07:

Emissions from the Development

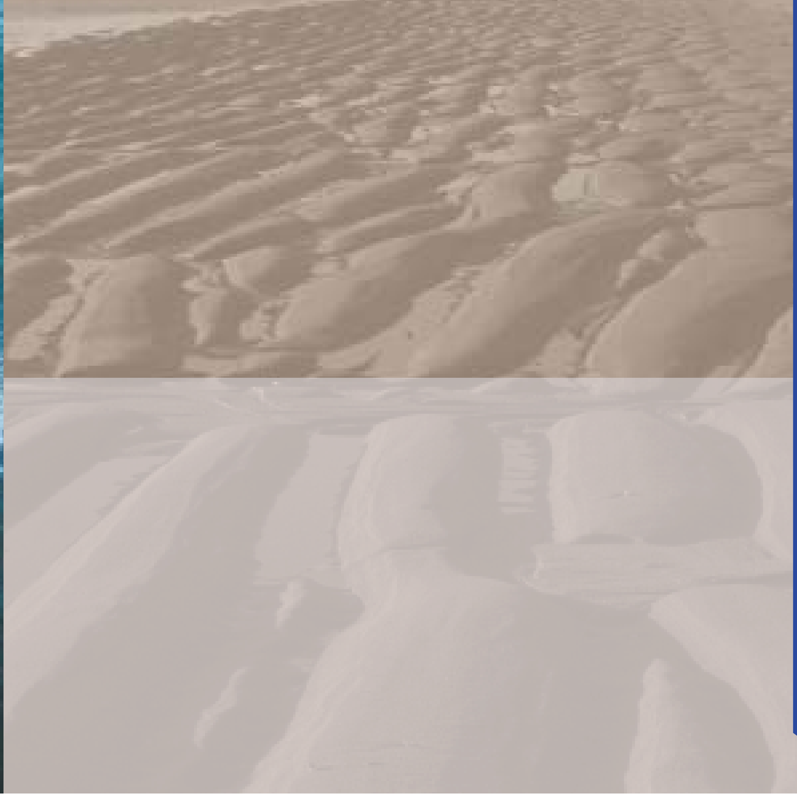
A range of emissions will be associated with the proposed Gorgon Development. In the context of this chapter, the term ‘emission’ refers to atmospheric emissions, discharges to the marine environment and solid wastes.

Numerical modelling has been applied to predict atmospheric, noise and light emissions and the trajectory of a number of potential hydrocarbon spill releases, should a release occur. Other aspects, such as solid and liquid wastes, are also described. Where appropriate, the predicted or expected emissions are compared to existing legislative standards and guidelines.

Some emission levels, such as solid wastes, dust and light will be greatest during the construction period. Other emissions, such as atmospheric emissions and waste water, will be greatest during operation of the gas processing facility.

The modelling results indicate that the proposed Gorgon Development will meet or measure below established emission regulations and guidelines and standards for air quality (EPA 1999a) and National Environmental Protection Measure (NEPM) requirements. Similarly, noise standards for workers and residences will be achieved or bettered by the Development.

The light emissions expected from the proposed Development were also modelled with design and management measures proposed to reduce the light spill from the gas processing facility and marine facilities.



The risk estimates (primary, secondary and joint risk) of hydrocarbon spills from potential manifold and pipeline incidents, tanker groundings, and refuelling accidents are described for a range of worst-case but credible scenarios. The reservoir gas has a low percentage of liquid hydrocarbons and this will naturally reduce the magnitude of many spill scenarios and potential impacts. This combined with robust design and engineering standards, construction and operational management and maintenance practices, will keep the risk of a potential spill to the lowest reasonably practicable. The fate of hydrocarbons, in the unlikely event of a release, was also modelled to determine the area potentially affected during different seasons. The results of the modelling are provided in this chapter, and an assessment of the potential environmental impacts provided in Chapters 10 and 11, while full details of the studies are provided in the Technical Appendices.

The Gorgon Joint Venturers are proposing to employ currently applied, best practice technology to reduce emissions to the lowest level practicable. New technology will continue to be considered during further planning and design of the Gorgon Development where it can be demonstrated that the technology could benefit the environment with due consideration of reliability, efficiency, personnel safety, and overall capital and operational costs.

7.1 Introduction

Emissions will occur during the construction, commissioning, operation, maintenance and decommissioning phases of the proposed Gorgon Development. In the context of this chapter the term ‘emission’ refers to atmospheric emissions, discharges to the marine environment and solid wastes.

The major emission sources associated with the Gorgon Development are identified and discussed in this chapter. Emissions will be both routine and non-routine. The emissions from the existing Barrow Island facilities are also included in order to address the potential cumulative levels. Conservative emission data and equipment specifications were used at this stage of Development planning to establish benchmark emission levels that can be used to identify potential issues. Opportunities to further reduce emission levels exist and will be pursued during the detailed design phases of the Development.

This chapter provides a summary of the results of a number of technical studies prepared by consulting companies specialising in predictive atmospheric emission, noise level, light, spill and trajectory modelling (Technical Appendices B1–B5).

Predicted emission levels are compared to existing legislative standards and guidelines where they exist. The potential impact, consequences, mitigation and management of these emissions are discussed in Chapters 10 and 11 of this Draft EIS/ERMP.

From the results of the ESE Review (ChevronTexaco Australia 2003a), carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions were identified as being topics of particular interest. These emissions and proposed mitigation strategies are addressed in Chapter 13.

7.2 Atmospheric Emissions

7.2.1 Predicted Emissions from Construction Activities

Atmospheric emissions from the proposed Development will be associated with marine vessel engines required during construction (e.g. drilling rigs, pipe-lay barges, tugs, dredges, hopper barges, supply boats and barges). There will be an increase in emissions from additional airline flights to and from Barrow Island and from vehicles and equipment required to support the large construction crew on the island. Incidental to this will be the increased traffic and construction related to the mainland supply base. These sources have been considered and will contribute to overall emission levels. However, the volume and duration of the emissions from the 15–20 marine vessels used during construction, the additional air traffic to Barrow Island and increased number of construction vehicles and equipment will not be significant in comparison to emission levels during the operation of the Gorgon Development. Further, they will not be concentrated in a single location for an extended period of time.

Dust emissions will be generated during construction and site development for the gas processing facility, onshore well drilling, construction of pipeline infrastructure and associated facilities such as roads, and through a number of activities including:

- clearing of vegetation and removal of topsoil
- earthmoving activities such as levelling of the site, excavation and the transport of fill within the Development site
- movement of heavy machinery and vehicles on unpaved surfaces
- blasting for site levelling and trenching.

Dust arising from some or all of these activities has the potential to adversely impact on human health, visual amenity, water catchment, vegetation and fauna in the immediate area. Use of water to reduce and control dust will limit the extent of this emission. Some of the major road and access surfaces will be sealed to further reduce dust emissions.

7.2.2 Predicted Emissions from Normal Operation of Gas Processing Facility

During operation of the gas processing facility on Barrow Island, there will be atmospheric emissions of greenhouse gases, other combustion products and waste gases.

Atmospheric emissions can have potential global, regional and local impacts. For example, global effects are caused by the accumulation of greenhouse gases and the depletion of ozone in the stratosphere. Regional impacts are those that could be encountered several kilometres to several hundred kilometres from the source, while local impacts would be those considered adjacent or within a few kilometres of the proposed Development.

The Gorgon Joint Venturers are proposing to employ the currently applied best practice technologies to reduce emissions to the lowest levels practicable. For example, specifying high quality valves, seals, fittings, and piping will significantly limit potential fugitive emissions from these point sources. Consequently the emission sources will be primarily restricted to the combustion and exhaust from natural gas turbines used in the LNG process and as power generators. The principal emission from the Development, after CO_2, will be oxides of nitrogen (NO_x).

It is recognised that while Dry, Low NO_x (DLN) burners are practical in reducing NO_x emissions in gas turbines which are running at full power, they may not be practical or efficient in the power generation turbines which will be running at low load and may actually increase NO_x emissions. The emission modelling described in this chapter has used DLN burner technology for all the process and power gas turbines as the base reference case. The final power and process design will determine the optimum application of DLN burners on the gas turbines to most effectively reduce NO_x and greenhouse gas emissions.

Typically almost all benzene, toluene, ethylbenzene, and xylene (BTEX) emissions from the gas processing facility occur during the CO_2 removal process.
The Joint Venturers have implemented several strategies to virtually eliminate hydrocarbon (including BTEX) emissions from the Development under normal operations. The Joint Venturers will approach this issue in the following ways:

- disposing of reservoir CO_2 by injecting it into the Dupuy formation along with associated traces of hydrocarbon, BTEX and hydrogen sulphide (H_2S). Note: some venting of this stream will occur during equipment downtime as discussed in Chapter 13.
- using of accelerated-Methyl Diethanolamine (a-MDEA) solvent to minimise the removal of hydrocarbon and BTEX from the gas stream.

Another potential source of BTEX from the facility will be from the regeneration of monoethylene glycol (MEG), which will be redirected to the LNG process stream.

Combustion Products

The principal emissions from the LNG process arise from combustion of natural gas. The most significant products of natural gas combustion include: CO_2 and NO_x together with some carbon monoxide (CO) and uncombusted hydrocarbons or volatile organic compounds (VOCs). There may also be traces of particulate matter and sulphur dioxide (SO_2) but such emissions will be negligible because of the efficient combustion equipment and the very low sulphur content of the natural gas.

Atmospheric emissions from the gas processing facility will vary depending on the operating and tanker loading conditions. These include normal plant operations, ship loading and non-routine operations such as commissioning, plant start-up and shut-down. Emission modelling for the Development assumed that normal operating conditions will occur in excess of 90% of the time. During normal operating conditions, LNG production will be accompanied by the loading of product onto LNG tankers for up to 30% of the time. Based on a typical 6-year maintenance cycle for gas turbines, the planned maintenance outages could result in an average of approximately 13 days/train/year. LNG production would be reduced during these periods.

Non-routine operations, including process upset situations, requiring some plant or equipment depressurising to flare or shut-down may occur approximately 10 times per year. A shut-down for planned and emergency situations will normally result in less than 1-hour of peak flaring as the high pressure gas streams are stopped and the process equipment depressured. Flaring during a normal start-up will be approximately 6 hours duration. Flaring during the initial plant commissioning will be more extensive, but this will be a once only occurrence

While the selection of the gas turbine drivers for the LNG facility has been determined, engineering options for the configuration of the gas turbines for electrical power generation are currently being studied with selection of the final configuration due after the release of this Draft EIS/ERMP for public review. At the time the atmospheric emissions modelling was undertaken, it was anticipated that the sources of atmospheric emissions would be dominated by:

- three 116 MW industrial gas turbines with DLN burners for electrical power generation
- four 80 MW industrial gas turbines with DLN burners for mechanical drive in the LNG processing facility
- two package boilers raising the equivalent of 150 MW of steam.

Table 7-1:
Predicted Combustion Emissions During Normal Operations

Source/Equipment	**Emission Estimates**			
	Total NO_x		**Total Particulate**	
	Kilograms/hour (kg/hr)	**Tonnes per annum (tpa)**	**(kg/hr)**	**(tpa)**
Basis of Atmospheric Modelling				
Electrical Generation: 3 x 116 MW gas turbines	190	1700	12	105
LNG Process Drivers: 4 x 80 MW gas turbines	240	2100	10	80
2 x Boilers (150 MW)	70	630	7	56
Total (Basis of Modelling)	500	4430	29	241
Current Design Reference Case				
Electrical Generation: 5 x 80 MW gas turbines operated at 67% load	240	2100	10	80
LNG Process Drivers: 4 x 80 MW gas turbines	240	2100	10	80
Total (Current Design Reference Case)	480	4200	20	160

The atmospheric emissions modelling documented in Appendix B1 is based on this configuration.

Engineering work completed recently has eliminated the option of the 116 MW industrial gas turbines. Consequently, the design reference case is now based on five, 80 MW gas turbines operated at 67% load for electrical generation and has eliminated package boilers. (Hot oil has replaced steam as the base case for the heating medium. Refer to Chapter 6.) The level of atmospheric emissions from this configuration is anticipated to be slightly less than that assumed in the atmospheric modelling. Table 7-1 lists the emissions estimated by the atmospheric modelling and the level of emissions anticipated from the revised design reference case design. Consequently, the modelled atmospheric emissions should be considered as worse than expected.

Emissions of sulphur oxides are expected to be extremely low, as 75% of fuel gas would be sourced from ‘end-flash’ gas (Chapter 6) which has negligible sulphur content. Sulphur levels in the raw feed gas are also predicted to be very low.

Carbon monoxide emissions will also be negligible and have not been examined in detail for this phase of the Development because modern combustion equipment has an extremely high conversion efficiency. Hydrogen sulphide in the raw feed gas will be removed along with CO_2 in the ‘acid gas’ removal process and disposed of by injection into the Dupuy formation 2000 m below Barrow Island. There will be no significant continuous hydrocarbon vents or emissions.

Non-Combustion Products

Volatilisation from storage and loading of hydrocarbon products, compressor seals and component leaks (e.g. valves, flanges and pumps) are all sources of non-combustion products that can be classified as potential non-combustion emissions.

Historically, compressor seals have been a significant source of fugitive emissions in LNG facilities. The proposed Gorgon Development will use dry-gas compressor seals or similar technology that virtually eliminate fugitive emissions from this source. The adoption of appropriate plant design and equipment has significantly reduced the potential level of these emissions from the gas processing facility.

Vapour recovery will be used on LNG storage and loading/handling facilities and other specific locations where practicable (Chapter 6). LNG boil-off gas will be captured and returned to the gas processing facility where it will be used as fuel gas. There will be two large condensate storage tanks which will have internal floating roofs to minimise fugitive emissions. During the subsequent phases of engineering design and equipment selection there will be further opportunities to consider eliminating and/or reducing hydrocarbon emissions.

There will be a vapour recovery system installed on the LNG tanker loading system. As with the storage tanks, LNG boil-off gas and displaced vapours will be captured and returned to the gas processing facility where it will be used as fuel gas. It is proposed to load condensate through the existing Chevron Australia tanker loading facility at Barrow Island. This loading facility does not have a vapour recovery system because the production rate of condensate is low. There will be minor VOC emissions of approximately 33 tonnes per year based on the use of floating roof tanks.

Volatile Organic Compound emissions will also occur when loading the trading tankers, but it is extremely complex to recover these emissions because:

- Tankers will be selected from the spot market, so it is not possible to add any equipment to the tanker fleet.
- Very few tankers (if any) are likely to have appropriate VOC recovery technology.
- VOC treatment would require either a barge mounted incineration facility or a dedicated subsea pipeline back to Barrow Island.
- A barge mounted facility adds a number of significant safety aspects and only burns VOCs instead of recovering them.
- If a subsea pipeline were used to recover the VOC, then some of the components would remain in the gaseous form while others would be in the liquid state. This two-phase mixture creates a number of technical difficulties.
- Recovery (if at all technically feasible and safe) would come at a very significant cost.

7.2.3 Predicted Emissions from Non-Routine Operation of Gas Processing Facility

Non-routine operations which may result in emissions include certain planned and unplanned events, including: commissioning, start-up and shut-down procedures; plant or process upset conditions; and emergency situations where there is a realistic threat/danger to personnel or facility. In these situations, high pressure gases will be collected and directed to the flare system in line with industry practice.

Where practicable and without compromising the safety of the facility and personnel, all significant continuous flaring or venting sources will be eliminated. The design will incorporate a high efficiency flare to minimise the portion of uncombusted hydrocarbon and particulates to as low as reasonably practicable (ALARP). The height of the flare will depend on the final facility layout and flare structure location, but is expected to be approximately 150 m. As mentioned in Chapter 6, one option currently being considered is the use of a ground flare similar to that installed at the Darwin LNG plant.

During Development commissioning, the emission levels will be higher as the compression and power equipment is tested and tuned to meet specifications. It is expected that during this period, the emission levels will be similar to those during start-up and shut-down procedures (Table 7-2).

Commissioning is much longer in duration than a typical shut-down, but is an essential activity which is only conducted once.

It is expected that the gas processing facility will be partially shut-down on approximately ten occasions per year. Following each of these shut-downs, the subsequent restart is expected to take approximately 6 hours, during which time approximately 30% of the normal flow rate of a single LNG train may be directed to the flare as the LNG is brought to product specification. Maximum predicted emissions of particulate matter and oxides of nitrogen are shown in Table 7-2. Emissions are unlikely to remain at the maximum for the full duration of the start-up process, but as subsequent detailed design phases develop this 30% of the normal flow rate figure will be challenged with the intention of reducing it to the lowest reasonably possible.

During a cold start, power will be supplied by a diesel generator (approximately 5 MW), which is expected to discharge approximately 75 kg/hr of oxides of nitrogen. The only appreciable emissions of SO_2 will occur from operation of the diesel generator where a maximum emission of 3.6 kg/hr may occur (based on an average sulphur content of the diesel supply).

Modelling for sulphur oxides is based on the assumption of 500 ppm which is the level in diesel that is currently available. However, by the time the Gorgon Development is operational, diesel will be either 50 ppm (1 January 2006) or 10 ppm sulphur (from 2009) in line with Australian legislation. Therefore modelling results shown are conservative.

Shut-downs of the gas processing facility will occur for different reasons. They will be required for planned maintenance programs, in which case there will be the opportunity to minimise emissions by reducing the amount of gas directed to the flare system. Alternatively, there could be a shut-down of one train requiring some flaring, or a total shut-down of both LNG trains requiring discharge to flare of the total process inventory of LNG (not the tank inventory) and other plant piping and systems. It is anticipated that such circumstances will occur less than ten times per year and be of less than one hour peak flaring.
The design capacity of the flare system is expected to be approximately 2100 t/hr. This capacity will be refined during subsequent design phases. Maximum emissions of particulate matter and oxides of nitrogen from each of the two flares are shown in Table 7-2.

When activated, the main process flare has the potential to partially impact the approach and departure pathway of the Barrow Island airport.
The Civil Aviation Safety Authority (CASA) has established a number of regulations for the safety of aircraft movements, some of which pertain to the flight path of aircraft for take-offs and landings (CASA 2003).
In particular, CASA has drafted guidelines for Plume Rise Assessment and the need to assess the potential hazard to aviation where the vertical velocity from gas efflux (flare) may cause airframe damage and/or affect the handling characteristics of an aircraft in flight.
This assessment will be undertaken during further detailed engineering planned for the subsequent design phases of development. It is assumed that the results of the CASA analysis will either determine that aircraft safety is not compromised, or other actions (such as change in approach and take-off procedures or navigational headings, slightly re-aligning the runway or possible relocation of the flare) will take place.

Reservoir CO_2 is proposed to be injected into the Dupuy formation beneath Barrow Island (Chapter 13). Non-routine situations may occur, for example stoppage of one or more of the CO_2 compressors, whereby the entire injection system is not available. In this event, it will be necessary to vent CO_2 from the acid gas removal unit to the atmosphere. As trace amounts of H_2S are also present in the feed gas and normally removed with CO_2, during a non-routine situation a trace amount will also be vented to atmosphere with the CO_2. It is estimated that approximately 100 kg/hr of uncombusted H_2S will be vented under these circumstances. It should be noted that H_2S may be oxidised to SO_2 if vented through one of the turbine stacks due to the presence of heat and excess oxygen (O_2). The gas processing facility will continue to operate normally whilst venting of the CO_2 and H_2S occurs. The CO_2 stream will also contain some hydrocarbons including BTEX. Refer to Section 7.2.5 for additional details.

Table 7-2 is a summary of predicted emissions resulting from non-routine operation of the gas processing facility.

7.2.4 Air Quality Criteria

Within Western Australia, the Environmental Protection Authority (EPA) assesses all new projects in terms of air emissions at the stack or vent outlet and the resultant ambient ground level concentrations.

Emission Standards and Limits

For emissions from industrial sources, the EPA requires that ‘all reasonable and practicable means should be used to prevent and minimise the discharge of waste’ (EPA 1999a). For new projects, the EPA requires an assessment of the best available technologies for minimising the discharge of waste for the processes and justification for the adopted technology.

Best practice for NO_x reduction is currently Selective Catalytic Reduction (SCR). This relies on the principle that ammonia reacts with NO_x to produce nitrogen and water. It involves injecting a solution of ammonia (or a solution of urea) into a gas turbine exhaust and the exhaust gases then pass over a catalyst. Transporting large quantities of ammonia or urea to Barrow Island, and using these materials introduces additional safety, quarantine and other operational implications which collectively weigh too strongly against using this technology. Therefore it is not considered best practice overall for use on Barrow Island and as discussed in Section 7.2.2 the Development will use DLN burner technology where appropriate.

Table 7-2:
Predicted Emissions from Non-routine Operation of Gas Processing Facility

Operating Scenario	**Emission Estimates**			
	NO_x (kg/hr)	**H_2S (kg/hr)**	**SO_2 (kg/hr)**	**Particulate (kg/hr)**
Shut-down Emissions are for worst-case, shut-down of both trains	160	0	0	2500
Start-up For both LNG trains	378	0	3.6	440
CO_2 Injection System Stoppage	0–500	0–100*	< 1	0–30
For Comparative Purposes Emissions from Routine Operation	500	0	0	30

** Based on the assumption that all is vented – otherwise it will be SO_2*

The EPA has developed a guidance statement for oxides of nitrogen emissions from gas turbines, with limits for emissions following the Australian Environmental Council/Natural Health and Medical Research Council (AEC/NHMRC) National Guidelines. These limits are 0.07 g/m^3 (Standard Temperature and Pressure, dry and 15% O_2) for gaseous fuels and 0.15 g/m^3 for other fuels. Modern natural gas-fired systems, employing NO_x control technology can be expected to achieve lower emissions than 0.07 g/m^3 (EPA 1999b). Current indications from gas turbines of a similar size are that NO_x emissions may be half to a third of this concentration (Woodside 2005); however the following evaluation is based on 0.07 g/m^3 and so is expected to be very conservative.

Ambient Air Quality Standards

The EPA does not have state-wide standards for ambient ground level concentrations. For these, the EPA requires that pollutants meet the NEPM standards (NEPC 1998) as listed in Table 7-3. These specify a maximum concentration and the goal that is to be achieved in a specified timeframe, but new developments should strive to meet the standard from the commencement of operations.

These standards apply outside industrial areas and to residence-free buffer areas around industrial estates. With no formally defined industrial buffer zone applied to Barrow Island, the Joint Venturers have elected to apply the NEPM at the nearest permanent residence, namely the existing Chevron camp.

These NEPM standards and goals have not been implemented in legislation throughout Western Australia as yet; however the Department of Environment (DoE) has indicated their intention to implement them through the development of a state-wide Environmental Protection Policy (EPA 1999a). Table 7-4 presents a comparison of the standards and goals of NEPM, World Health Organisation (WHO 2000) as well as the USEPA National Ambient Air Quality Standards (NAAQS) (USEPA 2004).

For other pollutants, the DoE tends to reference the lowest standards that are in use throughout Australia. For the Gorgon Development, the Victorian State Environmental Protection Policy (EPA (Vic.) 2001) design ground level concentration of 470 µg/m^3 (0.32 ppm) of H_2S for a 3-minute average has been adopted as it is the most stringent.

Table 7-3:
Relevant Environmental Protection Measures – Standards and Goals

Pollutant/Emission	Averaging Period	Maximum Concentration	Goals Maximum Allowable Exceedences
Nitrogen dioxide	1 hour 1 year	0.12 ppm (246 µg/m^3) 0.03 ppm (62 µg/m^3)	1 day per year none
Photochemical oxidants (as ozone)	1 hour 4 hours	0.10 ppm (214 µg/m^3) 0.08 ppm (171 µg/m^3)	1 day per year 1 day per year
Sulphur dioxide	1 hour 1 day 1 year	0.20 ppm 0.08 ppm 0.02 ppm	1 day per year 1 day per year none
Particles as PM10	1 day	50 µg/m^3	5 days per year
BTEX	Annual average	0.003 ppm (investigation level)	n/a

7.2.5 Atmospheric Dispersion Modelling – Methodology

Two different atmospheric dispersion models were used to predict the impact on air quality due to the operation of the proposed gas processing facility on Barrow Island (Technical Appendix B1). These models were:

- DISPMOD, the Western Australian coastal model, which was employed to estimate local ground level concentrations of the emissions from various operating scenarios.
- TAPM, the CSIRO's prognostic meteorological and air pollution model, which was used to address regional air quality impacts and local deposition rates.

Routine Operations

Figure 7-1 and Figure 7-2 present the local distribution of the maximum 1-hour and annual NO_2 concentrations (ppm) for normal gas processing facility operations. The maximum 1-hour concentration predicted over the entire modelling grid is 0.06 ppm, compared to the NEPM value of 0.12 ppm. Similarly, maximum annual concentrations of NO_2 are predicted to be very low: typically being 10% of the corresponding NEPM value. Most of the NO_x deposition occurs over water due to the prevailing winds.

In addition to CO_2, NO_2, and SO_2, particulate matter (expressed as PM10) is another product of combustion that will be released from the proposed gas processing facility during routine operations. The maximum predicted 24-hour PM10 concentration is 3 µg/m^3, which is approximately 5% of the corresponding NEPM value of 50 µg/m^3 (Technical Appendix B1).

Figure 7-1:
Maximum 1-hour NO_2 Concentration (in ppm)

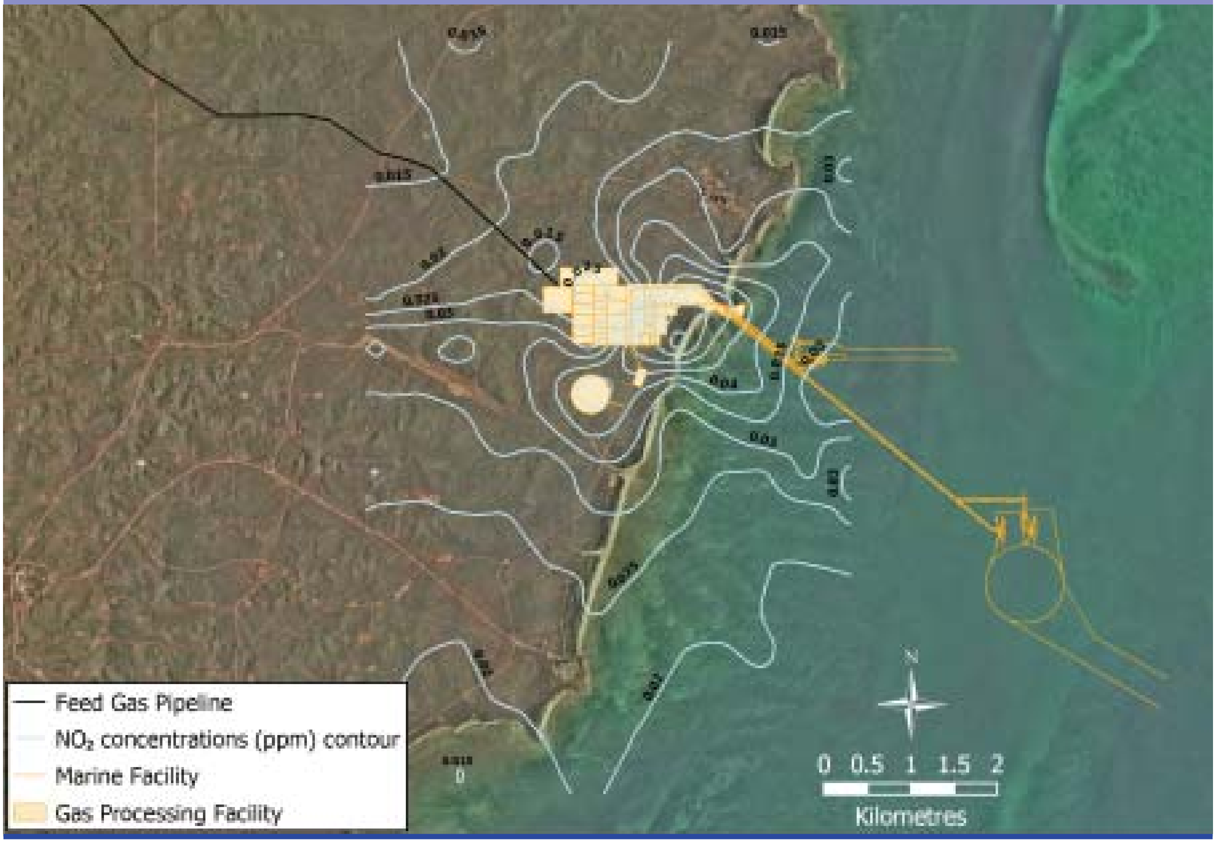
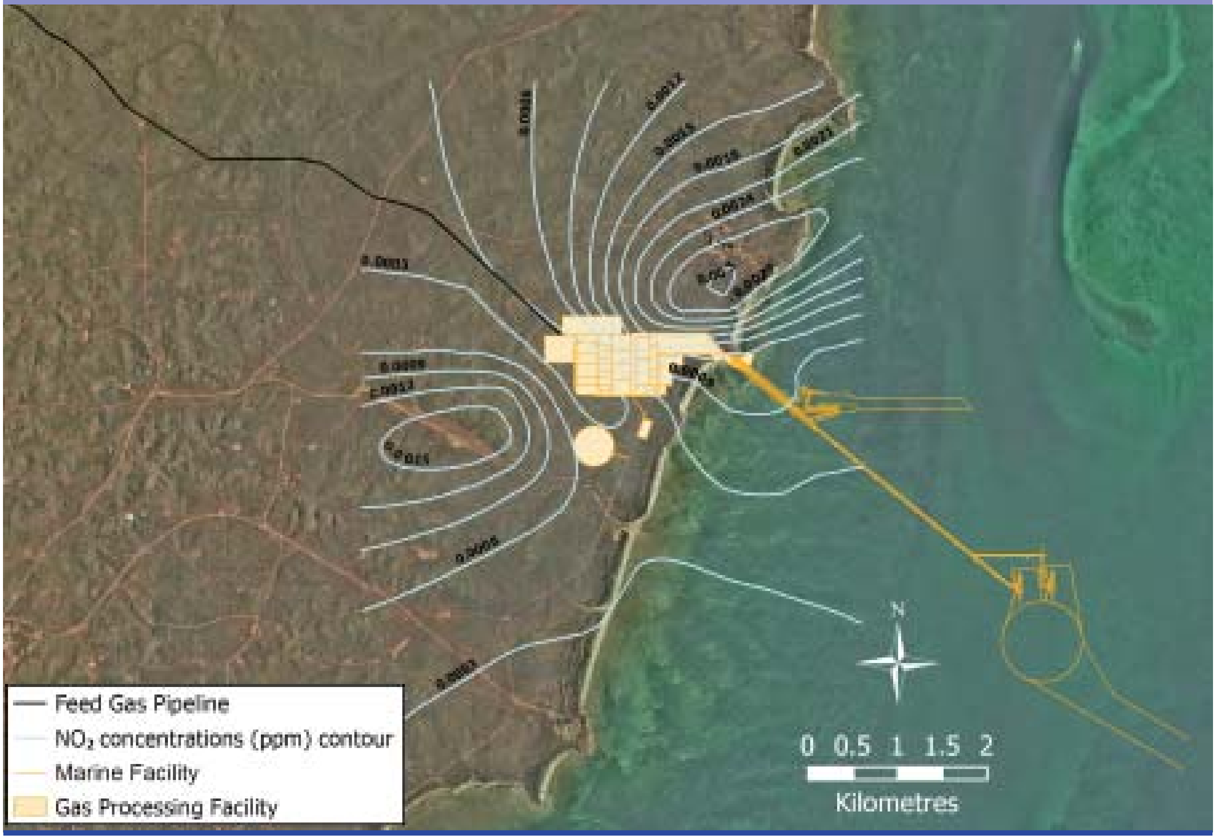


Figure 7-2:
Maximum Annual NO_2 Concentration (in ppm)



Some studies in other countries have indicated that more deaths are attributable to the concentration of particulate matter of diameter below 2.5 µm (PM2.5) than to the concentration of PM10. Particles with sizes between 2.5 and 10 µm may be more important in relation to asthma and respiratory illnesses.
There are few regular PM2.5 measurements undertaken in Australia, and no air quality standard has been set for PM2.5. The NEPM 24-hour PM10 standard of 50 µg/m^3 limits the atmospheric PM2.5 concentrations to between 20 and 40 µg/m^3 depending on the city and the season. This means that the NEPM provides an upper limit to the PM2.5 concentration that is more stringent than the United States EPA 24-hour PM2.5 standard of 65 µg/m^3 set in 1997.

It should also be emphasised that modern gas turbines are extremely efficient and so particulate matter from this source will be negligible, also flaring will be minimised as the natural gas is a valuable resource.

A summary of the maximum predicted concentrations of the various emissions for normal (routine) operations as well as a range of emission levels during start-up and plant upset conditions are presented in Table 7-5.

Table 7-4:
Comparison of NEPA, USEPA and WHO Ambient Air Quality Standards and Guidelines with Predicted Gorgon Development Emissions

Emission	NEPM		USEPA		WHO		Gorgon Development – Model Predictions	
	Averaging Period	**Maximum Concentration**	**Averaging Period**	**Maximum Concentration**	**Averaging Period**	**Maximum Concentration**	**Normal Operations (Max)**	**Non-Routine Conditions**
Nitrogen dioxide	1 hour	0.12 ppm (246 µg/m^3)					0.063 ppm (1 hr)	0.037–0.049 ppm (1 hr)
	1 year	0.03 ppm (62 µg/m^3)	Annual	0.053 ppm (100 µg/m^3)	NO$_x$ – Annual	0.016 ppm (30 µg/m^3)	0.003 ppm (annual)	N/A
Photochemical oxidants (as ozone)	1 hour	0.10 ppm (214 µg/m^3)	1 hr	0.12 ppm		0.2–10 ppm	regional cumulative concentration (<0.1 ppm)	regional cumulative concentration (<0.1 ppm)
	4 hours	0.08 ppm (171 µg/m^3)	8 hr	0.08 ppm	5 days – 6 months			
Sulphur dioxide	1 hour	0.20 ppm	SO$_x$ – 3 hr	0.5 ppm (1300 µg/m^3)			N/A (<0.001 ppm)	0.001 ppm (1 hr)
	1 day	0.08 ppm	SO$_x$ – 24 hr	0.14 ppm (human)	24-hr	100 µg/m^3	N/A	N/A
	1 year	0.02 ppm	SO$_x$ – Annual	0.03 ppm (human)	Annual	10–30 µg/m^3	N/A	N/A
Particles as PM10	1 day	50 µg/m^3	24 hr	150 µg/m^3 (human)			3 µg/m^3 (24 hr)	54–330 µg/m^3
			Annual mean	50 µg/m^3				
Nitrogen deposition					15–20 kg/ha/yr		0.06–0.55 kg/ha/yr	N/A

Non-Routine Operations

During non-routine operations, emissions from the flare and diesel generators may be much greater than under normal operations and could lead to higher ground level concentrations of NO_2, SO_2 and particulates. Dispersion modelling was conducted to predict the maximum concentrations of these emissions resulting from three non-routine operating scenarios: shut-down, start-up and non-operation of the CO_2 injection system. Despite being unlikely, the worst-case data was used in the modelling to predict the emission levels when both LNG trains would be in the non-routine mode.

Start of Both LNG Trains

Maximum predicted 1-hour concentrations of NO_2 resulting from a cold start of both trains of the gas processing facility are presented in Figure 7-3. Maximum concentrations are predicted to be well below the corresponding NEPM values. Other emissions released during a cold start would include small quantities of sulphur dioxide ($SO_2 < 5$ g/s) and particulate matter. The dispersion modelling confirms that the predicted ground level concentrations of both emissions would also be well below the NEPM standards.

Shut-Down of Both LNG Trains

Emissions due to a shut-down of both LNG trains would include oxides of nitrogen, CO_2, uncombusted hydrocarbons and particulates. Maximum predicted 1-hour concentrations of NO_2 resulting from a total shut-down of the gas processing facility are presented in Figure 7-4. The maximum value of 0.049 ppm is less than 50% of the relevant NEPM values. The predicted maximum 1-hour concentration of particulates during such an event, assuming that flaring occurred under the worst-case meteorological conditions, is 4561 $\mu g/m^3$. This equates to a 24-hour average of approximately 200 $\mu g/m^3$ during that day of occurrence. The maximum concentration would occur within the boundary of the gas processing facility. The maximum values decrease rapidly with distance from the gas processing facility, such that at the construction village the maximum 24-hour particulate concentration is estimated to be 30 $\mu g/m^3$, which is below the NEPM standard of 50 $\mu g/m^3$.

Figure 7-3:
Maximum Predicted 1-hour NO_2 Concentration (in ppm) from a Cold Start

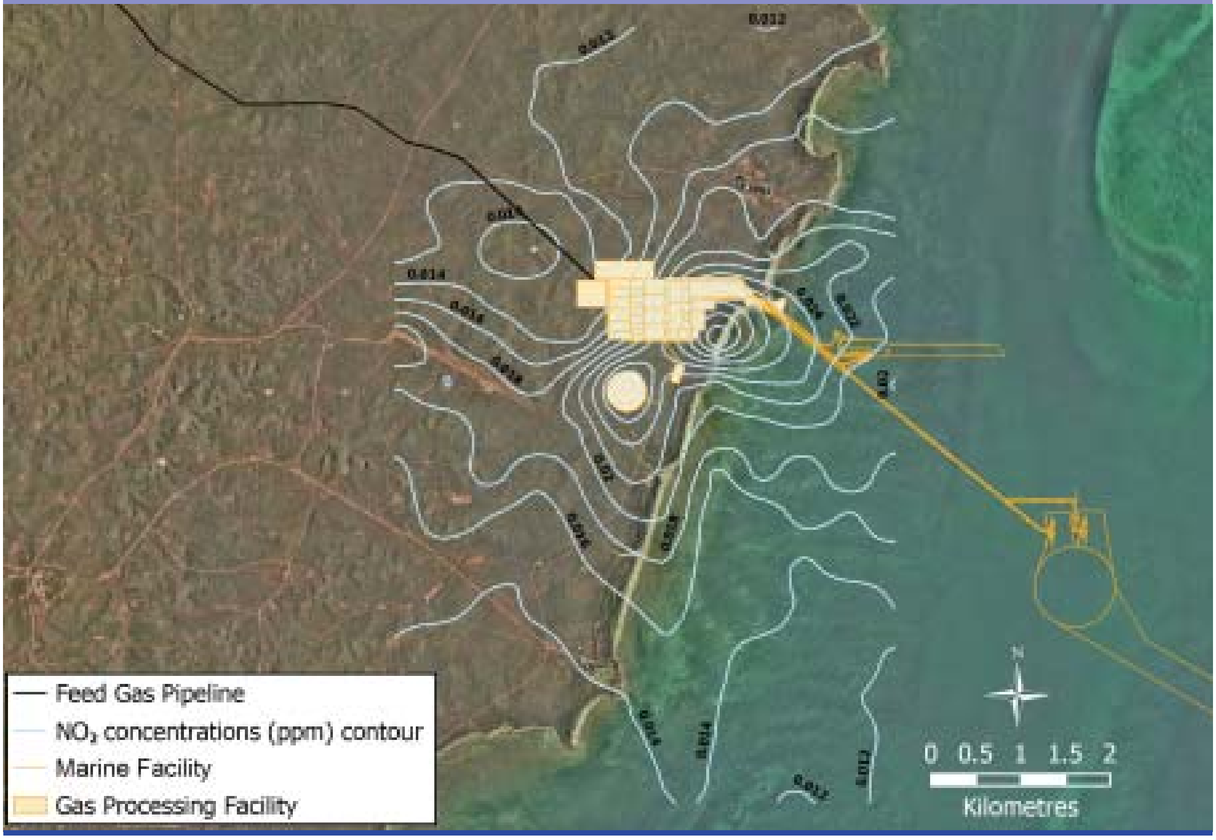
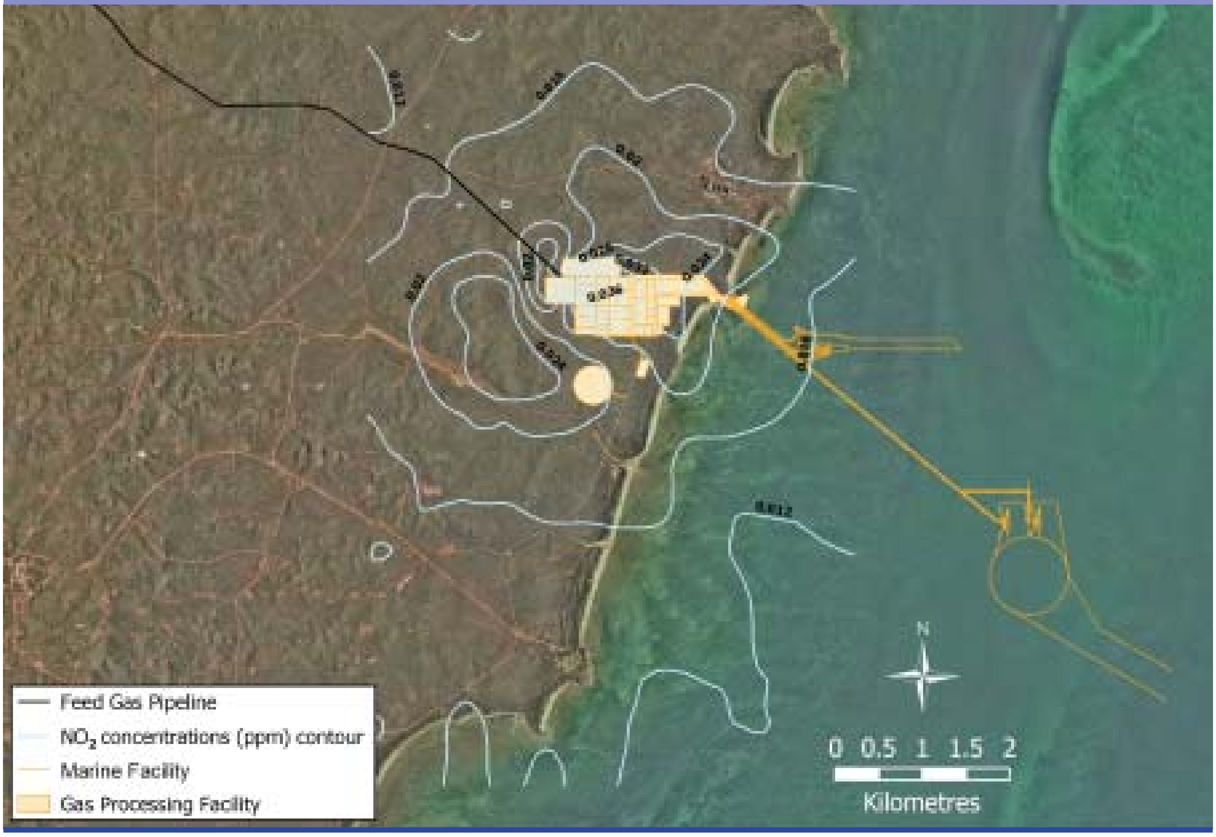


Figure 7-4:
Maximum Predicted 1-hour NO_2 Concentration (in ppm) from a Total Shut-Down



Shut-Down of CO_2 Injection System

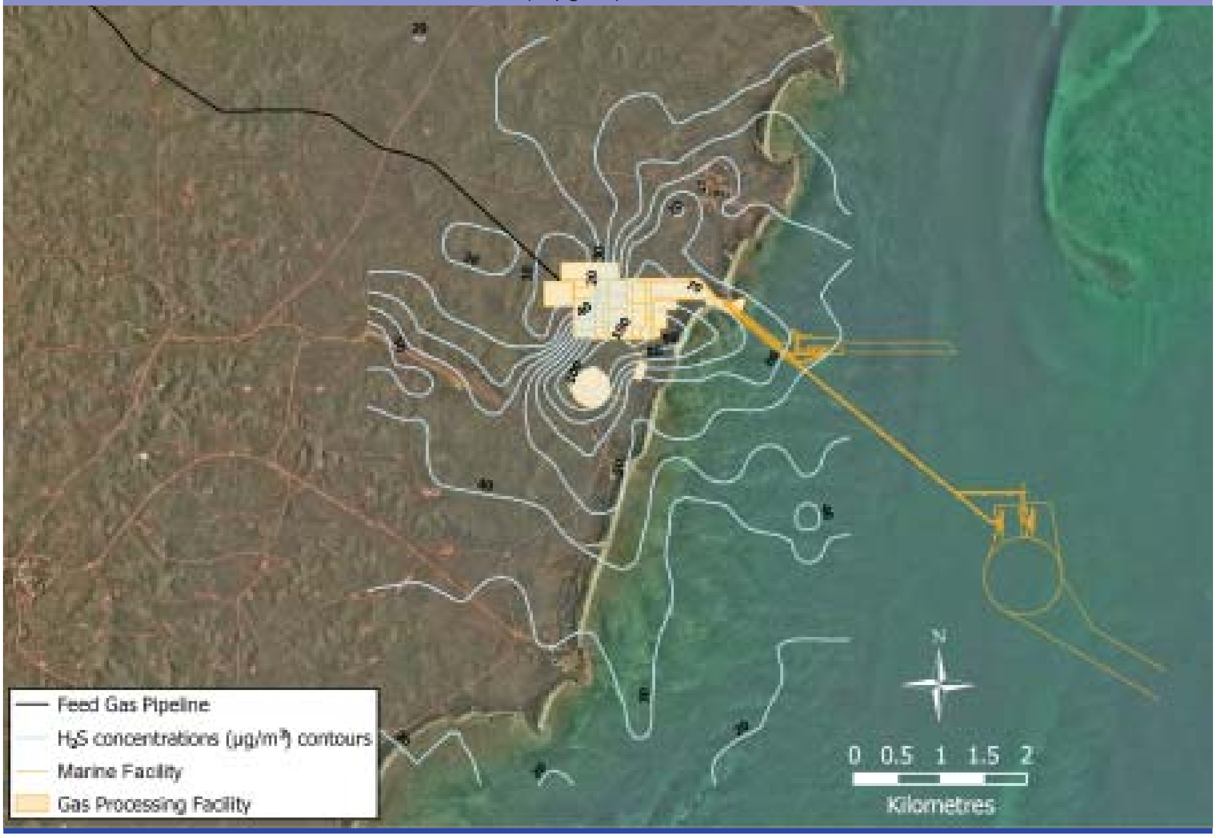
Maximum predicted 1-hour concentrations of NO_2 occurring during a shut-down of the CO_2 injection system would be the same as those presented under normal operating conditions, as illustrated in Figure 7-4. This is because the NO_x would be emitted from the gas turbines in the power generation system and the gas turbines driving the refrigerant compressors, which would all still be operating.

The maximum 3-minute concentrations of H_2S associated with the venting during the shut-down of the CO_2 injection system are presented in Figure 7-5. The maximum value of 113 µg/m^3 is less than a quarter of the Victorian EPA ground level concentration of 470 µg/m^3. Refer to Chapter 13 for further details on the availability of the CO_2 injection system.

Modelling has recently been undertaken directly by the Gorgon Joint Venturers for the full discharge of CO_2 from the acid gas removal unit through a dedicated vent 30 m above grade. An alternate case of 10% of the design flowrate has also been examined. The H_2S concentration in the CO_2 stream is predicted to be in the order of 200 ppm. The results show that for the 100% case, the maximum ground concentration of CO_2 will be approximately 400 ppm above ambient (750 ppm absolute) and the maximum H_2S ground level concentration will be approximately 0.1 ppm. For the 10% flow case, the velocity of the discharge is lower and modelling shows that the ground level concentrations are also lower, indicating that the full flow scenario is the worst-case. BTEX concentrations are expected to be in the order of 10% of the H_2S concentration and so BTEX ground level concentrations are expected to be less than 0.01 ppm. Assuming that the CO_2 system was operating 90% of the year, this would result in an annual average of 0.001 ppm which is below the NEPM investigation trigger levels for benzene.

The Gorgon Joint Venturers will undertake additional modelling during subsequent design phases to ensure that ground level concentrations of all components are safe.

Figure 7-5:
Maximum Predicted 3-Minute H_2S Concentration (in µg/m^3) from a Total Shut-Down



A summary of the maximum concentrations of the various emissions for non-routine operations (gas processing facility start-up, total plant shut-down and shut-down of the CO_2 injection system) is presented in Table 7-5.

Local Deposition Rates

Deposition of atmospheric pollutants can occur through both wet and dry mechanisms. Wet deposition or 'acid rain' describes the deposition of acidic pollutants through rainfall. The opportunity for potential acid rain deposition and impact is remote for Barrow Island because of the dry climate and prevailing winds over a vast marine receiving environment. When precipitation occurs, it tends to be during the summer and autumn months and is often associated with cyclones (Chapter 8). These large rainfall events occur over short periods of time which significantly dilute wet deposition rates.

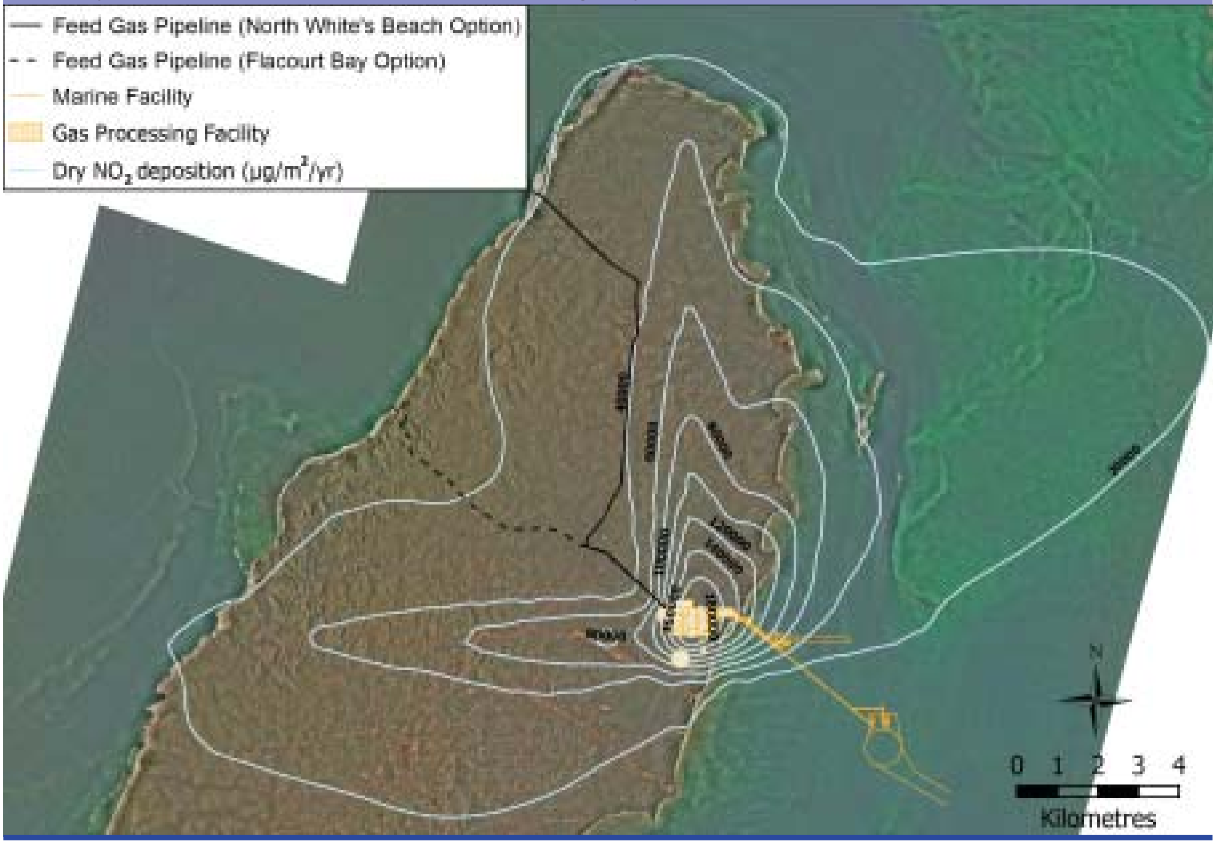
Dry deposition refers to the fall-out of gases and particulates to the ground surface without any interaction with water. Dry deposition tends to occur close to the source of pollution particularly in dry climates, but depends upon prevailing weather conditions and dominates in dry climates (Environmental Protection Authority (SA) 2001). The dominant mechanism on Barrow Island is dry deposition for both the terrestrial and aquatic environments.

The total dry deposition to the ground (vegetation, soil/rock and any water bodies) of NO_2 as predicted by TAPM modelling is presented in Figure 7-6. The highest NO_2 deposition rates are predicted to be over water where the dilution and dissociation in the marine environment would occur rapidly because of the warm water temperature, current and tidal influences and wave action. The receiving waters are not considered sensitive to nitrogen deposition as they are not entrained or eutrophic. Rates over land would be lower primarily due to the deposition to vegetation being dependent on daylight and the photosynthetic process; and because TAPM uses a moderately high solubility factor for NO_2. The maximum dry deposition would be approximately 180 000 µg/m^3 (or the equivalent of 1.8 kg/ha/year).

Table 7-5:
Maximum Ambient Concentrations with DLN Burners for Various Operating Scenarios

Operating Scenario	**NO_x**		**NO_2**		**PM10**	**H_2S**		**SO_2**	
	1-hour (ppm)	Annual (ppm)	1-hour (ppm)	Annual (ppm)	24-hour (µg/m^3)	3-minute (µg/m^3)	1-hour (µg/m^3)	1-hour (ppm)	24-hour (ppm)
Normal Operations	0.287	0.003	0.063	0.003	3	N/A	N/A	N/A	N/A
Start-up	0.150	N/A	0.037	N/A	54	N/A	N/A	0.001	N/A
Shut-down	0.212	N/A	0.049	N/A	200	N/A	N/A	N/A	N/A
Shut-down of CO_2 injection system	0.293	N/A	0.064	N/A	3	113	62	N/A	N/A

Figure 7-6:
Total Dry Deposition of NO_2 (Ground Concentration – µg/m^2/yr)



Comparison to the WHO (2000) critical load for Nitrogen (N) deposition of 15–20 kg/ha/year for dry heathland (the only vegetation studied which is 'similar' to Barrow Island), indicates that the deposition over land of between 0.2 to 1.8 kg NO_2/ha/year (0.06 to 0.55 kg N/ha/year) is relatively insignificant (0.4–3.6% of the criteria).

7.2.6 Current Emissions from Facilities on Barrow Island

The current operations on Barrow Island are described here as part of the cumulative assessment of local emission levels. Current atmospheric emissions on Barrow Island are associated with existing oil field operations and include emissions from diesel and gas engines, the local power station, ground-based flaring and hydrocarbon storage and transport.

The Central Power Station for power generation on Barrow Island currently consists of 2 x 2 MW gas turbine generators, 1 x 4 MW gas turbine generator, and 5 x 1 MW gas engines, all fuelled by natural gas. Combustion products are the most significant emissions from the turbines, with oxides of nitrogen (NO_x) being the major emission product after CO_2.

A summary of current atmospheric emissions is presented in Table 7-6.

It should be noted that the Gorgon Development provides the opportunity to eliminate many (if not all of these emission sources), e.g. power supplied to the existing operations from the more efficient equipment provided at the gas processing facility, or recovery of gas which is currently flared. However, the remainder of this chapter refers to the combined emissions from the Gorgon Development and existing emissions and therefore is conservative.

Regional Impacts of the Gorgon Development on Air Quality

As the emission levels for NO_x, SO_x, H_2S and particulates from the existing Chevron Australia operations on Barrow Island and the proposed Gorgon Development all fall within guidelines for the immediate (local) area, they will have a negligible impact on the regional air quality levels.

The potential impact of the Gorgon Development on regional air quality was investigated using TAPM to model peak ozone concentrations.

Table 7-6:
Current Annual Atmospheric Emissions from Barrow Island (ChevronTexaco Australia 2003b)

Source Description	SO_x (tonne)	NO_x (tonne)	VOC (tonne)	CO (tonne)
Diesel engines	3	0	0	0
Barrow Island power station	0	927	23	736
Barrow Island well field operations	0	638	19	582
Crude oil transport and storage	0	0	33	0
Flaring	26	31	246	169
Flashing	0	0	18	0
Venting	0	0	502	0
Fugitive emissions	0	0	544	0
Total	29	1596	1385	1487

Ozone (O_3) is a recognised atmospheric pollutant. Symptoms of exposure to O_3 include irritation of the airways and minor lung function changes in both healthy and susceptible individuals. Some plant species, including crop species, demonstrate a reduction in growth and visible injury when exposed to prolonged O_3 concentrations at levels lower than those that cause adverse effects in humans.
The concentration of O_3 in a polluted atmosphere is usually taken as an indicator of the amount of photochemical smog, because O_3 usually comprises about 85% of the total photochemical smog concentration. The rate of production of photochemical smog is limited by the amount of sunlight and reactive organic compounds available. The quantity produced is generally limited by the amount of NO_x available.

In Western Australia there are two primary standards for ambient O_3, a 1-hour average of 0.10 ppm and a 4-hour average of 0.08 ppm. Each of these concentrations may not be exceeded more than one day per calendar year.

The modelling was based on emissions from the current Chevron Australia operations on Barrow Island, regional emissions (e.g. publicly available data for industrial plants currently in operation or under construction on the Burrup Peninsula (Technical Appendix B1)) and the proposed Gorgon Development.

The maximum peak 1-hour ozone concentrations for the region are predicted to be below the NEPM standard of 0.10 ppm. With the inclusion of emissions from the proposed Gorgon Development, the maximum 1-hour ozone concentration increased only slightly (0.005 ppm) from 0.087 ppm to 0.092 ppm. Consequently the concentrations predicted for the Burrup Peninsula and Dampier/Karratha region exhibit very little, if any, change with the inclusion of emissions from the proposed Gorgon Development (further details are available in Technical Appendix B1).

Ozone Depleting Substances

It is Chevron Australia's policy to exclude the use of Ozone Depleting Substances (ODS) in new plant facilities such as the refrigeration and fire control systems. However use of ODS in quarantine systems may be required as there may be a need to use methyl bromide. This substance is mainly used as a fumigant in agriculture, for pest control in structures and stored commodities, and in quarantine treatments. Certain fire fighting (e.g. halon deluge systems) and refrigeration systems in older model dredges, drilling rigs and supply vessels could also potentially result in a release of ODS.

In the unlikely event of a fire, only small volumes of halons would be released. Potential environmental impact of such a small volume of halons released into the atmosphere is considered slight (Chapter 10) and would be reported in accordance with Australian Standard AS 4211.3. The risk of releasing ozone depleting substances during replacement of older-style refrigerant systems is also considered to be very low. Any systems containing ODS that need recharging or replacement will be exchanged to an ozone ‘friendly’ systems, wherever options are available.

7.3 Light Emissions

Extensive lighting for industrial plants is mandatory for general worker and public safety; therefore, the gas processing facility and associated facilities will be lit and a potential source of light spill. Shipping will require lighting for similar reasons and will also be a potential source of light spill. The following sections explain the lighting strategy for the proposed Development, while Chapters 10 and 11 include assessment of the potential environmental risks of the lighting regime.

7.3.1 Current Light Emissions

There are no permanent light sources in the area of the Gorgon gas field, although there is some lighting from occasional shipping and the existing drilling platform/monopods in the general offshore area. There are permanent light sources located at various sites on Barrow Island for the existing operations of Chevron Australia. These lights are associated with the central processing facility, airport and base area, all located inland from the coast. The main sources of artificial lights adjacent to the coast are the Chevron camp and associated recreational facilities, the terminal tanks and the barge landing site, all located on the eastern coast of Barrow Island. There are also permanent lights associated with the facilities at Varanus Island and a number of monopod production facilities in the immediate offshore area, mainly to the north of Barrow Island.

A recent survey (Technical Appendix C7) identified the most common outdoor lighting type in use at Barrow Island as sodium vapour (nominally 80 W and 400 W). These lights are typically atop 6–8 m tall poles and are oriented at approximately 20° from vertical. Metal halide, fluorescent and mercury vapour lights are less commonly used. While these lights are visible over long distances as point sources, their spectral emissions were not detectable as electrical signals over more than several hundred metres.

7.3.2 Light Emissions from Construction Activities

Most external work lights on floating drilling rigs and pipe-lay barges should be kept on 24 hours per day in accordance with safety requirements. Lights will also be required on the vessels (e.g. dredges, hopper barges, tenders, tugs and barges) during LNG plant construction, pipeline and optical fibre cable installation, MOF, jetty and shipping channel/basin construction.

It is anticipated that construction of the offshore sections of the feed gas and domestic gas pipelines will each require a construction period of approximately eight to ten months. For much of this time, construction activities will be remote to Barrow Island; therefore, lighting will be offshore.

The onshore feed gas pipeline construction will take approximately 10 months with the majority of the construction activities being undertaken during daylight hours, although night time activities will occur. Most of the onshore feed gas pipeline route is well away from the coast and so will provide a negligible source of light spill to the marine environment that could potentially impact turtles. Nevertheless the same basic principles discussed in Chapters 6, 7, 10 and 11 will be used to minimise potential for light spill reaching the coast.

The shore crossing construction activity will extend for approximately 12 months, with 3–5 months associated with the directional drilling operation. The remainder of the time will be spent in site preparation, pipeline pulling and clean up activities. These activities are expected to run for 24 hours per day; however where practical some construction activities will be scheduled for daylight shifts to avoid unnecessary disturbance at night. Also, where possible, the peak drilling activity will be scheduled to minimise coincidence with the turtle breeding season.

The CO_2 pipeline and water pipelines will be constructed primarily onshore away from the beaches. However lighting will be undertaken using the same principles as discussed in Chapters 6, 7, 10 and 11, so light spill from these facilities will be minimal.

It is planned that once the LNG site preparation is complete, the onshore construction of the gas processing facility will occur 24 hours per day, seven days per week. Safety considerations will require that the construction site is illuminated in accordance with safe working conditions. Most of the construction activity will be located at the gas processing site, away from the shore areas. Lights that emit at longer wavelengths (narrow spectrum) will be used and directed onto the construction activities to reduce light spill.

Two other basic principles will be followed which are considered to be the most important to protect turtles from light spill, namely:

- using fully shielded lights
- facing lights away from the beach so that there is no direct light visible from the shore where turtles may occur, but also not shining lights directly at large reflective surfaces.

As the design progresses, the Gorgon Joint Venturers will also continue to apply the principles contained within Witherington and Martin (1996) to minimise light spill from the onshore and offshore construction equipment.

7.3.3 Light Emissions from Operation of Proposed Development

The gas processing facility will normally be in operation on a continuous basis (24-hour operation) and lighting will be required. Specific facilities include: the gas processing facility, export jetty and tankers, village and recreational facilities. Lighting at these facilities will create some light spill.

Gas Processing Facility

The light spill generated from the gas processing and marine facilities will depend upon the actual light source (wavelength and intensity), location/placement of light fittings and the method of light switching. The characteristics of the potential light spill from the gas processing facility were predicted using an illumination model (using AGI32 software program – Technical Appendix C7) to estimate isolux contours over the affected areas.

Modelling of the light emissions from the gas processing facility predicts that, for a conventional lighting regime, the 20 lux isoline will be retained within the confines of the gas processing facility area, in general around 2 m from the nearest point sources of light.

Light intensity will diminish by the square of the distance to the source. A light intensity of 0.1 lux would therefore be achieved at a distance of around 30 m from the gas processing facility and therefore may be visible from the near shore and beaches located to the east. In comparison, moonlight provides between 0.25 and 1 lux depending on the phase of the moon and the weather conditions (Encyclopedia 2005).

To examine the sensitivity of the lighting contours to the lighting configuration a number of modelling runs were conducted which included:

- the base case with conventional lighting regime – ‘Base Case’ (250 watt high pressure sodium)
- turning lights so they face away from turtle beaches – Case A (all onshore lights face north and/or west away from the beach)
- reducing the height of the lights – Case B (10 m^{-5} m)
- reducing the wattage of the lights – Case C (250–150 watt).

The results (Figure 7-7) show that there is a difference between the Base Case and Case A, another marked difference between Case A and Case B, but the changes between Case B and Case C are minor to negligible. This modelling confirms expectations that the measures proposed by the Gorgon Joint Venturers will dramatically reduce lighting effects over a conventional lighting regime.

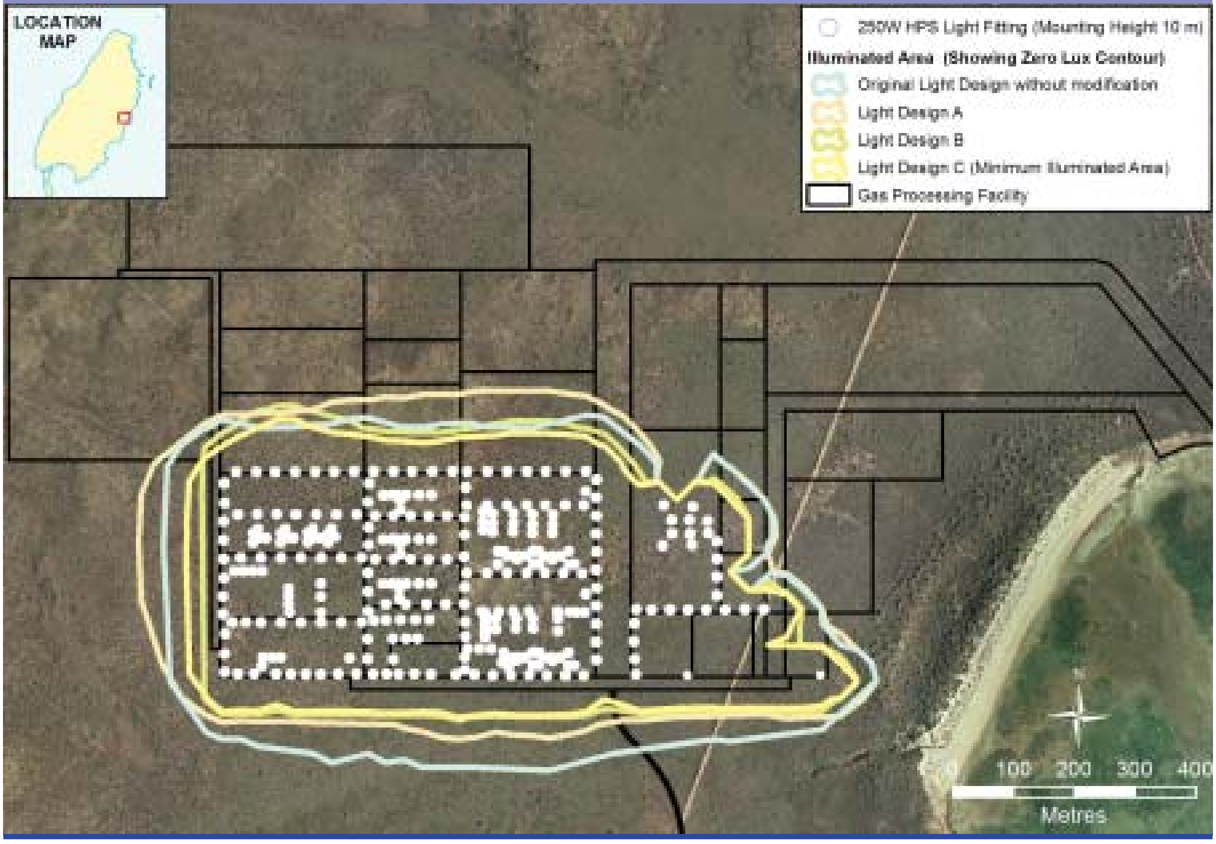
Various design measures will avoid the need for significant flaring of gas, which is a potential source of light which could disturb turtles. However, certain situations will require gas flaring including: Development commissioning; periods of process of shut-down and start-up; and upset conditions. Of these potential flaring scenarios, the process of shut-down and start-up will occur most frequently with each event typically lasting between one-to-six hours in duration. Commissioning will occur only once. During these periods, light produced by the flare will be visible during the night from the beaches adjacent to the gas processing facility and offshore.

One option which is currently being evaluated is the use a ground-based flare instead of the elevated flare, as the ground flare has the benefit of potentially reducing the effects of a light source on turtles.

It is anticipated that each LNG ship loading will take approximately 24 hours and occur once every three days. The loading of LNG tankers will be a 24-hour operation, thus both the LNG berth and the tankers will be lit in order to provide a safe working environment.

Currently there is a single shipment of crude oil from Barrow Island each month. An additional condensate ship loading will also occur once every month. These tankers will be lit to ensure personnel safety, but also to enable early detection of oil spills should one occur.

Figure 7-7:
Isolux Contours – Gas Processing Facility



Therefore, at the marine facilities there will be increased light emissions from an increase in tankers, associated tugs and pilot vessels, barges, the MOF and dedicated loading jetty and vehicle headlights on the jetty at night. Safe lighting at these facilities during loading and unloading operations will be designed with due consideration to minimise light spill as outlined in the following section.

Light Management

A lighting strategy will be updated for the Development with the objective to further minimise the amount of off-site illumination as much as reasonably possible. The LNG plant site, construction village and administration office will be constructed away from the beach areas. Keeping the elevation of the plant to a low, safe height and partially shielded by the existing dune formation will reduce light spill to the beach areas.

To minimise the potential impact of lighting on fauna (Chapters 10 and 11), a hierarchical lighting strategy has been proposed for the Development as described in Box 7-1.

Box 7-1:
Gorgon Development – Hierarchical Lighting Strategy

- Light levels will be minimised to those required for safe working conditions and security of the Development. Lights will be directed away from turtle beaches where possible.
- In certain areas, shielded or recessed lighting with long wavelength, reduced spectrum properties will be employed. Areas include the MOF causeway, jetty, parking and open areas.
- Areas that require routine night inspection and monitoring will have shielded white type lights (full spectrum) that would normally be in the off position and switched on as required.
- During commissioning, shut-down, or start-up extra lighting would be required for worker safety and potential evacuation.

In general, lighting levels will be minimised to those required for safe working conditions and for the security of the Development. Management of light spill can be achieved by designing and incorporating several simple measures (e.g. motion detection and localised switching) which will be applied, as appropriate, to the activities occurring at particular sites within the gas processing and marine facilities or at particular times (e.g. turtle nesting and emergence).

In specific areas, shielded red, long wavelength and/or lighting of a minimum necessary wattage rating will be provided. This includes areas such as the MOF causeway, jetty, access roads within the gas processing facility and general open areas. In areas where colour definition is required, a yellow/orange type of shielded light will be used, such as low pressure sodium vapour.

During construction of the Development, temporary lighting will be focused on the areas that are being worked on. Onshore on the east coast, where possible and during sensitive periods, lights will be shielded, mounted as low as practical and directed towards the west (and north) and not towards the coastline. Similarly on the west coast, where possible and during sensitive periods, lights will be shielded, mounted as low as practical and directed towards the east and not towards the coastline.

Areas and equipment that require inspection and monitoring during routine operator rounds and/or regular maintenance (e.g. filter change-outs) will utilise shielded white-type (full spectrum) lights that would normally be off. These lights are to provide adequate colour definition and shall be switched on as required. During an emergency, additional lights will be available for safety and security, including perimeter flood lights which will be activated on an ‘as required’ basis. Perimeter security lighting, cameras and motion detectors may be used in strategic locations. It may be possible to use lights with a long wavelength for these locations. One option which may prove feasible is the use of infrared cameras and new low lux cameras for perimeter surveillance.

These and further measures for managing and controlling light spill will be considered during subsequent design phases and will include options identified in Box 7-2.

Box 7-2:
Light Management Options

- Only installing necessary lights – ‘unnecessary lighting’ includes lighting in unused areas, decorative lighting or lighting that is brighter than needed.
- Minimising beach lighting from outdoor sources – this would be achieved by reducing wattage in sensitive areas, using focused luminaires to concentrate light, shielding light sources, using artificial or natural screens, recessing sources, lowering mountings, using timers or motion sensors, and possibly integrating screening in critical areas.
- Installing lighting along the MOF causeway and LNG jetty which will be activated by vehicles passing a specified shoreline checkpoint. Lighting along the MOF causeway and LNG jetty would be mounted low, shielded and focused towards the travelled pathway to avoid or reduce potential light spill into the surrounding waters. Floor lighting similar to that used in cinemas and aircraft will also be considered where appropriate.
- Scheduling routine maintenance work to avoid sensitive turtle hatching periods and maximise use of daylight conditions.
- Using torches to see equipment which does not normally require inspection (if safe).
- Minimising beach lighting from indoor sources – this will be achieved by avoiding or reducing the number of east-facing windows; applying window treatments (e.g. tinting); using curtains or opaque blinds after dark; and dimming lights near windows during times when sensitive fauna are using the surrounding area.
- Using alternative, long-wavelength (reduced spectrum) light sources – if light spill does reach fauna, the impact would be lessened if it has appropriate spectral properties. Low-pressure sodium vapour lamps, yellow filters, bug lights and red light-emitting diodes (LEDs) are examples of lights that could reduce impacts upon sea turtles.
- Directing lights away from large plant and equipment so that the surface does not act as a large light reflector.

Box 7-2: (continued)
Light Management Options

- Minimising the use of reflective surfaces, paints or coatings (e.g. using matt paints and colours such as greys or shades of brown/olive instead of white). This would reduce the amount of reflected light contributing to glow.
- Using directed beams of light similar to car headlights to minimise the spread of light outside areas that require lighting.
- Using spotlights instead of area flood lights.
- Locating and mounting shielded lights in locations which would be naturally blocked by other vessels, process equipment and/or structures.
- Installing entry doors, ladders and walkways on the western side of structures so that their lighting will be naturally blocked from and not reflected towards the eastern coastline. Where these aspects are not feasible, consideration will be given to enclosing stairs on the eastern side. The same principle will apply on offshore structures.
- Minimising the lighting required during the vessel loading to safe levels with due consideration to reducing light spill. This would reduce the visibility of these lights from the eastern beaches.
- Installing navigation aids on marine structures.
- Using infrared cameras for perimeter surveillance.
- Using cameras that offer detection in the visible spectrum down to 0.01 lux.

A combination of these lighting measures will be incorporated into the next level of design to minimise the potential impact of light spill from the Gorgon Development and still maintain acceptable worker safety and site security levels. As the design progresses, the Gorgon Joint Venturers will also apply the principles contained within Witherington and Martin (1996) to minimise light spill from the operational gas processing facility, and associated onshore and offshore equipment and activities.

A similar approach will be taken to reduce the light spill from all vessels operating within the vicinity of Barrow Island during the construction and operation phases of the Development. Refer to Chapters 10 and 11 for additional details.

7.4 Noise Emissions

7.4.1 Current Noise Emissions

The offshore Gorgon Development area is currently only subjected to noise generated by naturally occurring sources, such as wind, wave activity and marine animals, and noise associated with marine transport and drilling when it occurs. Barrow Island is subjected to noise generated by wind, weather and artificial sources. The artificial sources are associated with the existing Barrow Island Joint Venture operations and include: production and export facilities, support services such as planes and helicopters transporting the workforce to and from Barrow Island, mainland barge transport, an accommodation camp and vehicular traffic.

A survey of the existing noise levels at various proposed Development locations on Barrow Island was undertaken between 20 January and 10 February 2004 (further details are supplied in the Technical Appendix B2). The background noise levels at each location are summarised in Table 7-7.

Ambient noise at the existing Chevron camp site was dominated by noise from air conditioners. At the three other sites, ambient noise showed a pronounced diurnal cycle, with minimum levels occurring just prior to sunrise and peaking mid-afternoon. This is attributed to bird activity (and/or activities of other fauna), as the locations selected were remote from human activity. Wind generated noise also significantly contributed to the measured noise levels.

7.4.2 Noise Emissions from Construction Activities

Offshore Construction

Noise will be generated during drilling, installation, commissioning, production and decommissioning stages of the proposed offshore development, the MOF and jetty works. The potential sources of significant underwater noise are: support and installation vessels (tugs and tenders); drilling rigs and pipe-lay barges; possible pile driving; blasting; horizontal directional drilling (HDD) of the shore approaches; and from dredging and sea dumping activities. Typical noise levels and frequencies of vessels and marine construction equipment are identified in Table 7-8.

The noise characteristics of, and level from, various vessels that will be present during construction of offshore Development facilities will vary considerably between vessel types and their activities. Drilling rigs

Table 7-7:
Background Noise Levels (Natural and Artificial Sources)

Location	**‘L_{90}’ of L_{A90} noise levels – dB(A)**		
	0700–1900 hours Monday to Saturday	**1900–2200 hours Monday to Saturday and 0900–2200 hours on Sundays**	**2200–0700 hours Monday to Saturdays and 2200–0900 hours on Sundays**
Chevron Camp Site	50	50	49.5
Proposed gas processing facility site	30	24.5	23.5
T-Tree (north-end of Barrow Island)	30.5	36.5*	30.5*
Flacourt Bay (proposed feed gas pipeline shore crossing) – but also typical for west coast	40.2	42	41.5

** The second week of continuously monitored data at this location contains anomalous results and has therefore been excluded from the calculations of L90 of LA90 noise levels.*

Table 7-8:
Comparison of Sound Source Levels From Marine Vessels and Equipment (source: URS 2004)

Source	**Peak Frequency or Band**	**Peak Source Level/s (re 1 µPa @ 1 m)**
Large tankers and bulk carriers*	10–30 Hz	180–186 dB
Container ship**	7–33 Hz	181 dB
64 m Rig supply tender*	Broadband	177 dB
Tug towing barge*	1000–5000 Hz	145–171 dB
Cutter-suction dredge (working)	100 Hz tonal	~180 dB
Clamshell dredge (working)	250 Hz pulses	150–162 dB
Pile driving operations	Low tonal pulses	170–180 dB
20 m Fishing vessel*	Broadband	168 dB
Trawler#	100 Hz	158 dB
25 m Small Waterplane Area Twin Hull (SWATH) ferry with 2 x 950 hp inboard diesel engines**	315 Hz	166 dB
Bertram cabin cruiser with 2 x 165 hp inboard diesel engines*	400 Hz	156 dB
8 m Rigid Hull Inflatable Boat (RHIB) with 2 x 250 hp outboard motors*	315–5000 Hz	177–180 dB
Power boat with 2 x 80 hp outboard motors#	630 Hz	156–175 dB
Zodiac inflatable with 1 x 25 hp outboard motor#	6300 Hz	152 dB

** Recorded at 10–11 knots*
*** recorded at ~15 knots; # unrecorded speed or speed range*

emit noise from onboard machinery and the drill pipe. McCauley (1998) measured noise emitted from a drilling rig in the Timor Sea and found the broadband noise level to range from 169 dB re 1 μPa during drilling to approximately 146 dB re 1 μPa on standby. Under normal operating conditions, when the vessel is idling or moving between sites, support vessel noise would be detectable only over a short distance (2 km). The noise from a vessel holding its position using bow thrusters and strong thrust from its main engines, may be detectable above background noise levels during calm weather conditions for 30 km or more from the vessel.

The underwater noise generated by a typical drilling rig used in the Australian offshore petroleum industry was also measured by McCauley (1998). The drilling rig was found to have a maximum audible range of 11 km under ideal listening conditions while drilling and only 1–2 km while not drilling.

Noise from jetty construction activities may include the hammering sounds of pile driving or vibratory hammer operations. These can generate underwater sound pulses with received levels to 135 dB re 1 μPa at 1 km from the source, and an audible range extending to 10–15 km (URS 2004). A recent (2002) sound study of pile-driving operations (to construct a new Australian Defence Force wharfing area in Twofold Bay, near Eden, NSW) reported more intense underwater noise (McCauley et al. 2003). Maximum recorded average mean-squared pressure was 167 dB re 1 μPa (at 300 m from the operation), falling to 145 dB and 136 dB re 1 μPa at 1.8 and 4.6 km respectively. Curve-fitting of nine sets of measurements indicated that average signal strength fell from 150 dB to 140 dB re 1 μPa between 1 km and 3.1 km from the operation.

There will be noise associated with the pipe lay barge. In shallow waters the lay barge forward movement will via a series of winches and heavy anchors with tugboats placing the anchors. The pipe-laying vessels will likely use dynamic positioning (DP) in deeper water. Other sources of noise will be on-board diesel-driven cranes, compressors and generators. Near-field cumulative sound levels (i.e. overall received levels at some places within the near field) could be as high as 177 dB re 1 μPa rms. Continuous broad-band sounds will be transmitted through the vessel's hull from the gas turbines used to produce power for pipe welding station(s), movement of pipe sections and the welded pipe string, and other shipboard sound (Sakhalin Energy 2003).

Noise levels from some large trailer suction hopper dredges (TSHD) have been recorded in excess of 150 dB re 1 μPa at 1 km, while large cutter suction dredges (CSD) can emit strong tones from the water pumps which are audible to >20 km (Richardson *et al.* 1995). Noise from a dynamically positioned rig tender or TSHD may be detectable for 20–25 km during calm weather conditions, that is, when background noise levels fall below 80 dB re 1 μPa. Such conditions are most likely during the seasonally transitional periods in autumn (March–April) and spring (September–October), but are not common in the region of Barrow Island. Little noise is expected in the marine environment because the majority of the HDD process occurs from shore and the HDD equipment is located onshore.

Onshore Construction

Noise levels for various gas processing facility construction activities (e.g. site blasting, grading, excavating, levelling, material off-loading, grinding, erecting, etc) were predicted using an acoustic model, assuming a worst-case cumulative sound power level of 140 decibels (dB(A)) originating from the proposed site location (Technical Appendix B2). Consistent with the conservative approach to modelling, the screening effects of buildings and barriers at the site were excluded. Noise level predictions were produced for worst-case sound propagation conditions (e.g. 3 m/s winds combined with 2°C/100 m temperature inversion). Three wind directions were investigated: north, east, and south. Table 7-9 presents the predicted noise levels at the construction village site during construction.

Table 7-9:
Predicted Noise Levels at Village Site during Construction

Wind Direction	Wind Speed (m/s)	Temperature Inversion Rate (°C/100 m)	Predicted Noise Level dB(A)
North	3	2	44
East	3	2	41
South	3	2	31

Noise and Vibration from Blasting

The Western Australian Environmental Protection (Noise) Regulations 1997 specify maximum allowable noise levels resulting from blasting. The most stringent noise level, 90 dB $L_{\text{linear peak}}$, applies at any premises outside of the period from 0700 hours to 1800 hours. Considering the distance between the proposed gas processing facility site and the existing Chevron camp site (approximately 3.5 km) it is predicted unlikely that air blast energy levels will reach the 90 dB limit, even for very large blasts.

Further detailed information on the size and type of blasting to be used and the ground composition between the proposed development site and the existing Chevron camp is required before being able to predict vibration levels at the village site. However, assuming blast sizes are sequenced or limited to prevent structural damage to the existing oil tanks and pipeline terminal to the north of the proposed Development, it is unlikely that there will be any impact at the village site.

Noise and Vibration from Dust Removal Activities

During commissioning, a number of systems will use steam or air to remove dust and other trace construction contaminants. The commissioning will generally be conducted over a 6-month period as each system is completed and tested. Each of these activities will be very short in duration and result in localised noise, depending on pressures and volumes of piping involved.

7.4.3 Noise Emissions from Operation of the Proposed Development

Emissions from Operation of Offshore Gas Field

Gas pressure at the subsea gas wellheads and manifolds will be reduced and controlled, creating a noise source at the choke. McCauley (2002) measured the noise produced by an operating wellhead and found that the broadband noise level was low, 113 dB(A) re 1 µPa, which is only marginally above the ambient noise of rough sea conditions. For a number of nearby wellheads, the sources would have to be in very close proximity (<50 m apart) before their signals summed to increase the total noise field (adjacent sources only increase the total noise level by 3 dB(A). Therefore multiple wellheads and manifolds in the arrangement proposed in Chapter 6 are not expected to be much greater than 116 dB(A) re 1 µPa. This would reduce quickly to ambient conditions with increasing distance from the wellhead. Moving towards the shore of Barrow Island, there will be no flow restrictions in the feed gas pipeline that would create a noise source. There will be some minor noise created by the turbulent flow of gas and liquids within the pipeline. The pipeline will have an external coating of concrete which will reduce noise from the turbulent flow from reaching the surrounding water column. It is probable that under moderate sea conditions, any pipeline noise will be lost to the background sea noise within a short distance (<100 m).

Given the constant noise from the wells, manifolds and pipelines, and the fact that these noise sources will be stationary, it is expected that any marine fauna in the area would habituate to the noise. The potential impact of noise on marine life is discussed in more detail in Chapter 11.

Emissions from the Operation of the Proposed Gas Processing Facility

A preliminary environmental noise assessment of the proposed gas processing facility on Barrow Island was undertaken (full details are available in Technical Appendix B2) as summarised below.

An acoustic model was developed using the Environmental Noise Model (ENM) developed by RTA technology. The ENM program calculates sound pressure levels at nominated receiver locations or produces noise contours over a defined area of interest around the noise sources. The inputs required are noise source data, ground topographical data, meteorological data and receiver locations.

The model has been used to generate noise contours for the area surrounding the gas processing facility and also to predict noise levels at the Chevron camp and the proposed construction village sites. The model does not include predictions of noise emissions from any sources other than the proposed gas processing facility because they are relatively small in comparison and unlikely to contribute to the sound levels of the Development. Pipelines to and from the gas processing facility are not included in the noise model as it is not expected that they will emit any significant noise.

The acoustic model was used to predict noise levels for the following scenarios:

- normal gas processing facility operation
- emergency blow-down of gas processing facility
- current power station operated by the Barrow Island Joint Venture.

Noise contours and noise levels were predicted for a range of meteorological conditions, including: calm conditions and worst-case wind conditions for sound propagation in the eight cardinal directions. The effects of temperature inversions on the modelling results were also reviewed (refer to Technical Appendix B2).

Barrow Island is a Class A Nature Reserve and a producing oilfield, consequently public access to the island is limited and there are no noise sensitive premises. The Chevron camp site is located approximately 3.5 km to the south-south-east of the proposed gas processing facility site and the proposed construction village will be located approximately 400 m south. These are the only facilities located on the island where noise could be considered to have any social impact.

Since these facilities are designed to service industry on the island, they have been classed as industrial premises according to Schedule 1, clauses 7 and 8, of the Environmental Protection (Noise) Regulations 1997 (The Regulations). The assigned noise levels are therefore 65 dB(A), 80dB(A) and 90 dB(A) for the L_{A10}, L_{A1} and L_{Amax} descriptors respectively. The most significant of these descriptors for continuous plant noise is the L_{A10} assigned level of 65 dB(A).

Routine Operations

At this early stage of design, noise levels for normal operation of an LNG plant of this capacity are predicted to result in an overall sound power level of 126 dB(A) +/- 3 dB(A). Based on the analysis of equipment specifications, and experience from other LNG projects of this magnitude, air coolers, piping noise and large machinery constitute the most significant sources of noise.

Noise contours produced for night-time conditions and 3 m/s winds from the north-east combined with a 2°C/100 m thermal inversion are presented in Figure 7-8. These meteorological conditions typically generate the highest noise levels over the largest areal extent. The 65 dB(A) noise contour borders the near edge of the proposed construction village. It is approximately 36 dB(A) at the existing Chevron camp site.

The predicted noise levels for routine gas processing facility operation at the existing Chevron camp site for a range of meteorological conditions ranged from 23 dB(A) to 36 dB(A) with the highest noise levels predicted for northerly wind conditions (Figure 7-9). This is far below the assigned level of 65 dB(A) and it is likely that noise from the gas processing facility will be

Figure 7-8:
Predicted Night-Time Noise Contours (north-east) – Routine Operating Conditions

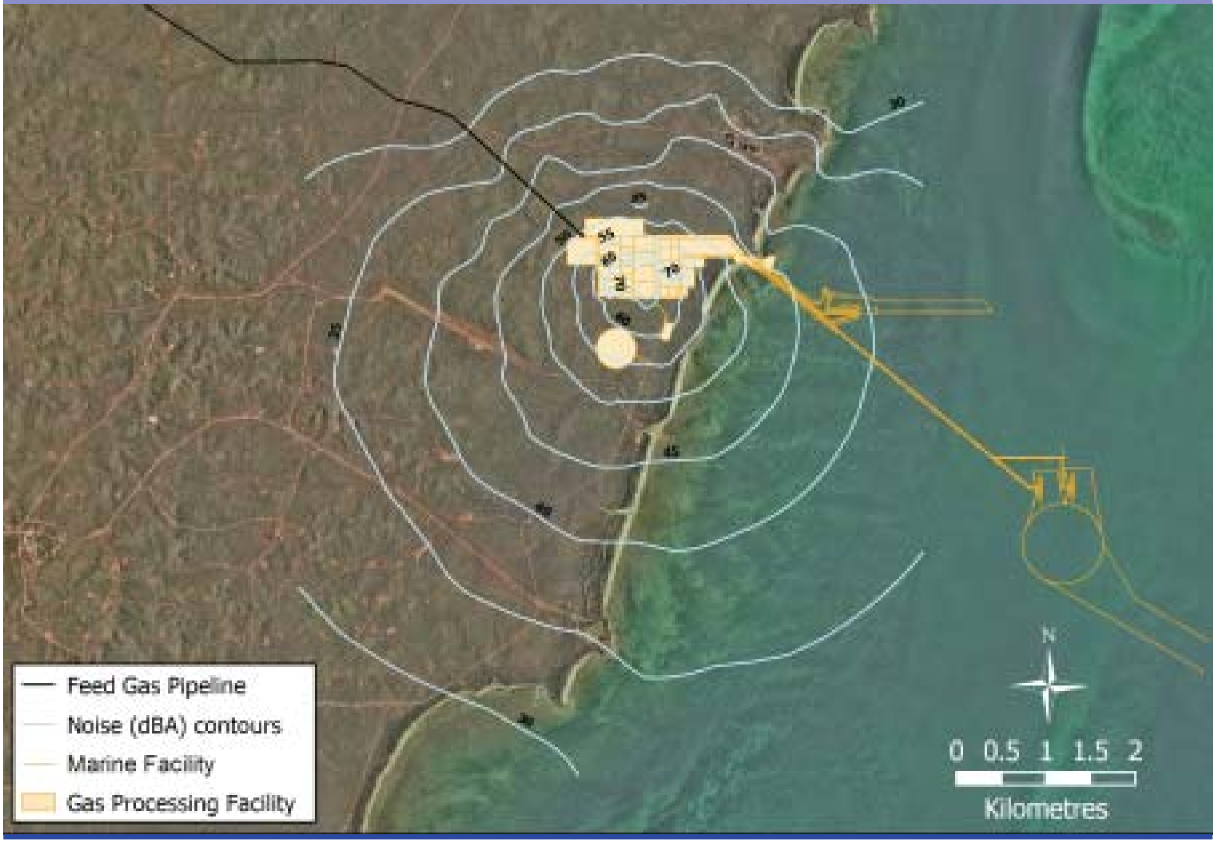
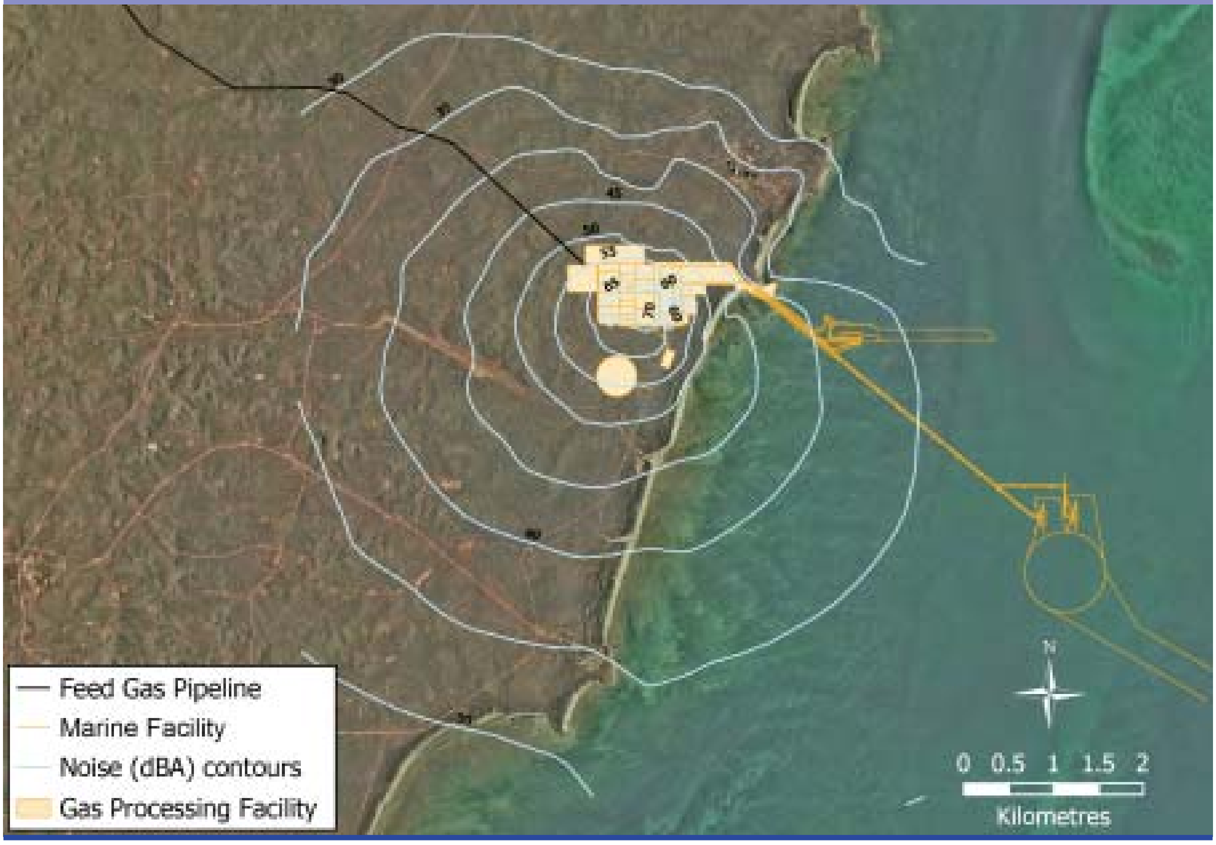


Figure 7-9:
Predicted Night-Time Noise Contours (north) – Routine Operating Conditions



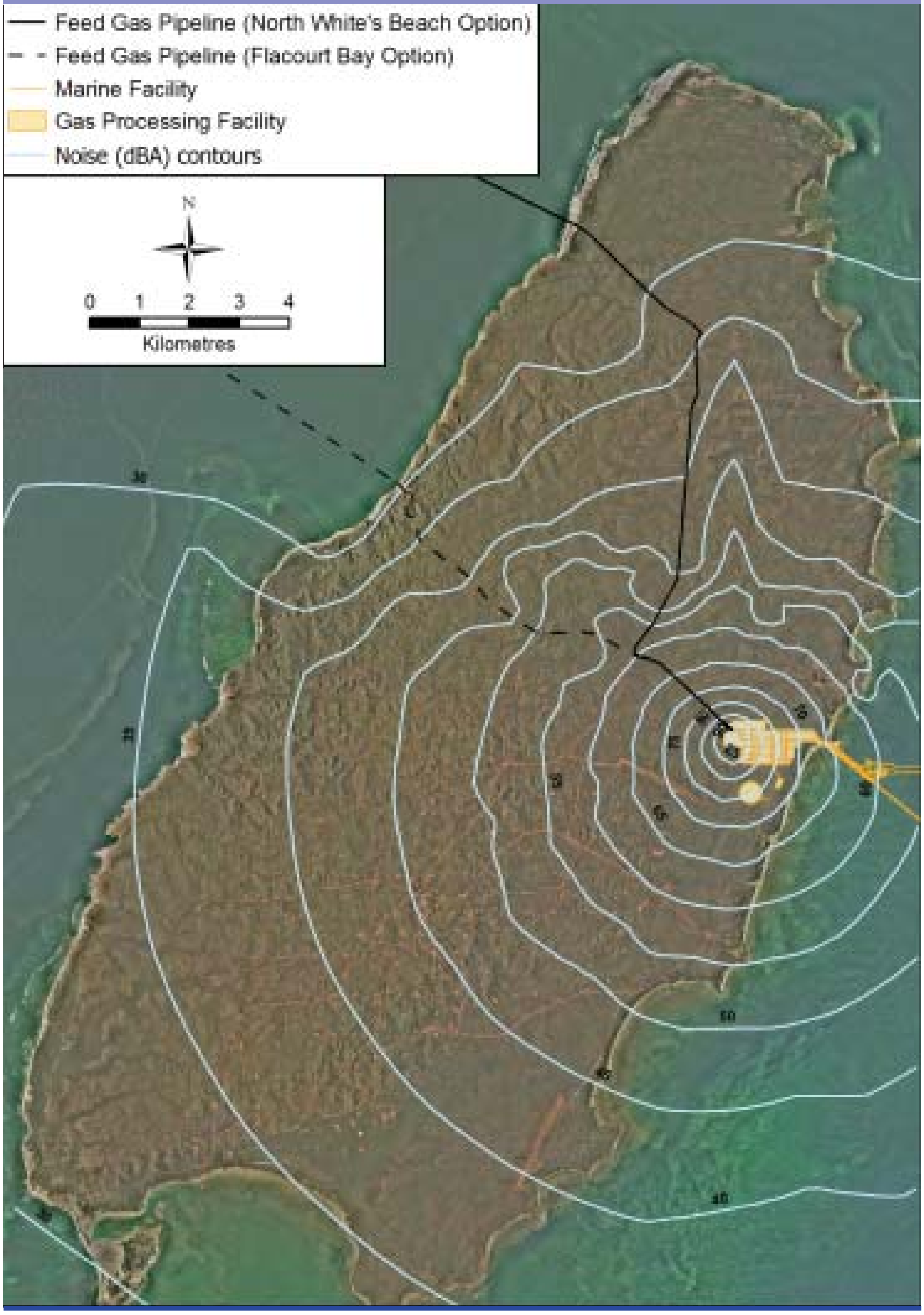
inaudible during normal operations. Under the same meteorological conditions, the noise levels at the Gorgon construction village during routine operations will range from 53 dB(A) to 65 dB(A), also within the assigned level of 65 dB(A).

As baseline information on noise levels, the noise contours were also predicted for the existing power station under worst-case sound propagation conditions. The acoustic model was used to predict noise contours using, as inputs, calculated noise levels from the existing power station and night-time wind and thermal inversion conditions. Maximum existing noise levels are predicted to be of the order of 55 dB(A) at the power station and diminishing to approximately 30 dB(A) within 2 km of this site. These levels do not contribute to the noise level at either the Chevron camp or the proposed construction village (Technical Appendix B2).

Non-Routine Operations

In terms of noise emissions, the most significant non-routine operation will be the flare used during an emergency shut-down of the gas processing facility. It was assumed that a sonic flare would be used in this situation; and a sound power level of 158 dB(A) was assigned for the flare when in operation. It is estimated that this flare will be operated approximately 10 times per year, but not all of these will be for process upset. Noise predictions for an emergency shut-down scenario were undertaken for worst-case sound propagation conditions, e.g. 3 m/s winds from the north combined with a 2°C/100 m thermal inversion. Three wind directions were investigated: north, east, and south. Predicted noise contours (Figure 7-10) for flaring associated with an emergency shut-down of the gas processing facility reach a maximum of 59 db(A) at the existing Chevron camp under worst-case meteorological conditions for sound propagation. This predicted level is below the assigned level of 65 dB(A). However, the level could exceed the existing background noise levels at the camp and may, therefore, be audible under some meteorological conditions. At the proposed construction village, the sound level during an emergency flaring could approach 80 db(A) for a short period of time.

Figure 7-10:
Predicted Noise Contours During an Emergency Shut-Down



7.5 Solid Non-Hazardous Wastes

7.5.1 Current Waste Generation

Solid non-hazardous waste is currently generated on Barrow Island from existing oilfield operations. Putrescible and office paper wastes are segregated and burned in the existing high temperature incinerator and the ashes are buried in a small landfill site on the island. Non-recyclable waste rubber and plastic are separated and compacted on Barrow Island and buried in the local landfill on Barrow Island without burning. In 2003, 390 tonnes of non-hazardous waste solid waste were disposed at the local landfill on Barrow Island. The landfill accepts only clean fill and inert (type 1) waste.

Other solid non-hazardous wastes are removed from Barrow Island for recycling or disposal on the mainland. Any recyclable wastes are segregated and stockpiled at the old airport hardstand area prior to shipment. In 2003, 265 tonnes of scrap metal, aluminium cans, tyres, oil filters, separators, 25 litre drums and thread protectors were removed from the island and recycled.

7.5.2 Expected Development Waste Streams

Solid non-hazardous wastes that will be generated by the Gorgon Development typically include plastic, packaging, scrap metal, general domestic waste, food waste, tyres, waste pipe, concrete and non-hazardous drums and containers.

Solid non-hazardous wastes will be generated in varying amounts throughout all phases of the Gorgon Development; however, it is expected that the majority of waste will be generated during the construction phase on Barrow Island. Wherever practical the following wastes will be re-used or recycled:

- vegetation, rock and soil overburden from site levelling, foundation preparation, pipe-laying, and drilling activity
- drilling fluids, cuttings and dredge spoil material
- scrap pipe, metal fabrication, insulation, concrete and general construction materials
- packaging.

Onshore construction and drilling wastes not reused or recycled will be collected, stored or contained on location at designated collection sites. Wastes generated on Barrow Island will generally be removed from the island for disposal at an approved disposal facility. Dredge spoil from excavation at the MOF, channel and turning basin will be disposed of in designated sites (location provided in Chapter 11) pursuant to the terms and conditions of the Commonwealth Sea Dumping Permit (*Environment Protection (Sea Dumping) Act 1981*) and National Ocean Disposal Guidelines for Dredged Material.

Drill cuttings from offshore activity will be separated from drilling fluids and disposed to the marine environment. Injection of cuttings into a suitable sub-surface formation is extremely unlikely in a subsea wellhead development program at the water depth (>190 m depth) and receiving environment in the Gorgon area. Drill cuttings and fluids from the onshore HDD associated with the shore approaches for the feed gas pipelines will initially be collected, separated and the fluid reused in the drilling process. However, once the drill has broken through the seafloor, some bentonite and drill cuttings will be discharged to the marine environment.

Subsea control fluids will be used to operate, protect and maintain the upstream manifolds and wellheads in the offshore field area. These fluids are specifically designed for this purpose and are commonly used in subsea exploration and development wells in north-west Australia, the Gulf of Mexico, the North Sea and offshore Brazil. An open loop system for subsea control fluids is planned with small volumes of control fluid released from the valves on the seabed when they are operated. Control fluids will be selected for low toxicity and biodegradability while meeting operational requirements. Details will be available in the Environmental Management Plan (EMP).

In the subsequent design phases, it will be possible to provide a better estimate of the volume of construction phase waste that will be generated. Development wastes will be identified, categorised, handled, stored and managed in accordance with a Development-specific Waste Management Plan to be approved prior to any construction activity. Wastes will be greatest during the period of construction when wells and shore crossings are being drilled, the shipping channel and MOF are being dredged and constructed, the gas processing facility and associated pipeline(s) are being constructed. Waste volumes generated during operations and maintenance of the Gorgon Development will be substantially less.

7.6 Liquid Wastes

7.6.1 Liquid Waste Management

Table 7-10 shows the major liquid discharges that will be associated with the Gorgon Development.

Ballast Water

Ballast water is sea water that is taken on to maintain ship/vessel stability. Ballast water will be discharged from the drilling rig, dredges, heavy haul cargo ships, possibly lay-barges and the LNG and condensate tankers. Ballast water tanks on modern vessels are usually segregated from other fuel and product tanks; consequently the potential for contamination from hydrocarbons is very low. Australian ballast water management requirements are consistent with International Maritime Organisation (IMO) Guidelines for minimising the translocation of harmful aquatic species in ships. The potential for introducing non-indigenous marine pest species as part of the ballast water is described in Chapter 12.

Currently all tankers visiting Chevron Australia's marine terminals have been informed of the 'Australian Quarantine and Inspection Service (AQIS) Voluntary Guidelines for the Handling and Treatment of Ballast Water Carried in Ships Entering Australian Waters.'

Since 1993, the source and volume of ballast water discharged from tankers visiting the Barrow and Thevenard Island marine terminals has been monitored.

The options available for managing ballast water include:

- exchange at sea (beyond the 12 nautical mile limit) by an approved method is deemed acceptable
- commitment not to discharge ballast water in Australian ports or waters
- use of the Ballast Water Decision Support System (BWDSS). While not mandatory, this application can provide vessels with a risk assessment of ballast water.

Deck Drainage

Clean deck drainage water on the drill rig, dredges, tankers and support vessels will be directed overboard. If it contains traces of oil, grease or hydrocarbon it will be directed to a sump and oily water separator. The discharge of surfactants, dispersants and detergents will be minimised. Detergents or dispersants used for wash-down will be biodegradable and phosphate free. All endeavours will be made to keep detergents out of oily water separation systems as they adversely affect the separation.

Table 7-10:
Major Liquid Discharges

Liquid Waste – Major Discharges	Development Phases or Activities			
	Drilling	Construction and Commissioning	Operations	Decommissioning
Ballast water	✓	✓	✓	✓
Deck washing and run-off	✓	✓	✓	✓
Treated sewerage/ grey-water	✓	✓	✓	✓
Drilling fluids	✓	✓	✓	
Produced water	✓	✓		
Wellhead control fluids	✓	✓	✓	✓
Pressure testing/ hydrostatic test water		✓	✓ small	
Desalination brine from potable water system		✓	✓	✓
Storm water		✓	✓	✓

If not stored, or directed to onboard tanks, all wastewater prior to discharge will meet or be better than all regulatory requirements. The discharge will be introduced below the surface of the water (if the particular vessel allows this) and will have no significant sheen, visible oil or foam. Sewage and grey-water will be stored in tanks and then pumped to an approved shore-based treatment system if a vessel is operating less than 12 nautical miles from land, or otherwise discharged in line with legislation. Offshore food wastes will be macerated so that they can pass through a 25 mm mesh before being discharged to sea, in compliance with Clauses 222 and 616 of the Schedule to the Petroleum (Submerged Lands) Act, and the International Convention for the Prevention of Pollution from Ships (MARPOL) regulations. Waste management measures are outlined in the Framework Environmental Management Plan (Technical Appendix A).

Onshore, a waste water system will be designed to protect soils, groundwater and the marine environment from contamination. To achieve this, a multi-tiered waste water management approach has been adopted (Chapter 6) in order to minimise the discharge of contaminants and nutrients.

Drilling Fluids

Drilling fluids used in the Gorgon Development are likely to be a combination of water-based and non-aqueous drilling fluids (non-aqueous drilling fluids (NADF)-low toxicity fluids, such as synthetic based fluids which are commonly used in north-west Australia with Regulator approval). The specific fluid systems will be selected when geological information, well development and operating designs are sufficiently advanced for each well. The drilling fluid used offshore is expected to be primarily bentonite with silica, salts, polymers, barite (which often contains heavy metals) and a very small amount of other chemicals, mixed with fresh or sea water. However, technical challenges in the offshore drilling program may require drilling fluids with drilling properties that exceed those of water based fluids. Directional and extended reach drilling may be required to develop many new resources economically. Such drilling requires fluids that provide high lubricity, stability at high temperatures and well-bore stability. These challenges have led to the development of more sophisticated NADFs (e.g. synthetic based mud) that deliver high drilling performance and ensure environmentally sound operations.

The introduction of NADFs into the marine environment is associated with fluid adhering to discharged cuttings following treatment. Significant advances have been made to reduce the toxicity and environmental impacts of NADFs. Where NADF cuttings discharge is allowed, diesel and conventional mineral oils have largely been replaced with fluids that are less toxic and less persistent. Polyaromatic hydrocarbons, the most toxic component of drilling fluids, have been reduced from 1–4% to less than 0.001% for newer fluids (International Association of Oil and Gas Producers 2003). New generation drilling fluids, such as paraffins, olefins and esters are less toxic and are more biodegradable than early generation diesel and mineral oil base fluids. Synthetic based muds and ester based muds are currently used widely in north-western Australia with regulatory approval.

Drilling fluid will be mixed, stored, maintained and recycled in surface tanks. In a closed circulation system used during the drilling of the lower hole sections, the fluid will return to the surface equipment where it will be processed and separated using a range of solids-removal equipment. Drilling fluids and drill cuttings will become wastes at different stages of the drilling process. Drill cuttings are generated throughout the drilling process as formation is cut and removed, although higher quantities of cuttings are generated when drilling the first few hundred metres of the well because the borehole diameter is the largest during this stage.

Waste fluid is handled at completion of drilling because the entire drilling fluid system is removed from the hole as it is replaced by completion equipment and fluids. After completion of drilling, fluid components can be recovered by treatment at the rig or by returning the entire fluid to the supplier. As discussed in Section 7.5.2, a small portion of fluid will be lost during the separation of drill cuttings. The drilling fluid components proposed will have very low to extremely low toxicity to marine life. Further details on mud selection and cuttings management will be included in the Environment Plan required under the P(SL)A for Department of Industry Resources (DoIR) approval.

Produced Formation Water

Produced formation water from the gas fields along with additives such as monoethylene glycol (MEG) and corrosion inhibitor will be brought to the gas processing facility and separated from the gas stream at the slugcatcher. The liquids will then be separated into a water phase and condensate. Monoethylene glycol will pass with the water and will be recovered from the water stream and recycled and condensate will be sent off for stabilisation and storage. If a corrosion inhibitor is used, then any present in the water phase would be directed with the produced water into dedicated injection wells on Barrow Island.

Hydrostatic Test Water

Pressure testing the feed gas pipeline and domestic gas pipelines will require the lines to be filled with chemically treated hydrotest water. Following successful testing, the hydrostatic test water would be emptied prior to commissioning of the pipelines. Chemicals added to the test water would typically include an oxygen scavenger (e.g. ammonium bisulphite, or OS2) and a biocide (e.g. phosphonium sulphate or Bactron). Ammonium bisulphite reacts with the oxygen within the hydrotest water to form ammonium sulphate, consuming all oxygen in the water.

Where possible and practical, test water will be re-used to test other components of the gas processing facility. Following successful testing, the hydrostatic test water will either be discharged by injection into dedicated disposal wells on Barrow Island. If it meets testing requirements, it will be discharged into the marine environment at an approved location and discharge rate. Hydrostatic testing is not a continuous operation and once the facilities have been tested, approved and commissioned, there will be little need for additional test water.

The principal environmental consideration of this discharge would be the anoxic state of the hydrotest water, potential toxicity presented by the phosphonium sulphate and the potential scavenging of oxygen from the ambient seawater. Modelling was applied to quantify whether dilution of the hydrotest water discharge and subsequent dispersion by ambient currents would be sufficient to ensure that oxygen concentrations in the receiving waters will not be significantly reduced.

For the feed gas pipeline, modelling was undertaken on a typical hydrotest water composition which included Bactron at 150 mg/L and OS2 at 100 mg/L. It was assumed that the water is discharged at a depth of 200 m, at production manifold station 2, through a pipe with an internal diameter of 697 mm to represent the feed gas pipeline scenario. The total volume of hydrotest water was estimated at 32 000 m^3 which was discharged in a 23-hour period.

Modelling was applied to determine whether concentrations of phosphonium sulphate would be below the ‘no-effect’ concentration (nominally <0.19 mg/L), and where this no-effect concentration would occur.

Discharge of hydrotest water at the offshore production area (probable location for the feed gas pipeline discharge) was predicted to generate 10-minute average concentrations of 1750 ppb. The concentration of phosphonium sulphate near the discharge is predicted to be maintained below 0.0016 mg/L (i.e. lower than the no-effect concentration) and that oxygen concentrations are estimated above 99% of ambient concentrations. The release rate of hydrostatic test water can be controlled. A reduction in the discharge rate would further increase dilution rates and decrease phosphonium sulphate concentrations.

For the domestic gas pipeline, modelling was undertaken on a typical hydrotest water composition which included Bactron at 150 mg/L and OS2 at 100 mg/L. It was assumed that the water is discharged at a depth of 2 m, 1 km from Barrow Island adjacent to the MOF, through a pipe with an internal diameter of 440 mm to represent the domestic gas pipeline scenario. The total volume of hydrotest water was estimated at 13 600 m^3 which was discharged in a 25-hour period.

For the domestic gas pipeline, the discharge of hydrotest water into the tidal channel off the eastern shore of Barrow Island was predicted to generate maximum 10-minute average concentrations near the discharge of 19 566 ppb. Thus, the maximum concentration of phosphonium sulphate near the discharge would be maintained below 0.0018 mg/L (lower than the no-effect concentration) and oxygen concentrations should similarly be above 99% of ambient concentrations. Concentrations during periods of tidal flow were predicted to be generally lower than 5000 ppb within the immediate area of the discharge. As mentioned above, the release rate of hydrostatic test water can be controlled and any reduction in the discharge rate will increase dilution rates.

Water Maker Brine

As mentioned in Chapter 6, the potable water supply for the Gorgon Development will be provided by a reverse osmosis plant, or similar water making technology. One option currently being examined is to discharge effluent (water maker brine) from this system back into the ocean.

The water maker brine is essentially sea water which has been concentrated by approximately 50% and is close to ambient temperature. It is likely that approximately 3000 m^3/day of this brine would be discharged, which is approximately the volume of an Olympic-sized swimming pool. This will be discharged along the LNG jetty, or subsea line, at an appropriate disposal location. Due to the currents and large volume of water passing the jetty area, each tidal cycle the effluent will be dissipated quickly into the receiving waters and would have negligible environmental impact.

Storm Water

The volumes and quantities of waste water, stormwater, fire water runoff, food and village wastes that will be generated cannot be accurately quantified until subsequent design phases have been completed. Stormwater treatment systems are discussed in Chapter 6.

Waste management measures are outlined in Technical Appendix A. During detailed design, development wastes will be identified and characterised, their volumes estimated and management and disposal options (e.g. avoidance, reduction, recycle and re-use, storage, evaporation, injection and potential marine discharge) prescribed in a Development-specific Waste Management Plan.

7.7 Hazardous Waste

7.7.1 Waste Generation and Expected Hazardous Waste Streams

Hazardous wastes are defined as the waste stream which has one or more components that pose a threat to human health, safety or the environment. Hazardous waste will be generated in varying amounts throughout all phases of the Gorgon Development. It is expected that the majority of hazardous waste will be generated during the construction phase of the Development. In subsequent design phases, it will be possible to estimate the volume of potential hazardous wastes that will be generated and will include recovered solvents, excess or spent chemicals, paints, oil and process-contaminated materials (e.g. sorbents, filters and rags), certain drilling fluid constituents (polymer, bacterial control and corrosion inhibition additives), spent X-ray films, used lubricating oils and filters.

The Gorgon Joint Venturers will implement routine maintenance where many of the filters, spent catalyst and other production wastes will be systematically removed from service, collected, stored or contained on location at designated collection sites and removed from Barrow Island to an approved disposal facility.

All hazardous wastes associated with the Gorgon Development will be managed in accordance with a Development-specific Waste Management Plan. The Plan will include systems and details for tracking wastes from source to final destination or disposal.

Scale

Under certain natural pressure, temperature and chemical conditions, solid minerals (scale) will form from the produced water, usually where there is a significant pressure drop. The most common scales consist of barium sulphate ($BaSO_4$), strontium sulphate ($SrSO_4$) and calcium carbonate ($CaCO_3$). The potential for scale in the Gorgon Development has been assessed and appropriate inhibitors will be used throughout the production process as required. If scales form, they will be treated as hazardous waste and appropriate management and controls will be implemented bearing in mind that they might contain low specific activity materials.

Mercury

Trace amounts of elemental mercury occur naturally in Gorgon feed gas, as in many other oil and gas reservoirs. The mercury removal unit is a vessel which usually contains a bed of granules. As gas passes through the vessel containing the granules, the traces of mercury react and remain chemically trapped. The bed material essentially acts like a filter and so will be removed periodically during routine maintenance (likely to be in excess of six years) and will be returned to the supplier for recycling and handling or disposed on the Australian mainland at an approved facility.

7.8 Dredging and Dredge Spoil Disposal

Dredging on the east coast of Barrow Island is located within the existing Barrow Island port boundary and the proposed dredge spoil disposal site is located over the south-eastern section of the boundary (Figure 7-11).

Construction of the causeway, MOF, jetty and dredged channels and other infrastructure on the east coast of Barrow Island will involve direct disturbance to the seabed in these areas. The dredging and other construction activities required to create the channels and berth areas for the Development will result in physical disruption to localised areas of the seabed, direct loss of some coral habitat, and the generation of turbidity plumes at both the dredging and disposal regions.

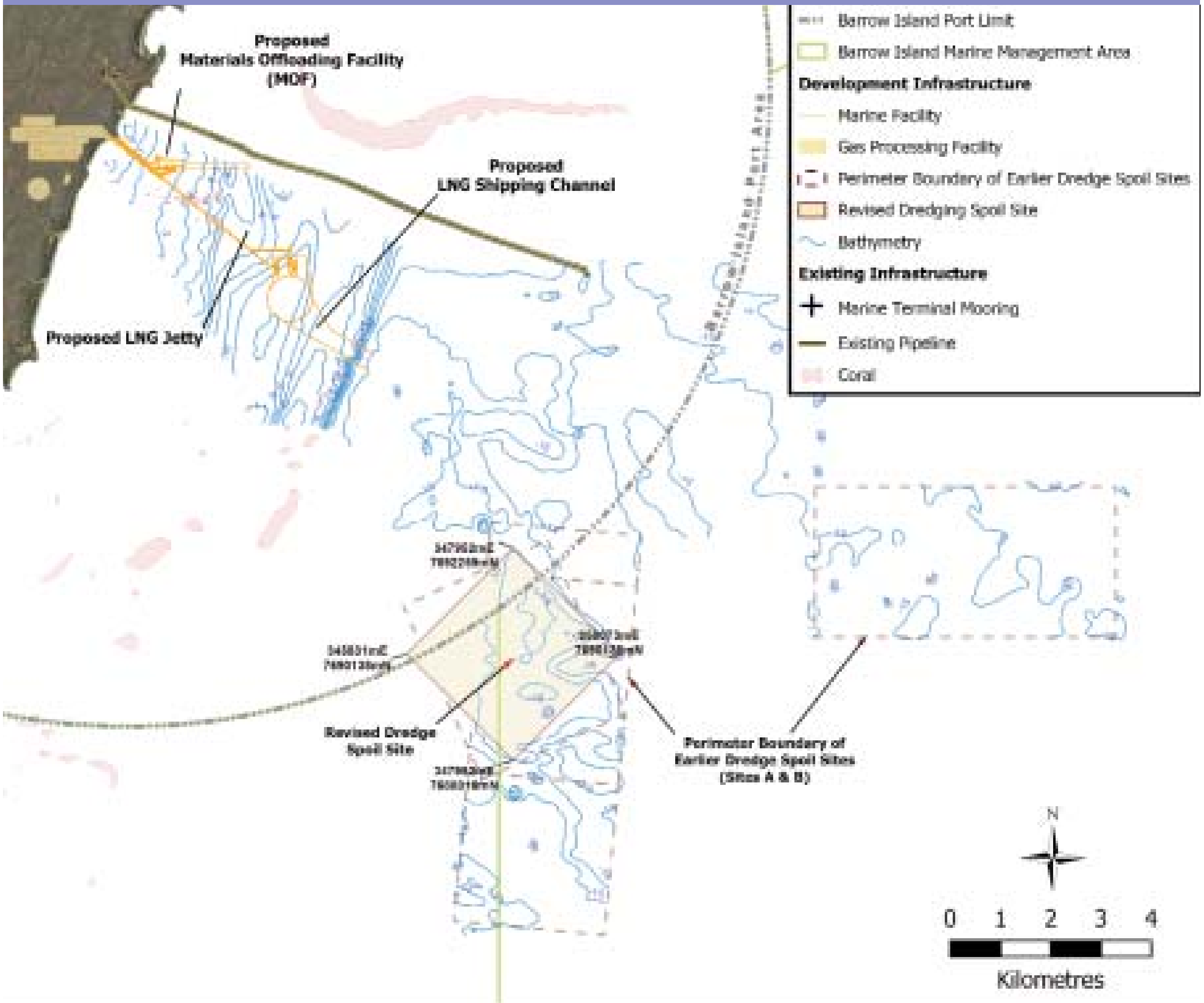
Dredge spoil will be disposed to the seabed at a defined dredge spoil disposal location and will modify the substrate characteristics in the receiving area.

An area of sandy seabed and appropriate bathymetry has been selected for dredge spoil disposal to minimise the changes in substrate type and to minimise migration of the spoil from the disposal ground (Figure 7-11).

Marine Benthic Surveys were undertaken in accordance with a draft Sampling and Analysis Plan (SAP) prepared and submitted to the Department of the Environment and Heritage (DEH) in support of a Sea Dumping Permit for the Development. The program involved:

- sampling at forty sites in areas of potential disturbance (MOF, LNG shipping channel/basin and proposed disposal sites)
- twenty-nine sledge surveys to collect baseline data and investigate the potential concentration of benthic primary producers and other epifauna
- an extensive towed video survey (MOF, LNG shipping channel/basin, proposed disposal sites and other areas of interest).

Figure 7-11:
Proposed Location of Dredge Spoil Site



A series of settlement plates and sediment traps have been installed in the proposed dredging area to provide further information on marine flora and colonisation as well as natural levels of sediment deposition in the areas planned to be dredged (Plate 7-1). The sediment trap data will assist the Joint Venturers in determining the amount of sediment that may potentially infill the dredged channels and turning basins and hence maintenance dredging requirements. In addition, the sediment traps will allow quantification of the natural deposition rate of sediment that corals are presently exposed to and serve as monitoring locations during dredging.

The dredging required to create the channels and berth areas for the Development (Chapter 6) will result in physical disruption to localised areas of the seabed and the generation of turbidity plumes at both the dredging and disposal regions. In order to adopt a conservative approach to potential environmental impacts, prediction of the disturbed areas and plumes has relied on:

- surveying marine habitats and species sensitivities in the proposed Development area
- examining the range of dredging equipment which will be used and potential impacts, such as turbidity at the dredge site due to the action of the cutter head
- reviewing two hydrodynamic models and their dispersion results under a number of seasons to identify potential worst-case scenarios
- using material distributions (as relevant) from past dredging projects in Western Australia, namely the Geraldton Port Enhancement, Hamersley Iron's (Pilbara Iron) Dampier Port Upgrade and the Dampier Port Authority's Bulk Liquids Berth Project since some of the dredging techniques and particle sizes will be similar to the Gorgon Development
- using available preliminary geophysical and geotechnical data supplemented with recent bathymetric and geotechnical (near shore drilling and vibrocore program) information
- using results from sediment analysis of 40 sample locations taken in the Development area
- surveying the physical and availability constraints of the site and/or equipment (i.e. potential restriction of certain dredges due to shallow waters or sea states).

Table 7-11 identifies the proposed locations, equipment, volumes and duration for the dredging program.

To predict and assess the potential impacts on corals and determine the monitoring that will be required, numerical modelling was undertaken using a particle tracking technique (Technical Appendix B5). The modelling was carried out in two steps. Firstly, the 3-dimensional ocean circulation of the region from south of Barrow Island to north of the Montebello Islands was predicted for 16 months using the GEMS coastal-ocean model GCOM3D. Then the total dredging program was simulated over 450 days using a sophisticated particle tracking model which simulates the daily behaviour of the dredge(s) based on an estimated dredge log. Refer to the Technical Appendix B5 for full details of the modelling and results.

For the modelling simulation of the dredged MOF, several assumptions were made as outlined in Box 7-3.

For the simulation of the dredged LNG access channel and turning basin, several assumptions were made and are outlined in Box 7-4.

Plate 7-1:
Installation of Settlement Plates and Sediment Traps – Barrow Island

Table 7-11:
Location, Equipment and Estimated Volumes and Duration of Dredging Activity

Dredging Location/Activity	Dredger/Equipment Proposed	Volume (Mm^3)	Duration
MOF Channel and Basin to -6.5 m LAT	Cutter suction dredge Discharge pipeline to MOF causeway for fill	~0.80	~21 weeks
LNG channel and turning basin to –14 m LAT	Cutter suction dredge and trailer suction hopper dredge and self-propelled hopper barges with bottom dump	~8.0–9.0	~ 45 weeks
Disposal of dredged material to proposed 3 x 3 km spoil disposal site taking advantage of local bathymetry (Figure 7-11)	Self propelled hopper barges with bottom dump	Capacity to handle 12.0	≥45 weeks

Box 7-3:
Summary of Assumptions for MOF Dredging – Cutter Suction Dredge (CSD) Pumping to Bund

- A bund wall in the MOF outline will be filled with dredge spoil pumped directly from the CSD.
- The volume of cut and fill is estimated to be 800 000 m^3.
- According to the geotechnical data available, the material to be dredged is crystalline limestone with a capping of calcarenite.
- The hardness of the rock is believed to be harder on average than that encountered at the recent Geraldton dredging program.
- The characteristics of the spoil is anticipated to be similar to that generated at Geraldton (i.e. a high proportion of fines/flour and coarse limestone rubble).
- The duration of the dredging/reclamation program is estimated to be 18 weeks plus 2+ weeks weather downtime.
- Vessels will work 24-hours per day but a mean dredge work rate of 96 hours of dredging per week should be achieved. (Rate will vary depending on hardness of rock).
- Lost time is due to dredge stopping and changing teeth every few hours (more frequently in harder rock) and for maintenance or refuelling activities.
- Maintenance will occur only in response to difficulties. However, when dredging rock there will be shut-downs each 7 to 14 days in harder material and longer in softer materials. Refuelling will be undertaken each four to six weeks for 2 days.
- The dredge will start at outer end of the access channel and gradually work towards the shore creating a 6.5 m deep channel (LAT).
- It is assumed that 5% of total material cut will fragment to a size below 75 microns and that the distribution of these particle sizes will be similar to the Geraldton dredging program.
- It is assumed that 50% of these fines will be released at the cutter head and 50% from the tailwater discharge.

Box 7-4:
Summary of Assumptions for the LNG Access Channel and Turning Basin

- The total volume to be dredged is estimated to be between 7 and 8 Mm^3.
- Roughly 40% of the total volume in the LNG access channel and turning basin will be sediment, or soft or fragmented rock, which can initially be removed by TSHD.
- The TSHD dredging and disposal cycle period will be approximately 2.5 hrs (based on 90 minutes of dredging, 1 hour of travel to and from spoil ground including 10 minutes for dumping at the spoil ground).
- TSHDs are less weather dependent than CSDs and will be able to deliver about 134 hours production per week which equates to 53 loads per week on average.
- Assuming an average load of 6 000 m^3, giving a bulk production rate of approx. 300 000 m^3 per week, the sands can be removed in 11–12 weeks.
- In general, maintenance will be undertaken travelling to and from the spoil grounds but the TSHD will cease operations for two days every 4 to 6 weeks to refuel and undertake major maintenance.
- Overflow will operate for the last 60 minutes of dredging and will be released under the keel of the THD (–6 m depth).
- Overflow discharge will be approximately 8 m^3/sec (2 x 4 m^3/sec dragheads).
- As the surface sediments are coarse this material is expected to remain low in the water column.
- Fines within the sediments may be released.
- When dredging, the principal source of fines is anticipated to be from propeller action. Overflow of fines from the hopper are added to this from beneath the keel.
- Given that the sands are coarser than the ‘rock flour’, this activity is anticipated to release less fines than CSD operations.
- The particle size distribution used in this part of the simulation is based on laboratory analyses of field samples taken from Development area.
- A large CSD pumping directly into one of two self propelled hopper barges that will transport the material to the spoil ground for disposal.
- Dredge behaviour and production rates are anticipated to be similar to the MOF Dredging rates described in Box 7-3 above (effective production of 96 hours/week).
- The duration of dredging is anticipated to be 55 weeks.
- Fines/flour will be generated at the CSD cutter head and at the hopper barge overflow which will be beneath the keel of the barge.

Modelling has relied on the best available metocean, meteorological, and bathymetric information available to date, including assumptions and details from other recent dredging programs throughout Western Australia. The model will be further validated through more geotechnical, baseline water quality, coral health, and metocean data that will be collected for the Development area and will be available prior to any dredging activity. In addition, a monitoring program will be developed and form part of the comprehensive Dredge and Spoil Disposal Management Plan.

Modelling predicted the daily distribution of Total Suspended Solids (TSS) and seabed coverage to be developed over the total dredge program (approximately 450 days). The daily output was analysed to derive periods of continuous exposure to turbidity and/or sedimentation above defined thresholds. The result of this analysis is summarised in maps of exposure zones showing regions affected by turbidity or sedimentation that result in total mortality, partial mortality or no mortality. Figures showing TSS distributions and the derived exposure zones are shown in Chapter 11 along with the discussion of the assessment and management of potential impacts. Where there was uncertainty in model parameters, conservative values were chosen such that the model would tend to overestimate the extent and magnitude of impact. The model predictions were aligned to the current dredging schedule, which is throughout the year except for the period(s) of coral spawning.

The modelling predicts a build up of deposited sediments in the immediate vicinity of the dredging area and spoil disposal site from the settlement of the larger sediments (>75 µm). Finer sediment fractions remain suspended for longer periods and lead to increased turbidity which varies significantly in space and time. These variations are due to the active ocean circulation around Barrow Island driven by strong tides and marine winds.

The assessment of the potential impacts of dredging and spoil disposal on the marine environment and the basis of the dredge monitoring program are described in detail in Chapter 11.

Recent dredging and spoil disposal programs undertaken by Hamersley Iron for their Port Upgrade at Parker Point and the Dampier Port Authority's Bulk Liquids Berth Project involved prolonged dredging (10 months in total) of significant quantities of material (4.1 Mm^3 and 4.9 Mm^3 respectively), similar in volume to that proposed for the Gorgon Development. Comprehensive water quality and coral monitoring studies for the two programs were incorporated into a single monitoring program (MScience 2005).

The key findings of the studies are as follows:

- Turbidity needs to be elevated for extended periods to produce impacts on coral species. Some species are more sensitive than others.
- While turbidity was high at many sites during the dredging programs, the one site where coral mortality occurred was characterised by high TSS levels, suggesting that the cause of coral mortality during the program was one or more acute episodes of sedimentation. In the case monitored, suspended sediment concentrations from bottom samples which exceeded 60 mg/L in waters within a few hundred metres of coral appeared to be the sole cause of mortality. Chronic sedimentation with TSS levels below 40 mg/L did not appear to result in elevated coral mortality in the two dredging and disposal programs.
- Dissolved oxygen and pH varied little between sites and times and there was no evidence that these parameters were influenced by dredging effects.
- Modelling of TSS levels was used to predict areas where corals could be impacted and where impact monitoring should take place as well as where reference sites should be located. The model provided conservative estimates and actual effects appeared more localised and ephemeral than predicted, principally because the sediments settled out of the waster column much faster than had been predicted.
- Monitoring of TSS and sedimentation rates appear to provide predictive measures of potential coral impacts prior to coral mortality taking place.
- Resuspension of deposited sediment takes place relatively quickly (~10 weeks) and is an important mechanism for removal of the fine sediment from coral areas into deeper soft sediment regions where impacts are minimal.

7.9 Accidental Releases (Spills) to the Marine Environment

The nature of LNG production and supply necessitates robust and reliable design and execution to meet corporate and stakeholder expectations. Consequently, control and planning during execution should achieve optimum supply reliability. This, in turn, will provide the lowest possible risk of hydrocarbon release by ensuring that the highest standards of design, material selection and construction and operation are applied.

The potential hydrocarbon releases that were identified for the Gorgon Development include:

- an onshore release from the feed gas pipeline, condensate from the rupture or leak from a pipeline or tank within the gas processing facility. The risk and management of onshore releases and management are described in the Leaks and Spills section of Chapter 10 and the Public Risk section of Chapter 14.
- a release of condensate and produced water (containing dissolved hydrocarbons and monoethylene glycol (MEG)) from the subsea production equipment, subsea flow lines or the feed gas line running from the supply fields to the western shore of Barrow Island
- release of processed condensate from either of the subsea condensate off-loading pipelines (existing or new) on the eastern side of Barrow Island
- a release of diesel from shore facilities or small vessels operating around facilities on the east and west coasts of Barrow Island
- a release of condensate, crude oil (from other sources) and bunker fuel oil from tankers brought to the export terminal.

Potential releases of other, non-hydrocarbon, fluids from the Development include: accidental spills of MEG which will be piped from Barrow Island to the subsea production wells; heat transfer fluid from a ruptured pipeline or tank within the processing facility, and the controlled discharge of hydrotest water prior to commissioning of the feed gas and domestic gas pipelines and other large inventories (i.e. LNG tanks).

Chemical and product storage areas will be engineered and designed to handle the volumes and operating conditions (both normal and upset conditions) specifically required for each substance, including product identification, transportation, storage, control and loss prevention (e.g. bunding and drainage). If a spill occurs, close adherence to product Material Safety Data Sheets (MSDS) will assist in the appropriate handling and clean-up will reduce the potential impact to the environment. Tank and storage areas will be provided with appropriate bunding and drainage systems in line with Australian Standards (as a minimum) to reduce the extent of potential spills, and to assist containment and subsequent clean-up.

For liquid spills outside of bunded areas, valves will be provided to enable shut-in of production and limit the volume of any release. Areas of surface flow that can be contaminated would be contained within the gas processing facility and directed to the oil recovery system with the risk of spills outside of hardstand areas very low. Soil potentially contaminated by a hydrocarbon or chemical spill will be evaluated and treated by a method that will have the least environmental harm while meeting operational requirements (refer to Chapter 10).

To fully understand the potential environmental risks associated with spills, it is necessary to examine three independent aspects, namely:

- the likelihood that a spill occurs – this is often referred to as ‘Primary Risk’
- if a spill occurs, the way that the material moves with wind and currents and ambient/water temperature (hence there are seasonal aspects) and how the material behaves with other natural processes such as evaporation, dissolution into the water column, and natural degradation – this is often referred to as ‘Secondary Risk’
- given the above two aspects, and for any given spill scenario in specific weather conditions, it is necessary to consider whether the material will reach sensitive receptors. If so, what are the possible impacts on those receptors – this is often referred to as ‘Tertiary Risk’ or ‘Joint Risk’.

The modelling assessment undertaken for the Gorgon Development therefore took into account the following risk categories:

Primary Risk – the potential of an accidental hydrocarbon release occurring from a pipeline, refuelling accident, a marine vessel collision or grounding, and other similar scenarios. For this study, worst-case release scenarios were assessed for the pipelines. This involved a full pipeline rupture and release of contents. For the refuelling and marine collision or grounding scenarios, realistic release volumes were assessed. Spills from onshore tanks were not examined as these will be bunded in line with Australian Standards, as a minimum. The assessment of primary risk is considered to be very conservative, i.e. frequency used in the assessment is much higher than is actually likely. Refer to Technical Appendices B3 and B4 for full details.

Secondary Risk – assuming that a spill has occurred, the secondary risk is the probability of any released hydrocarbon reaching a shoreline or environmentally sensitive area. For this study, the hydrocarbon concentration limit used was 0.8 g/m^2. At this concentration, the hydrocarbon would take on the appearance of a rainbow or dull sheen on the water. The modelling was undertaken during different seasonal climatic conditions and the worst-case was selected. Modelling assumes that no intervention (i.e. booms or dispersants) has taken place and so is a worst-case scenario. (Refer to Technical Appendices B3 and B4 for modelling details).

Tertiary or Joint Risk – represents the overall risk of exposure of sensitive receptors and is very conservative. It is the likelihood that a release occurs and it reaches an area of potential significance and has an effect on sensitive receptors. This conservatively assumes that no intervention (e.g. booms, dispersants, etc) has taken place and so is a worst-case assessment. Refer to Chapter 11 for full details.

Determining the environmental risk associated with a hydrocarbon release to the marine environment requires an assessment of primary, secondary and joint risk which is discussed collectively in Chapter 11. Conservative factors were included in the assessment such that credible ‘worst-case’ release volumes were modelled for each of the scenarios (refer to Table 7-12). For example, the primary risk of pipeline failure has assumed a large/full bore rupture which generates the most significant hydrocarbon losses. In general, for pipelines over 406 mm outside diameter (OD) (16 inch OD), these ruptures only comprise approximately 30% of the recorded incidents within the recorded database (refer to Technical Appendices B3 and B4). In addition, to date there have been no known incidents of full bore rupture of large diameter (609 mm OD to 1067 mm OD) offshore trunklines in operation. Such pipelines are extremely robust and are protected (or kept remote) from known significant risk factors such as vessel anchoring or dropped objects. The data sets applied for the spill modelling relate to failure frequencies of smaller pipelines and are therefore inherently conservative.

There has not been a blowout of a subsea well in the North West Shelf of Australia, therefore spills associated with blowouts are not considered a credible scenario. A blowout is also not considered credible for the Gorgon Development because:

- several wells have already been drilled in the formations and the reservoir pressures are well-known
- blowout prevention equipment is provided and tested in line with legislation
- personnel are fully trained in the use of this blowout equipment.

7.9.1 Control Measures used to Reduce Primary Risk of Hydrocarbon Release

The Gorgon Venturers will employ best practice measures to reduce the primary risk of hydrocarbon releases. Significant focus in the design will ensure that releases from the pipeline systems and the gas processing facility will not occur. The equipment design, material selection and construction standards and techniques adopted for the Gorgon Development will be based upon proven, robust solutions used worldwide and extensively in similar environments and applications.

Given that the feed gas pipeline transports potentially corrosive products, and will be exposed to severe environmental forces over the operational life, some challenges exist with respect to assurance of long-term integrity. The main risks that could result in an unplanned release of hydrocarbons and production water, together with the design mitigation/control measures, planned are summarised in the following sections.

Potential Internal and External Pipeline Corrosion/Reduction in Wall Thickness

As described in Chapter 6, the base case pipeline material for the feed gas pipeline is a lining of Corrosion Resistant Alloy (CRA). In addition to material selection and inhibitor injection, a corrosion management plan will be implemented over the operating life of the pipeline system to monitor corrosion products and sand production. Thresholds will be established and monitored to identify any increase in parameters that may signify increased corrosion or erosion rates within the system. Investigation (including intelligent pigging) and potential intervention will be initiated to define and resolve any technical problems.

Externally, a combination of anodes, cathodic protection, corrosion coatings and monitoring will be employed to eliminate the risk of external corrosion. Systems will be designed with additional capacity beyond the design life to provide contingency. Periodic inspection of the effectiveness of the system will be performed throughout the operating life of the Development.

Potential Pipeline Buckling or Damage During Installation

The subsea pipelines will be designed and installed in accordance with recognised world-class design codes (AS 2885 1997; and DNV OS-F101 1996). Installed pipelines will be inspected and monitored to identify any buckles, coating damage and free-spans greater than design specifications. All damage will be assessed and remedial work performed as required to assure long-term pipeline integrity.

Potential Pipeline Movement or Displacement During Storm Conditions

The pipeline systems will be designed to remain stable during severe environmental loadings created by cyclonic events and major winter storms. For the subsea pipelines, stability will be achieved by the most appropriate stability technique, such as addition of concrete coating, lowering of the pipeline below the seabed and, where necessary, the placement of rock berm(s) or armouring over the installed pipeline(s).

Where pipeline spanning occurs which may result in pipeline overstress during severe weather conditions, the free-span lengths will be reduced by placement of rock or grouted supports. Monitoring of scouring effects that may create or extend free-spans during the design life will be performed by remotely operated vehicle (ROV) and intervention will be initiated as required.

Potential Hydrate Blockage and Overpressure During Operation

The feed gas pipelines will have continuous hydrate inhibitor (MEG) injection over the field life to prevent hydrate internal build-up/blockage. Should a hydrate blockage or leakage occur past a wellhead valve causing pipeline pressure to build up beyond normal operating levels, the pipeline integrity will not be impacted due to protective measures built into the pipeline design.

Potential Pipeline Weld Failure During Operation

Offshore pipeline material and welding process selection will be performed in accordance with design standard DNV OS-F101 (1996). Steel grades selected will be of high strength. Weld materials will be carefully matched to assure the same or improved strength. Stress concentration effects will be assessed during pipeline installation analysis.

All weld procedures and welders used offshore will be fully tested, qualified and approved by third party inspection agencies. Installation will be performed by world-class contracting companies using automatic or semi-automatic welding processes, automatic ultrasonic inspection/testing systems or other appropriate non-destructive testing techniques.

The pipelines will also be hydrostatically tested in line with legislation to ensure their integrity.

Potential Flange/Connector Failure During Operation

The main feed gas pipeline(s) will be fully welded along the length, but some flanged connections will be required within the pipeline system and these connections will be inspected and tested. Connections used subsea will be extensively tested onshore and will have facilities to verify seal integrity during subsea make-up before hydrocarbon pressurisation.

The entire pipeline systems will be fully hydrotested and gauged to verify strength and connection integrity, in accordance with AS 2885 requirements before commencing operation.

During the operational life of the pipeline system, a number of risks exist from external sources that could result in leakage of hydrocarbons. The various risks which have the potential to result in hydrocarbon release, together with controls and mitigation measures that could/will be adopted are summarised below.

Dropped Object Risk

Dropped objects of a size capable of significantly damaging a large diameter pipeline comprise drilling equipment (drill collars, blow-out preventer etc) or vessel anchors. During subsequent drilling phases and subsea well work-over operations, handling of heavy equipment will be performed some distance from the pipeline, with procedures in place to minimise the risk and consequences of such an incident.

The pipeline will be clearly identified on navigation charts with clear warnings to avoid anchoring within a set exclusion zone along the pipeline. The pipeline corridor will run over a very exposed (unsheltered) area which is unlikely to be used for large vessel anchoring except in emergency situations.

The pipeline will also be concrete weight coated over most of its length. It is expected to have a wall thickness in excess of 40 mm which will provide very significant impact resistance in the unlikely event of an anchor being dropped (recreational vessel anchors will not significantly damage the pipeline). In some areas it is also likely that rock berm will be placed over the pipeline for stability reasons, further reducing levels of risk from dropped objects.

The smaller utility pipelines associated with the feed gas pipeline will also be protected. They will be largely protected by the presence of the feed gas pipeline itself.

Fishing Gear Interaction

Currently, there are no significant risks envisaged along the pipeline routes from fishing activities. Based on the co-existence of operating pipelines and the fishing industry in the Onslow/Dampier area, the potential for snagging and significant displacement of one or more of the pipelines with consequential damage to the pipelines is considered extremely low. Generally the boats involved in the commercial fishery (prawn trawl and trap) are small, manoeuvrable and their activities are controlled by limited entry, seasonal and area closures, gear controls and catch reduction devices. Pipelines can affect trawling activities as they create a ‘no-go zone’, but equally can act as an artificial reef which attracts fish life and increases yields. No pipeline appurtenances will be on the pipeline design that could be damaged and result in leakage.

Vessel Sinking/Grounding

Vessel sinking and impacting directly onto the pipeline is a very remote risk, given the limited vessel traffic in the area. Should such an event occur, it is likely that only large vessels would result in significant pipeline damage and that smaller vessels (e.g. cray boats, pleasure and recreational fishing craft) would be unlikely to have sufficient mass to cause a release.

The remote risk of a large vessel running aground is restricted to the shallow water shore crossing area. On the west coast, the feed gas pipeline will be installed under the seabed in the near shore area. It will be protected by a rock berm or similar covering material outside of this shore crossing area to assure near shore pipeline stability. The LNG and condensate tankers will have an experienced navigational pilot on the bridge when within the port boundaries. These tankers will be escorted/assisted by tugs during berthing and departure. A tug will be on standby during cargo loadings. In the event of a cyclone, the ships will depart the loading terminals and standby at sea until favourable docking and loading conditions return.

Vessel Anchor Dragging

Anchor dragging has the potential to damage the pipeline; however, only large vessels are likely to have anchors of a sufficient size to pose a significant threat. As noted for dropped objects, the pipeline will be clearly identified on navigation charts with clear warnings to avoid anchoring within a set exclusion zone along the pipeline.

The level of risk this presents to the pipeline will be assessed as part of a Quantitative Risk Assessment during subsequent design phases of the Development. If required, a rock berm could be placed over the pipeline to deflect dragged anchors in areas where the risk of large vessel anchoring is considered credible.

Sabotage

Sabotage of the pipeline is a credible risk only in areas where it is accessible. Given that the offshore and shore crossing areas are inaccessible (either subsea or encased in a drilled conduit or backfilled trench), the sabotage risk with subsequent hydrocarbon leakage is a very low risk for the offshore pipeline system.

Refuelling

The probability of hydrocarbon release is highest for refuelling vessel/ships, especially during construction. A number of basic procedures that will be carried out during refuelling to avoid or reduce the possibility of a release include:

- undertaking fuel transfer activities in accordance with established procedures and adhering to all port authority and pollution regulations
- refuelling within established safety boundaries and during weather/sea/visibility conditions that will minimise potential release risk
- training personnel involved with refuelling or fuel transfer in their roles, functions and responsibility, including emergency response
- maintaining open communication channels
- deploying spill prevention systems in accordance with established procedures and regulatory requirements
- maintaining emergency response equipment to ensure that it is readily available.

7.9.2 Fate and Transport of Spilled Hydrocarbon

The fate and consequences of hydrocarbon spills, in terms of their trajectory, change in nature due to weathering. The potential for harmful effects upon shoreline and shallow water habitats are a product of the nature of the oil type, the release conditions and the environmental conditions prevailing during and after the spill occurs (French 2000). Modelling of such spills has been undertaken and is based on the assumption that no intervention has taken place to contain the spill should one occur. Thus the modelling represents the worst-case for each spill scenario. The Gorgon Joint Venturers will have in place a comprehensive spill contingency plan, which will include pre-approved use of dispersants in line with current best practice. Neither of these response considerations is included in the results of spill modelling discussed below.

Numerical modelling was applied to determine where a hydrocarbon or other liquid release could spread in the unlikely event of a full pipeline rupture (worst-case scenario). Table 7-12 is a summary of the release source (location), the type of fluid released, the depth of the release, the volume and the duration (the estimated time from initial release to its control). Table 7-13 is a summary of the risk of exposure associated with various release scenarios.

Table 7-12:
Hydrocarbon Release Scenarios used for the Prediction of Spill Trajectories

Release source	Released fluid	Depth (m)	Volume (m^3)*	Break-down	Duration (hours)
Rupture at central manifold of Gorgon production area	Condensate & formation water	200	2200	630 m^3 condensate, rest water and MEG	3
Rupture of feed gas pipeline 14 km from Barrow Island	Condensate & formation water	50	1600	590 m^3 condensate, rest water and MEG	4.5
Rupture of feed gas pipeline 200 m from Barrow Island	Condensate & formation water	12	1600	590 m^3 condensate, rest water and MEG	4.5
Rupture of condensate export pipeline 2.2 km from Barrow Island	Condensate	2	1550	100% condensate	3
Refuelling accident during the supply of the pipe-laying barge 10 km west of Barrow Island	Diesel fuel oil	Surface	2.5	100% diesel	<1
Refuelling or incident or spill of fuel from the port facilities adjacent to the MOF jetty	Diesel fuel oil	Surface	0.1–10**	100% diesel	<1
Work vessel collision within port approaches. Randomised within 2000 m radius of a location 2.7 km west of the proposed MOF jetty	Diesel fuel oil	Surface	2–20**	100% diesel	1–6**
Randomised most likely grounding site for a tanker along the 12 m depth contour. Most likely grounding site during each major wind season.	Processed condensate, light crude oil or bunker fuel oil	Surface	10–100**	100% hydrocarbon	1–24**

** Volume is total fluid (i.e. condensate, MEG and water)*

*** Release duration and volume randomised within this range*

The nature of each discharge, potential release conditions and seasonally varying environmental conditions was modelled as described in more detail in the following sections. A stochastic model was used to determine the fate of 100 simulations for a given release scenario and season combination. A threshold thickness of 0.01 mm (0.8 g/m^2 or the equivalent to a dull sheen/'rainbow' film on water) was defined as a threshold for recording episodes of contact with surface cells by surface-bound hydrocarbons. A minimum concentration of 10 parts per billion (ppb) was defined for entrained oil.

Results of the multiple simulations were analysed to provide a statistical weighting to potential spill outcomes following the procedures defined in French et al. (1999). The following sections describe each of these scenarios in greater detail.

Essentially this process summarises the likelihood, if a spill occurs, that it will move in a certain direction under the forces of wind and currents. For example, if 75% of the year the wind and currents both move from the south-west to the north-east, for 24% of the year they move from the north-west to the south-east and for the remaining 1% of the year they move from the east to west, if a spill occurred, there is a chance of 1 in 100 that a sensitive receptor located west of the spill site might be affected. If a spill had a primary risk of occurring of 1 in ten million (1×10^{-7} per year), then the chance of impacting that specific sensitive receptor is 1% of 1×10^{-7} per year or 1×10^{-9} per year.

It is also highly unlikely that, if a spill occurred, the material would move to have any impact on a sensitive receptor which is situated north-west or south-west of the spill site.

In the following section, the term per cent probability (%) refers to the same concept, assuming a spill has occurred, but using real wind and current data. It should be noted that the probabilities given in this section as percentages must be combined with the primary risk to reach a conclusion regarding risks to sensitive receptors.

Releases of Condensate and Reservoir/Formation Water from the Upstream Supply

Fluids within the production well, production flowlines and feed gas pipeline to Barrow Island are expected to include water, MEG and hydrocarbon condensate. The natural gas component (predominantly methane) will not be a liquid under these operating conditions. The worst-case scenario for these facilities is a rupture at one of the offshore manifolds, the infield flowlines or the feed gas pipeline to the island during production, at normal operating pressures.

From statistical and actuarial records, submarine facilities and pipeline constructed in Australian waters are inherently safe. As mentioned previously, to date there has been no known incidents of full bore rupture of large diameter (609 mm OD to 1067 mm OD) offshore trunklines in operation.

For the purpose of this assessment, failure data for smaller lines has been used and so it has been assumed that there is very low probability (primary risk) of hydrocarbon spills occurring (2.81×10^{-5} per kilometre year, or the probability of 2.81 incidents every 100 000 years for a 1 km segment of pipeline). Further discussion on the probability of release and the risk to workers and the public are described in Chapter 14 and in the Technical Appendix B4. As described earlier (Section 7.9.1), the primary risk will be further reduced by incorporating physical and chemical/electrical protection measures, modern construction and operating procedures, as well as developing appropriate navigational hazard identification and exclusion zones. However, in the unlikely event of an incident, such a rupture is assumed to result in a release of gas and all entrained liquids within the pipeline. The assumption that all of the liquids are released is also a very conservative assumption.

Modelling of the three scenarios involving high-pressure release from the manifold and feed gas pipeline indicated that the atomised plume of condensate would tend to rise towards the surface, where it would pool to form a thin slick. Dissolved hydrocarbon plumes generated in this process were also predicted to rise, due to entrainment by the rising plume of condensate.

Potential Manifold Rupture

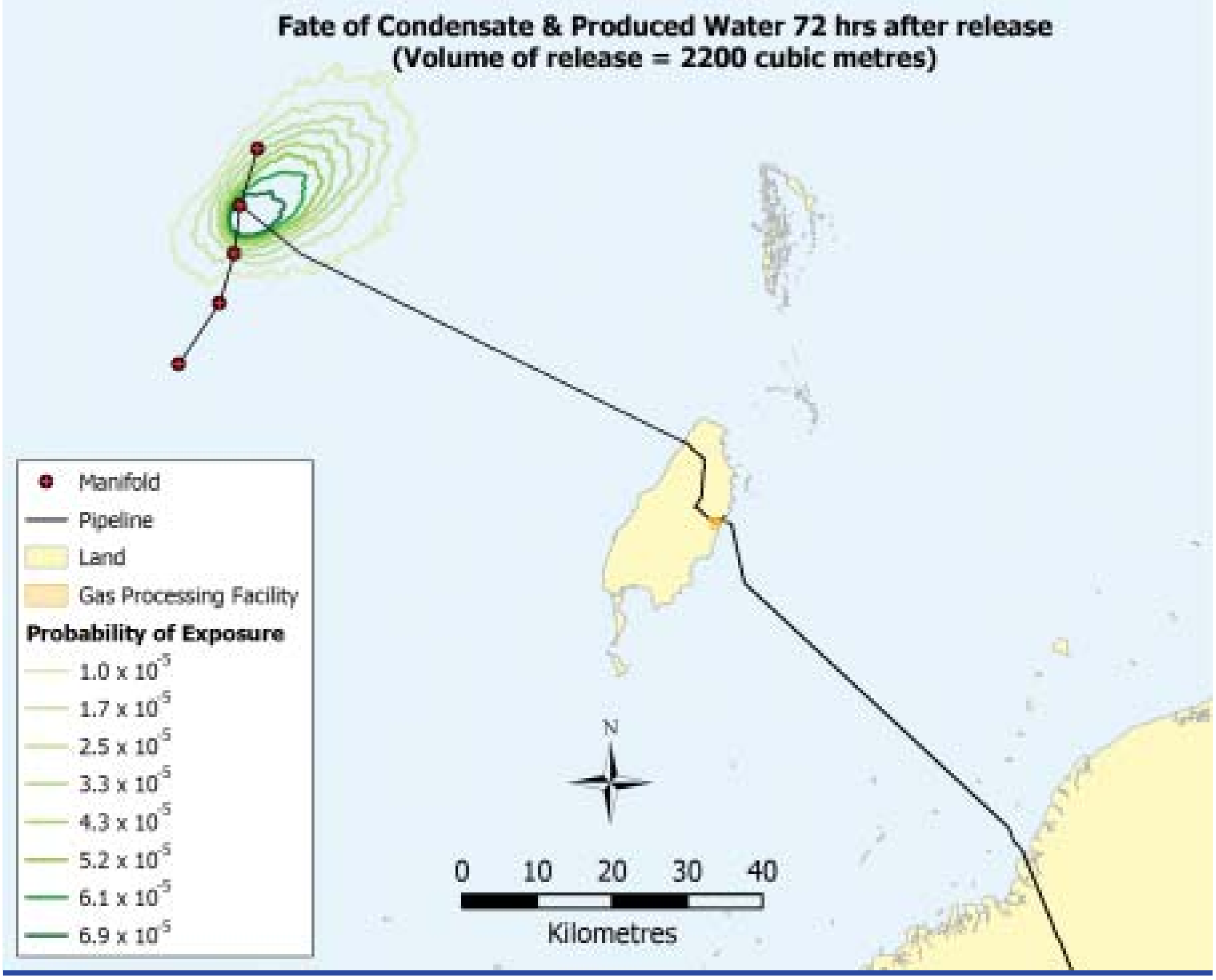
The probability of the manifold or feed gas pipeline rupturing is very unlikely. However, if a rupture occurred, the risks of exposure from surface slicks and dissolved hydrocarbons would vary markedly among the three release sites modelled (Technical Appendix B4). Stochastic modelling indicated that a floating condensate slick generated by a rupture at the manifold would most commonly drift towards the north-east to the seaward side of the Montebello Islands (Figure 7-12). Further, this slick was predicted to thin to a rainbow-sheen 72 hours after the release. A rainbow-sheen is a very thin layer of oil less than 0.0003 mm in thickness. The sheen could potentially extend to a distance of approximately 40 km, so could dissipate before landfall. Peak concentrations of aromatic hydrocarbons in the surface layer were predicted to decrease to <10 ppb within 30 km. Consequently, if such a release occurred, the probability of exposure to shallow water habitats by potentially harmful concentrations of floating oil or aromatic hydrocarbons was predicted to be very low (<1%). Therefore the combined primary and secondary risk is two orders of magnitude less than the primary risk which is already very low.

Potential Feed Gas Pipeline Rupture

Modelling of the fate of a feed gas pipeline rupture 14 km off Barrow Island predicted that the resultant slick of condensate could reach landfall before thinning to a rainbow-sheen. However, as this does not represent the worst-case scenario, it is not described further (specific details are provided in Technical Appendix B3).

The worst-case scenario (albeit extremely unlikely) is a full pipeline rupture 200 m from the western shore of Barrow Island. In the unlikely event that this scenario eventuated, the probability of condensate and production water washing onto the shoreline was predicted to be very high year-round (Figure 7-13). It is estimated that the maximum extent of the slick would occur within 72 hours of the release. After this

Figure 7-12:
Release of Condensate and Produced Water from Central Manifold



time, the condensate would evaporate due to the weathering caused by wind, waves, tides, water and air temperature. Under light wind conditions, all volatile hydrocarbons were expected to evaporate within 48 hours.

The potential length of affected shoreline and the potential volume that could wash ashore are also markedly larger (up to 43 km and 159 m^3, respectively) than for a rupture further offshore. Concentrations of aromatic hydrocarbons exceeding 300 ppb could reach shallow water habitats between the Montebello Islands and the Lowendal Islands, while concentrations up to 4 ppm are predicted for the central-west and north-west coasts of Barrow Island. Simulations indicated a high probability that these elevated concentrations could be trapped inshore for extended periods (>12 hours) under onshore wind conditions, especially during summer, indicating a high potential of exposing resident biota.

Release of Processed Condensate from the Condensate Offloading Pipeline

The condensate offloading pipeline and the future option to run a dedicated condensate loadout line along the proposed LNG jetty and then subsea to a single buoy mooring are both located within the Barrow Island Port boundary. The existing offloading pipeline is, and if required the new offloading line would be, marked on navigational charts with an appropriate exclusion zone. To date there has never been a spill recorded from the existing export pipeline in its 40 years of operation.

Figure 7-13:
Predicted Release of Condensate and Produced Water from Feed Gas Pipeline (200 m from Barrow Island)

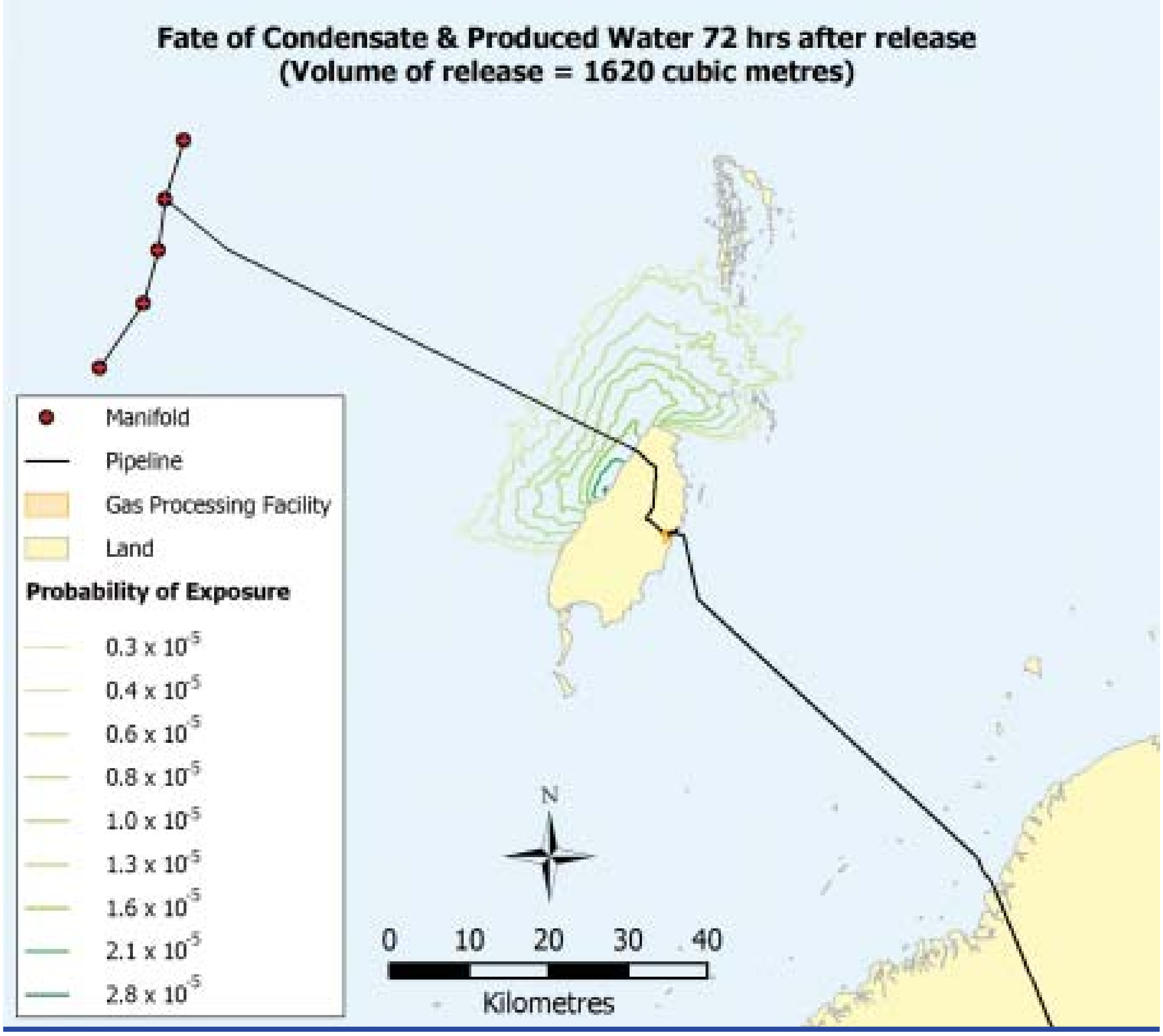


Table 7-13:
Estimates for the Risks of Exposure Associated with Defined Release Scenarios**

Spill Scenario				Risk Estimates			Shoreline Exposed (km)		Volume on Shore (m^3)	
Spill Source	Season	Spilled Fluid	Approximate Spill Volume (m^3)	Primary Risk of Spill Occurring	Secondary Risk of Oil Onshore (per incident)	Joint Risk of Spill Occurring	Maximum	Mean ± St. dev.	Maximum	Mean ± St. dev.
Rupture at central manifold	Summer	Condensate & water	2200 total (630 cond)***	7.50×10^{-5}/y	$<1 \times 10^{-2}$	$<7.50 \times 10^{-7}$	NC	NC	NC	NC
	Annual	Condensate & water	2200 total (630 cond)***	1.50×10^{-4}/y	NT	NT	NT	NT	NT	NT
Rupture of feed gas pipeline	Summer	Condensate & water	1600 total (590 cond)***	1.41×10^{-5}/kmy	9.9×10^{-1}	1.39×10^{-5}	43.4	14.4 ± 6.3	158.6	129.4 ± 25.9
200 m from Barrow Island on route 1	Transitional	Condensate & water	1600 total (590 cond)***	4.68×10^{-6}/kmy	1.0×10^{-0}	4.68×10^{-6}	37.9	15.6 ± 6.9	116.6	75.9 ± 10.4
	Winter	Condensate & water	1600 total (590 cond)***	9.37×10^{-6}/kmy	9.6×10^{-1}	8.99×10^{-6}	20.6	9.3 ± 5.3	39.1	12.8 ± 3.6
	Annual	Condensate & water	1600 total (590 cond)***	2.81×10^{-5}/kmy	9.8×10^{-1}	2.76×10^{-5}				
Rupture of condensate offloading pipeline	Summer	Condensate	1550	7.40×10^{-5}/kmy	7.2×10^{-1}	5.33×10^{-5}	57.9	10.2 ± 15.0	22.4	3.8 ± 1.1

Table 7-13: (continued)
Estimates for the Risks of Exposure Associated with Defined Release Scenarios**

Spill Scenario				Risk Estimates			Shoreline Exposed (km)		Volume on Shore (m^3)	
Spill Source	Season	Spilled Fluid	Approximate Spill Volume (m^3)	Primary Risk of Spill Occurring	Secondary Risk of Oil Onshore (per incident)	Joint Risk of Spill Occurring	Maximum	Mean ± St. dev.	Maximum	Mean ± St. dev.
2.2 km from Barrow Island	Transitional	Condensate	1550	2.47×10^{-5}/kmy	9.6×10^{-1}	2.37×10^{-5}	49.6	24.5 ± 13.5	47.8	33.8 ± 8.6
	Winter	Condensate	1550	4.93×10^{-5}/kmy	1.0×10^{-0}	4.93×10^{-5}	81.3	32.4 ±17.9	605.8	295 ± 137
	Annual	Condensate	1550	1.48×10^{-4}/kmy	8.5×10^{-1}	1.26×10^{-4}				
Release alongside MOF jetty	Summer	Diesel	0.1–10*	4.50×10^{-3}/y	8.4×10^{-1}	3.78×10^{-3}	17.8	3.6 ± 3.8	0.5	0.2 ± 0.2
	Transitional	Diesel	0.1–10*	1.50×10^{-3}/y	7.2×10^{-1}	1.08×10^{-3}	21.7	4.8 ± 4.2	0.5	0.4 ± 0.1
	Winter	Diesel	0.1–10*	3.00×10^{-3}/y	1.6×10^{-1}	4.80×10^{-4}	30.6	6.6 ± 5.0	0.5	0.4 ± 0.1
	Annual	Diesel	0.1–10*	9.0×10^{-3}/y	5.9×10^{-1}	5.34×10^{-3}				

NC – No Contact

NT – Not Tested because of very low risk and probability of shoreline exposure

* *Release volume randomised within this range*

** *Results are for hydrocarbon concentrations exceeding 0.8 g/m^2. Seasonal rates for primary spill risk assume a proportion of the annual risk based on the number of months in summer (6), winter (4) and transitional (2) seasons. The joint risk is calculated as the product of the primary and secondary risk. The volumes and shoreline expose assume no intervention of any kind, but the Gorgon Joint Venturers will have in place a comprehensive spill contingency plan, which will include pre-approved use of dispersants in line with current best practice.*

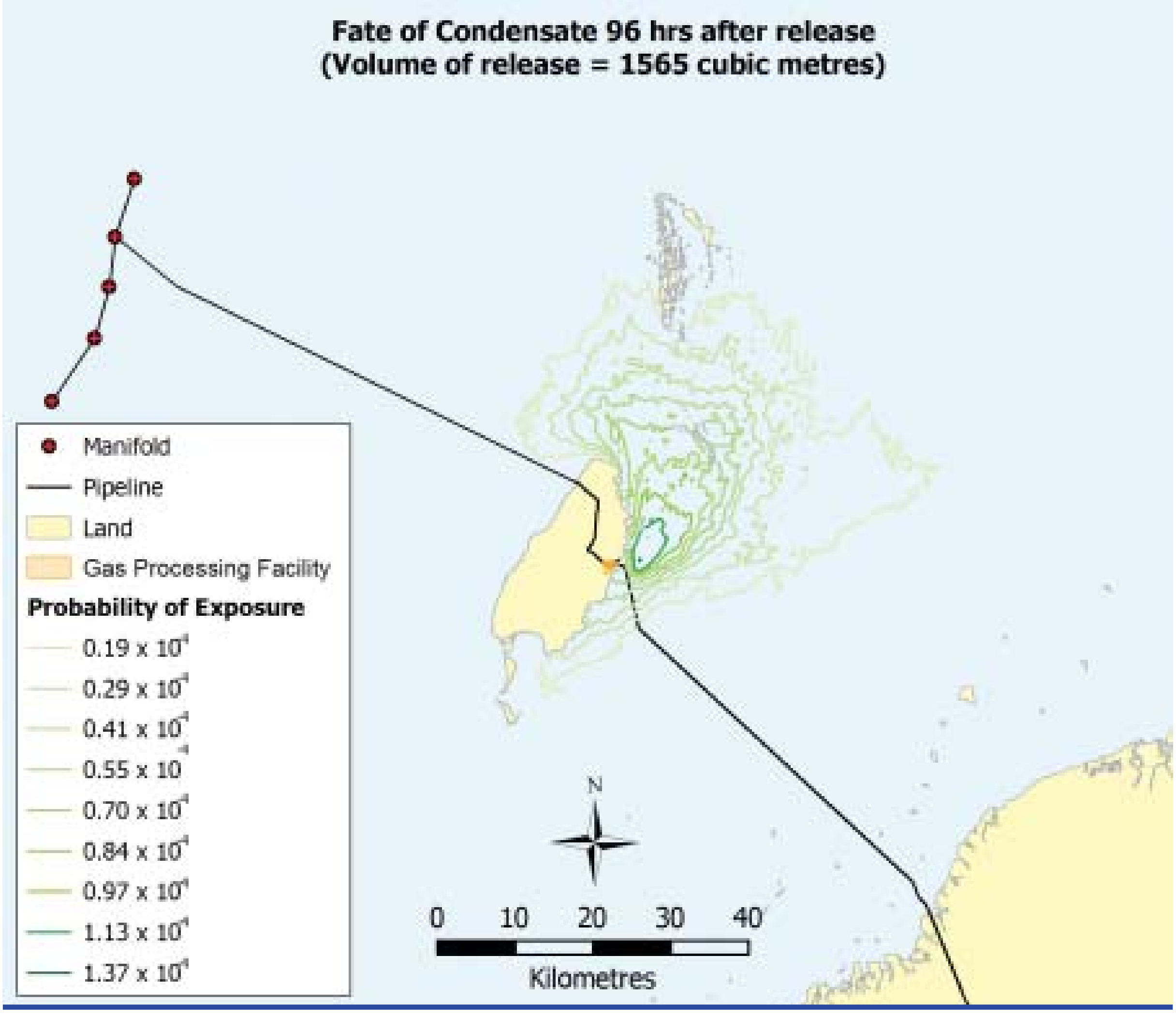
*** *Represents the condensate (hydrocarbon) component of the spilled fluid*

A complete rupture of the existing condensate offloading pipeline, when pressurised and delivering condensate to a tanker, was identified as the worst-case scenario. A rupture point about 2 km offshore was identified as the worst-case location, due to the proximity of shallow reef habit and the strong currents between Barrow Island and the Lowendal Islands (Figure 7-14).

Simulation of this spill scenario predicted that if such a release occurred (joint risk of 4.93×10^{-5}) a slick of floating condensate would most commonly drift along a north-south axis with the prevailing tidal currents. Depending on climate and metocean conditions, after 96 hours, parts of the slicks were predicted to have a high probability of washing onto shorelines throughout the adjacent islands, year-round (72–100% depending upon the season). The highest probability of shoreline exposure (100%), the largest potential shoreline area (81%), and the highest potential volumes of condensate (606 m^3) were predicted for winter when prevailing easterly winds would tend to force the hydrocarbon slick onto Barrow Island. During winter, the probability of the Lowendal Island shorelines receiving floating condensate at the concentration of 0.8 g/m^2 was predicted to be 60% and those at the Montebello Islands was up to 30%. Dissolved aromatic hydrocarbons within the intertidal and shallow sub-tidal areas along the east coast of Barrow Island were of the order of 10–30 ppm, while the average predicted concentrations among simulations were 1–3 ppm.

The lighter and more variable winds during the transitional months (April and September) were predicted to increase the risk of exposure to the Lowendal Islands (to 70%) and reduce the risk of

Figure 7-14:
Predicted Release of Condensate from Condensate Offloading Pipeline (2 km from Barrow Island)



exposure to the west coast of Barrow Island. Slicks were still predicted to most commonly drift along a north-south axis with the prevailing tidal currents under summer wind conditions. However, the high frequency of winds from the south-east is expected to increase the probability that slicks would drift to the east and pass south of the Lowendal Islands. This would result in the probability of exposure to shorelines (the average length of affected shoreline and the average volume of stranding condensate) being lower.

The modelling shown in Figure 7-14 was for the existing condensate loadout line. If the new condensate line failed, the consequences, especially the worst-case scenarios mentioned above, would be similar to those already described. It must also be emphasised that at the 2 km point the new line (either to the single buoy mooring or the LNG jetty head) would be on the jetty structure, and the likelihood of such a failure is less than the existing line.

It is not considered credible that both lines would fail simultaneously.

Releases from a Grounded Tanker

Export tankers that arrive or leave the Barrow Island tanker terminal could potentially be carrying bulk quantities of condensate, crude oil from other sources, and bunker oil (as fuel). There have been no spills resulting from a grounded tanker in the 40 years of operations at Barrow Island. The probability of a spill from a grounded and holed tanker is low, based on data from other areas, and is estimated to be 2.34×10^{-5} per cargo transfer (refer to Chapter 14 on Public Risk). The use of single hulled tankers is assumed, so with the international trend to use double hulled tankers, the assessment in this section is very conservative.

The likelihood of a hydrocarbon spill from a grounded and holed tanker in the vicinity of the tanker terminal is remote. However, if a spill occurred, it would pose a relatively high risk of oil and dissolved aromatic hydrocarbon exposure to shorelines and shallow habitats throughout the east coast of Barrow Island, the Lowendal and Montebello archipelago. The potential risks to marine flora and fauna are described in Chapter 11 and will vary depending upon the oil type that may be released and the prevailing season. Factors associated with the oil

type that affect risks include the spreading rate of the oils (a function of the viscosity) and the rates of evaporation (a function of the volatility of the oil components).

Condensate spills are predicted to spread quickly, increasing the areas potentially affected, but reducing the thickness involved. In contrast, a heavy bunker fuel is predicted to spread and evaporate more slowly so that higher loads could potentially come ashore from a grounded tanker spill.

During summer and the transitional months, the most likely grounding site predicted for a tanker that drifts from the tanker terminal without power is on the north-east side of the tanker terminal. Slicks of floating oil from this area are expected to most commonly drift to the north-east, passing to the south of the Lowendal Islands. However, if a spill occurred, shorelines of the Lowendal group are predicted to have up to 20% probability of exposure depending upon the oil type. Shorelines along the eastern coast of Barrow Island have a 10% probability of exposure.

Overall, the probability that some shoreline would be affected is estimated to range from 25 to 51%, depending on the oil type. Potential shoreline exposure for bunker fuel, crude oil and condensate spills is estimated to be up to 39%, 18% and 6% of the spill volume, respectively. Aromatic hydrocarbons associated with the slicks are predicted to expose the shallow pavement areas and coral to the south and south-east of the Lowendal Islands during these seasons, at concentrations up to 500 ppb.

Under winter wind conditions, the shallow water west of the existing tanker terminal is predicted to be the most likely grounding site. Slicks are most likely to drift with the strong current operating along the Barrow Island channel before traversing west around the north or south ends of Barrow Island. Consequently, Barrow Island was predicted to have the highest risk of exposure (50 to 70%) from this type of event. There is also the potential that other shorelines on adjacent islands will be at risk. Potential shore loads are predicted to be up to 50% of the spill volume for a bunker fuel spill and 12% for a condensate spill. Sub-surface plumes of aromatic hydrocarbons are predicted to affect the east coast of Barrow Island (at up to 260 ppb) and would reach Barrow Island shoals (at >10 ppb).

If a dedicated condensate loadout line is provided for the Gorgon Development (and the existing condensate loadout line is still used by the Barrow Island Joint Venture) then there is an extremely remote possibility that two condensate ships could be in the vicinity at the same time. The total number of condensate ship movements in a year would still be the same. A collision could theoretically occur between the two ships, but given the large distance between the two offloading systems and the port controls which will be in place to control vessel movements, a collision is not a credible scenario.

Diesel Spills from Operational Vessels

The probability of a diesel spill from an operating vessel is low and the volumes of fuel transferred are usually quite small; however, this type of spill has the highest probability rating of occurring and is estimated to be 9.0 x 10^{-3} per cargo transfer (or 9 incidents every 1000 transfers (refer to Chapter 14 on Public Risk). Diesel spills onto water tend to spread rapidly and to entrain readily. Diesel fuel is also unique in that the toxicity of the oil is not directly related to the aromatic content, but is thought to relate to other less volatile components within the entrained oil (French 2000). Thus, concentrations of entrained diesel are more indicative of the potential for toxicity to submerged habitats.

Modelling to predict risks of exposure to either surface oil or entrained oil at shorelines from a refuelling spill off the west coast predicted a decrease with distance offshore, especially during summer (Table 7-13). For the volumes modelled, the rate of contact with shorelines during summer is predicted to be 84% at 2.5 km offshore, 60% at 5 km offshore and 16% at 10 km offshore. In addition, the longer time required for diesel to drift towards shore from 10 km offshore increases the probability for effective dispersal of entrained and floating diesel before exposing shallow waters off Barrow Island or the adjacent islands.

Surface slicks of diesel generated by spills at the MOF are not expected to travel more than about 12 km before entraining and dispersing to a thin sheen (Figure 7-15). Entrained diesel is predicted to affect a larger area. Entrained diesel is predicted to drift along a north-south axis from the strong currents along the Barrow Island channel. Wind driven currents during winter and the transitional months are expected to force plumes of entrained diesel against the shore (99% probability; Figure 7-15), resulting in highest concentrations (up to 2.4 ppm) within the shallow waters along the east coast of Barrow Island. A higher risk of exposure to the shallow pavement areas west of the Lowendal Islands is predicted for summer.

Larger spills of diesel generated further offshore within the port approaches are predicted to potentially affect a larger area at higher concentrations. Visible diesel slicks were predicted to potentially drift as far as the Lowendal Islands to the north and potentially extend to the southern ends of Barrow Island. Entrained diesel is expected to affect similar areas, at similar concentrations to those predicted for a diesel spill at the MOF.

7.9.3 Other Potential Releases (Non Hydrocarbon)

Spills of Monoethylene Glycol (MEG)

Monoethylene glycol would be pumped from Barrow Island to the production wells via a separate pipeline running parallel with the feed gas pipeline. Rupture probability is remote and estimated at 4.32 x 10^{-5} per kmy. Rupture of the line is expected to result in rapid (within 2 minutes) depressurisation, releasing about 11 m^3 of MEG before the supply is isolated automatically in response to the pressure drop.

Simulation of this release scenario at 50 m depth along the pipeline indicated that the MEG will be initially dispersed by the velocity of the release, resulting in peak concentrations of around 6000 mg/m^3 of MEG adjacent to the discharge, which would disperse to <50 mg/m^3 within about three hours. Stochastic modelling of this scenario under randomly selected currents indicated that the plume would tend to drift along the axis of the local tidal currents and dilute to <10 mg/m^3 within 3 km of the discharge.

Figure 7-15:
Predicted Release of Diesel from an Operating Vessel (at MOF)