Gorgon Gas Development and Jansz Feed Gas Pipeline

Best Practice Pollution Control Design Report

Document ID:	G1-NT-REPX0001730
Revision ID:	3.0
Revision Date:	15 January 2020
Information Sensitivity:	Public

Contents

Tables

Figures

1 Introduction

1.1 Proponent

Chevron Australia Pty Ltd (CAPL) 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) Pty Ltd
- Mobil Australia Resources Company Pty Limited
- Osaka Gas Gorgon Pty Ltd
- Tokyo Gas Gorgon Pty Ltd
- Chubu Electric Power Gorgon Pty Ltd.

1.2 Project

CAPL proposes to develop the gas reserves of the Greater Gorgon Area (Figure 1-1). The gas will be processed in a gas treatment plant on Barrow Island, which is located off the Pilbara coast 85 km north-north-east of Onslow in Western Australia (WA)

Subsea gathering systems and pipelines deliver feed gas from the Gorgon and Jansz–Io gas fields to the west coast of Barrow Island. The underground feed gas pipeline system then traverses Barrow Island to the east coast where the Gas Treatment Plant (GTP) is located. The GTP includes natural gas trains that produce liquefied natural gas (LNG) as well as condensate and domestic gas. Carbon dioxide, which occurs naturally in the feed gas, is separated during the production process and injected into deep rock formations below Barrow Island. The LNG and condensate are loaded onto tankers from a jetty and then transported to international markets. Gas for domestic use is exported by pipeline from Barrow Island to the domestic gas collection and distribution network on the WA mainland.

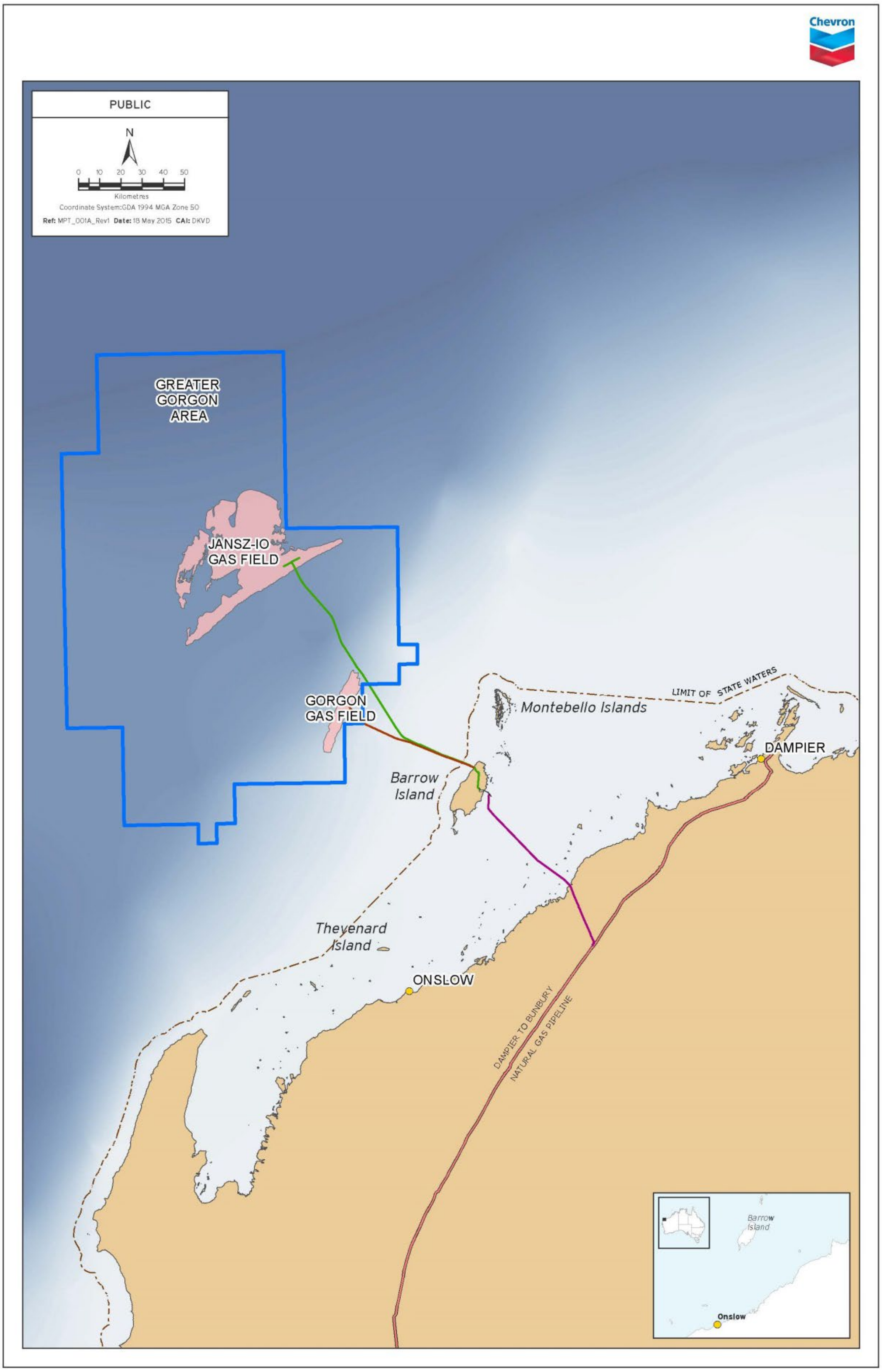

Figure 1-1: Location of the Greater Gorgon Area

1.3 Environmental Approvals

Table 1-1 describes State and Commonwealth approvals for the components of the Gorgon Gas Development.

These approvals, and projects as approved under these approvals, have been and may continue to be amended (or replaced) from time to time.

Table 1-1: State and Commonwealth Approvals

Project Approval Stage	State	Commonwealth
Jansz Feed Gas Pipeline	Ministerial Statement (MS) 769 (Ref. 1) 28 May 2008	EPBC Reference: 2005/2184 (Ref. 2). 22 March 2006
Initial Gorgon Gas Development (2 LNG Trains)	Initial Gorgon Gas Development comprising 2 LNG Trains – MS 748 (Ref. 9). This was superseded by MS 800. 6 September 2007	Initial Gorgon Gas Development comprising 2 LNG Trains – EPBC Reference: 2003/1294 (Ref. 5). 3 October 2007
Revised and Expanded Gorgon Gas Development (3 LNG Trains)	MS 800 (Ref. 3) provides approval for both the initial Gorgon Gas Development and the Revised and Expanded Gorgon Gas Development (compromising 3 LNG Trains). This statement supersedes MS 748. 10 August 2009	The Revised and Expanded Gorgon Gas Development (EPBC Reference: 2008/4178 [Ref. 4]) was approved, and the conditions for the initial Gorgon Gas Development (EPBC Reference: 2003/1294 [Ref. 5]) were varied. 26 August 2009
Dredging Amendment	MS 865 (Ref. 7) provides approval to establish a restart mechanism in the event of a project-attributable coral health management trigger. This statement is an amendment to Conditions 18, 20 and 21 of MS 800. 8 June 2011	N/A
Additional Support Area	MS 965 (Ref. 6) applies the conditions of MS 800 to an Additional Support Area. 2 April 2014	The conditions for the initial Gorgon Gas Development (EPBC Reference: 2003/1294 [Ref. 5]).and for the Revised and Expanded Gorgon Gas Development (EPBC Reference: 2008/4178 [Ref. 4]) were varied. 15 April 2014
Gorgon Gas Development Fourth Train Expansion[1]	MS 1002 (Ref. 8) applies the conditions of MS 800 to the Fourth Train Expansion, and has additional conditions. 30 April 2015	EPBC Reference: 2011/5942. Approval pending (at time of publishing).

[1] Fourth Train Expansion is not currently being implemented, and is not within the scope of this Plan.

1.4 Purpose of this Report

1.4.1 Legislative Requirements

This Report is required under Condition 28 of MS 800, which is quoted below:

The Proponent shall submit to the DEC as part of its Works Approval application for the Gas Treatment Plant a report that:

i. Demonstrates that the proposed works adopt best practice pollution control measures to minimise emissions from the Gas Treatment Plant;

ii. Sets out the base emission rates for major sources for the Gas Treatment Plant and the design emission targets; and

iii. Addresses normal operations, shut down, start up, and equipment failure conditions.

This Report was submitted to the WA Department of Environment and Conservation (DEC; now known as the Department of Water and Environmental Regulation [DWER]) as part of CAPL's Works Approval application for the GTP and contains references to best practice measures current at that time and applied to inform the design of relevant elements of the GTP. Revisions to this report have been, and may be in the future, subsequently submitted to address new or changed components of the GTP. These revisions cannot retrospectively apply more recent practices to facilities that have already been built and consequently the original references have been retained to provide appropriate context.

1.4.2 Contents of this Report

Table 1-1 lists the State MS 800 (Condition 28) requirements of this Report, and the sections in this Report that fulfil those requirements.

Table 1-2: Requirements of this Report

Ministerial Document	Condition No.	Requirement	Section Reference in this Report
MS 800	28(i)	Demonstrate that the proposed works adopt best practice pollution control measures to minimise emissions from the Gas Treatment Plant.	Sections 3.4.1.1, 3.4.2, 3.4.3, 3.5.1.1, 3.5.2, 3.5.3, 3.6.1.1, 3.6.2, 3.7.1.1, 3.7.2, 3.8.2, 3.9.2, 3.10.2
MS 800	28(ii)	Set out the base emission rates for major sources for the Gas Treatment Plant and the design emission targets.	Sections 3.4.4, 3.5.4, 3.6.3, 3.7.3, 3.8.3, 3.9.3, 3.10.3
MS 800	28(iii)	Address normal operations, shut down, start up, and equipment failure conditions.	Sections 3.4.5, 3.5.5, 3.6.4, 3.7.4, 3.8.4, 3.9.4, 3.10.4

Any matter specified in this Report is relevant to the Gorgon Gas Development only if that matter relates to the specific activities or facilities associated with that particular development.

1.4.3 Stakeholder Consultation

Regular consultation with stakeholders was undertaken by CAPL throughout the development of the environmental impact assessment management documentation for the Gorgon Gas Development. This consultation has included engagement with the community, government departments, industry operators, and contractors to CAPL via planning workshops, risk assessments, meetings, teleconferences, and the formal approval processes.

1.4.4 Scope

This Report outlines the approach, criteria, and decisions in selecting the best practice pollution control equipment for the major sources of atmospheric pollutants and air toxics for the GTP. Only emission sources from the GTP, as defined in Schedule 1 of MS 800, are included in the scope of this Report.

Atmospheric pollutants and air toxics emitted from the GTP were identified and discussed in detail in the Air Quality Management Plan (Ref. 10) required under Condition 29 of MS 800. These include:

- nitrogen dioxide (NO_2), as representative pollutant for nitrogen oxides (NO_x), which is a generic term for the mono-nitrogen oxides, i.e. nitric oxide (NO) and NO_2
- airborne particulate matter (PM_{10}), which also includes particulate matter of size 2.5 microns and lower ($PM_{2.5}$)
- sulfur dioxide (SO_2), as representative pollutant for sulfur oxides (SO_x), which include also sulfur monoxide (SO), sulfur trioxide (SO_3), and other combinations of sulfur and oxygen
- non-methane volatile organic compounds (NMVOCs), including aliphatic hydrocarbons (propane and longer straight chain hydrocarbons) and aromatic hydrocarbons such as benzene, toluene, ethylbenzene, and xylene, which are collectively known as BTEX, as well as polycyclic aromatic hydrocarbons (PAH) and formaldehyde
- carbon monoxide (CO)
- hydrogen sulfide (H_2S)
- mercury (Hg).

The sources of the identified atmospheric pollutants and air toxics emissions for the GTP are listed in Table 1-2.

Table 1-3: GTP Atmospheric Pollutants and Air Toxics Emission Sources

GTP Emission Sources	Associated Atmospheric Pollutants and Air Toxics
Frame 9 Gas Turbine Generators (GTGs)	NO_x, PM_{10}, SO_2, NMVOCs[1], CO, Hg[4]
Frame 7 Process Gas Turbines (GTs)	NO_x, PM_{10}, SO_2, NMVOCs[1], CO, Hg[4]
Heating Medium Heaters	NO_x, PM_{10}, SO_2, NMVOCs[1], CO, Hg[4]
Essential Diesel Power Generators	NO_x, PM_{10}, SO_2, NMVOCs[2], CO
Wet and Dry Ground Flares	NO_x, SO_2, NMVOCs[1], CO, Hg[4]
Boil-off Gas (BOG) Flare	NO_x, SO_2, NMVOCs[1], CO, Hg[4]
Acid Gas Vents	NMVOCs[3], H_2S, Hg[4]
Condensate Storage Tanks (Fugitive Emissions)	NMVOCs, Hg[4]

Notes:

1. *NMVOCs associated with combustion of clean fuel gas in gas turbines, boilers, and flares consist mainly of the unburnt portion of the aliphatic hydrocarbons present in the fuel gas.*

2. *NMVOCs present in the exhaust gases from the essential diesel power generators also include PAHs and formaldehyde.*
3. *NMVOCs in the vented acid gas stream include up to 30% BTEX (on a molar basis).*
4. *Whilst Hg is present within the emission stream, it is at very low levels.*

The major emissions sources, as listed in Table 1-2, include:

- five 116 MW (nominal capacity) General Electric (GE) Frame 9 GTGs in the GTP power generation facility
- six 80 MW (nominal capacity) GE Frame 7 GTs, driving the refrigeration compressors within the GTP LNG trains
- two Heating Medium Heaters (boilers)
- Wet, Dry, and BOG Flares
- Acid Gas Vents within the Acid Gas Removal Units (AGRUs) and associated CO_2 Injection Trains.

The Essential Diesel Power Generators are expected to be used infrequently and for short periods of time, e.g. during GTP shutdowns and maintenance periods; hence, they are not considered to be major emission sources due to both the limited frequency of occurrence and overall volume of associated emissions. Similarly, the condensate storage tanks, diesel storage tanks, and other sources of fugitive emissions (such as valves, flanges, connectors, pump seals and compressor seals in hydrocarbon service, flow lines, and connections), are also not considered to be major sources of emissions due to the expected low emission rates (fugitive emissions) of atmospheric pollutants and air toxics.

Finally, greenhouse gas (GHG) emissions of carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) are excluded from the scope of this Report. Reference should be made to the Greenhouse Gas Abatement Program (Ref. 11) for specific information pertaining to the management of these emissions associated with the operation of the GTP, and specifically Section 6 of that document, which outlines the best practices in GHG emissions management adopted for the Gorgon Gas Development.

2 Facility Description

2.1 Overview of Production Facilities

The Gorgon Gas Development concept is a three-LNG train (3 × 5 MTPA) GTP, with the GTP located near Town Point on the east coast of Barrow Island (Figure 1-2). The offshore supply configuration comprises two subsea developments within the Gorgon and Jansz fields, tied back via separate production pipelines to the GTP. The produced fluids will be transported from each gas field to the GTP through separate large-diameter, high-pressure multiphase (gas, condensate, and aqueous phase) pipelines.

At Barrow Island, the hydrocarbon liquid (condensate) and water phases will be separated from the gas stream in inlet separation facilities. The saturated gas will form the feedstock for the LNG production and export facility. The GTP will comprise the following key processes:

- inlet processing, monoethylene glycol (MEG) regeneration and condensate stabilisation
- acid gas removal and CO_2 compression and injection
- dehydration and mercury removal
- liquefaction, fractionation, and refrigerant make-up
- nitrogen removal and end flash gas compression
- LNG and condensate storage and offloading
- domestic gas (DomGas) unit and export pipeline.

The GTP has an anticipated average stream day capacity of up to 47 520 tonnes per day of LNG production from three LNG trains run down to the LNG storage tanks. This equates to a nominal annual average LNG production of 15.6 MTPA Freight On Board (FOB) based on 340.4 stream days per year.

Figure 2-1 shows a block flow diagram of these processes within the GTP.

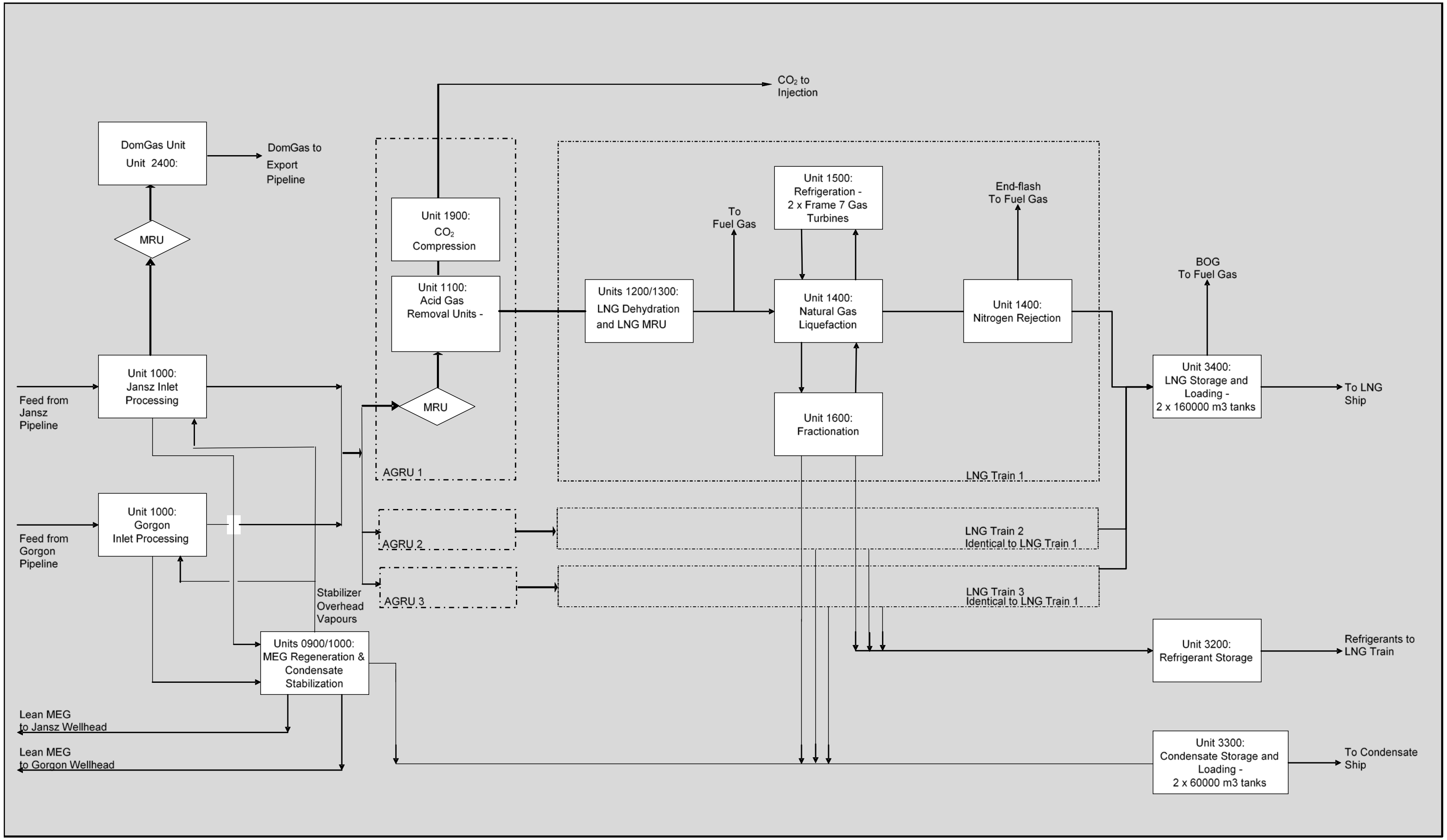

Figure 2-1: Gorgon Gas Development Gas Treatment Plant Block Flow Diagram (Normal Operations)

2.2 Gas Treatment Plant Processing Facilities

2.2.1 Inlet Processing, MEG Regeneration, and Condensate Stabilisation

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

The aqueous phase is sent to the 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. MEG flash gas is compressed and directed to the Condensate Stabilisation units, or either vented or flared in the Wet Gas Flare when this system is not available.

The condensate stream is sent to Condensate Stabilisation, where further stripping of the light hydrocarbon components occurs to produce a stabilised condensate stream, which is combined with the condensate from the LNG Train Fractionation Unit prior to storage and export. Vapours (including those received from the MEG gas compressor) are directed back to the inlet facilities and added to the gas stream routed to the AGRU trains.

2.2.2 Acid Gas Removal and Carbon Dioxide Compression and Injection

The commingled Gorgon and Jansz gas phase streams from the slug catchers and the condensate stabilisation unit are routed to the AGRUs for CO_2 and 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 at low temperatures in the cryogenic sections of the GTP and to meet the LNG product CO_2 and sulfur specifications.

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

- an MRU to remove mercury from the acid gas stream prior to injection via the CO_2 Injection System or venting to the atmosphere
- an Absorber System to remove CO_2 and H_2S from the natural gas by absorption in an a-MDEA solvent
- a Regenerator System 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 per cent 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 if a compression and injection system failure occurs.

The CO_2 Injection System comprises two 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 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 GTP, but are described here for information.

The compressed acid gas is injected via nine CO_2 injection wells, drilled directionally from three CO_2 drill centres. A CO_2 pipeline runs from the CO_2 compressors on the north side of the GTP to these drill centres.

Figure 2-2: Acid Gas Removal and CO_2 Injection System Block Flow Diagram

2.2.3 Dehydration and Mercury Removal in LNG Trains 1–3

The purpose of the Dehydration Unit in each LNG Train 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 MRU in each LNG Train 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).

2.2.4 Liquefaction, Fractionation, and Refrigerant Make-Up in LNG Trains 1–3

Heavy hydrocarbons, which can freeze in the LNG, need to be removed before the dry treated gas from the MRUs can be liquefied. The dry treated gas is pre-cooled and fed to the Scrub Column. The Scrub Column 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. Each LNG train has refrigeration compressors driven by Frame 7 GTs. Figure 2-3 shows the APCI 5 MTPA Refrigeration Cycle.

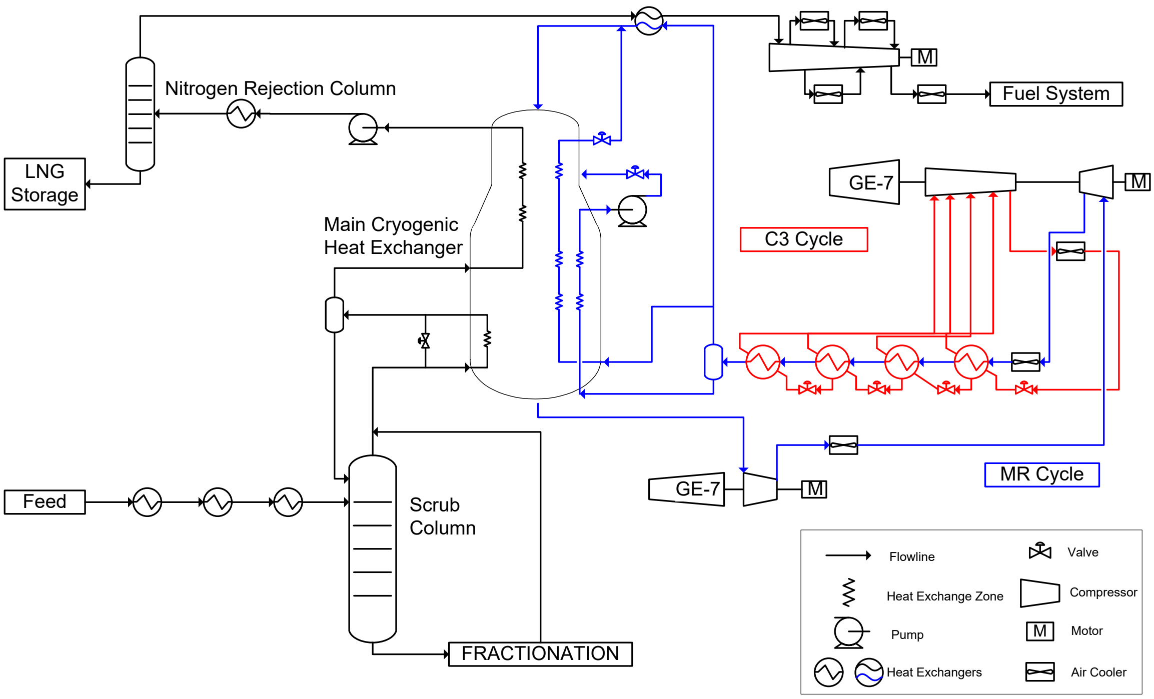

Figure 2-3: APCI 5 MTPA Refrigeration Cycle

Legend:

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

2.2.5 Nitrogen Removal and End Flash Gas Compression in LNG Trains 1–3

LNG 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.

2.2.6 LNG and Condensate Storage and Offloading

The LNG Storage and Loading unit provides 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. The 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 GTP 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 the 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 Condensate Storage and Loading Unit provides storage and loading facilities to allow continuous production of condensate at the design capacity of the GTP 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 LNG Jetty and terminates at the loading platform at two 50% condensate loading arms.

2.2.7 Domestic Gas (DomGas) Unit and Export Pipeline

The DomGas Unit is designed for 300 Terajoules of sales gas per day (TJ/d), derived from Jansz feed gas. The unit uses 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.

Mercury is predicted to be in the feed gas that is diverted to the DomGas Unit after passing through the Inlet Systems. This gas passes through an MRU to remove the mercury, thus ensuring that the DomGas produced meets the specification for gas to be received by the Dampier to Bunbury Natural Gas Pipeline.

2.3 Gas Treatment Plant Ancillary Systems and Facilities

The main ancillary systems and facilities are listed in Sections 2.3.1 to 2.3.6.

2.3.1 Fuel Gas and Recycle Gas Systems

The Fuel Gas and Recycle Gas systems reliably provide fuel gas to users throughout the GTP, and 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 GTs
- high-pressure fuel gas system in the Utilities Area to supply the GTs for power generation – an MRU is included on the start-up/backup fuel gas from the Inlet System to ensure the GTGs are operated free of mercury contamination
- high-pressure fuel gas 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
- Recycle Gas system to compress flash gas from the AGRUs back to the process units for further treatment.

2.3.2 Power Generation System

The power generation system generates power for electrical consumers in the GTP and other areas (e.g. Permanent Operations Facility, Butler Park). The estimated total electrical power load for all electrical consumers is 416 MW (with contingency).

Electrical power is provided by five Frame 9 GTGs (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 GTs running.

2.3.3 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 GT exhausts in the Waste Heat Recovery Units (WHRUs) and sent to various heat consumers around the GTP, including inlet gas heating, AGRU reboilers, MEG regeneration package, etc.

2.3.4 Pressure Relief/Liquids Disposal, Flare and Vent Systems

The design of the flare system is based on the 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 GTP specifies no routine flaring during normal operations other than flare pilots and purged gas (Ref. 12).

The wet and dry gas flare systems each comprise a collection header system for vapours and a collection header system for liquids, a knockout drum, and a staged ground flare. No liquid burners are installed. The BOG flare system comprises two 100% low-pressure flares (one operational, one spare) located near the LNG Storage Tanks.

The design basis for the GTP specifies no routine hydrocarbon venting and there are no routine vents provided on hydrocarbon process streams (Ref. 12). Acid gas (CO_2) venting will occur if the CO_2 compression or injection system fails. The availability of the CO_2 compression and injection system, which can dispose (by underground injection) 100% of the volume of reservoir CO_2 to be removed during routine processing operations, is expected to be more than 80%, expressed as a five-year rolling average.

2.3.5 Water Supply and Distribution

Fresh water will be supplied via the Desalination Water Plant located at the General Utilities Area. A seawater intake caisson is part of the Materials Offloading Facility offshore from Town Point. Fresh water may either be conditioned for use as potable and service water on the GTP, or demineralised further for use in the Heating Medium System.

2.3.6 Diesel Storage and Distribution

Diesel storage provides periodic diesel supply to these GTP consumers:

- emergency power and black start generators
- freshwater and seawater fire pumps
- marine support vessels
- vehicle refuelling bay.

3 Best Practice Pollution Control Measures

3.1 Legal and Regulatory Background

It is a requirement of the WA Environmental Impact Assessment process that new proposals referred to the EPA for assessment should demonstrate use of best practice processes and technologies and that cumulative impacts on the environment are acceptable (Ref. 13). It is also a requirement of the Works Approval and Licensing process that best practice measures are used to control pollution from the industrial premises assessed under the process (Ref. 14).

3.1.1 Best Practicable Measures (BPM)

Best practice and the synonymous ‘best practicable measures’ are defined in the Guidance on Implementing Best Practice in Proposals Submitted to the Environmental Impact Assessment Process (Ref. 13), as follows:

> *Best practicable measures incorporates technology and environmental management procedures which are practicable having regard to, among other things, local conditions and circumstances (including costs), and to the current state of technical knowledge, including the availability of reliable, proven technology.*
>
> *Best practice involves the prevention of environmental impact, or, if this is not practicable, minimising the environmental impact, and also minimising the risk of environmental impact, through the incorporation of Best Practicable Measures. No significant residual impact should accrue as a result of a proposal.*

3.1.2 Best Available Technology (BAT)

The Organisation for Economic Cooperation and Development, which includes most of the European Community (EC) member states and other developed economies, uses the term ‘best available technology’ or ‘best available techniques’ as synonymous terms to ‘best practice’ and ‘best practicable measures’, respectively. This term is referenced in this Report as some of the best available technologies were used to assess and benchmark against the selected GTP best practice pollution control measures.

The term ‘best available techniques’ is defined in article 2(12) of the EC Integrated Pollution Prevention and Control (IPPC) Directive 2008/1/EC of the European Parliament and of the Council of 15 January 2008 concerning integrated pollution prevention and control (Ref. 15) as:

> *...the most effective and advanced stage in the development of activities and their methods of operation that indicate the practical suitability of particular techniques for providing in principle the basis for emission limit values designed to prevent and, where that is not practicable, generally to reduce emissions and the impact on the environment as a whole.*

The term ‘available’ means ‘*developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions...*’.

3.2 Selection of Best Practice Pollution Control Measures

3.2.1 Environmental Design Requirements and Risk Acceptance Criteria

The Environmental Basis of Design (BoD) (Ref. 12) document is the principal guidance document for implementing pollution prevention and control measures in the design of the GTP. The Environmental BoD outlines several environmental performance standards and design features, which have been extracted from CAPL requirements (CAPL environmental performance standards); regulatory requirements, including guidance notes; Project environmental commitments; and Australian and international Standards.

3.2.2 Best Practice and ALARP Demonstration

The Environmental Risk Management Implementation Plan (Ref. 16) is the implementation document for the Chevron RiskMan2 Process (Ref. 17) and supports the Environmental BoD (Ref. 12) in selecting the best practicable environmental design option and demonstrating the environmental acceptability of design (as shown in Figure 3-1).

For the Gorgon Gas Development, best practice has been achieved and demonstrated through:

- reducing risks to As Low As Reasonably Practicable (ALARP) levels, and testing the reasonability of new proposed safeguards for risks within the ALARP region, which should satisfy the requirement of using best practice in the design and planning for construction
- testing risk reduction criteria (for further reducing risks within the ALARP region) for reasonability against these risk areas: health, environment, and safety (HES); reliability (e.g. proven versus untested technology) and operability; maintainability risks; costs; and any other reasonability criteria that might apply to the examined risk reduction options.

Therefore, the best practice pollution control measures were identified through a combination of technology selection and assessment across a range of criteria, including effectiveness, operability, maintainability, costs, and HES risk assessment of the residual risks associated with each option considered. Following this process, the best practice option was deemed to be the one that ranked most favourably across that range of criteria, inclusive of HES protection, in the context of the specific project location and any other relevant project and economic constraints.

Risk rankings for HES and asset risks associated with each pollution control design option considered were carried out using Chevron Corporation's internal RiskMan2 process (Ref. 17). The internal Chevron Integrated Risk Prioritization Matrix (Appendix A) was used to categorise identified risks into four groups, which determine the level of response and effort in managing the risks.

The selected design/pollution control option cannot be deemed to be best practice if it ranks at a risk level greater than risk level 6 across any of the HES or asset risk categories, i.e. HES ALARP demonstration is the final acceptability test that each design option must pass to be considered as best practice.

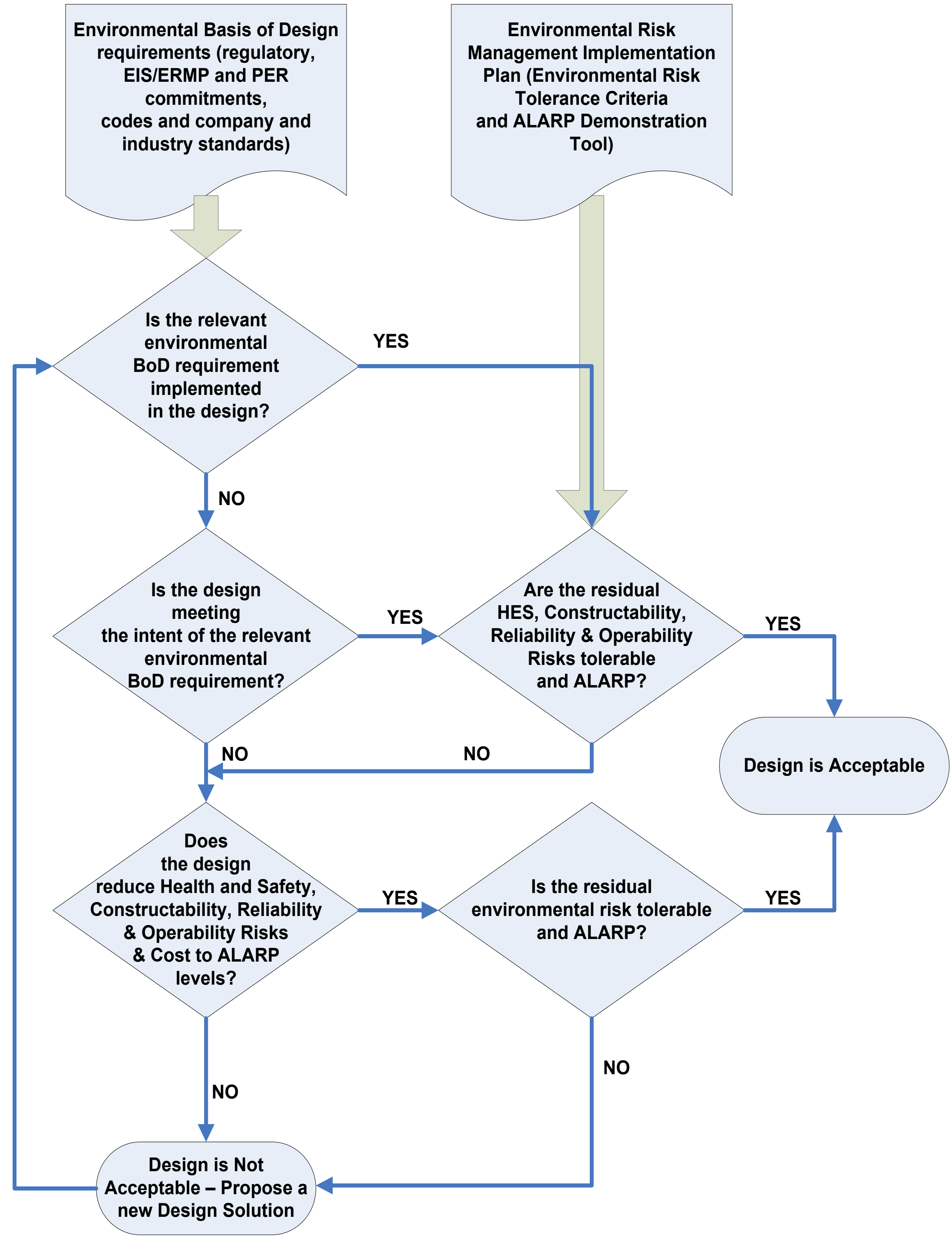

Figure 3-1: Demonstration of Environmental Acceptability of Design

Source: Ref. 12

3.3 Major Emission Sources

The Gorgon Gas Development has adopted best practice pollution control measures to minimise atmospheric pollutant and air toxic emissions from the GTP to ALARP levels, to ensure that ambient air quality meets appropriate standards for human health in the workplace (as discussed in the Air Quality Management Plan [Ref. 10]), and that the residual risk of material or serious environmental harm to the flora, vegetation communities, and fauna on Barrow Island is ALARP.

The sections below provide details on:

- the location of each major emission source within the GTP
- the process used for selecting the best practice pollution control measure for each major emission source, including:
  - a description of the best practice pollution control measure adopted and other control measures considered, including benchmarking
  - the associated base emission rates and design emission targets (where applicable)
  - discussion of the deviations from normal (routine) operating conditions.

Figure 3-2 highlights the location of the major atmospheric pollutant emission sources in the current design layout of the GTP.

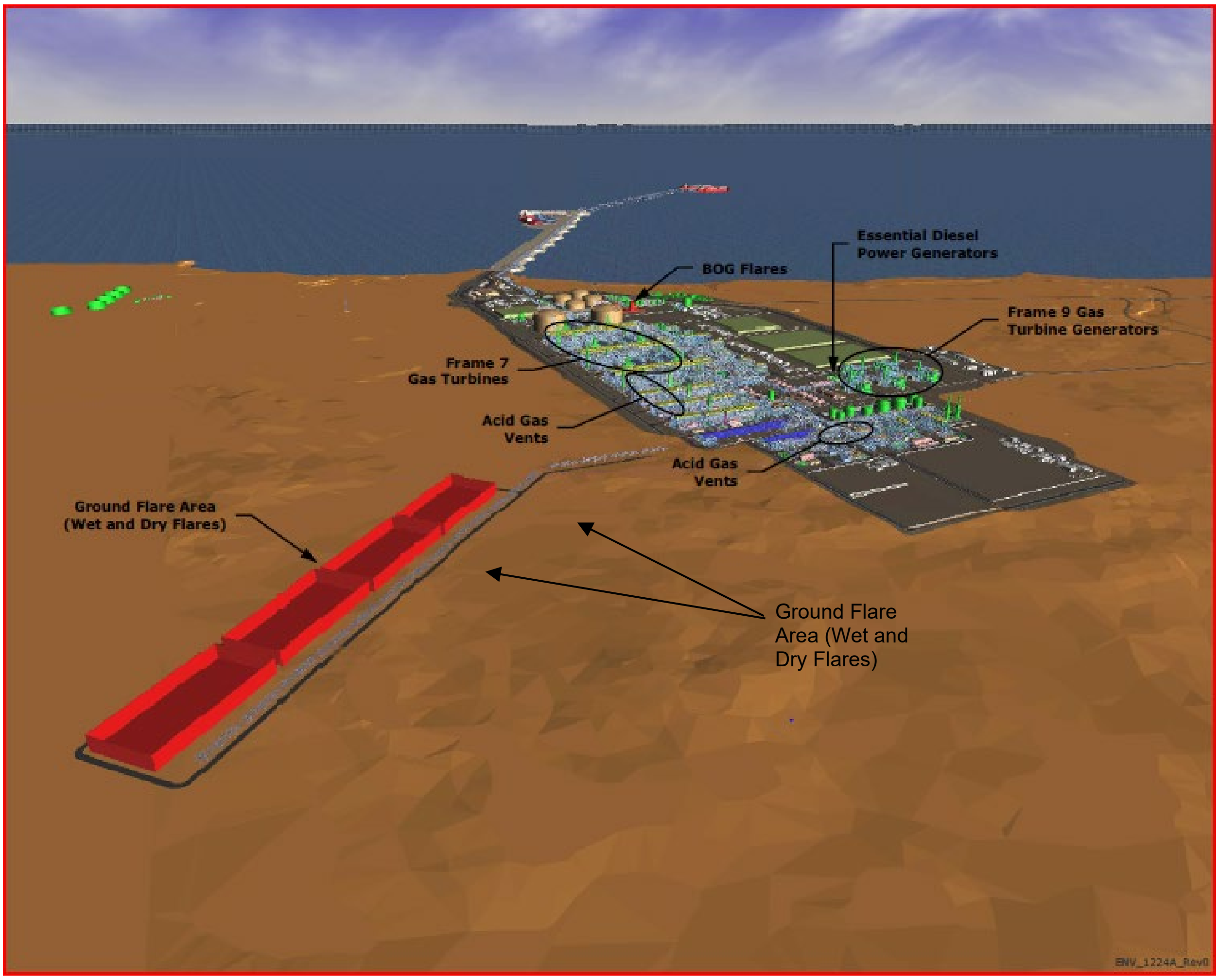

Figure 3-2: Location of Major Atmospheric Pollutant Emission Sources

3.4 Power Generation GTGs

3.4.1 Description of Equipment and Operating Regime

Given the remoteness of Barrow Island, the power generation system must be highly reliable to avoid unplanned outages of the three LNG trains; these trains operate most efficiently when running at optimal capacity over long time periods. An unreliable electrical power supply would result in the LNG trains operating at less than peak efficiency, or in the worst case, having to be shut down. A shutdown could result in increased emissions, because part of or the entire gas inventory within the trains may need to be flared to make the GTP safe.

Several power generation studies were completed to select the most suitable power generation system for the Gorgon Gas Development (Ref. 18). It was decided that five 116 MW (nominal capacity) Frame 9 GTGs would provide electrical power, running continuously and sharing the load, between 80 and 100 MW each under normal operating conditions. This operating strategy will ensure that should one of the turbines accidentally trip, the remaining four will ramp up and share the extra load equally. Thus the average loading of each turbine under normal operating conditions is expected to range between 68% and 86%, and would increase should any turbine trip.

3.4.1.1 Best Practice Pollution Control Design Measure

Atmospheric pollutants associated with the operation of the power generation plant include NO_x, PM_{10}, SO_x, NMVOCs, and CO. For gas-fired combustion plants using natural gas as a fuel, emissions of PM and SO_x are very low (Ref. 19). Emission levels of PM are normally well below 5 mg/Nm^3 and SO_2 emissions are well below 10 mg/Nm^3 (at 15% oxygen [O_2] reference level) without any additional technical measures (Ref. 19). The sulfur content in the Gorgon fuel gas is extremely low—around 150 ppbv—and PM and NMVOC emissions are also estimated to be low due to the high burning efficiency of the turbines. Therefore, the pollutants of major concern for GTGs are NO_x and CO.

Pollution control has focused on minimising NO_x in the exhaust gas stream and ensuring compliance with environmental regulatory requirements; however, the concentrations of CO in the exhaust gas were also considered in the selection of NO_x pollution control measures, as presented in Section 3.4.2.

Design emission targets for the GTGs, based on the prescribed pollutant emission rates in applicable environmental regulations, are summarised in Section 3.4.3.

3.4.2 Selection and Evaluation of Best Practice Pollution Control Measures

A best practice evaluation and ALARP demonstration process was applied to various NO_x pollution control design options.

Table 3-1 outlines the options reviewed and the considerations taken into account. The following criteria were applied in this assessment:

- Ability to achieve or improve upon the design emission targets.
- Preference for primary (at source) over secondary (end-of-pipe) pollution control measures. Secondary pollution control measures are often combined with primary pollution control measures (to further reduce pollutant emission rates) and in locations of poor air quality (e.g. urban centres), where additional emission sources must be tightly regulated.

- Technology Risk – proven versus unproven technology. The Chevron Technology Qualification Process (Ref. 20) requires that a certain technology has a documented track record in the field, for a defined environment, to be considered 'proven' and of acceptable operational risk.
- Energy Efficiency – the energy efficiency most central to each design option, be it thermal, electrical, or mechanical energy efficiency, is discussed in Table 3-1. A reduction in energy efficiency may result in increased fuel requirements and consequently increased emissions.
- Operability/Maintainability – design options that are difficult to operate or require high maintenance may result in higher emissions through suboptimal operating conditions and any additional shutdown and start-up events that may occur.
- Pollutant Emissions – impact on CO, NMVOCs, or other pollutant emissions, e.g. because of reduced combustion temperature.
- Availability – impact of pollution control technology on combustion equipment availability.
- HES – additional HES considerations, including waste generation, use of natural resources (e.g. water), occupational health exposures, and safe operations.

Combustion processes produce three main types of NO_x gases:

- Thermal NO_x results from the reaction between the oxygen and nitrogen from the air. The formation of thermal NO_x mostly depends on temperature. If combustion is achieved at temperatures below 1000 °C, emissions of NO_x are significantly lower. If peak flame temperatures are below 1000 °C, the formation of NO_x mostly depends on the fuel nitrogen. The formation of thermal NO_x is the dominant pathway by which NO_x is generated in installations using gaseous or liquid fuels.
- Fuel NO_x is formed from the oxidation of nitrogen contained in the fuel. The nitrogen (N_2) content of the GTP fuel gas can vary between 15 and 20% (mole, dry basis) (Ref. 21).
- Prompt NO_x is formed by the conversion of molecular nitrogen in the flame front in the presence of intermediate hydrocarbon compounds. Generally, the quantity of NO_x formed by prompt NO_x is much smaller than that generated by the other reaction paths.

Therefore, the primary methods for NO_x control can be further distinguished by the mechanism by which NO_x species are produced and how the technology affects the formation of those NO_x gases and other pollutants in the combustion exhaust gases, as discussed above.

Table 3-1: Evaluation of NO_x Pollution Control Options and Associated Considerations

No.	Pollution Control Option	Assessment Criteria						
		NO_x Emissions	Technology Risk	Energy Efficiency	Operability and Maintainability	Impact on other Pollutant Emissions	Availability	HES
Primary Pollution Control Measures:								
1	**Dry Low Emission (DLE) Burners**: DLE combustors use a series of annular rings with pre-mixers. Fuel is staged to various combinations of these pre-mixers during part power operations, maintaining nearly constant flame temperature over the entire operating range[1].	NO_x emissions potentially reduced by up to approximately 30 to 50%. Ability to control NO_x emissions over the entire operating range. Peak flame temperature reduced through increased mixing and homogeneity. Reduced peak temperature and residence time will result in reduction of thermal NO_x.	Previously used in similar applications and offered by most turbine manufacturers.	Reduced combustion efficiency due to reduced flame temperatures.	The burner control system requires the turbine manufacturer's assistance to tune the burners. Increased burner complexity and higher maintenance.	Potential for increased CO emissions if DLE burners operate at variable loading.	Potentially lower availability than turbines fitted with standard burners. DLE not available for Frame 9 machines.	No significant HES risks were identified with this technology.
2	***Dry Low NO_x (DLN) Burners[2]:*** *Two main types of DLN burners were considered: lean pre-mixed combustion and rich/quench/lean combustion. Lean pre-mixed combustion is the most common. The concept of lean pre-mixed combustion is to have a uniform, lean fuel-air mixture throughout the*	*NO_x emissions potentially reduced from approximately 68 to 98% when turbines operate above 55% of base load for site temperatures. DLN burner technology for gas turbines can guarantee 25 ppmv NO_x emissions, and have achieved 15 ppmv NO_x emissions over a wide*	*This is the standard technology for NO_x control; it is widely used in similar applications and is offered by most turbine manufacturers. DLN burner design is specific to the type of gas turbine used.*	*Reduced combustion efficiency due to reduced flame temperatures.*	*Potential flame out issues at air-to-fuel ratios required for NO_x emission reduction.* *Increased burner complexity and increased maintenance.*	*Potential for increased CO emissions at air-to-fuel ratios required for NO_x emission reduction.*	*Widely available and offered by most turbine manufacturers.*	*No significant HES risks were identified with this technology.*

No.	Pollution Control Option	Assessment Criteria						
		NO_x Emissions	Technology Risk	Energy Efficiency	Operability and Maintainability	Impact on other Pollutant Emissions	Availability	HES
	combustion zone, with no fuel-rich pockets where high flame temperatures would cause thermal NO_x to be formed[1].	*50% to 100% load range (Ref. 22).* *Peak flame temperature reduced through increased mixing and homogeneity, reduced residence time, therefore reduction in thermal NO_x.*						
3	**Wet Low Emissions (WLE) or Water Injection**: WLE uses large amounts of processed purified demineralised water or steam injected into the turbine to reduce the flame temperature and thus limit the amount of NO_x produced[1].	NO_x emissions potentially reduced by up to approximately 80%. WLE has been reported to achieve 42 ppmv of NO_x for large gas turbines (160 MW) (Ref. 23). Reduction dependent on water injection ratio and the efficiency of mixing. Peak flame temperature reduced (water acts as a thermal sink), therefore reduction in thermal NO_x.	Previously used in similar applications and offered by most turbine manufacturers.	WLE generally results in an increase in power output but a reduction in thermal energy efficiency, as heat is transferred to the injected water or steam.	Additional operational requirements due to large freshwater demand and treatment to ensure high water purity. Subsequent increase in maintenance. Issues with variable power loads, resulting in potential loss of efficiency. Increase in erosion and wear in the hot section of the turbine leads to increased	Potential for increased CO or unburnt hydrocarbon emissions as water reduces the combustion efficiency of the turbine.	Potentially lower availability than turbines fitted with standard burners.	Additional land take for water purification plant and use of a precious natural resource (water) on Barrow Island. Increased generation of wastes related to use of ion exchange resins, catalysts, chemicals, packaging, etc. associated with water purification.

No.	Pollution Control Option	Assessment Criteria						
		NO_x Emissions	Technology Risk	Energy Efficiency	Operability and Maintainability	Impact on other Pollutant Emissions	Availability	HES
					maintenance requirements.			
4	**Catalytic Oxidation/Combustion**: A flameless combustion method using a catalytic surface to create an even high heat release with completed reaction temperatures of approximately 1500 °C and low NO_x emissions[1].	Combustion occurs below temperatures associated with thermal NO_x formation. Potential to decrease overall NO_x emissions from uncontrolled 150–200 ppmv to fewer than 5 ppmv.	Not yet operationally demonstrated in large-scale power generation (>10 MW). This is because the catalyst must be active enough to ensure ignition at temperatures as low as 350 °C, yet be thermally stable enough to resist temperatures as tested. Also because of the lack of mixing in the structure, differences within the channels produce hot spots that ruin the catalyst.	Potential for catalyst performance degradation that may result in a reduction in energy efficiency.	Potential operability issues due to flashback. Turbine balancing and increased maintenance requirements due to multiple burners. Limited operational temperature range, and therefore of limited applicability to GTs that may be subject to rapid load changes.	Reduces CO and unburnt hydrocarbon emissions due to a more efficient burning process.	Potentially lower availability than other design options.	Potential safety issues due to flashback, and high operating temperatures. Waste management issue – disposal of damaged catalyst.

No.	Pollution Control Option	Assessment Criteria						
		NO_x Emissions	Technology Risk	Energy Efficiency	Operability and Maintainability	Impact on other Pollutant Emissions	Availability	HES
Secondary Pollution Control Measures:								
5	**Selective Catalytic Reduction (SCR)**: The process of injecting ammonia in the presence of a catalyst into the exhaust stream of a GT as it passes through a WHRU, where fitted. This process reduces NO_x to nitrogen and water. It is used as a polishing step to reduce NO_x emissions from an already low emission rate (as a result of the use of primary pollution control) to a very low emission rate.	NO_x emissions could be reduced from a low emission rate (e.g. 42 ppmv) to 9 ppmv (Ref. 23). Reduction efficiency reduces over time with catalyst masking, poisoning, and sintering.	Previously used in similar applications. Good compatibility with WHRUs.	Ammonia salt formation in the WHRUs leads to reduced heat transfer efficiency. Decreased power generation output due to increased back-pressure in the turbine exhaust system.	Narrow exhaust temperature window where this technology is effective; e.g. 315 °C to 510 °C for zeolite catalysts (Ref. 23). Potential salt build up in the WHRU. Requires liquid ammonia storage, injection grid and mixing system, the SCR catalyst module, and a heat source . Issues with catalyst effectiveness and service life, typically around 2 to 3 years. Issues with variable power loads, resulting in potential loss of efficiency.	Helps to remove PM_{10}, CO, NMVOCs from the GT exhaust using the catalyst.	Potentially lower availability than turbines fitted with standard burners.	Potential for residual ammonia to be present in the flue gas (up to 10–20 ppmv). Waste management issues for spent catalyst. Safety concerns regarding the storage and handling of liquid ammonia. Additional land take required for ammonia storage and dosing equipment.

No.	Pollution Control Option	Assessment Criteria						
		NO_x Emissions	Technology Risk	Energy Efficiency	Operability and Maintainability	Impact on other Pollutant Emissions	Availability	HES
6	**Non Ammonia Catalytic Systems (e.g. SCONOX)**: A post-combustion catalytic system that removes both NO_x and CO from the GT exhaust, but without ammonia injection. The catalyst is platinum and the active NO_x removal reagent is potassium carbonate.	NO_x emissions could be reduced to as low as 2 ppmv NO_x. Reduction efficiency reduces over time with catalyst degradation.	Limited number of applications to date.	Potential for catalyst performance degradation that may result in a reduction in energy efficiency.	Process efficiency sensitive to sulfur compounds in the exhaust gas stream. Large pressure drop through the catalytic bed causes higher back-pressure in the exhaust gas treatment system. Degraded reliability and performance over time.	Helps to remove PM_{10}, CO, and NMVOCs from the GT exhaust with a catalyst.	Potentially lower availability than other design options.	Catalytic modules' footprint is large, requiring additional land take. Waste management issues for spent catalyst.

Notes:

1. *Emission reduction data sourced from United States Environmental Protection Agency (USEPA; Ref. 24)*
2. *Selected best practice option shown in italics. '*

3.4.3 Discussion of Best Practice Pollution Control Option

The results of the comparative evaluation shown in Table 3-1 were confirmed by a risk assessment of the residual HES risks associated with each option (Ref. 25). Dry Low NO_x (DLN) has been adopted as the best practice control option for the GTGs, as it is an engineering solution that has been widely applied in the oil and gas industry, requires minimal additional complexity and maintenance, and does not significantly increase associated HES risks. This technology also provides the lowest atmospheric pollutant emissions possible during normal operating conditions by reducing the temperature of combustion, whilst balancing power output and efficiency requirements. In addition, DLN is the most cost-effective technology (Ref. 26) and has been endorsed by Chevron Corporation as one of several preferred pollution control technologies for NO_x emissions (Ref. 27). It is also recognised by the EPA as best practice for new power generation facilities (Ref. 28) and as a BAT by the EC IPPC Reference Documents on Best Available Techniques for Mineral Oil and Gas Refineries (Ref. 23) and Large Combustion Plants (Ref. 19).

Figure 3-3 shows a typical DLN burner on a gas turbine.

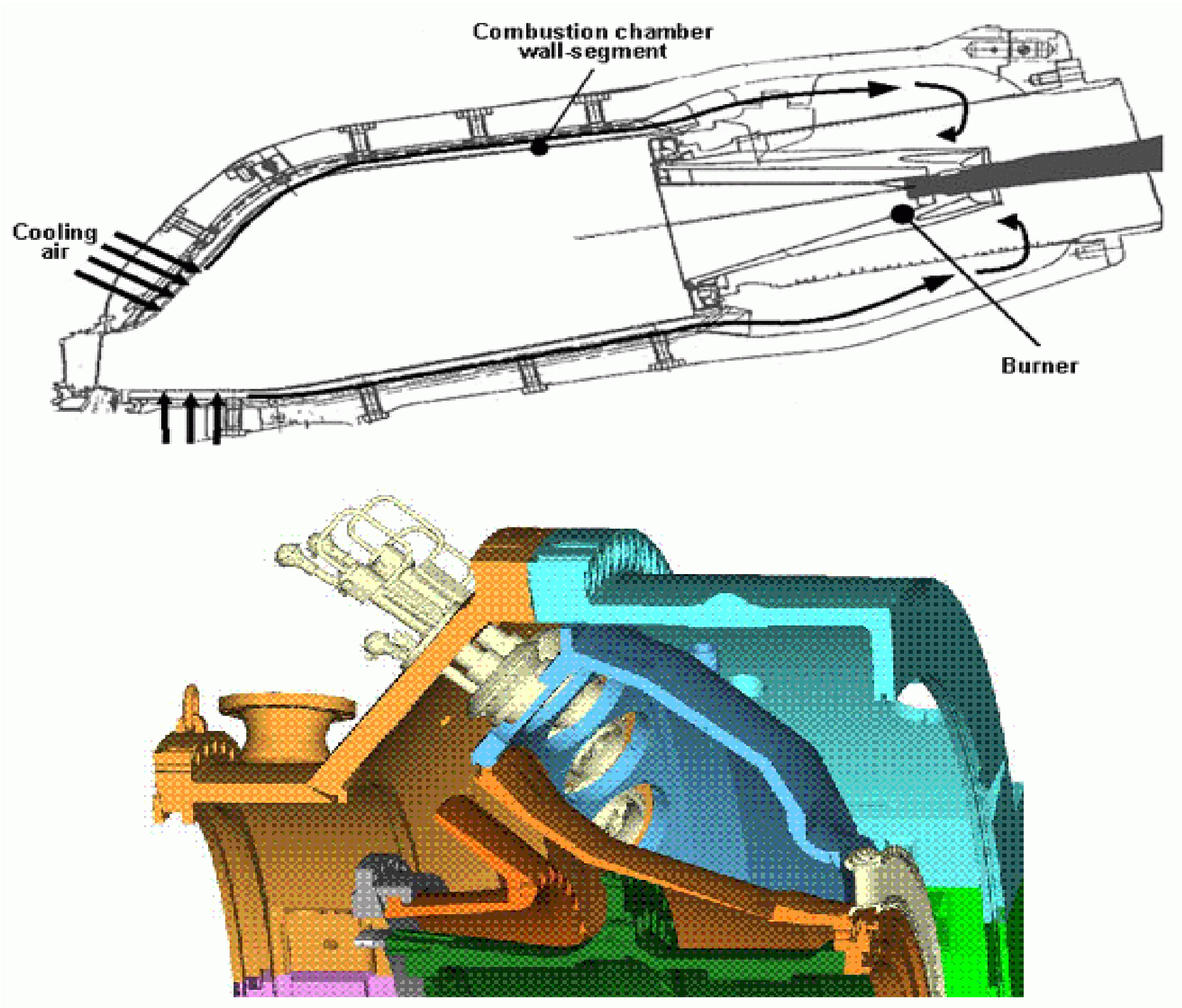

Figure 3-3: DLN Combustion Chamber Schematic

Source: Reference Document on Best Available Techniques for Large Combustion Plants (Ref. 19)

In addition, the air quality modelling studies completed for the GTP (Ref. 10) indicate that under all modelled conditions, ambient NO_x levels are expected to be well below the relevant National Environment Protection Measure (NEPM) NO_x criteria (Ref. 29), including background NO_x concentrations.

The examples in Table 3-2 demonstrate that DLN is considered to be the current best practice technology for NO_x emissions management in power generation facilities operated on fuel gas.

Table 3-2: DLN Technology Benchmarking for Power Generation Facilities

Facility	Industry	Power Generation Equipment	Pollution Control Technology
International Experience			
Snohvit 4.3 MTPA LNG Plant, Norway	Oil and Gas	LM-6000 aero-derivative gas turbines	DLE/DLN burners
Qianwan LNG No. 2, Dachan Island, China	Oil and Gas	3 × 390 MW Mitsubishi 701F gas turbines	Pre-mix DLN burners
Tamazunchale I Combined Cycle Power Generation Plant, Mexico	Power Generation	4 × GE Frame 7FA gas turbines	DLN burners
Australian Experience			
Pluto LNG Plant, Burrup Peninsula, Western Australia	Oil and Gas	4 × GE Frame 6 gas turbines (40 MW nominal capacity each)	DLN burners
Karratha Gas Plant, Burrup Peninsula, Western Australia	Oil and Gas	Gas Turbines (226.8 MW)	Low NO_x burners
Gladstone LNG Facility, Queensland	Oil and Gas	Gas Turbines	DLN burners
Darwin LNG Plant, Northern Territory	Oil and Gas	2 × Solar Taurus 60 Dual Fuel Turbines 3 × Solar Taurus 60 Gas Turbines	SoloNO$_x$ II

In addition, the EC Reference Document on Best Available Techniques for Large Combustion Plants (Ref. 19) provides numerous examples of DLN applications for power generation facilities and concludes that for new GTs, DLN burners are considered to be the standard BAT. Therefore, the application of an additional SCR system is not necessary. For further reduction of NO_x, SCR can be considered where local air quality standards require a further reduction of NO_x emissions from 25 to 34 ppmv to 9 ppmv (e.g. operation in densely populated urban areas). Furthermore, industry experience indicates that in the case of simple cycle GTs, SCR is not cost-effective because the exhaust gas needs to be cooled down, which requires an additional cooler to reduce the temperature to a level that enables the SCR to operate (Ref. 19). This additional cooler will increase the already high investment and operational costs. Hence, the high investment, operational, and maintenance costs render the implementation of SCR technology in a GT economically unviable.

3.4.4 Base Emission Rates and Design Emission Targets

The base emissions rates and design emission targets are summarised in Table 3-3.

Table 3-3: GTGs Base Emission Rates and Design Emission Targets

Pollutant	Base Emission Rates at Actual Exhaust Gas Conditions[1] [g/s]	Base Emission Concentrations at Standard Reference Conditions[2] [mg/m^3]	Design Emission Targets[3] [mg/m^3]
NO_x	14.9	51.3	70
CO	5.5	18.7	125
NMVOC	0.4	1.2	40
SO_x	0.004	0.01	–

Notes:

1. *Base emission rates reported in g/s are emission rates at actual exhaust gas conditions, i.e. 1 atmosphere and 550 °C temperature; 8.15% water content, and 13.47% oxygen level.*
2. *Base emission concentrations reported in mg/m^3 are calculated at standard reference conditions (e.g. dry conditions, 1 atmosphere, 0 °C, 15% oxygen reference level).*
3. *Design emission targets are sourced from the New South Wales (NSW) EPA Protection of the Environment Operations (Clean Air) Amendment (Industrial and Commercial Activities and Plant) Regulation 2010 and the WA EPA Guidance for the Assessment of Environmental Factors, Guidance Statement for Emissions of Oxides of Nitrogen from Gas Turbines (Ref. 30).*

3.4.5 Impact of Deviations from Normal Operating Conditions

As noted above, during normal operating conditions, the Frame 9 GTGs share the load equally, operating within their optimum for DLN load range (between approximately 55% and 100% load). In the event of a single generator trip, the other four generators share the shortfall in the load, thus increasing the individual machine loading whilst still maintaining the effectiveness of the DLN technology.

Transient conditions are likely to occur during shutdown, start-up, or changes in electrical power requirements from the GTP. DLN technology, once turned on, is anticipated to be effective down to approximately 55% load. In cases where the shared load remains in this effective range, these conditions are expected to have little to no effect on the emissions profile of these machines. In cases where the shared load drops below the effective range of the DLN technology, the burners will perform as standard combustors with a higher atmospheric pollutant emissions profile.

Upon initial start-up of the GTP, the Frame 9 GTGs will not be tuned, and the DLN technology will not be turned 'on' until sufficient plant electrical power load exists. Prior to tuning, the burners will perform as standard combustors with a higher atmospheric pollutant emissions profile.

Once Frame 9 GTG steady state conditions are achieved, in accordance with the manufacturer's recommendations, the Frame 9 GTGs may be shut down for maintenance in accordance with this schedule (Ref. 31):

- at 18 months into operations for approximately seven days for a combustion inspection
- once every three years for approximately 12 to 14 days for a hot path inspection
- once every six years for approximately 28 days for a major overhaul.

Where practicable, maintenance shutdowns are intended to be scheduled to coincide with planned maintenance shutdowns.

3.5 Frame 7 Process GTs

3.5.1 Description of Equipment and Operating Regime

Each LNG train has two refrigeration compressors driven by Frame 7 GTs that are supplemented with power from electric helper motors. The refrigerant compressor configuration uses the APCI Split-MR™ configuration, with the Low Pressure Mixed Refrigerant (MR) compressor driven by one GT, and the High Pressure MR/Propane (MR/PR) compressors driven by the other GT (i.e. six Frame 7 GTs for the three 5 MTPA LNG trains).

3.5.1.1 Best Practice Pollution Control Design Measure

The Frame 7 GTs are the largest fuel gas consumer at the GTP and without any pollution control would be the largest single source of NO_x and other pollutant emissions. As discussed in Section 3.4.1.1, SO_x, NMVOC, and PM_{10} emissions are expected to be low; hence, pollution control measures focus on minimising NO_x and CO in the exhaust gas stream.

3.5.2 Selection and Evaluation of Best Practice Pollution Control Measures

A best practice evaluation and ALARP demonstration process was applied to several NO_x pollution control design options.

Table 3-1 outlines the options reviewed and the considerations taken into account. The same selection criteria applied to the Frame 9 GTGs (see Section 3.4.2) were applied to the Frame 7 GTs.

3.5.3 Discussion of Best Practice Pollution Control Option

As with the Frame 9 GTGs, the pollution control design option selected for use on the Frame 7 GTs is DLN Burners (Option 2 in Table 3-1). Using the same pollution control technology has operational, maintenance, and contractual advantages such as similar control interfaces and operational issues and controls, as well as benefits arising from using the same vendor.

The Frame 7 GTs in the LNG trains are fitted with WHRUs to recover additional energy from the hot exhaust gases released to atmosphere. Using WHRUs on Frame 7 GTs is established best practice in heat integration in LNG plant design.

The examples in Table 3-4 demonstrate that DLN is considered to be the current best practice technology for NO_x emissions management for process GTs in LNG plants throughout the world.

Table 3-4: DLN Technology Benchmarking for Process GTs

Facility	Industry	Gas Turbines	Pollution Control Technology
International Experience			
RasGas Train 5, Qatar	Oil and Gas	Manufacturer and type not specified	DLN burners
Qatargas 2	Oil and Gas	GE Frame 9 Gas Turbines	DLN burners
Australian Experience			
Pluto LNG Plant, Burrup Peninsula, Western Australia	Oil and Gas	Manufacturer and type not specified	DLN burners
Karratha Gas Plant, Burrup Peninsula, Western Australia	Oil and Gas	Manufacturer and type not specified	Low NO_x burners

Facility	Industry	Gas Turbines	Pollution Control Technology
Gladstone LNG Facility, Queensland	Oil and Gas	Manufacturer and type not specified	DLN burners
Darwin LNG Plant, Northern Territory	Oil and Gas	6 × GE LM-2500+ aero-derivative gas turbines	Water Injection (WLE)

3.5.4 Base Emission Rates and Design Emission Targets

The base emissions rates and design emission targets are summarised in Table 3-5.

Table 3-5: GTs Base Emission Rates and Design Emission Targets

Pollutant	Base Emission Rates at Actual Exhaust Gas Conditions[1] [g/s]	Base Emission Concentrations at Standard Reference Conditions[2] [mg/m^3]	Design Emission Targets[3] [mg/m^3]
NO_x	11.6	51.3	350
CO	4.0	18.8	125
NMVOC	0.3	1.2	40
SO_x	0.004	0.02	–

Notes:

1. *Base emission rates reported in g/s are emission rates at actual exhaust gas conditions, i.e. 1 atmosphere and 548.3 °C temperature; 8.04 % water content, and 13.59 % oxygen level.*
2. *Base emission concentrations reported in mg/m^3 are calculated at standard reference conditions (e.g. dry conditions, 1 atmosphere, 0 °C, 15% oxygen reference level).*
3. *Design emission targets are sourced from the NSW EPA Protection of the Environment Operations (Clean Air) Amendment (Industrial and Commercial Activities and Plant) Regulation 2010 and the WA EPA Guidance for the Assessment of Environmental Factors, Guidance Statement for Emissions of Oxides of Nitrogen from Gas Turbines (Ref. 30).*

3.5.5 Impact of Deviations from Normal Operating Conditions

As with the Frame 9 GTGs, during normal operating conditions the Frame 7 GTs are expected to operate within their optimum for DLN load range (between approximately 75% and 100% load), allowing for NO_x emissions to be kept low.

Transient conditions are likely to occur during shutdown, start-up, or operating at suboptimal load conditions. During these scenarios, the Frame 7 GTs are expected to be ramped up/down in a controlled manner to ensure equipment integrity is maintained, and as such, the Frame 7 GTs are expected to be operated at variable loading, which is expected to affect the efficiency of the DLN technology, which once tuned, is anticipated to be effective down to 75% load. As a result, associated atmospheric pollutant emissions may potentially increase for short durations; however, these transient conditions are not expected to impact adversely on the air quality around the GTP.

The Frame 7 GTs are expected to be tuned relatively early during initial start-up, however, during this period the operating load may not be in the effective DLN range. As a result, associated atmospheric pollutant emissions may be higher.

In accordance with the manufacturer's recommendations, any of the Frame 7 GTs may be shut down for maintenance in accordance with this eight-year cycle (Ref. 32; Ref. 31):

- at two years for approximately seven days for a combustion inspection

- at four years for approximately 20 days for a hot gas path inspection
- at six years for approximately seven days for a combustion inspection
- at eight years for approximately 28 days for a major overhaul.

3.6 Heating Medium Heaters

3.6.1 Description of Equipment and Operating Regime

The Heating Medium System comprises two pressurised, closed-loop hot water circulating systems. The primary circuit supplies heating medium to the majority of users at 220 °C and a smaller, secondary circuit operates at a lower pressure and supplies heating medium to the remainder of the users at 180 °C.

The purpose of the Heating Medium System is to recover available waste heat from the Frame 7 GT exhausts (via WHRUs) and supply the heat to users. Major users include inlet gas heating, AGRU reboilers, the MEG regeneration package, various reboilers in the liquefaction/fractionation units, condensate stabilisation, and fuel gas heaters. The equipment for the Heating Medium System is physically located at user locations in the GTP. The WHRUs are located within the exhaust of the Frame 7 GTs inside the LNG trains.

The WHRUs provide the routine process heat requirements during normal operation of the GTP.

3.6.1.1 Best Practice Pollution Control Design Measure

Atmospheric pollutants associated with the operation of Heating Medium Heaters include NO_x, PM_{10}, SO_x (as SO_2), NMVOCs, and CO; however, SO_x emissions are expected to be very low because of the low sulfur content in the fuel gas (i.e. around 150 ppbv). PM_{10} and NMVOC emissions are also estimated to be low as a result of the high combustion efficiency of the heaters. Therefore, pollution control focuses on minimising NO_x in the exhaust gas stream; however, the concentrations of CO in the exhaust gas were also considered in the selection of NO_x pollution control measures (Section 3.6.2).

3.6.2 Selection of the Best Practice Pollution Control Measure

A best practice review and an ALARP demonstration process were applied to several pollution control design options to identify the best practice pollution control measure to reduce emissions from the Heating Medium Heaters.

The same assessment criteria were used in the assessment as those listed in Section 3.4.2. Table 3-6 outlines the options reviewed and the considerations taken into account.

As a result of the comparative evaluation, low NO_x burners were adopted as best practice pollution control for the Heating Medium Heaters. Low NO_x burners are widely used in the oil and gas industry, require minimal additional complexity and maintenance, and do not significantly increase associated HES risks. Furthermore, since the Heating Medium Heaters are expected to be used only occasionally (if duty heat from the WHRUs is not sufficient to meet GTP demand), the use of a technology that offers up to 70% reduction in NO_x emissions at a reasonable cost is considered best practice for this application.

Table 3-6: Reviewed NO_x Pollution Control Options and Associated Considerations

No.	Pollution Control Option	Assessment Criteria						
		NO_x Emissions	Technology Risk	Energy Efficiency	Operability/ Maintainability	Pollutant Emissions	Availability	HES
1	**Standard Burner**: No emission controls	Potential for NO_x emissions to exceed 250 ppmv.	Widely applied and offered by most manufacturers.	Optimal thermal efficiency can be achieved as flame temperature is not restricted.	Reliable and easy to control.	Higher emissions expected due to no pollution control technology being used.	Widely available and offered by most manufacturers.	No significant HES risks, including risk of pollutant emissions due to the low use of the heating medium heaters.
2	***Low NO_x Burners**[1]: Low NO_x (LN) burners reduce the formation of NO_x by staging the combustion process by producing fuel-rich and fuel-lean zones within the flame. The fuel-rich zone is the primary combustion zone and prevents the formation of thermal NO_x (formation of NO_x caused by high flame temperatures), resulting from low oxygen concentration. The cooler, fuel-lean zone prevents thermal and fuel NO_x (formation of NO_x resulting from the oxidation of fuel bound nitrogen [2].*	*NO_x emissions reduced by up to approximately 70% compared to standard burners.* *Reduction in formation of thermal NO_x through reducing peak flame temperatures.*	*Previously used in similar applications and offered by most burner manufacturers.*	*Reduced combustion efficiency due to reduced flame temperatures.*	*Increased burner complexity and increased maintenance.*	*Issues with turndown and potential for elevated emissions when operating at variable loading.*	*Widely available and offered by most manufacturers.*	*No significant HES risks.*
3	**Ultra Low NO_x Burner**: Similar to LN burners with the inclusion of internal recirculation of flue gases,	NO_x emission reduced by up to approximately 75% has been achieved for this technology	Previously used in similar applications and offered by	Reduced combustion efficiency due to reduced	More difficult to control than LN burner as the Ultra Low NO_x burner operates	Issues with turndown and potential for elevated pollutant emissions when	Widely available and offered by most manufacturers.	No significant HES risks.

No.	Pollution Control Option	Assessment Criteria						
		NO_x Emissions	Technology Risk	Energy Efficiency	Operability/ Maintainability	Pollutant Emissions	Availability	HES
	enabling further NO_x reductions[2].	when applied to process heaters and boilers. Reduction in formation of thermal NO_x through reducing peak flame temperatures.	most burner manufacturers.	flame temperatures.	at the limit of stability (i.e. flame might extinguish suddenly).	operating at variable loading. Limited operating envelope, which may result in higher emissions overall than for LN burners because of proportion of time spent outside of optimum operating regime.		
4	**Selective Non-Catalytic Reduction** (SNCR): SNCR requires the injection of ammonia, which reacts with thermal and fuel NO_x, into exhaust gases to form water and molecular nitrogen. Due to uneven and incomplete mixing of exhaust gases and ammonia, ammonia slip may occur[2].	NO_x emissions, regardless of formation type, potentially reduced by up to approximately 70%.	Previously used in similar applications.	Narrow exhaust temperature window where this technology is efficient.	Requires liquid ammonia storage, injection grid and mixing system. Narrow exhaust temperature window where this technology is effective. Difficult to control the process of injecting ammonia into the flue gas.	Potential for increased particulate emissions.	Potentially lower availability than heaters fitted with standard burners.	Potential for residual ammonia to be present in flue gas if injected outside narrow temperature window. Potential for increased N_2O and ammonia emissions. Safety concerns of storage and handling of liquid ammonia.

No.	Pollution Control Option	Assessment Criteria						
		NO_x Emissions	Technology Risk	Energy Efficiency	Operability/ Maintainability	Pollutant Emissions	Availability	HES
5	**Selective Catalytic Reduction** (SCR): Involves a process of injecting ammonia in the presence of a catalyst into the exhaust stream of the burner. This process reduces NO_x to nitrogen and water[2].	NO_x emissions, regardless of formation type, potentially reduced by up to approximately 90%. Reduction efficiency reduces over time with catalyst masking, poisoning, and sintering.	Previously used in similar applications.	Ammonia salt formation in the WHRUs reduces heat transfer efficiency. Decreased power output due to increased back-pressure in the burner exhaust system. Potential for catalyst performance degradation that may reduce energy efficiency.	Narrow exhaust temperature window where this technology is effective. Requires liquid ammonia storage, injection grid and mixing system, the SCR catalyst module, and a heat source. Issues with catalyst effectiveness and service life, typically around 2 to 3 years. Issues with variable power loads, resulting in potential loss of efficiency.	Removes PM_{10}, CO, NMVOCs from the burner exhaust with a catalyst.	Potentially lower availability than heaters fitted with standard burners.	Potential for residual ammonia to be present in flue gas (up to 10–20 ppmv). Potential salt build up in the WHRU. Waste management issues for spent catalyst. Safety concerns of storage and handling of liquid ammonia. Additional land take required for ammonia storage and dosing equipment.

Notes:

1. *Selected best practice option shown in italics.*
2. *Emission reduction data sourced from USEPA (Ref. 24).*

3.6.3 Base Emission Rates and Design Emission Targets

Table 3-7 lists the base emission rates and design emission targets for the Heating Medium Heaters fitted with LN technology. These emission rates reflect a single heater operating at full design duty fuel consumption rates. Stand-by fuel consumption rates are anticipated to be approximately 10 times lower than the full design duty fuel consumption rates; consequently, the actual pollutant emission rates are expected to be lower than those listed in Table 3-7.

Table 3-7: Heating Medium Heaters Base Emission Rates and Design Emission Targets

Pollutant	Base Emission Rates at Actual Exhaust Gas Conditions[1] [g/s]	Base Emission Concentrations at Standard Reference Conditions[2, 4, 5, 6] [mg/m^3]	Design Emission Targets[3] [mg/m^3]
NO_x	1.7	80	350
CO	0.8	39	125
NMVOC	0.2	8	40
SO_x	0.001	0.4	–

Notes:

1. *Base emission rates reported in g/s are emission rates at actual exhaust gas conditions, i.e. 1 atmosphere and 442 °C temperature; 18.04% water content, and 2.4% oxygen level.*
2. *Base emission concentrations reported in mg/m^3 are calculated at standard reference conditions (e.g. dry conditions, 1 atmosphere, 0 °C, 7% oxygen reference level).*
3. *Design emission targets are sourced from the NSW EPA Protection of the Environment Operations (Clean Air) Amendment (Industrial and Commercial Activities and Plant) Regulation 2010.*
4. *NO_x base emission concentrations is based on 50 ppmv NO_x (manufacturer's data, dry conditions, 3% oxygen level).*
5. *CO base emission concentrations is based on 40 ppmv CO (manufacturer's data, dry conditions, 3% oxygen level).*
6. *NMVOC base emission concentrations are calculated using the USEPA AP42 factors for a boiler/furnace with a heat output greater than 100 MMBtu/h at 15% excess air (Ref. 33).*

3.6.4 Impact of Deviations from Normal Operating Conditions

During non-routine operating conditions, the Heating Medium Heaters are expected to operate at the minimum necessary load to accomplish process objectives and for the minimum necessary duration until the WHRUs can supply the process heat demand. Non-routine operating conditions that may result in the use of the Heating Medium Heaters include train start-up, train trip, and maintenance operations. For example, one Heating Medium Heater may be required to operate for up to two weeks at approximately 70% of design load during start-up of a train. During a typical operating year, non-routine operating conditions (due to planned maintenance of the GTs) are not expected to occur for more than two per cent of the time (Ref. 32).

The Heating Medium Heaters may also be required for certain operating scenarios (e.g. different combinations of feed gas concentration and ambient temperature), where the duty heat from the WHRUs alone is not sufficient for the GTP heat demand. For example, during three-train operation, a single fired heater may be required to operate at 80% of the design load, until the duty heat provided by the WHRU can supply the process heat demand.

During the initial start-up of the GTP, it is intended that the Heating Medium Heaters are used until the WHRUs are in operation. During this time, the Heating Medium Heaters are not expected to be running at design load; it is expected that during most of this period, only one heater will operate at approximately 36% of design load. During this time, the operating load may not be in the effective LN range, and as a result, associated atmospheric pollutant emissions may be higher.

3.7 Ground Flares (Dry and Wet Flare)

3.7.1 Description of Equipment and Operating Regime

The wet and dry flare systems safely and reliably collect and dispose of hydrocarbon vapour and liquids during commissioning, start-up, and operations (including shutdown, start-up, venting, draining, purging, and heating and cooling of equipment and/or piping), process upsets, or emergencies.

The design of the flare system is based on the 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 does not restrict the operation of GTP systems. Two separate systems are provided—the wet and dry flare systems, which each comprise a collection header for vapour and a collection header for liquids, a knockout drum, and a staged ground flare. The primary flare header purge gas medium is fuel gas with nitrogen as backup (Ref. 34; Ref. 35). The flare headers must be purged to maintain positive pressure within the system and to prevent any air ingress.

The wet and dry ground flares are constructed as linear relief enclosed ground flares using a series of staging valves that open up progressively, depending on the volume of gas being flared. Each stage will feed a number of runners, with each runner having multiple flare tips. Most flaring events will be managed by the first three stages, with the additional stages opening for a limited number of low probability, higher flow-rate flaring scenarios. The tips design uses the high-pressure gas flow to efficiently combust, in a smokeless manner, the flare gas. The first stage tips use the Coanda effect to minimise the purge gas requirement.

The ground flares use proven, robust, and durable technology so as to maximise the availability of pilots and their igniters, and to ensure combustion of the flared gas. Pilots and igniters are duplicated and two pilots are provided for each runner within the flare fence. Two different ignition methods are intended to be used for each runner to mitigate potential scenarios that could impact any one type. The ignition methods are:

- automatic spark ignition
- manual flame front backup.

Pilots remain online; hence, pilot ignition is not a frequent activity. A flame front close to the pilot maximises serviceability and maintainability in the highly unlikely scenario of primary ignition failure.

The GTP ground flares are designed to achieve smokeless flaring. The most common cause of smoke is liquids entrained within the flare gas. The burning of entrained liquids also has the potential to damage the flare tips. As such, the wet and dry gas flare knockout drums are appropriately sized to remove liquids from the flare gas, and have a liquid transfer system with sufficient capacity to return the liquids to the process and prevent liquid carry over. A fence encloses the flares and protects personnel from the effects of radiation by avoiding direct line of sight with the flames.

3.7.1.1 Best Practice Pollution Control Design Measure

The design of the GTP is based on no routine gas flaring during normal operations. Routine flaring is 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 GTP (e.g. small flows from equipment purges, which are not practicable to collect) during normal production operations.

However, flaring above operation of the pilots and purge system cannot be completely eliminated and is necessary in scenarios such as these:

- abnormal operating scenarios (process upsets) and GTP start-up and shutdown – several mitigating measures are incorporated into the design to minimise flaring associated with such events
- to reduce emissions and/or GLC's from venting (e.g. when MEG flash gas cannot be directed to the Condensate Stabilisation units)
- GTP emergencies (e.g. gas leaks, fire and explosions).

The EC IPPC Reference Document for Best Available Techniques for Mineral Oil and Gas Refineries (Ref. 23) identifies these best practices for flare systems:

- use flaring as a safety system (start-up, shutdowns, and emergencies)
- ensure smokeless and reliable operation (discussed in Section 3.7.1)
- minimise flaring by a suitable combination of:
  - balancing the refinery fuel gas system
  - installing a gas recovery system
  - using high-integrity relief valves
  - applying advanced process control
  - reducing relief gas to flare by management/good housekeeping practices.

The adoption of these best practices at the GTP is discussed in Section 3.7.2.

3.7.2 Selection of the Best Practice Pollution Control Measures

Several elements are incorporated into the design so as to achieve no routine flaring during normal GTP operations, including:

- Flash vapours from the MEG unit are recovered, compressed, and sent via the Condensate Stabilisation units to the CO_2 injection system for compression and injection, once mercury and hydrocarbons have been removed, rather than disposed of via venting or flaring.
- The process gas used for dehydration regeneration is recovered and sent to the fuel gas system rather than flared.
- Flash vapours from the High Pressure Amine Flash Drum in the AGRU are recovered, compressed in the Recycle Gas Unit, and returned to the process feed to the AGRU. In other facilities, this CO_2-rich gas is often sent to the fuel gas system or flared.
- Any vapour generated in the refrigerant storage vessels is sent to the LNG storage tanks rather than flared.

- LNG within the LNG storage tanks boils off continuously due to heat ingress from the atmosphere; this BOG is collected, compressed, and sent to the fuel gas system, rather than flared.
- All vapour produced during LNG ship-loading operations is collected and compressed back into the feed gas to be turned into product, rather than flared.

During non-routine operations, flaring may be necessary for limited periods. To minimise flaring associated with process upsets, several mitigating measures are incorporated into the design of the GTP:

- Where appropriate, compressors can restart from a pressurised condition following a non-emergency trip, thus avoiding the need to depressurise to flare for restart.
- During normal operation, the methane-rich gas from the Stabilisation Unit is compressed and returned to the feed gas. Where the stabiliser overhead compressors are unavailable, the gas is routed to the Recycle Gas system where any available compression capacity is used to reprocess as much gas as possible and hence mitigate/minimise flaring.
- A line from the MCHE shell side in the liquefaction unit routes gas to the End Flash Gas Compressor suction. Thus, any tube leaks in the MCHE can be routed to fuel gas instead of flared.
- The BOG recycle compressor acts as a spare for the main BOG compressor so that if the primary machine fails, the BOG vapour does not have to be flared during LNG holding mode.

In the case of GTP emergencies, the safety instrumented systems (SIS) are designed to shut down the production facilities in a staged manner within the pressure limitations of each system, and hence prevent flaring. If required (e.g. fire scenario), the SIS has emergency blowdown provisions to maintain the integrity of the facilities.

The fuel gas system is balanced to the needs of the GTP and the Gorgon Gas Development power generation facilities, preventing flaring of any excess produced. Fuel gas is obtained from multiple sources within the facilities, including:

- LNG Boil-off Gas (via BOG Compressors)
- Regeneration gas from Dehydration (via End Flash Gas Compression)
- End Flash Gas from Liquefaction (via End Flash Gas Compression), which supplies fuel gas to both the LNG Train and the common fuel gas system
- Inlet feed gas.

Effective balancing of the fuel gas system is critical to minimise flaring. During lower fuel gas demand operating scenarios, the feed gas flow taken from the GTP's inlet facilities is reduced to minimise flaring of fuel gas obtained from the other process sources.

Relief valves are the final level of protection for pressurised systems from overpressure resulting from abnormal and emergency situations. By design, relief valves allow large volumes of gas to be relieved from the process; once a relief valve has lifted (operated), the potential exists that it may not completely re-seat (close) and gas will continue to flow to the flare.

Two levels of pressure protection prevent relief valve operation. The first level is pressure control via the Process Control System. Pressure Control Valves (PCVs) are strategically located in the GTP facilities to control the process within optimal operating parameters; thus, when minor process upset conditions occur, some of these PCVs allow small volumes of gas to be released to flare and allow the operation to be maintained. The second protection level is the SIS, discussed above.

3.7.3 Base Emission Rates and Design Emission Targets

No design emission targets are identified for the flare systems. The data used for estimating the base emission rates for the flare system were sourced from USEPA AP-42 data (Ref. 33), which uses a very large sample of industry data to derive 'representative' average industry flare emission factors.

Furthermore, the NSW EPA Protection of the Environment Operations (Clean Air) Amendment (Industrial and Commercial Activities and Plant) Regulation 2010 specifies emission values for flares and afterburners for destruction of toxic substances or landfill gas (which could contain up to 50% CO_2 and other impurities). However, these requirements do not apply to the flare systems at the GTP, which burn clean and liquid-free hydrocarbon fuel—either fuel gas or process gas evacuated to the flare under upset process conditions. Hence, only base emission rates are reported in this section.

Base emission rates are reported separately for routine operations (pilot, purge, and compressor seal gas only; enrichment gas is also injected during routine operations to achieve at least 800 BTU/scf calorific value to prevent hard ignition) and non-routine flaring operations, and are outlined in Table 3-8 and Table 3-9 for the dry and wet flare systems, respectively. Enrichment gas emissions are outlined in Table 3-10. Pollutant rates for non-routine flaring operations would depend on the stream being flared; therefore, the flare design sizing case and composition were considered in the pollutant estimates.

Table 3-8: Dry Flare System Base Emission Rates

Pollutant	Base Emission Rates – Routine Flaring[1] [g/s]	Base Emission Rates – Non-Routine (Process Upset) Flaring[2] [g/s]
NO_x	0.2	246
CO	1	1338
NMVOC	0.2	611
SO_x	0.00004	0.009

Notes:

1. *Base emission rates for CO and NO_x were calculated based on emission factors for industrial flares in USEPA AP42, Fifth Edition, Volume I, Chapter 13: Miscellaneous Sources (Ref. 36), and calculated for a combined pilot and purge gas flow rate of 263 kg/h and compressor seal gas flow rate of 260.9 kg/h. Sulfur emissions are based on the maximum expected content of sulfur in the fuel gas (approx. 150 ppbv). The flare is specified as smokeless; hence, PM_{10} emissions are negligible and not included above.*
2. *The process upset flaring rate is assumed to represent 20% of the design dry flare relief case of 831.3 kg/s (Ref. 37), equivalent to 598 320 kg/h. The dry flare relief case is based on a propane refrigerant compressor blocked outlet (one LNG train) plus LNG train start-up flaring from scrub column overhead at 30% flow.*

Table 3-9: Wet Flare System Base Emission Rates

Pollutant	Base Emission Rates – Routine Flaring[1] [g/s]	Base Emission Rates – Non-Routine (Process Upset) Flaring[2,3] [g/s]
NO_x	0.1	170
CO	0.6	926
NMVOC	0.04	223
SO_x	0.00004	10

Notes:

1. *Base emission rates for CO and NO_x were calculated based on emission factors for industrial flares in USEPA AP42, Fifth Edition, Volume I, Chapter 13: Miscellaneous Sources (Ref. 36), and calculated for a combined pilot and purge gas flowrate of 273 kg/h and compressor seal gas flowrate of 28.6 kg/h. Sulfur emissions are based on the maximum expected content of sulfur in the fuel gas (approx. 150 ppbv). The flare is specified as smokeless; hence, PM_{10} emissions are negligible and not included above.*
2. *The process upset flaring rate is assumed to represent 20% of the design wet flare relief case of 574.5 kg/s (Ref. 35), equivalent to 413 640 kg/h. The wet flare relief case is based on a blocked discharge at the Gorgon inlet facilities scenario.*
3. *Mercury will be present at very low concentrations during MEG flash gas flaring but due to the predicted infrequent nature of this scenario base emission rates are negligible and not included.*

Table 3-10: Enrichment Gas (Dry and Wet Flares) Base Emission Rate

Pollutant	Base Emission Rates – Routine Flaring[1] [g/s]
NOx	0.9
CO	5.1
NMVOC	1.2
SOx	0.001

Notes:

1. *Base emission rates for CO and NO_x were calculated based on emission factors for industrial flares in USEPA AP42, Fifth Edition, Volume I, Chapter 13: Miscellaneous Sources (Ref. 36) for an enrichment gas flow rate of 2285 kg/h.*

3.7.4 Impact of Deviations from Normal Operating Conditions

As previously noted, no routine flaring is intended during normal operations other than flare pilots and purge gas. Flaring during non-routine operations is intended to be limited to only that essential for the safe operation of the GTP.

During non-routine operating conditions (see Table 3-8 and Table 3-9), an increase in base emission rates is expected; however, during a typical operating year, flaring beyond pilots and purge gas is estimated to occur for 135 hours (average) for the wet and dry flares combined (Ref. 32).

The frequency and duration of non-routine flaring events are expected to reduce over time as GTP operating knowledge builds up and GTP performance and efficiency improve.

3.8 Boil-off Gas (BOG) Flare

3.8.1 Description of Equipment and Operating Regime

The BOG flare system is an independent flare system that collects and disposes of emergency operational releases from the low-pressure LNG Storage and Loading System. Excess pressure in the LNG tanks above the capacity of the BOG compressor/BOG recycle compressor is relieved directly to the BOG flare.

The first level of relief from the LNG storage tanks is to the BOG flare via a pressure control valve, and the second and ultimate level of relief is to atmosphere via the LNG tank relief valves.

During LNG carrier de-inerting, the BOG flare receives a low calorific value mixture of mostly CH_4, N_2, and CO_2 vapours from the LNG carrier vapour return line.

The BOG flare is an enclosed flare to reduce light glow. The BOG flare does not require a liquid knockout drum as all sources of flare relief from LNG storage/loading are in vapour form.

3.8.2 Selection of the Best Practice Pollution Control Measures

The BOG flare is a high burning efficiency flare. Additionally, these design measures reduce the amount of BOG flared:

- Recovery and re-use of LNG BOG generated during LNG carrier loading operations by compressing it to the front end of the GTP via a BOG recycle compressor.
- Recovery of BOG from the LNG storage tanks during normal holding mode by using redundant BOG compressors. This recovered gas is sent to fuel, where it displaces an equivalent amount of fuel that would otherwise be sourced from the feed gas. The redundant BOG compressors reduce the potential for flaring if one compressor fails.

3.8.3 Base Emission Rates and Design Emission Targets

No design emission targets are identified for the BOG flare system (see discussion in Section 3.7.3). Hence, only base emission rates are reported in this section.

The BOG flare system is designed to handle LNG flow due to a BOG compressor trip during LNG carrier loading at a maximum rate coincident with a 100% LNG rundown to the LNG storage tanks. As such, flaring rates during warm LNG carrier de-inerting operations and BOG compressor trips were considered for the upset conditions.

Table 3-11: BOG Flare System Base Emission Rates

Pollutant	Base Emission Rates – Routine Flaring[1] [g/s]	Base Emission Rates – Non-Routine (Process Upset) Flaring[2] [g/s]
NO_x	0.01	47
CO	0.1	253
NMVOC	0.003	116
SO_x	0.000005	0.0016

Notes:

1. *Base emission rates for CO and NO_x were calculated based on emission factors for industrial flares in emission factors for industrial flares in USEPA AP42, Fifth Edition, Volume I, Chapter 13: Miscellaneous Sources (Ref. 36), and calculated for a pilot gas flowrate of 36 kg/h. Sulfur emissions are based on the actual content of sulfur in the LNG (<17 mg/Nm^3, Ref. 38). The flare is specified as smokeless; hence, PM_{10} emissions are negligible and not included above.*
2. *The worst-case process upset flaring rate is assumed to represent simultaneous failure/unavailability of both BOG compressors, resulting in an instantaneous hydrocarbon rate to flare of 31.5 kg/s (Ref. 38), equivalent to 113 364 kg/h.*

3.8.4 Impact of Deviations from Normal Operating Conditions

Non-routine flaring operations for the BOG flare include:

- planned flaring associated with warm LNG carrier de-inerting
- unplanned flaring associated with BOG compressor/BOG recycle compressor failure.

The design basis assumes up to 12 'warm' LNG carriers are used annually, each with fully inerted LNG tanks. Warm LNG carrier de-inerting entails displacing the inert gas from the carrier's LNG tanks with LNG. During de-inerting, the inert gas/BOG mixture initially bypasses the BOG compressors and flows to the BOG flare. When the composition of the inert gas/BOG mixture is adequate for compression and re-use, it is routed to the BOG recycle compressor.

De-inerting takes between 18 and 24 hours, resulting in up to 24 hours of flaring with an increasing flame size as the methane concentration in the inert gas/BOG mixture increases over time (until such time as the methane concentration in the inert gas/BOG mixture renders it suitable for compression and re-use). Once de-inerting is complete, the cool-down process commences and continues until the tanks are sufficiently cool to start loading LNG at full rate. This cool-down period takes another 12 to 24 hours, but is not associated with flaring. The BOG produced during the cooling process is diverted to the BOG recycle compressor and recycled back to the AGRUs in the LNG trains.

If a BOG compressor or BOG recycle compressor fails, the LNG tank BOG or LNG carrier BOG, respectively, are sent to flare. The BOG recycle compressor provides backup to the BOG compressor, when not engaged in LNG loading operations. This results in a small increase in the reliability and availability of the BOG compressor. The LNG Reliability, Availability, and Maintainability Report (Ref. 32) indicates that unplanned BOG flaring could occur for up to a total of 115 hours a year.

3.9 Acid Gas Vents

3.9.1 Description of Equipment and Operating Regime

In compliance with Condition 26 of MS 800, the Gorgon Joint Venture is to design a CO_2 injection system that can dispose 100% of the volume of reservoir CO_2 removed during normal gas processing operations. Furthermore, Condition 26 also requires that all practicable measures are used to ensure the injection of at least 80% of reservoir CO_2 removed during gas processing operations on Barrow Island that would otherwise be vented to the atmosphere (expressed as a five-year rolling average).

In line with this, the Project has designed facilities to extract CO_2-rich acid gas—99.4 mole per cent CO_2 and 139 ppm H_2S (200 ppm maximum)—released from the GTP's AGRUs and inject it into the Dupuy Formation. These facilities have vents to safely dispose of the removed acid gas to the atmosphere during initial start-up, Jansz-only operations, maintenance, unit shutdown, or process or injection formation upset conditions.

Table 3-12 lists the acid gas venting locations in the GTP.

Table 3-12: Acid Gas Vents – Location and Intended Use

No. [1]	Vent Description and Location	Intended Use	Vent Tip Elevation AHD[1] [m]	Vent Diameter[2] [m]
Vent 1	The main low-pressure acid gas vent stack from the discharge of the Amine Regenerator Reflux Drum Vent in each of the AGRUs (3 in total)	During planned maintenance or a process trip condition (e.g. a CO_2 injection compressor trip) or when the entire CO_2 compression train or injection wells are unavailable. Worst-case scenario is venting from all three AGRU Reflux Drums due to CO_2 Injection Pipeline inspection/maintenance	72.5	0.4
Vent 2	The secondary low-pressure acid gas vent stack for emergency/process upset venting from the CO_2 compression unit—Vent 2 is co-located with Vent 1 in each of the AGRUs (3 in total)	When de-pressuring the low-pressure end of the CO_2 compression system in emergency/process upset conditions	72.5	0.1
Vent 3	Local vents for the high-pressure CO_2 compression system. Each source has a dedicated short vent line (these vents are not combined due to potential for dry ice formation) (3 sets of vents in total)	When de-pressuring the high-pressure CO_2 compression system (fourth stage compressor drum and discharge)	54	Range from 0.08 to 0.2
Vent 4	CO_2 injection pipeline pig receiver/launcher vent (1 in total)	During CO_2 pipeline pigging operations.	42.2	0.2
Vent 6	Low-pressure vent upstream of MEG Flash Gas Compressor (1 in total)	When the MEG flash gas compressor is not available or the wet gas flare and Condensate Stabilisation unit are simultaneously not available.	60.5	0.25

Notes:

1. *Vent 5 is not included as this vent is located at the CO_2 well sites, which are not in scope of this Report.*
2. *Vent height and diameter are based on acid gas dispersion modelling studies (Ref. 34).*

3.9.2 Selection of the Best Practice Pollution Control Measures

To minimise potential impacts associated with the venting of acid gas, several best practices in the design of the GTP and its associated facilities have been implemented, including:

- providing facilities to allow the total injection of the removed acid gas inventory into the Dupuy Formation during normal gas processing operations, thereby reducing emissions of VOCs (including BTEX) and H_2S to the atmosphere to ALARP levels
- using a-MDEA as the acid gas removal medium in the AGRUs, as a-MDEA uses significantly less energy for removal of acid gases than other solvents,

thus saving electrical energy (from a smaller circulation rate) and thermal energy (from a lower heat of desorption and less circulation)

- ensuring the location, diameter, and height of each acid gas vent is such that ambient concentrations of CO_2, H_2S, and NMVOCs, including BTEX, at ground level, or within impacted work locations at height, are within the applicable occupational health exposure levels (Ref. 10).

3.9.3 Base Emission Rates and Design Emission Targets

There are no design emission targets for the acid gas removal system, as the intent is to inject the acid gas stream rather than dispose of it to the atmosphere. Therefore, the design emission target is a volume of acid gas that must be injected (at least 80% of the extracted/removed acid gas must be injected, expressed as five-year rolling average), rather than concentrations of pollutants in the acid gas stream.

Thus, the base emission rates represent the maximum pollutant (NMVOCs and H_2S) emission rates in the acid gas vented during upset conditions (i.e. CO_2 injection failure, such as equipment failure or well unavailability); these rates are listed in Table 3-13. These emission rates are indicative only, as the composition of the acid gas and the rate at which it is vented will vary depending on:

- the composition of these contaminants in the incoming streams and the operation of the GTP and the AGRUs
- the specific process upset scenario that caused venting to occur.

Table 3-13: Acid Gas Venting – Anticipated Maximum Base Emission Rates

Source	Pollutant Base Emission Rates [g/s]		
	NMVOC	BTEX	H_2S
Vent 1	8.04	104.9	8.1
Vent 2	0.63	5.65	0.34
Vent 3	4.08	36.4	2.19
Vent 4	0.53	4.76	0.29
Vent 6	2.03	6.05	0.65

3.9.4 Impact of Deviations from Normal Operations

Deviations from normal operations that result in acid gas venting include process upsets, emergencies, and planned events.

Approximately half the acid gas venting events are estimated to last between 15 minutes and one hour, with most of the remaining events lasting between four hours and one week. The cumulative annual total of these reasonably foreseeable acid gas venting scenarios is approximately 1317 hours (55 days).

Acid gas venting events are expected to last longest when the GTP is operating on Jansz gas only, which could occur during normal operations if Gorgon feed gas is instantaneously lost. This scenario is expected to occur very infrequently. In this instance, the CO_2 compressors would either be shut down or put into recycle mode and the acid gas vented (due to the low flow).

During the initial start-up of LNG Train 1 on Jansz gas, acid gas venting is expected to continue for AGRU Train 1 for up to six months, until the Gorgon feed gas is introduced into the GTP.

Specific details associated with GTP commissioning and start-up will be addressed in a series of Commissioning Plans that CAPL will submit to DWER.

3.10 Mercury Management Facilities

3.10.1 Description of Equipment and Operating Regime

The key process streams and locations of mercury management facilities within the GTP are described below and outlined in Table 3-14.

3.10.1.1 Acid Gas Removal Units

Early in the gas treatment process, feed gas is sent to the AGRUs to separate the acid gas (predominately CO_2). Additional MRUs are to be installed upstream from each AGRU train to ensure mercury is removed from the acid gas stream (which is normally injected via the CO_2 Injection System) if venting to the atmosphere occurs.

One temporary MRU is to be installed on AGRU Vent 1 for use during LNG Train 1 start-up (Jansz-only gas), and remain in use until the other MRUs are installed and commissioned.

3.10.1.2 DomGas System

Feed gas diverts to the DomGas System after passing through the Inlet Systems. This gas passes through an MRU to remove any mercury to ensure that the DomGas produced meets the specifications for gas to be received by the Dampier to Bunbury Natural Gas Pipeline.

3.10.1.3 Utilities Area Fuel Gas System

The Utilities Area Fuel Gas System treats and supplies fuel gas, primarily for the Frame 9 GTGs. This system includes an MRU on the start-up/backup fuel gas from the Inlet System, and operates such that it is free of mercury contamination, resulting in improved operability and reduced HES risks. This treatment removes mercury from the fuel gas combustion exhaust emissions released to the atmosphere.

3.10.1.4 LNG Trains

The design of the GTP includes an MRU at the inlet to each LNG Train, which removes trace quantities of mercury present in the feed gas to the Liquefaction Unit to prevent corrosion of the heat exchanger tubes in the MCHE.

Table 3-14: Mercury Management Facilities within the GTP

Location	Function	Availability	Volume (m^3)	Adsorbent (m^3)	Approx. Change out Frequency (Years)
AGRUs 3 MRUs in total – 1 upstream of each AGRU train	Remove mercury from the feed gas and associated fuel gas streams	Continuous – one unit per AGRU train	432	282	4

Location	Function	Availability	Volume (m^3)	Adsorbent (m^3)	Approx. Change out Frequency (Years)
AGRU Vent 1 1 temporary MRU on AGRU Train 1 only	Remove mercury from Vent 1 during initial Train 1 start-up (Jansz-only operations) until the MRUs are installed and commissioned in the AGRUs	Temporary – only during initial start-up of the GTP	10	9	1
DomGas System 1 MRU in the DomGas System	Remove mercury from the DomGas product	Continuous	57	43	8
Fuel Gas System in the Utilities Area 1 MRU in the high-pressure fuel gas system	Remove mercury from fuel gas taken upstream of the AGRU MRUs and then fed to high-pressure and low-pressure utility systems	Continuous	13	10	4
LNG Trains 3 MRUs in total – 1 upstream of each MCHE Note – existing units within GTP design	Remove mercury prior to the MCHE and downstream of LNG equipment	Continuous – one unit per LNG Train	167	88	4

3.10.2 Selection of the Best Practice Pollution Control Measures

MRUs are current best practice in the oil and gas industry for managing mercury in a gas processing plant and have been selected for use in the GTP, as outlined in Table 3-14. No alternative technologies were considered for use.

3.10.3 Base Emission Rates and Design Emission Targets

There are no design emission targets for the AGRUs, as the AGRUs vent acid gas according to the acid gas stream composition, which is expected to vary depending on the composition of the well fluids and process conditions at time of venting (Ref. 10). Additionally, the MRUs on the AGRU Trains reduce mercury to very low levels (i.e. less than 10 ng/Nm^3 or less than 0.01 µg/Nm^3).

No design emission targets apply to the DomGas System or LNG Trains, as no emissions occur from these GTP facilities.

No design emission targets have been provided for the Frame 9 GTGs, as the MRU in the fuel gas system reduces mercury to very low levels.

The base emission rates represent the mercury concentrations in each stream following MRU treatment (see Table 3-15). For the AGRUs, this base rate is the maximum mercury emission rate during upset conditions (i.e. during acid gas venting); for the Fuel Gas System, this base rate is the maximum emission rate for combustion emissions (i.e. Frame 9 GTGs).

No base emission rates apply to the DomGas System or LNG Trains, as no emissions occur from these GTP facilities.

Table 3-15: Mercury Base Emission Rates and Design Emission Targets

Source	Base Emission Rates at Actual Exhaust Gas Conditions [g/s]	Base Emission Concentrations at Standard Reference Conditions [mg/Sm^3]
AGRUs[1]	1.31E-06	5.81E-05[2]
AGRU Vent 1[3]	2.21E-09	9.83E-06[2]
DomGas System	--	--
Fuel Gas System in the Utilities Area (Frame 9 GTGs)[4]	2.78E-08	1.15E-07[5]
LNG Trains	--	--

Notes:

1. *Base case when CO_2 Injection System is down. The base case assumes average feed gas conditions to the GTP and maximum normal well stream fluid arrival temperatures at the inlet to the GTP (i.e. slug catchers).*
2. *AGRU emission concentrations reported in mg/Sm^3 dry gas. Sm^3 refers to standard conditions, which are defined as 101.235 kPa and 15 °C.*
3. *Initial period of operation with Jansz-only feed gas. The temporary MRU is assumed to be provided on acid gas vent 1.*
4. *Mercury rate and concentration for Frame 9 GTGs is averaged over a 24-hour period. Peak values will be higher.*
5. *Frame 9 GTG emission concentrations reported in mg/Sm^3, and are calculated at standard reference conditions (e.g. dry conditions, 1 atmosphere, 0 °C, 15% oxygen reference level).*

3.10.4 Impact of Deviations from Normal Operations

As outlined in Table 3-14, the MRUs to be installed within the GTP are expected to be available at all times, and the MRU adsorbent beds are expected to be replaced at the frequency indicated (in accordance with manufacturers' specifications).

Routine performance monitoring of MRUs are undertaken to ensure manufacturers' specifications are achieved, including:

- regular monitoring of the mercury concentration upstream, within, and at the exit of the MRU to assure that the unit is performing to specification and to predict the end of the adsorbent's useful life. The MRU adsorbent is replaced when it is close to the end of its operational life to ensure that mercury breakthrough does not occur
- monitoring the pressure drop across the adsorbent bed to identify liquid carryover and channelling within the MRU (liquid carryover causes an increase in pressure drop)
- monitoring MRU effluent concentrations.

Dehydration units, or superheaters, upstream of the MRUs also reduce the likelihood of liquids entering the MRU adsorbent bed.

In the event that a specific MRU's performance reduced and the manufacturer's specifications were not achieved, mercury concentrations downstream of the MRU could potentially increase. However, this is considered highly unlikely given industry experience and the planned routine performance monitoring outlined above.

4 Acronyms and Abbreviations

Table 4-1 defines the acronyms and abbreviations used in this document.

Table 4-1: Acronyms and Abbreviations

Acronym / Abbreviation	Definition
AFAT	Average Feed Composition, Average Ambient Temperature
AGRU	Acid Gas Removal Unit
AHD	Australian Height Datum
Air Toxics	As described in the National Environment Protection (Air Toxics) Measure (Ref. 39) includes benzene, formaldehyde, benzo(a)pyrene (as a marker for Polycyclic Aromatic Hydrocarbons), toluene, and xylenes (as total of ortho, meta and para isomers).
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.
Ambient Air	As described in the National Environment Protection (Ambient Air Quality) Measure (Ref. 29) is considered the external air environment, and does not include the air environment inside buildings or structures.
a-MDEA	Activated Methyl Di-Ethanol Amine
APCI	Air Products and Chemicals Incorporated
Atmospheric Pollutants	As described in the National Environment Protection (Ambient Air Quality) Measure (Ref. 29) includes carbon monoxide (CO), nitrogen dioxide (NO_2), photochemical oxidants (such as ozone – O_3), sulfur dioxide (SO_2), lead, and particles (such as PM_{10}). In principle, this includes gaseous, aerosol, or particulate pollutants which are present in the air in low concentrations with characteristics such as toxicity or persistence so as to be a hazard to human, plant or animal life.
Base Emission Rate	The rate at which atmospheric pollutants are emitted from a source with pollution control in place.
BAT	Best Available Technology
Best Practice / Best Practicable Measures	Best Practice, as described in Guidance Document No. 55 (Ref. 13), involves the prevention of environmental impact, or if this is not practicable, minimising the environmental impact and also minimising the risk of environmental impact, through the incorporation of Best Practicable Measures. Best Practicable Measures therefore incorporate the technology and environmental management procedures which are practicable, having regard to, among other things, local conditions and circumstances, including costs, and to the current state of technical knowledge, including the availability of reliable, proven technology.
BoD	Basis of Design
BOG	Boil-off Gas; vapours produced as a result of heat input and pressure variations that occur within various LNG storage and offloading operations.
BPM	Best Practicable Measures
BTEX	Benzene, toluene, ethylbenzene, and xylene compounds.
BTU/scf	British thermal units per standard cubic foot
CAPL	Chevron Australia Pty Ltd
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.

Acronym / Abbreviation	Definition
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
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.
DEC	Former Western Australian Department of Environment and Conservation (now DWER)
DWER	Western Australian Department of Water and Environmental Regulation (formerly DEC)
Design Emission Target	The rate at which an atmospheric pollutant is emitted from a source, which complies with or is lower than a regulator-prescribed emission threshold.
DLE	Dry Low Emission
DLN	Dry Low NO_x
DomGas	Domestic Gas
EC	European Community
EPA	Western Australian Environmental Protection Authority
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: 2005/2184	Commonwealth Ministerial Approval (for the Jansz Feed Gas Pipeline) 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.
FOB	Freight On Board
g/s	Grams per second
Gas Treatment Plant	Includes the following components: Liquefied Natural Gas (LNG) Trains, LNG Tanks, Gas Processing Drivers, Power Generators, Flares, Condensate Tanks and Utilities Area.
GE	General Electric
GHG	Greenhouse Gas
Gorgon Gas Development	The Gorgon Gas Development as approved under MS 800 and EPBC Reference: 2003/1294 and 2008/4178 as amended or replaced from time to time.
Greenhouse Gases	Components of the atmosphere that contribute to the greenhouse effect. These include carbon dioxide (CO_2), methane (CH_4), sulfur hexafluoride (SF_6), and nitrous oxide (N_2O).
GT	Gas Turbine
GTG	Gas Turbine Generator
GTP	Gas Treatment Plant
H_2S	Hydrogen sulfide
ha	Hectare

Acronym / Abbreviation	Definition
HES	Health, Environment, and Safety
Hg	Mercury
IPPC	Integrated Pollution Prevention and Control
Jansz Feed Gas Pipeline	The Jansz Feed Gas Pipeline as approved in MS 769 and EPBC Reference: 2005/2184 as amended or replaced from time to time.
JT	Joule-Thomson
kg/h	Kilograms per hour
kg/s	Kilograms per second
km	Kilometre
LN	Low NO_x
LNG	Liquefied Natural Gas
m	Metre
MCHE	Main Cryogenic Heat Exchanger
MEG	Monoethylene glycol
mg	Milligram
mg/m^3	Milligrams per cubic metre
MMBtu/h	Million British Thermal Units per hour
MR	Mixed Refrigerant
MR/PR	Mixed Refrigerant/Propane
MRU	Mercury Removal Unit
MS	Western Australian Ministerial Statement
MS 748	Western Australian Ministerial Statement No. 748 (for the Gorgon Gas Development) as amended from time to time [superseded by MS 800].
MS 769	Western Australian Ministerial Statement No. 769 (for the Jansz Feed Gas Pipeline) as amended from time to time.
MS 800	Western Australian Ministerial Statement No. 800 (for the Gorgon Gas Development) as amended from time to time.
MS 865	Western Australian Ministerial Statement No. 865 (for the Gorgon Gas Development).
MTPA	Million Tonnes Per Annum
MW	Megawatt
N_2	Nitrogen
N_2O	Nitrous oxide
NEPC	National Environment Protection Council
NEPM	National Environment Protection Measure (NEPM) for Ambient Air Quality
ng	Nanogram
Nm^3	Normal cubic metres. The metric expression of gas volume at normal conditions, defined as 0 °C and 101.323 kPa
NMVOC	Non-Methane Volatile Organic Compounds
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide

Acronym / Abbreviation	Definition
NO_x	Nitrogen Oxides (NO and NO_2)
NSW	New South Wales
O_2	Oxygen
O_3	Ozone
OE	Operational Excellence
Operations (Gorgon Gas Development)	In relation to MS 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 contract, or equivalent contract entered into in respect of that LNG train of the GTP; until the date on which the Gorgon Joint Venturers commence decommissioning of that LNG train.
PAH	Polycyclic Aromatic Hydrocarbons
PCV	Pressure Control Valve
Performance Standard	Are matters which are developed for assessing performance, not compliance, and are quantitative targets or where that is demonstrated to be not practicable, qualitative targets, against which progress towards achievement of the objectives of conditions can be measured.
Pig	Pipeline inspection gauge; a tool that is sent down a pipeline and propelled by the pressure of the product in the pipeline.
PM	Particulate Matter
PM_{10}	Suspended particulate matter consisting of particles having an Equivalent Aerodynamic Diameter (EAD) of less than 10 μm, which is passed by a size classifier having performance characteristics as defined in US Code of Federal Regulations: 40 CFR 50, Part 53, Subpart D (Ref. 40).
ppbv	Parts per billion by volume
ppm	Parts per million
ppmv	Parts per million by volume
Practicable	Practicable means reasonably practicable having regard to, among other things, local conditions and circumstances (including costs) and to the current state of technical knowledge.
Risk	The chance of something happening that will have an impact upon objectives; measured in terms of consequence and likelihood.
RiskMan2	Chevron HES Risk Management Process
Routine flaring	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 GTP (e.g. small flows from equipment purges, which are not practicable to collect) during normal production operations.
SCONOX	A SCONOX system is a catalytic reduction technology that has been developed for natural gas-fired turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidised to CO_2 and NO_2. The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst.
SCR	Selective Catalytic Reduction
SF_6	Sulfur hexafluoride
SIS	Safety Instrumented System
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.

Acronym / Abbreviation	Definition
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur dioxide
SO_x	Sulfur oxide
TAPL	Texaco Australia Pty. Ltd.
TJ/d	Terajoules of Sales Gas per day
USEPA	Unites States Environmental Protection Agency
VOC	Volatile Organic Compounds; organic chemical compounds that have high enough vapour pressures under ambient atmospheric conditions to vaporise and enter the atmosphere.
WA	Western Australia
WHRU	Waste Heat Recovery Unit
WLE	Wet Low Emissions

5 References

The following documentation is either directly referenced in this document or is a recommended source of background information.

Table 5-1: References

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Appendix A Chevron Integrated Risk Prioritization Matrix

Chevron

Chevron Integrated Risk Prioritization Matrix

For the Assessment of HES & Asset Risks from Event or Activity

Legend

Legend applies to identified HES risks (see guidance documents for additional explanations)

1, 2 , 3, 4 - Short-term, interim risk reduction required. Long term risk reduction plan must be developed and implemented.

5 - Additional long term risk reduction required. If no further action can be reasonably taken, SBU management approval must be sought to continue the activity.

6 - Risk is tolerable if reasonable safeguards / management systems are confirmed to be in place and consistent with relevant requirements of the Risk Mitigation Closure Guidelines.

7, 8, 9, 10 - Manage risk. No further risk reduction required. Risk reduction at management / team discretion.

Likelihood Descriptions & Index (with confirmed safeguards)

Likelihood Descriptions	Likelihood Indices		Decreasing Likelihood						
Consequence can reasonably be expected to occur in life of facility	1	Likely		6	5	4	3	2	1
Conditions may allow the consequence to occur at the facility during its lifetime, or the event has occurred within the Business Unit	2	Occasional		7	6	5	4	3	2
Exceptional conditions may allow consequences to occur within the facility lifetime, or has occurred within the OPCO	3	Seldom		8	7	6	5	4	3
Reasonable to expect that the consequence will not occur at this facility. Has occurred several times in industry, but not in OPCO	4	Unlikely		9	8	7	6	5	4
Has occurred once or twice within industry	5	Remote		10	9	8	7	6	5
Rare or unheard of	6	Rare		10	10	9	8	7	6

Consequence Descriptions & Index (without safeguards)

Decreasing Consequence/Impact

Consequence Indices		6	5	4	3	2	1
		Incidental	**Minor**	**Moderate**	**Major**	**Severe**	**Catastrophic**
Consequence Descriptions	**Safety**	**Workforce:** Minor injury such as a first-aid. *AND* **Public**: No impact	**Workforce:** One or more injuries, not severe. *OR* **Public**: One or more minor injuries such as a first-aid.	**Workforce**: One or more severe injuries including permanently disabling injuries. *OR* **Public**: One or more injuries, not severe.	**Workforce:** (1-4) Fatalities *OR* **Public**: One or more severe injuries including permanently disabling injuries.	**Workforce**: Multiple fatalities (5-50) *OR* **Public**: multiple fatalities (1-10)	**Workforce**: Multiple fatalities (>50) *OR* **Public**: multiple fatalities (>10)
Consequence Descriptions	**Health** (Adverse effects resulting from chronic chemical or physical exposures or exposure to biological agents)	**Workforce:** Minor illness or effect with limited or no impacts on ability to function and treatment is very limited or not necessary *AND* **Public:** No impact	**Workforce**: Mild to moderate illness or effect with some treatment and/or functional impairment but is medically managable *OR* **Public**: Illness or adverse effect with limited or no impacts on ability to function and medical treatment is limited or not necessary.	**Workforce**: Serious illness or severe adverse health effect requiring a high level of medical treatment or management *OR* **Public**: Illness or adverse effects with mild to moderate functional impairment requring medical treatment.	**Workforce** (1-4): Serious illness or chronic exposure resulting in fatality or significant life shortening effects *OR* **Public**: Serious illness or severe adverse health effect requiring a high level of medical treatment or management.	**Workforce** (5-50): Serious illness or chronic exposure resulting in fatality or significant life shortening effects *OR* **Public** (1-10): Serious illness or chronic exposure resulting in fatality or significant life shortening effects.	**Workforce** (>50): Serious illness or chronic exposure resulting in fatality or significant life shortening effects *OR* **Public** *(>10)*: Serious illness or chronic exposure resulting in fatality or significant life shortening effects.
Consequence Descriptions	**Environment**	Impacts such as localized or short term effects on habitat, species or environmental media.	Impacts such as localized, long term degradation of sensitive habitat or widespread, short-term impacts to habitat, species or environmental media	Impacts such as localized but irreversible habitat loss or widespread, long-term effects on habitat, species or environmental media	Impacts such as significant, widespread and persistant changes in habitat, species or environmental media (e.g. widespread habitat degradation) .	Impacts such as persistant reduction in ecosystem function on a landscape scale or significant disruption of a sensitive species.	Loss of a significant portion of a valued species or loss of effective ecosystem function on a landscape scale.

The above legend applies only to HES risks, where risk levels 1-6 are actionable and mandatory.
For risks that may result in facility damage, business interruption, loss of product, the "Assets" category below should be used.
Asset risk reduction is at the discretion of management. Under no circumstances may a direct or indirect translation of Asset loss to HES consequences, or between any discrete categories of HES consequences be inferred.

Consequence Descriptions & Index (without safeguards)

Consequence Indices		6	5	4	3	2	1
		Incidental	**Minor**	**Moderate**	**Major**	**Severe**	**Catastrophic**
Consequence Descriptions	**Assets** (Facility Damage, Business Interruption, Loss of Product)	Minimal damage. Negligible down time or asset loss. Costs < $100,000.	Some asset loss, damage and/or downtime. Costs $100,000 to $1 Million.	Serious asset loss, damage to facility and/or downtime. Costs of $1-10Million.	Major asset loss, damage to facility and/or downtime. Cost >$10 Million but <$100 Million.	Severe asset loss or damage to facility. Significant downtime, with appreciable economic impact. Cost >$100MM but <$1billion.	Total destruction or damage. Potential for permanent loss of production. Costs >$1billion

This matrix is endorsed for use across the Company.
It is not a substitute for, and does not override any relevant legal obligations.
Under no circumstances should any part of this matrix be changed or modified, adapted or customized.
This matrix identifies health, safety, environmental and asset risks and is to be used only by qualified and competent personnel.
Where applicable it is to be used within the Riskman2 structure and governance of an OE Risk Management Process. If applied outside of these Processes, it is also mandatory to manage identified intolerable risks and comply with the Risk Mitigation Closure Guidelines.

Appendix B Compliance Reporting Table

Section No.	Actions	Timing
3.4.3	Dry Low NO_x (DLN) has been adopted as the best practice control option for the GTGs, as it is an engineering solution that has been widely applied in the oil and gas industry, requires minimal additional complexity and maintenance, and does not significantly increase associated HES risks.	Design
3.5.3	The pollution control design option selected for use on the Frame 7 GTs is DLN Burners.	Design
3.5.3	The Frame 7 GTs in the LNG processing trains are fitted with WHRUs to recover additional energy from the hot exhaust gases released to atmosphere.	Design
3.6.1.1	The WHRUs provide the routine process heat requirements during normal operation of the GTP.	Design
3.6.2	As a result of the comparative evaluation, low NO_x burners were adopted as best practice pollution control for the Heating Medium Heaters.	Design
3.7.2	A number of elements are incorporated into the design so as to achieve no routine flaring during normal GTP operations, including: • Flash vapours from the MEG unit are recovered, compressed, and sent to the CO_2 injection system for compression and injection rather than disposed of via venting or flaring. • The process gas used for dehydration regeneration is recovered and sent to the fuel gas system rather than flared. • Flash vapours from the High Pressure Amine Flash Drum in the AGRU are recovered, compressed in the Recycle Gas Unit, and returned to the process feed to the AGRU. In other facilities, this CO_2-rich gas is often sent to the fuel gas system or flared. • Any vapour generated in the refrigerant storage vessels is sent to the LNG storage tanks rather than flared. • LNG within the LNG storage tanks boils off continuously due to heat ingress from atmosphere; this BOG is collected, compressed, and sent to the fuel gas system, rather than routed to flare. • All vapour produced during LNG ship-loading operations is collected and compressed back into the feed gas to be turned into product, rather than routed to flare.	Design
3.7.2	To minimise flaring associated with process upsets, a number of mitigating measures are incorporated into the design of the GTP: • Where appropriate, compressors shall be provided with the ability to restart from a pressurised condition following a non-emergency trip avoiding the need to depressurise to flare for restart. • During normal operation, the methane-rich gas from the Stabilisation Unit is compressed and returned to the feed gas. If the stabiliser overhead compressors are unavailable, the gas is routed to the Recycle Gas system where any available compression capacity is used to reprocess as much gas as possible and hence mitigate/minimise flaring. • A line from the MCHE shell side in the liquefaction unit will be installed to route gas to the End Flash Gas Compressor suction. This provides the capability to route any tube leaks in the MCHE to fuel gas instead of flare. • The BOG recycle compressor acts as a spare for the main BOG compressor, so that if the primary machine fails, the BOG vapour does not have to be flared during LNG holding mode.	Design

Section No.	Actions	Timing
3.7.2	In the case of GTP emergencies, the safety instrumented systems (SIS) are designed to shut down the production facilities in a controlled manner within the pressure limitations of each system, and hence prevent flaring. If required (e.g. fire scenario), emergency blowdown provisions exist within the SIS to maintain the integrity of the facilities.	Design
3.7.2	Effective balancing of the fuel gas system is critical to minimise flaring. During lower fuel gas demand operating scenarios, the feed gas flow taken from the GTP's inlet facilities is reduced in order to minimise flaring of fuel gas obtained from the other process sources.	Design
3.8.2	The BOG flare is a high burning efficiency flare. Additionally, these design measures reduce the amount of BOG flared: • Recovery and re-use of LNG BOG generated during LNG carrier loading operations by compressing it to the front end of the GTP via a BOG recycle compressor. • Recovery of BOG from the LNG storage tanks during normal holding mode by using the BOG compressor. This recovered gas is sent to fuel, where it displaces an equivalent amount of fuel that would otherwise be sourced from the feed gas. This is expected to reduce the potential for flaring if one compressor fails.	Design
3.9.2	Several best practices in the design of the GTP and its associated facilities have been implemented, including: • Providing facilities to allow the total injection of the removed acid gas inventory into the Dupuy Formation during normal gas processing operations, thereby reducing emissions of VOCs (including BTEX) and H_2S to the atmosphere to ALARP levels. • Using a-MDEA as the acid gas removal medium in the AGRUs, as a-MDEA uses significantly less energy for removing acid gases than competing solvents. This means that electrical energy (from a smaller circulation rate) and thermal energy (from a lower heat of desorption and less circulation) is saved. • Ensuring the location, diameter and height of each acid gas vent is such that ambient concentrations of CO_2, H_2S and NMVOCs, including BTEX, at ground level, or within impacted work locations at height, are within the applicable occupational health exposure levels.	Design
3.9.4	Specific details associated with GTP commissioning and start-up will be addressed in a series of Commissioning Plans that CAPL will submit to DWER.	Prior to Commissioning and Start-up of relevant GTP Systems
3.10.1	The key process streams and locations of mercury management facilities within the GTP are outlined in Table 3-14.	Design