Design, Construction and Operations
4.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant start-up and commissioning and operations phases. These actions include, but are not limited to: ♦ Developing start-up, commissioning and operating procedures that aim to reduce the duration and frequency of hydrocarbon flaring and venting and/or acid gas venting.	Construction
4.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant start-up and commissioning and operations phases. These actions include, but are not limited to: ♦ Developing operational, start-up, shutdown and maintenance procedures with the objective of reducing GHG emissions during normal operations and planned maintenance shutdowns.	Operations
4.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant start-up and commissioning and operations phases. These actions include, but are not limited to: ♦ Developing marine operational procedures to reduce flaring associated with 'warm' LNG carrier de-inerting operations.	Operations
4.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant start-up and commissioning and operations phases. These actions include, but are not limited to: ♦ Once the Gorgon Gas Treatment Plant is operational, undertaking Energy Optimisation Studies in line with requirements in Chevron Australia's OEMS and in line with the obligations under the *Energy Efficiency Opportunities Act 2006* (Cth).	Operations

Action No.	Key Action	Timing
4.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant start-up and commissioning and operations phases. These actions include, but are not limited to: ♦ Continuing to periodically review and where practicable, adopt advances in technology and operational processes aimed at reducing GHG emissions per tonne of LNG produced.	Operations
6.1.1	Any document that is required to be implemented under this Program will be made available to the relevant DEC auditor.	All Phases
6.1.2	The findings of external regulatory audits will be recorded and actions and/or recommendations will be addressed and tracked.	All Phases