Appendix I Preliminary Hazard Analysis

GLOUCESTER COAL SEAM GAS PROJECT

GAS GATHERING AND PROCESSING FACILITIES AND TRANSMISSION PIPELINE

PRELIMINARY HAZARD ANALYSIS

UPDATE

AGL GLOUCESTER L E PTY LTD

PREPARED FOR:	**Stuart Galway** **AGL Gloucester L E Pty Ltd**
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Gloucester Coal Seam Gas Project Gas Gathering and Processing Facilities and Transmission Pipeline Preliminary Hazard Analysis Update	P. JOHNSON
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ABBREVIATIONS

AC	Alternating Current
API	American Petroleum Institute
AS	Australian Standard
CP	Cathodic Protection
CPF	Central Processing Facility
DN	Nominal Diameter
DWTT	Drop Weight Tear Test
EA	Environmental Assessment
EGIG	European Gas Pipeline Incident Data Group
ERP	Emergency Response Plant
ESP	Export Sales Pipeline
FHA	Final Hazard Analysis
GCSG	Gloucester Coal Seam Gas (Project)
GJ/s	Giga-Joules per second
HAZID	Hazard Identification
HAZOP	Hazard and Operability (Study)
HDD	Horizontal Directional Drilling
HDPE	High Density Polyethylene
HDS	Hexham Delivery Station
HIPAP	Hazardous Industry Planning Advisory Paper
km	kilometres
KP	Kilometre Post
kPa	kilo-Pascal
kV	KiloVolt
LFL	Lower Flammability Limit
m	metres
MAOP	Maximum Allowable Operating Pressure
mm	millimetres
MPag	MegaPascal (gauge)
MW	MegaWatt
^oC	Degrees Celsius
P&ID	Piping and Instrumentation Drawing
PCV	Pressure Control Valve
PE	Polyethylene
PEL	Petroleum Exploration License
PHA	Preliminary Hazard Analysis
PLC	Programmable Logic Controller

SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
scmh	Standard cubic metres per hour
SDV	Shutdown Valve
SMYS	Specified Minimum Yield Strength
TEG	Tri-ethylene Glycol
TJ/d	Tera-Joules per day
VCE	Vapour Cloud Explosion
WHRU	Waste Heat Recovery Unit
WT	Wall Thickness

1. EXECUTIVE SUMMARY AND RECOMMENDATIONS

1.1. Purpose and Scope

AGL Gloucester L E Pty Ltd (AGL) operates a coal seam gas pilot facility in the Gloucester Basin (Licence PEL 285). The location of the PEL area is approximately centred on the township of Stratford, approximately 70 kilometres north of Newcastle in New South Wales. The area extends approximately 60 km north to south and approximately 20 km east to west comprising some 18 blocks and about 1,308 square kilometres. The area completely contains the Gloucester Geological Basin. PEL 285 was granted in 1992. The coal seam gas pilot project was developed and operated by Lucas Energy Pty Ltd on behalf of the joint venture partners AJ Lucas Group Ltd and Molopo Australia.

The gas field is currently being evaluated for commercial gas production with the installation of a pilot gas field project. The pilot gas project is located 7.2 kilometres Southeast of Gloucester town.

Lucas Energy commissioned EPCM Consultants (EPCM) to undertake project management, design and environmental work for the expansion of the project beyond the pilot project stage. In turn, EPCM commissioned Sherpa Consulting Pty Ltd to undertake a Preliminary Hazard Analysis (PHA) for the expanded project (Ref. 1).

AGL Energy acquired the development from the joint venture operators at the end of 2008. Following design changes, AGL wish to update the PHA. The design is still in the conceptual stage. The PHA assumes a full production capacity of 80TJ/d for the gas gathering system and the processing/ compression station at Gloucester, with some sensitivity cases for various capacities and diameters for the gas gathering and spine lines.

AGL Gloucester has engaged Sherpa Consulting Pty Ltd (Sherpa) to update the PHA for the proposed Gloucester Coal Seam Gas (GCSG) Project, including the following features:

- the coal seam gas well-sites
- the gas gathering and spine lines from the well-sites to the Central Processing Facility (CPF)
- the Central Processing Facility
- the Export Sales Pipeline (ESP) from the CPF to the Hexham Delivery Station (HDS)
- the Hexham Delivery Station.

This report summarises the objectives, scope of work, methodology and results of the PHA update.

1.2. Study Findings

Individual fatality risk transects were generated for the gas gathering and spine lines (from the well-sites to the Central Processing Facility) and the gas transmission pipeline between the Central Processing Facility and the Hexham Delivery Station (for pipe running through both R1 and T1 location class areas).

Individual fatality, injury and escalation risk was evaluated (and risk contours generated, as required) for the following facilities:

- the coal seam gas well-sites
- the Central Processing Facility
- the Hexham Delivery Station

The following sections summarise the findings of the risk assessment.

1.2.1. Well-Sites Risk Profile

Risk contours were generated for the well-sites. There will be approximately 110 production well-sites, each with provision for up to 4 well-heads. The following were the results of the assessment of the risk contours:

- The 0.5 x 10^{-6} per year individual fatality risk contour (sensitive land-use) was found to extend by about 40m from the centre of the well site. This will not extend to any sensitive land-uses.
- The 1 x 10^{-6} per year individual fatality risk contour (residential areas) was found to extend by about 38m from the centre of the well site. This will not extend to any residential areas as well sites will be located to provide a minimum exclusion zone
- The 5 x 10^{-6} per year individual fatality risk contour (commercial areas) was found to extend by about 20m from the centre of the well site and will not extend to any commercial land-uses.
- The 10 x 10^{-6} per year individual fatality risk contour (active open spaces) was found to extend by about 15m from the centre of the well site and will not extend to any active open spaces.
- The 50 x 10^{-6} per year individual fatality risk contour (industrial areas) was not generated by the well-site hazard scenarios.

The radius of the risk contours for the well-sites depends on a number of factors with a predominant factor being the pressure assumed for the well-site equipment. For the well-sites at the Gloucester coal seam locations, a pressure of 10.2 MPa was assumed based on design rating of well-site equipment upstream of the well-head shutdown valve. The actual operating pressure will be much less than this early in the wellhead life (typically 4 MPa) and will degrade over the operating life of the wellhead. The assumption of a 10.2 MPa pressure will give a conservative estimate of risk level compared with similar facilities where a lower operating pressure is assumed.

1.2.2. Gas Gathering and Spine Lines

The proposed polyethylene gas gathering and spine lines will be provided with marker tape at a minimum of 200 mm above the lines and will be covered to depths of 600 mm, 750 mm (roadway crossings) and 900 mm (creek crossings), following the guidelines of AS4645.3:2008, Table 5.1 (Ref. 2). Gathering and Spine Lines to be constructed of PE100 SDR13.6 polyethylene pipe. Gathering lines will be of 12 mm wall thickness and spine lines of 43 mm wall thickness. The gathering and spine lines will traverse mainly rural land.

Risk transects were produced for the gas gathering and spine lines, showing the individual risk of fatality versus the distance from the centreline of the pipe. A number of cases are considered taking into account a range of pipe diameters and process flow rates.

The risk transects calculated for the gathering and spine lines showed that the risk of fatality would not be expected to exceed about 3 x 10^{-7} p.a. for all cases. Therefore the risk near these pipelines will meet the NSW DoP criteria for all land use types (including sensitive land uses).

1.2.3. Central Processing Facility (CPF) Risk Profile

CPF-1 Option

Risk contours were generated for two proposed CPF location options (CPF-1 and CPF-7). The following assessment findings relate to the **CPF-1** option:

- The 0.5 x 10^{-6} per year individual fatality risk contour (sensitive land-use) was located within the boundary of the site and does not extend to sensitive land uses.
- The 1 x 10^{-6} per year individual fatality risk contour (residential areas) was located within the boundary of the site and does not extend to residential areas.
- Risk levels for other land use types (commercial, active open spaces, industrial) were located within the boundary of the site and do not extend to the relevant land use types.

CPF-7 Option

The following were the results of the assessment of the risk contours for **CPF-7**:

- The 0.5 x 10^{-6} per year individual fatality risk contour (sensitive land-use) was located within the boundary of the site and does not extend to sensitive land uses.
- The 1 x 10^{-6} per year individual fatality risk contour (residential areas) was located within the boundary of the site and does not extend to residential areas.
- Risk levels for other land use types (commercial, active open spaces, industrial) were located within the boundary of the site and do not extend to the relevant land use types.

1.2.4. Export Sales Pipeline Risk Profile

Risk transects were produced for a number of cases showing the individual risk of fatality versus the distance from the centreline of the pipe. Table 1.1 summarises the distances estimated for the ESP to risk criteria levels for land uses as measured from the centreline of the pipe. This shows the minimum separation distances required for various land use types to ensure compliance with the risk criteria of the NSW DoP.

DN 450 Pipeline – R1 Locations

For the DN 450 pipeline in R1 locations (Case 1), the fatality risk contour level for sensitive land uses (5×10^{-7} per year) was found to extend up to 190 m from the centreline of the pipe, however, sensitive land uses (including hospitals, schools, child care facilities, aged care housing, etc.) were not identified to exist within a this distance from the centreline of the pipeline.

Risk levels with the potential for significant impact to residential areas (1×10^{-6} per year) were shown to extend 35 m from the centreline of the ESP. From a review of the separation distances to the nearest residences identified near the pipeline (Section 6.3), the nearest residences are located as close as 15 m from the pipeline.

These locations are within the first 16 km of the pipeline, in R1 locations. Therefore, Case 1 (with 750 mm DOC and no marker tape) will not comply with the NSW DoP risk criteria. Therefore, additional measures will be required near these locations, such as additional depth of cover and/or marker tape.

DN 450 Pipeline – T1 Locations

For the DN 450 pipeline for T1 locations (Case 2, with 900 mm DOC and marker tape), the fatality risk contour level for sensitive land uses (5×10^{-7} per year) was found to extend up to 41 m from the centreline of the pipeline. Sensitive land uses (including hospitals, schools, child care facilities, aged care housing, etc.) were not identified to exist within a this distance from the centreline of the pipeline.

Risk levels with the potential for significant impact to residential areas (1×10^{-6} per year) were not reached at any distance from the centreline of the ESP.

TABLE 1.1: DISTANCES TO CRITERIA OF INDIVIDUAL RISK OF FATALITY – EXPORT SALES PIPELINE

Case	Distance to Individual Risk of Fatality (m)				
	Sensitive (hospitals, nursing homes)	**Residential**	**Commercial**	**Active Open Spaces**	**Industrial**
	(5×10^{-7} per year)	**(1×10^{-6} per year)**	**(5×10^{-6} per year)**	**(1×10^{-5} per year)**	**(5×10^{-5} per year)**
DN 450 Pipeline					
Case No. 1	190	35	Not Reached	Not Reached	Not Reached
Case No. 2	41	Not Reached	Not Reached	Not Reached	Not Reached
DN 250 Pipeline					
Case No. 3	230	215	20	Not Reached	Not Reached
Case No. 4	35	Not Reached	Not Reached	Not Reached	Not Reached
Case No. 5	43	Not Reached	Not Reached	Not Reached	Not Reached
Case No. 6	45	12	Not Reached	Not Reached	Not Reached
Case No. 7	10	Not Reached	Not Reached	Not Reached	Not Reached

1.2.5. Hexham Delivery Station (HDS) Risk Profile

Risk contours were generated for the HDS and the risk assessment showed the following:

- The 0.5×10^{-6} per year individual fatality risk contour (sensitive land-use) was found to extend off-site by a maximum of about 30m. The contour remains within the Zone 4a Industrial Area, and does not reach any sensitive land-uses.
- The 1×10^{-6} per year individual fatality risk contour (residential areas) was found to extend off-site by a maximum of about 20m to the southern boundary of the HDS site. The contour remains almost entirely within the Zone 4a Industrial Area and does not reach any residences.
- The 5×10^{-6} per year individual fatality risk contour (commercial) was found to be contained within the boundary of the HDS site and therefore will not extend to adjacent commercial zones (i.e. retail centres, office or entertainment centre).
- The risk levels for other land use types (active open spaces, industrial) were not generated for the site, i.e. risk levels at the HDS did not reach the criteria levels for these land use types at any point on the HDS site.
- The 50×10^{-6} per year injury risk contours were not generated on the site.
- The 50×10^{-6} per year escalation (accident propagation) risk contours were not generated on the site.

1.3. Societal Risk

Due to the low off-site risk levels at each facility, societal risk was not evaluated.

1.4. Bio-Physical Effects

The following general comments concerning biophysical and environmental impacts were made as a result of the assessment:

- The effects of an accidental emission of methane gas are unlikely to threaten the long-term viability of the ecosystem or any species within any sensitive natural environmental areas which may exist near the proposed development.
- The potential biophysical effects of produced-water (including accidental emission) are evaluated in the Environmental Assessment (EA, Ref. 3).

1.5. Conclusions

A PHA was undertaken to determine the off-site risk profile of the proposed Gloucester Coal Seam Gas (GCSG) Project, including the well-sites, gathering lines, processing facility, transmission pipeline and delivery station.

The PHA found that the off-site risk of fatality, injury and accident propagation posed by the GCSG project meets the requirements of the NSW Department of Planning Risk Criteria for Land-Use Safety Planning (Ref. 4).

The effects of an accidental emission of methane gas are unlikely to threaten the long-term viability of the ecosystem or any species within any sensitive natural environmental areas which may exist near the proposed development. The potential biophysical effects of produced-water are evaluated in the EA (Ref. 3).

1.6. Recommendations

1. It is recommended that, near existing residences in R1 locations (or land identified for future residential use) that are within 35 m of the centreline of the Export Sales Pipeline, safeguards in addition to those provided for Case 1 (DN 450mm pipeline in R1 locations) should be implemented. These additional safeguards may include marker tape and/ or additional depth of cover.

2. The proposed Export Sales Pipeline would not cross any known areas of mine subsidence. However, as this may change in the future, it is recommended that AGL liaise with the Mine Subsidence Board to determine likely future mining activity and the potential for subsidence.

3. The PHA should be updated when final design details are known, particularly for the operation of the flare.

4. Once final design details are known, the design should be HAZOPed, particularly to assess abnormal operating modes such as flare and blowdown operations.

As the design develops, the project is generally required to complete a number of other safety and risk studies, as part of the NSW Department of Planning Seven Stage

Approval Process, which are to be undertaken in accordance with the relevant Departmental guidelines.

2. INTRODUCTION

2.1. Background

AGL Gloucester L E Pty Ltd (AGL) operates a pilot facility for a coal seam gas facility in the Gloucester Basin (Licence PEL 285). The location of the PEL area is approximately centred on the township of Stratford, approximately 70 kilometres north of Newcastle in New South Wales. The area extends approximately 60 km north to south and approximately 20 km east to west, comprising some 18 blocks and about 1,308 square kilometres. The area completely contains the Gloucester Geological Basin. PEL 285 was granted in 1992. The coal seam gas pilot project was developed and operated by Lucas Energy Pty Ltd on behalf of the joint venture partners AJ Lucas Group Ltd and Molopo Australia.

The gas field is currently being evaluated for commercial gas production with the installation of a pilot gas field project. The pilot gas project is located 7.2 kilometres Southeast of Gloucester town.

Lucas Energy commissioned EPCM Consultants (EPCM) to undertake project management, design and environmental work for the expansion of the project beyond the pilot project stage. In turn, EPCM commissioned Sherpa Consulting Pty Ltd to undertake a Preliminary Hazard Analysis (PHA) for the expanded project (Ref. 1).

AGL Energy acquired the development from the joint venture operators at the end of 2008. Following design changes, AGL wish to update the PHA. The design is still in the conceptual stage. The PHA assumes a full production capacity of 80TJ/d for the gas gathering system and the processing/ compression station at Gloucester, with some sensitivity cases for various capacities and diameters for the gas gathering and spine lines.

These assumptions (summarised in Section 9), which may change prior to finalisation of the design, will be reviewed in the Final Hazard Analysis.

2.2. Study Objectives

The objectives of the study were to undertake a Preliminary Hazard Analysis (PHA) of the GCSG Project, in accordance with NSW Department of Planning guidance: Hazardous Industry Planning Advisory Paper (HIPAP) No. 6 (Ref. 5), ‘Guidelines for Hazard Analysis’, HIPAP No. 4, ‘Risk Criteria for Land Use Safety Planning’ (Ref. 4) and ‘Multi Level Risk Assessment’ (Ref. 6).

The Multi-level Risk Assessment Guideline (Ref. 6) was consulted to identify the most appropriate level of risk assessment. This PHA is based on a Level 2 Risk Assessment where the results are sufficiently quantified to allow an assessment of the offsite risk levels against acceptance criteria.

2.3. Study Scope

The scope of the PHA included the following GCSG Project facilities:

- Wellhead and well-site facilities
- Gas gathering lines and spines lines (from well-sites to processing facility)
- Central Processing Facility (CPF)
- Export Sales Pipeline
- Hexham Delivery Station (HDS)
- Gas fired power station located adjacent to the CPF.

NOTE: The tie-in from the Hexham Delivery Station to the Sydney Newcastle Pipeline was not reviewed in the PHA.

2.4. Scope Changes

Since the previous PHA (Ref. 1), the proposed design has changed, requiring an update. The main change is that the CPF will be increased from 60 TJ/day to 80 TJ/day. The compression facility will be provided with a total of 8 compressors (7 duty, 1 standby).

Two options are now proposed for the CPF site, as follows:

- CPF-1 (adjacent to the 'Teidman' property)
- CPF-7 (adjacent to a rail loop)

2.4.1. Gathering Line Case Studies

A total of 110 well sites will be included in the updated project (60 were included in the original PHA). A number of sensitivity cases were considered for the gathering lines as follows:

- Case 1 - 110mm diameter lines with a design flow rate of 2 TJ/day
- Case 2 - 160mm diameter lines with a design flow rate of 4 TJ/day
- Case 3 - 200mm diameter lines with a design flow rate of 6 TJ/day

2.4.2. Spine Line Case Studies

A number of sensitivity cases were assessed for the spine lines as follows:

- Case 1 - 315mm diameter lines with a design flow rate of 10 TJ/day
- Case 2 - 315mm diameter lines with a design flow rate of 20 TJ/day
- Case 3 - 450mm diameter lines with a design flow rate of 10 TJ/day
- Case 4 - 450mm diameter lines with a design flow rate of 20 TJ/day
- Case 5 - 450mm diameter lines with a design flow rate of 40 TJ/day
- Case 6 - 450mm diameter lines with a design flow rate of 60 TJ/day
- Case 7 - 540mm diameter lines with a design flow rate of 40 TJ/day

- Case 8 - 540mm diameter lines with a design flow rate of 60 TJ/day
- Case 9 - 630mm diameter lines with a design flow rate of 40 TJ/day
- Case 10 - 630mm diameter lines with a design flow rate of 60 TJ/day

2.5. Study Limitations

This PHA is based on preliminary process flow diagrams and data from the design basis manual (Ref. 7) and contains calculations based on assumptions relating to process conditions (summarised in Section 9). Distances to the site boundary and equipment locations were interpreted from the preliminary site layout plans.

The biophysical effects of a produced-water release are not addressed in this report (see the Environmental Assessment, Ref. 3).

The tie-in from the Hexham Delivery Station to the Sydney-Newcastle Pipeline was not reviewed in this PHA.

3. DESCRIPTION OF PROPOSED DEVELOPMENT

3.1. Overview

AGL are in the processing of developing the Gloucester Basin (PEL 285) coal seam methane field to full production and to transport processed gas, via a 100 kilometre transmission pipeline, to a connection point on the Sydney-Newcastle Pipeline at Hexham.

The design is in the conceptual phase and a number of assumptions have been made regarding the pipeline and compressor station capacity. This Preliminary Hazard Analysis (PHA) assumes a full production capacity of 80 TJ/d for the gas gathering system and the processing/ compression station at Gloucester. The transmission pipeline options are either a DN 250 transmission pipeline designed to flow the field capacity as well as a DN 450 option which would be used as a gas storage pipeline.

These assumptions (summarised in Section 9), which may change prior to finalisation of the design, will be reviewed in the Final Hazard Analysis.

The subsequent sections provide a description of the proposed Gloucester Coal Seam Gas Project, as described in the Project Basis of Design (Ref. 7).

4. DESCRIPTION OF GAS WELLS AND GATHERING LINES

4.1. Overview

Approximately 110 well-sites (with provision for up to 4 wells per site) will be drilled through an identified coal package with maximum depth up to 1300m dependant on location in the Gloucester basin. These wells will be completed with production casing and zones selected for perforation based on open hole logs. Hydraulic fracturing operations will be designed and carried out in stages on the basis of coal seam thicknesses and proposed perforation intervals.

4.2. Above-Ground Wellhead

The coal seam methane wellheads will be located in one hectare lots during initial drilling and completion reducing to a minimal pad size for ongoing production. Typical arrangements will be an area of 6 m x 4 m for single wellhead sites and approximately 40 m x 30 m for four-wellhead sites.

Each wellhead (up to 4 per well-site) will include the following equipment:

- Down-hole water pump controlled by a variable speed drive, surface hydraulic ram to stroke downhole pump or velocity string are the basic completion that may be installed below the surface wellhead depending on operational requirements
- Wellsite PLC that controls downhole and surface operations, metering calculations and data acquisition and storage for transmittal to the main SCADA computer located at the CPF.
- Carbon steel gas piping connection to the gas gathering system including:
  - Wellhead isolation valve
  - Wellhead shutdown valve configured to close on process disturbances as identified in the HAZOP
  - Wellhead 2-phase separator to remove free water from the gas
  - Full flow relief valve sized for full wellhead gas flow
  - Water pump for pumping separated water into the water distribution system
  - Gas flow meter for measuring wellhead gas flowrate
- Carbon steel liquids line including the following:
  - Isolation valve
  - Water flow meter

There is a specification break on the wellheads between the wellhead and the lower pressure gathering systems. The lower pressure gas pipework is protected from high pressure by a shutdown valve configured to shut on detection of high pressure and a full flow relief valve to provide two layers of protection. The water system is protected from high pressure from the wellhead pump by a pressure switch which will stop the pump. There are no regulators included in the design of the wellheads.

Modifications to the design of any wellhead facility will be covered under a management of change system that may trigger a subsequent HAZOP.

4.3. Gas Gathering and Spine Lines

Gas gathering lines will be provided from the wellhead gas connection to the field spine line connection (with sensitivity cases for diameter and design flow as per Section 2.4.1). Gas gathering lines will be constructed from polyethylene pipe to AS4130:2009 (Ref. 8). Low point drains will be fitted at low points to allow free water to be removed.

Table 4.1 summarises the concept-stage design specifications for the gathering lines.

TABLE 4.1: GATHERING LINE DESIGN PARAMETERS

Gathering Line Design Parameter	Value
Design Pressure	500 kPa
Minimum Design Temperature	0ºC
Maximum Design Temperature	30ºC
Flow Capacity	Sensitivity cases as per Section 2.4.1 (2, 4 and 6 TJ/d)

The gathering lines will then connect to spine lines which will be provided to connect each quadrant of the coal seam methane field to the gas processing facility at Gloucester. Spine lines will be constructed from polyethylene pipe with diameters as given in the sensitivity cases in Section 2.4.2.

Table 4.2 summarises the concept-stage design specifications for the spine lines:

TABLE 4.2: SPINE LINE DESIGN PARAMETERS

Spine Line Design Parameter	Value
Design Pressure	500 kPa
Minimum Design Temperature	2ºC
Maximum Design Temperature	30ºC
Flow Capacity	Sensitivity cases as per Section 2.4.2 (10, 20, 40 and 60 TJ/d)

The polyethylene pipes will be welded together using an automatic electro-fusion welding technique.

The minimum depth of cover for buried polyethylene pipelines will be as follows:

- Under roadways 750 mm (sealed/ non-sealed roads)
- Creek crossings 900 mm
- Other locations 600 mm (soil/ shale)

These depths will be reviewed following the conceptual design stage, including an external load calculation to ensure the piping can absorb the expected external loads from traffic.

All polyethylene gas pipelines will be provided with yellow marker (warning) tape/ polymeric cover strip placed above the pipeline at a depth of 200 mm below the ground level. Where the strip is joined, it is to overlap by at least 150 mm.

The polyethylene line will be tested using a pressure leak test in accordance with AS4645.1.

5. DESCRIPTION OF CENTRAL PROCESSING FACILITY

5.1. Process Description

The function of the CPF will be to condition, compress and meter the gas provided by the field gathering system.

The overall process for gas conditioning is a combination of compression and dehydration via a tri-ethylene glycol (TEG) contactor.

TEG will be regenerated (water removed) and re-used until such time as it is chemically degraded and requires replacement. A very small quantity of TEG may be lost from the system, mainly as carry-over in the water boiled-off from the TEG during regeneration.

There are two design cases for the gas transmission pipeline, each with a different CPF design pressure:

- DN 250 Class 600 pipeline that would have excess capacity to deliver the required flow rate.
- DN 450 Class 900 pipeline that would be used as a gas storage pipeline.

Therefore, the compressors at the CPF will have two different pressure design cases for the discharge; however, the design flowrate will be 80 TJ/d for both pressure cases.

5.2. Major Equipment

The gas processing facility will include the following equipment:

- Suction header connecting the polyethylene spine lines. The polyethylene to carbon steel interface will occur subsurface.
- Inlet separator for removing bulk free water and any hydrocarbons.
- Inlet filter coalescer vessels for final removal of particulates, free water and lubrication oil from the inlet gas stream.
- Inlet pressure control valves for controlling compressor suction pressure.
- Gas Compressor skids (8 off, 7 duty, 1 standby) including:
    - Inter-stage fin fan coolers coupled to the gas engine. Waste heart recovery units will be provided to use waste heat to aid in energy recovery (e.g. for TEG reboiler)
    - Gas engine
    - Reciprocating multistage compressors
    - Inter-stage dewatering
- Discharge scrubber for removing compressor lube oil prior to dehydration.

- TEG dehydration package including the following:
  - TEG contactor vessel utilising structure packing. The gas flows against a TEG stream to dehydrate the gas to the required pipeline specification
- TEG regeneration skid including:
  - Reboiler for flashing off water from the rich TEG stream
  - Dual redundant electric pumps for injecting lean TEG into the contactor vessel
- Discharge filter coalescer for removing TEG carryover.
- Station backpressure control valve to maintain backpressure on the TEG Contactor.
- Oily water separation system; to collect and separate oily water from the inlet separators, coalescers, inter-stage scrubbers and the discharge scrubber. The system includes:
  - Distribution pipework for connecting the vessels to the oily water separator
  - Separator vessel designed for oil water separation
  - Clean water connection connected to the process water disposal system
  - Oily connection to storage tanks for transport offsite and recycling
  - An activated bentonite waste oil recovery mixer that captures process waste oil in flocculated bentonite of quality for landfill disposal and released water of suitable quality for direct disposal in the evaporation pond pending ongoing water analysis
- Oil storage facility:
  - Oil storage tanks for engine and compressor lube oil storage directly connected to the compressor day tanks
- Instrument, fuel and start gas skid including:
  - Connection to the plant discharge upstream of the back pressure control valve
- Flare system connecting the compressor station suction and discharge pipework and the compressor blowdown to a vent.
- Control room including:
  - SCADA interface for field, pipeline and compressor station telemetry
  - Office and amenities
- Power generation facilities adjacent to the CPF

5.3. Water Treatment Facility

Produced water will be pumped to water storage ponds. The produced water will be pumped from the ponds into a water treatment plant. The water treatment plant will include water filtration, a Reverse Osmosis plant followed by a waste stream brine concentrator where the brine stream will be concentrated for disposal. The treated water stream will then be used for irrigation.

6. DESCRIPTION OF EXPORT SALES PIPELINE

6.1. Overview

Gas from the CPF will be transported to the Hexham Delivery Station (for connection to the Sydney-Newcastle Gas Pipeline) via a 100 km transmission pipeline.

The transmission pipeline options are either a DN 250 transmission pipeline designed to flow the field capacity as well as a DN 450 option which would be used as a gas storage pipeline, designed to AS 2885.1. The PHA study assumed a 450 mm pipeline as the base case, as this is the larger inventory. As a sensitivity case, the DN 250 pipeline option was also assessed for comparison.

Table 6.1 summarises the concept-stage design parameters for the pipeline:

TABLE 6.1: EXPORT SALES PIPELINE DESIGN PARAMETERS

Pipeline Design Parameter	Value
Design Flow Rate DN 250 Case	80 TJ/d
Design Flow Rate DN 450 Case	500 TJ/d
Minimum Design Temperature	-10ºC
Maximum Design Temperature	65ºC
Maximum Allowable Operating Pressure DN 250 Case	10,200 kPa
Maximum Allowable Operating Pressure DN 450 Case	15,300 kPa
Maximum Discharge Pressure (at the delivery station)	6895 kPa
Corrosion Allowance	0 mm

A design factor of 0.72 has been used in the design of the transmission pipeline; however, the governing case for pipelines in T1 class locations is resistance to penetration, therefore, the maximum design factor is 0.72 and in some cases it is lower.

6.2. Location Analysis

The first 64 km of pipeline (from KP 0 to KP 64) will be in a Class R1 location and the following land use and crossing types have been identified:

- Rural land uses (mainly grazing country)
- Isolated farm houses inside and outside the 4.7 kW/m^2 and 12.7 kW/m^2 radiation zones (as identified within 30m of the pipeline)
- Adjacent 11 and 33 kV power lines running parallel or crossing the pipeline
- Gravel and bitumen road crossings
- Minor and intermediate creek crossings
- Non-electrified rail crossing

From KP 64 to KP 96 the class location is R1 with isolated sections of T1 as the pipeline approaches towns. At Hexham (KP100), the location class is T1 with a secondary class of I for industrial land-use. The following land use and crossing types have been identified:

- Towns of Seaham/ Maitland and Hexham
- Adjacent 132 kV power lines running parallel to the pipeline
- Gravel and bitumen road crossings including the Pacific Highway
- Electric rail crossing
- Minor, intermediate and major river crossings

6.3. Nearest Residences

Table 6.3 shows the nearest residences that have been identified near the pipeline (within about 30-40m of the centerline of the pipeline). The table shows the Kilometre Post (KP) measurement, i.e. the distance along the pipeline (from the CPF), the location (east and north co-ordinates) and other identifying data.

Aerial photos showing these locations and the pipeline alignment are given in APPENDIX 6.

TABLE 6.2: NEAREST RESIDENCES TO EXPORT SALES PIPELINE

KP	Lot Plan	Approx. Distance Pipeline to Residence (m)	Easting	Northing	Local Government Area	Comments
2.4	1//1003762	15	398938	6441852	Gloucester Shire Council	Approx 1.8 km West of Craven village on Woods Rd. House located 275m south of Woods Rd
15.5	1//80329	40	398247	6429857	Great Lakes Council	South of Wards River and just north of Monkerai Rd from Bucketts Way
26	17//998668	22	398413	6420688	Great Lakes Council	West of Stroud Rd village. 125m north of Reidsdale rd along Williams rd
	111//546092	33	396426	6414862	Dungog Shire Council	Black Camp Rd. 5km South of Stroud-Dungog Rd
39	122//526671	41	394921	6410313	Dungog Shire Council	Approx 1.4km north of Flat Tops Rd/Black Camp Rd Intersection

KP	Lot Plan	Approx. Distance Pipeline to Residence (m)	Easting	Northing	Local Government Area	Comments
39.8	14//505209	25	394235	6409830	Dungog Shire Council	House currently uninhabitable/ in disrepair. Approx 420m north from Flat Tops/Black Camp Rds intersection
33.3	11//733189	30	390735	6404353	Dungog Shire Council	Black Camp Creek Rd. Approximately 2.5km north of Glen Martin Rd/ Black Camp Creek rd intersection.
61.3	1//705895	30	386364	6392282	Port Stephens Shire council	East Seaham Rd. Approximately 2.3km south of Limeburners Creek Rd intersection

6.4. Pipeline Design Issues

6.4.1. Odourant

The gas will not to be odourised. Odourant will be injected in the sale gas at the Hexham Delivery Station after it has been metered.

6.4.2. Corrosion and Corrosion Allowance

The design corrosion allowance, both internally and externally is zero. The absence of an external corrosion allowance is due to the high integrity of the pipe coating to be applied and cathodic protection practices, the quality assurance measures planned for the prevention of coating defects, and the requirement that the cathodic protection system will be operated and maintained in accordance with AS 2885 Part 3 for the duration of the pipeline design life. Regular cathodic protection potential readings may be supplemented by intelligent pig runs as part of the integrity management program. The pipeline pigging facilities will be sized to accommodate these devices.

6.4.3. Stress Corrosion Cracking

A potential risk on the pipeline is stress corrosion cracking, which has been found on high pressure pipelines in various locations but is more prevalent at coating defects downstream of compressor stations. The higher temperature caused by compression is a significant factor. The mitigation strategy for the ESP will be to use a tri-laminate coating system with improved SCC resistance for the entire length of the pipeline. Additionally:

- after-coolers will be provided for compressor discharges with temperature monitoring

- the immediate downstream section of pipe from the compressors will be of adequate wall thickness to compensate for the temperature de-rating as a result of high temperature and will be designed in accordance with AS4041 and ANSI B 31.3
- the MAOP will be regularly reviewed taking into account any pressure fluctuations experienced during the operating life of the pipeline.

6.4.4. Pipeline Fracture Mitigation

Brittle fracture is extremely unlikely for this pipeline; however, the pipe specification shall require a Drop Weight Tear Test (DWTT) with an 85% shear area transition temperature to match the minimum pipeline design temperature.

Low energy ductile fracture is a remote possibility for the pipeline. To mitigate the likelihood of ductile fracture propagation, the line pipe material will be specified to have adequate fracture toughness to arrest a crack within the initiating pipe. The toughness value used will be calculated using the Battelle Short Form Formula. This is based on assuming a lean gas composition with <5% ethane and <1% higher hydrocarbons.

6.5. Pipeline Safety Design

The design shall comply with all relevant statutory regulations and codes, and industry codes of practice. The criteria for determining safe design shall address construction, operation and maintenance. A Safety Management Study will be prepared for the pipeline, per AS 2885.

6.5.1. Emergency Response Plan (ERP)

The pipeline operator will develop Emergency Response Plans including the need for procurement of emergency equipment. Where necessary, provision will be made for storage and maintenance of emergency response equipment at the appropriate pipeline facilities. All staff will undergo training in emergency scenarios and equipment prior to operation of the pipeline, and at regular intervals during the operation of the pipeline.

6.5.2. Pipe Material

The transmission pipeline options are either a DN 250 transmission pipeline designed to flow the field capacity as well as a DN 450 option which would be used as a gas storage pipeline. The PHA study assumed a 450 mm pipeline.

The pipe specification for the DN 250 and DN 450 options is shown in Table 6.3.

TABLE 6.3: PIPELINE DESIGN SPECIFICATION

Locations	Wall thickness	Penetration Resistance	Material Specification	Toughness Specification
DN 250 Pipeline				
R1 Cross Country	5 mm	5T Tiger Tooth	API 5L X-70 PSL 2	45J
Road rail, intermediate and major creek crossings	7.5 mm	15T Tiger Tooth	API 5L X-42 PSL 2	30J
T1 Class Locations	12.7 mm	40T Tiger Tooth	API 5L X-42 PSL 2	27J
DN 450 Pipeline				
All Locations	11 mm	40T Tiger Tooth	API 5L X-70 PSL 2	90J
Assumptions: 1. Penetration calculations based on B factor of 1 2. Penetration calculations based on Appendix M of AS2885 Part 1: 2007				

6.5.3. Pipe External Coating

The pipeline will be coated with a Tri-laminate coating system.

6.5.4. Pipe Jointing and Joint Coating

Pipes will be joined using a Manual Metal Arc butt welding technique. Welding procedures are subject to the development and qualification of a welding procedure in accordance with the requirements of AS 2885 Part 2.

Pipe joint coating is a three layer epoxy heat shrink sleeve attaches using a qualified procedure and subject to ongoing testing during application.

6.5.5. Depth of Pipeline Cover

The pipeline will be buried for its entire length except for aboveground items such as pipeline stations and transition piping. The minimum depth of cover specification for various locations is shown in Table 6.4.

TABLE 6.4: PIPELINE DEPTH OF COVER

Location	Minimum Depth of Cover
R1 Locations	750 mm
T1 Locations	900 mm
Insider road or rail reserve	1200 mm
Major water course crossing	2000 mm
Intermediate water course crossings	1500 mm
Minor water course crossing	1200 mm
Minor road track crossing	1200 mm under table drain or road surface
Bitumen Road Crossing	1200 mm under the table drain with slabs or 2000 mm under the road surface whichever is greater.
Rail Crossing	1200 mm under the table drain with slabs or 2000 mm under the rail tracks whichever is greater.
Service Crossing	Under the service with a minimum separation of 500 mm with a concrete slab between the two.

6.5.6. Pipeline Marking

The pipeline location will be identified to third parties through its entire length, using a combination of marking techniques, appropriate to the third party risk to the pipeline. In general, the following principles will apply:

- Warning markers will be placed at each change of direction, at fence lines, and each side of road, rail and river crossings.
- Warning markers will be intervisible.
- Marker tape located at a minimum of 300 mm above the buried pipeline and located in the follow areas:
  - In the vicinity of and within pipeline stations
  - Inside road reserve
  - At road and rail crossings
  - At other areas where tape significantly reduces the risk of damage to the pipeline
  - T1 class locations.

In addition, the pipeline location will be made available to the appropriate authorities for marking on public mapping, to land holders, and emergency services. The information will also be provided to a “One Call” buried services information bureau.

6.5.7. Pipeline Pressure Protection

To meet the requirements of AS 2885, two separate methods of pipeline pressure protection will be provided:

- a high pressure transmitter at the inlet to the pipeline, which will override the compressor speed control to slow down all the compressors if the plant discharge pressure reaches the pipeline MAOP.
- a plant outlet shutdown valve which will close on detection of an overpressure in the pipeline inlet.

6.5.8. Pipeline Leak Detection System

Leak detection will be carried out by the following methods:

- 24 hour monitoring of alarms on pressure transmitters via SCADA.
- Metering discrepancy and gas-unaccounted-for monitoring daily.
- General patrolling of the pipeline.
- Current defect assessment surveys and cathodic protection (CP) monitoring

6.5.9. Road and Railway Crossings

At all road and rail crossings, the pipe installation will be designed to resist the external loads imposed by traffic. Casings may be used if required by the railway authority or due to geotechnical considerations. If required, they will utilise concrete casing pipes with the pipeline grouted into position. The pipe will be separated from the casing wall via thinsulators.

Pipe stress from traffic loads at major highways and railways will be formally calculated using the methods of API 1102.

Horizontal Directional Drilling (HDD) and boring techniques may be used at some crossings subject to environmental and constructability considerations.

6.5.10. Cathodic Protection

The pipeline will be protected from external corrosion by an impressed-current cathodic protection system. The system will also accommodate the need to mitigate stray currents from parallel electricity transmission lines and railways along part of the route. The requirements will be specified when the final route is selected and the necessary stray current analysis is performed.

6.5.11. Open Cut Watercourse Crossings

For each major river crossing, individual investigation and design will be carried out. Typical standard designs will be used for the numerous minor watercourse crossings. Further details are provided in the Environmental Assessment report (Ref. 3).

6.5.12. Directionally Drilled Crossings

Locations requiring directional drilling will be identified during detailed construction planning. Further details are provided in the Environmental Assessment report (Ref. 3).

7. DESCRIPTION OF HEXHAM DELIVERY STATION

7.1. Overview

The HDS will include remote shutdown, gas heating, flow control and custody transfer metering. The Hexham delivery station will include the following equipment:

- Inlet shutdown valve for remote pipeline isolation and over pressure shutdown.
- Dual redundant inlet dry gas filtration with isolation for removing dust and other contaminants in the pipeline.
- Dual redundant water-bath heaters connected in series to preheat the gas to ensure it retains a margin above the water dew point.
- Dual redundant flow control valves with overriding pressure control to control gas flow into the downstream pipeline.
- Dual redundant ultrasonic meters to provide custody transfer accuracy metering
- Dual redundant gas chromatographs and dew point analysers to perform gas quality measurement and to provide gas heating values for energy flow calculations.

8. METHODOLOGY

8.1. Study Approach

The PHA for the Gloucester Coal Seam Gas Project was undertaken following the guidelines of the NSW Department of Planning. The methodology for undertaking the PHA is as described in the NSW Department of Planning documents, Hazardous Industry Planning Advisory Paper (HIPAP) No. 6, 'Guidelines for Hazard Analysis' (Ref. 5) and HIPAP No.4, 'Risk Criteria for Land Use Safety Planning', (Ref. 4).

The following is an outline of the methodology adopted in this PHA:

- Establish the context, including level of assessment and risk tolerability criteria.
- Undertake hazard identification for the proposed development and identify a list of credible scenarios for carrying forward for quantification of consequences and likelihood.
- Undertake a consequence analysis for the identified credible scenarios. Where off-site impact is found to have the potential to occur, carry the scenario forward for frequency analysis.
- Undertake frequency analysis for the scenarios with the potential for off-site impact.
- Undertake quantitative risk assessment by combining the off-site scenario consequences and their associated frequency in order to generate:
    - risk contours for the well-sites, CPF and HDS
    - risk transects for the gas gathering and spine lines and the ESP.
- From a review of the risk contours and risk transects, assess the risk to neighbouring land uses against the requirements of the NSW Department of Planning Risk Criteria for Land-Use Safety Planning (Ref. 4).
- Make recommendations for risk reduction, where the risk is found to be intolerable.

8.2. Level of Assessment

Multi Level Risk Assessment (Ref. 6) sets out three levels of risk assessment that may be appropriate for a PHA, as shown in Table 8.1. This document was consulted to identify the level of assessment required in this study.

TABLE 8.1: LEVEL OF ANALYSIS

Level	Type of Analysis	Appropriate if:
1	Qualitative	No major offsite consequences and societal risk is negligible
2	Partially Quantitative	Offsite consequences but with a low frequency of occurrence
3	Quantitative	Where level 1 and 2 are exceeded

Based on a review of the findings of the HAZID, it would not be credible to state that no events had offsite impact without more detailed consequence analysis. Hence a Level 1 Assessment was not considered suitable.

It was decided to follow a Level 2 Assessment (i.e. assess consequences of releases and carry forward incidents with offsite impact to risk assessment).

8.3. Consequence Criteria

The consequences of hazardous incidents which have been assessed in the current study are:

- Release of pressurised natural gas, followed by immediate ignition, resulting in jet fire
- Release of pressurised natural gas, followed by delayed ignition, resulting in flash fire.

The criteria for heat radiation impact from fires used in the study are summarised in Table 8.2.

TABLE 8.2: THERMAL RADIATION CRITERIA

Heat Radiation Level (kW/m^2)	Effect	Critical Criteria
4.7	Will cause pain in 15-20 seconds and injury after 30 seconds exposure.	Injury
6	10% chance of a fatality for extended exposure.	Fatality
10	50% chance of a fatality for extended exposure.	Fatality
14	100% chance of a fatality for extended exposure.	Fatality
23	Likely fatality for extended exposure; chance of fatality for instantaneous exposure Unprotected steel will reach thermal stress temperatures which can cause failures	Escalation potential

8.4. Risk Criteria

The risk guidelines provided in the DoP publication *Risk Criteria for Land Use Safety Planning* (Ref. 4) are outlined in the subsequent sections.

8.4.1. Individual Risk of Fatality

The risk criteria adopted for land use safety planning in NSW are summarised in Table 8.3. The figures quoted show the risk criteria for various land use types to an individual, assuming 24 hour exposure to the risk, with no allowance for the protection buildings may offer or for the potential to move away (escape) from a developing incident.

TABLE 8.3: NSW LAND-USE PLANNING INDIVIDUAL FATALITY RISK CRITERIA

Risk Levels/ Probability of Fatality (per annum)	Land-Use	Limit of Exposure at the Following Locations
0.5×10^{-6}	Sensitive	Hospitals, child-care facilities and old age housing developments.
1×10^{-6}	Residential	Residential developments and places of continuous occupancy such as hotels and tourist resorts.
5×10^{-6}	Commercial	Commercial developments, including offices, retail centres, warehouses with showrooms, restaurants and entertainment centres.
10×10^{-6}	Active Open Space	Sporting complexes and active open space areas.
50×10^{-6}	Industrial	Site boundary

8.4.2. Societal Risk of Fatality

The Department of Planning (Ref. 4) suggests that judgements on societal risk be made on the basis of a qualitative approach rather than on specifically set numerical criteria.

Despite the lack of formal societal risk tolerability criteria in NSW, societal risk estimation is warranted only where significant and potentially vulnerable populations exist beyond the boundary of the proposed development.

8.4.3. Risk of Injury

NSW Department of Planning guidelines on land use safety planning (Ref. 4) set criteria for injury risk levels. This is in recognition of the fact that society is concerned with the risk of injury as well as death and that certain members of the community are more vulnerable. The injury risk criteria are discussed in more detail in the following paragraphs.

DoP proposes that a heat radiation level of 4.7 kW/m^2 be considered high enough to lead to injury in people who cannot escape or seek shelter. This level of heat radiation will cause injury after 30 seconds. A risk of injury criteria of 50×10^{-6} p.a. is suggested for fire events. Within the guidelines, this is stated as:

- Incident heat flux at residential areas should not exceed 4.7 kW/m^2 at frequencies of more than 50 chances in a million years.

Department of Planning also proposes criteria for the risk of injury from explosion overpressure and toxic gas dispersion. These have not been reproduced here as the HAZID did not identify explosion or toxic release events with potential offsite impacts.

8.4.4. Risk of Accident Propagation

NSW Department of Planning guidelines on land use safety planning (Ref. 4) present criteria covering accident propagation. The guidelines are aimed at ensuring the likelihood of an accident at one plant triggering an accident at another neighbouring plant is low and that adequate safety separation distances exist. The criterion for accident propagation is:

- Incident heat flux radiation at neighbouring potentially hazardous installations or at land zoned to accommodate such installations should not exceed a risk of 50 in a million per year for the 23 kW/m^2 heat flux level (23 kW/m^2 is considered the level at which unprotected steel may start to fail).

DoP also proposes criteria for the risk of escalation from explosion overpressure. These have not been reproduced here as the HAZID did not identify explosion events with potential offsite impacts.

8.4.5. Risk to the Biophysical Environment

The risk tolerability criteria suggested by the NSW Department of Planning (Ref. 4) for sensitive environmental areas relate to the potential effects of an accidental emission on the long-term viability of the ecosystem or any species within it. HIPAP No. 4 (Ref. 4) summarises these criteria as follows:

- Industrial developments should not be sited in proximity to sensitive natural environmental areas where the effects of the more likely accident emissions may threaten the long-term viability of the ecosystem or any species within it.
- Industrial developments should not be sited in proximity to sensitive natural environmental areas where the likelihood of impacts that may threaten the long-term viability of the ecosystem, or any species within it, is not substantially lower than the background level of threat to the ecosystem.

Risk to the biophysical environment is discussed in detail in the Environmental Assessment Report (Ref. 3), although it should be noted that the HAZID carried out for this PHA did not identify any accident events with potential for serious environmental impacts.

9. STUDY ASSUMPTIONS

9.1. Process Data

The following process data extracted from the Basis of Design (Ref. 7) were used for the assessment.

TABLE 9.1: PROCESS DATA ADOPTED IN PHA

Potential leak source	Press. (MPag)	Temp. (ºC)	Flow (TJ/day)	PHA Update
Well Sites				
Wellheads	10.2	30	110 x 2 (maximum)	Consequence analysis Risk analysis
Wellhead Production separators	0.5	30	110 x 2 (maximum)	Consequence analysis Risk analysis
Gathering Lines				
Gathering lines (110 off)	0.5	30	110 Gathering Lines with three (3) options: - 110 mm at 2 TJ/day - 160 mm at 4 TJ/day - 200 mm at 6 TJ/day	Consequence analysis Risk analysis
Spine Lines				
Spine lines (2 off)	0.5	30	2 Spine Lines. with ten (10) options - 315 mm at 10 TJ/day - 315 mm at 20 TJ/day - 450 mm at 10 TJ/day - 450 mm at 20 TJ/day - 450 mm at 40 TJ/day - 450 mm at 60 TJ/day - 540 mm at 40 TJ/day - 540 mm at 60 TJ/day - 630 mm at 40 TJ/day - 630 mm at 60 TJ/day	Consequence analysis Risk analysis
CPF Gas Side				
Plant Suction Header	0.7 (max.)	30	80	Consequence analysis Frequency analysis Risk analysis
Inlet Pressure Control Valve				
Inlet Separator				
Filter Coalescers (2oo3)	0.7 (max.)	30	2 x 40	Consequence analysis Frequency analysis Risk analysis

Potential leak source	Press. (MPag)	Temp. (ºC)	Flow (TJ/day)	PHA Update
Compressor Suction Pressure Control Valves (1oo2)	0.7 (max.)	30	80	Consequence analysis Frequency analysis Risk analysis
Compressors (7oo8)	16.8 (max.)	55	7 x 11.4	Consequence analysis Frequency analysis Risk analysis
Compressor Discharge Scrubber	16.8 (max.)	55	80	Consequence analysis Frequency analysis Risk analysis
TEG Contactor Towers (2oo2)	16.8 (max.)	55	2 x 40	Consequence analysis Frequency analysis Risk analysis
Particulate Filter	16.8 (max.)	55	80	Consequence analysis Frequency analysis Risk analysis
Meter Skid				
Plant Pressure Control Valve	15.3 (max.)			
Plant Discharge Header				
CPF Utilities				
Horizontal Pit Flare	16.8	-	80	Consequence analysis Frequency analysis Risk analysis
Utility gas skid	1.965	30	4	None
Utility gas recycle				
Lean TEG Storage	[Atm.]	30	2 x 8 m^3	Consequence analysis Frequency analysis Risk analysis
Waste Heat Recovery Unit	TBA	Typically 200-250°C Operating Range	Design details to be determined.	Typical heating medium products are combustible. Not carried forward to consequence/risk assessment

Potential leak source	Press. (MPag)	Temp. (ºC)	Flow (TJ/day)	PHA Update
CPF Power Station				
High Pressure Equipment	0.45	47	0.4 kg/s	Consequence analysis Frequency analysis Risk analysis
Letdown Pressure to gas engines	0.45	47	8 x 0.1 kg/s	Consequence analysis Frequency analysis Risk analysis
CPF Water Side				
The PHA considers this as non-hazardous: non-toxic, non-flammable. Potential for environmental impact is covered in the EA.				None
Export Sales Pipeline				
Transmission Pipeline	15.3 (max.)	30	80	Consequence analysis Risk analysis
HDS				
Scraper receiver	15.3 (max.)	30	80	Consequence analysis Risk analysis
Dry gas filters				
Custody transfer meters				
Bath heaters				
FCV				

9.2. Aboveground Facilities

- The likelihood of vapour cloud explosions is negligible as natural gas will tend to disperse readily in the open air and there are no congested areas at the well-sites, CPF and HDS which could result in the accumulation of unignited gas.
- The direction of jet fire releases from equipment was assumed to be horizontal (in order to evaluate the worst-case heat radiation impact).
- Due to the safeguards in place (aboveground piping, inspection and maintenance vehicle barriers), the likelihood of full bore rupture of pipework is very low and was not carried forward to the risk assessment.
- Where the consequence effect resulting from a release was found to have negligible potential for offsite impact, the scenario was not carried forward for further analysis.
- The assessed risk was based on the parts count undertaken using the P&IDs.
- Isolation valves and equipment on the pressurised side of the isolation valve (e.g. gaskets, fittings) were included in the parts count.
- Pipe lengths were estimated based on site layout drawings and similar plant.

- The analyses conservatively do not account for safeguarding, e.g. isolation and blowdown.
- Injury risk and escalation risk contours were not assessed for the well sites and CPF due to the remoteness of the locations and low population. Escalation and injury risk contours were assessed for the HDS which is located within the industrial zone of Hexham.

9.3. Gathering Lines, Spine Lines and Transmission Pipeline

- The likelihood of vapour cloud explosions is negligible as natural gas will tend to disperse readily in the open air and there are no congested areas near the pipeline which could result in the accumulation of unignited gas.
- The release rates were estimated assuming the maximum pipeline operating pressure.
- The direction of pipeline releases was assumed to be 80% vertical and 20% at 45°.
- The frequency of pipeline releases was based on European Gas Pipeline Incident Data Group (EGIG) data which will be conservative for this proposal. Discussion regarding the applicability of the data to polyethylene gathering lines is provided in APPENDIX 5.
- The analyses conservatively do not account for safeguarding, e.g. isolation and blowdown.

10. HAZARD IDENTIFICATION - OVERVIEW

10.1. Hazardous Incidents

A hazard identification table for the well-sites, gathering lines/ spine lines, CPF, export pipeline and delivery station is given in APPENDIX 1. This table was compiled from a review of previous gas processing facility and pipeline risk assessments and the design basis for the proposed pipeline and facilities.

The description of major hazards for the separate plant sections are discussed in separate sections for clarity. The hazard identification is used as a basis for identifying a list of scenarios for carrying forward to the quantitative risk assessment.

10.2. Hazardous Materials

The proposed project will generate natural gas and produced water. The focus of this PHA was therefore the potential for loss of containment of methane, a highly flammable (hydrocarbon) gas and simple asphyxiant.

The potential biophysical effects of produced water are covered in the Environmental Assessment (Ref. 3).

Other potentially hazardous materials include:

- Triethylene Glycol (TEG) used in the gas dehydration unit
- Heating medium used in the waste heat recovery unit (WHRU) system
- Diesel used for local power generation at the well sites.

10.3. Natural Gas Releases

Ignited gas methane releases from the equipment and pipework could result in:

- Jet fire, if ignited immediately;
- Flash fire, if ignition is delayed; and
- Vapour Cloud Explosion (VCE) if a flash fire occurs within a congested or confined plant area.

Gas releases could result in a jet fire if ignited immediately, resulting in a jet flame. Heat radiation from the jet fire will impact people within the vicinity of the release.

If ignition is delayed, a vapour cloud may form, however as natural gas is buoyant and will disperse easily, the potential for a significant cloud buildup is low. Ignition of the vapour cloud could result in a flash fire.

In the event of a flash fire, the vapour cloud burns rapidly without a blast wave and will flash back to burn as a jet flame from the release point. In the event of a flash fire, there is a high (100%) chance of a fatality within the vapour cloud, but due to the short duration of the flame, there is a low chance of significant impact outside the vapour cloud radius. However, the impact from the jet fire that continues after the flash fire remains.

A vapour cloud explosion (VCE) could occur if the flame front burns through a vapour cloud that is within a congested area, resulting in turbulence (promoting combustion) and flame front acceleration and, hence, the generation of overpressure. The proposed well-site, CPF and HDS equipment layouts do not generate significant congestion; therefore, there is a very low likelihood of flash-fire flame-front acceleration and vapour cloud explosion overpressure.

Therefore explosion events (e.g. VCEs) were not been considered further in this study and jet fires and flash fires were considered to be the significant scenarios.

Notwithstanding, there is a potential for gas accumulation in the compressor-enclosures (at the CPF) to result in an explosion in the event of ignition. The chance of leak resulting in fire and explosion in the compressor enclosure, however, is minimal as the enclosures will be provided with:

- gas detection to detect releases and fire detection to detect lube oil fires;
- forced (fan-driven) ventilation with a trip function which will shutdown and depressurize the compressor in the event of ventilation system failure;
- the main actuated valves (shutdown and vent valves) located outside the enclosure, minimising the number of potential leak sources.

Compressor enclosure explosions were not quantified in this study.

11. HAZARD IDENTIFICATION – ABOVEGROUND FACILITIES

11.1. Loss of Containment Scenarios

The following potential methane release scenarios have the potential to occur at the well-sites, Central Processing Facility (CPF) and Hexham Delivery Station (HDS):

- Loss of containment during pigging operations.
- Loss of containment from pipework (from holes in pipework due to corrosion, impact, etc.).
- Loss of containment from flanged connections, valves, filters, meters, heaters due to flange leaks, instrument tapping point failures, etc.
- External events (bushfire, ground movement, lightning, flooding).

11.2. Proposed Safeguards

The following general safeguards have been included in the design of the proposed well-sites, CPF and HDS to prevent, control and mitigate jet fire incidents at the sites.

11.2.1. Leak Prevention/ Minimisation

- No free oxygen present in the coal seam methane
- Painting of aboveground pipework
- Coating of underground pipework
- Maintenance/ inspection
- Spiral wound gaskets on HP flanged equipment
- Pressure control and shutdown valve on pressure regulating skid
- High fracture tough steel
- Permit to work system
- Management of Change system
- Security fencing
- Vehicle barriers
- Hydrostatic testing of equipment
- 100% radiography of all circumferential welds
- Security fencing around aboveground facilities
- Hazardous area classification as per AS 2430 to minimise the risk of ignition sources
- Gravel or hardstand area inside aboveground facilities around gas filled equipment to minimise the risk of grass fires
- Lightning protection
- Maintenance procedures

- Standard operating procedures

Control

- Monitoring of field, CPF and ESP process parameters via SCADA system
- Remote ESD of well shutdown valves and automated shutdown when process parameters exceed range detailed in HAZOP
- Relieving of stress where ground movement stresses pipework

Mitigation

- Separation distance between release point and site boundary
- Emergency Response Procedures

11.3. TEG Releases

TEG has a flash point of 165°C which will classify TEG as a combustible liquid. Given the low likelihood of ignition of spills of TEG, the impact of TEG releases was not carried forward to consequence and risk assessment.

11.4. Heating Medium Releases

Details of the proposed waste heat recovery system (including circulating oil flow, pressure and temperature) were not available at the time of the current study. An ethylene glycol product or oil (depending on temperature requirements) is typically used in waste heat recovery units to aid energy recovery of compressor units by extracting heat from the gas engine discharge, using a heat exchange in the engine stack. Heating medium is circulated via pumps to heat exchangers in the end user system. It is likely that the heating medium will be used for aiding heating of the TEG reboiler.

Heating medium leaks could occur from the waste heat recovery system, either from pipework or from the heating medium reservoirs. Typical heating medium products will be combustible, i.e. they will have a high flash point. Releases of heating medium will not readily ignite and so pool fires resulting from spill are unlikely to occur. The only scenarios of concern with heating medium will be escalation from external fires which will result in combustion of heating medium. There is no other flammable liquid storage near the heating medium systems and therefore the likelihood of combustion of heating medium is very low. The impact of heating medium releases was not carried forward to consequence and risk assessment.

11.5. Diesel Releases

Diesel generators will be provided at well sites for local power use. No bulk storage of diesel will be provided at the well sites. Diesel generators will be refuelled directly from tankers. Given the low quantities of diesel stored on site and the low flammability, the impact of diesel spills will not be significant and was not carried forward to consequence and risk assessment. Diesel generators will be located outside the designated Hazardous Area as per AS2430 and API RP 500.

11.6. Flare Operations

Operation of the flare has the potential for hazardous impact to personnel. The flare is directed in a lateral direction over the evaporation pond. Blowdown valves will be provided at the CPF inlet and discharge. Flaring will be undertaken under the following circumstances:

- Emergency blowdowns
- Production gas venting
- Compressor unit blowdown (via blowdown valves on individual compressor units)

Potential hazards with the flare operation include:

- Noise generation
- Dispersion of unignited coal seam methane
- Heat radiation from flare operations.

No details of the flare operation have been included in the design basis. It is recommended that the FHA should include analysis of flare operations and the site layout. It is also recommended that the final design be HAZOPed, particularly for abnormal operations including flare operations.

12. HAZARD IDENTIFCATION - PIPELINES

12.1. Releases from Gathering/ Spine Lines and Export Sales Pipeline

The main incident of concern that could result from the operation of the gathering lines and transmission pipeline is a loss of containment, release of coal seam methane to the atmosphere and subsequent ignition. The range of release sizes may range from a small leak to a full bore rupture.

From a literature review of gas pipeline failures, the main cause of pipeline leaks is due to external mechanical damage as a result of third party impact on the pipeline (Ref. 9). Australian industry sources indicate that pipeline failure modes are similar to overseas experience. Anecdotally, failures would appear to be less frequent in Australia compared to overseas experience. However, a compiled source of failure rates for pipelines within Australia is not readily available and estimates of frequency based on reported incidents are therefore not considered reliable.

There are over 21,000 km of major gas transmission pipelines in Australia. Very few incidents have been reported for major Australian pipelines. On this basis, generic European data was used for the frequency assessment as it provides a more statistically valid sample size.

The main types of failure incident reported by the various sources (both overseas and Australian) are:

- External interference from heavy equipment (e.g. mechanical damage to pipe during excavation by third parties)
- Scour damage (e.g. river bed scouring, exposing and damaging pipes)
- Construction and material defects
- Internal and external corrosion and stress corrosion cracking
- Subsidence damage (e.g. banks and levees washing away, exposing and damaging pipes, mine subsidence, construction work near the pipeline)
- Faulty construction (e.g. welding defects, lack of weld testing)
- Ground movement (e.g. buckled pipework from excessive ground movement from earthquakes, slips and ground subsidence)
- Error during ‘hot tapping’

12.1.1. Export Sales Pipeline Release

There is an option to operate the Export Sales Pipeline as a gas storage pipeline. In this mode, there is potential for significant pressure cycling during the operation which needs to be considered in the design. This cycling may impose additional hazards including:

- Fatigue due to pressure cycling

- Stress corrosion cracking which can occur as a result of pressure cycling (with high gas temperature and certain soil conditions).

Fatigue

Fatigue may result in fracture failure, leading to a pipeline rupture in the worst case. However, the impact of fatigue would be readily detectible from the operating history and maintenance inspections conducted during the pipeline life. Early fatigue impact would require restrictions on the pipeline operation, e.g. pressure restrictions or limits on the pipeline life.

Fatigue will be managed by reviewing the pipeline thermal and pressure cycling at each pipeline MAOP review (5 yearly) to determine if the resulting stress cycling has the potential to cause a defect that could initiate a crack and propagate. The evaluation method of BS7910 will be adopted. If the result is found to be unacceptable, mitigation methods would be incorporated into the pipeline operation to reduce the threat to an acceptable level.

Given the effectiveness of the proposed safeguard and the ongoing monitoring of pressure fluctuations, no increase in the failure rate for this failure mode was included in the frequency analysis.

Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a phenomenon which can occur in pipelines that are subject to pressure cycles under high operating temperatures and in soil conditions which are conducive to corrosion. If detected, stress corrosion cracking may require pipeline repairs or may require derating of the pipeline. If undetected, stress corrosion cracking may lead to pipeline failure.

The pipeline design has made allowance to minimise the impact of stress corrosion cracking. This will be provided by use of a tri-laminate coating system with improved SCC resistance for the entire length of the pipeline, which will minimise the impact of external corrosion and by an appropriate design for the cathodic protection system. Additionally:

- after-coolers will be provided for compressor discharges with temperature monitoring
- the immediate downstream section of pipe from the compressors will be of adequate wall thickness to compensate for the temperature de-rating as a result of high temperature and will be designed in accordance with AS4041 and ANSI B 31.3
- the design life of the pipeline will include allowances for fluctuations.

Given the proposed safeguards and the low likelihood of SCC impact, no increase in the failure rate for stress corrosion cracking was included in the frequency analysis.

12.1.2. Location Specific Hazards

Other hazards specific to the locations where the gathering lines and transmission pipeline cross existing geographic features include the following:

- Impact from vehicle loading or construction work near road and rail crossings
- Alternating current induction effects from power lines near the transmission pipeline (not an issue for polyethylene gathering lines)
- Alternating current corrosion (not an issue for polyethylene gathering lines)
- Stray currents from high voltage DC traction lines at the railway line (not an issue for polyethylene gathering lines)

These issues are commonly encountered in pipeline designs in Australia and there are adequate safeguards to mitigate the hazard. The most significant of these are the impact of alternating current (AC) induction and corrosion which is discussed in more detail in the next sections.

Power Line Impacts on Export Sales Pipeline

The pipeline will traverse a route that is parallel to power transmission lines at a number of locations. Appropriate safety measures will be designed and adopted to ensure the safety of personnel and equipment. Typical mitigation measures include selective earthing at particular positions on the pipeline, zinc ribbon installed in the trench with the pipeline, inline isolation installed in the pipeline, restricted access to the pipeline and its facilities, and the use of equi-potential grids or other safety equipment during maintenance of the pipeline. The test points for the cathodic protection system may also be made lockable at all locations depending on final requirements.

Given the safeguards proposed in the design basis document and corrosion protection reports, the impact of AC induction effects near power lines will be minimised and an allowance for an increased failure rate has not been included in the frequency analysis.

Notwithstanding, the impact of power lines near pipelines is a well known hazard and can give rise to additional hazards to the pipeline and to personnel constructing the pipeline or operating and maintaining equipment. Construction hazards are outside the scope of a PHA and have not been included herein.

AC Corrosion

AC corrosion occurs at ‘holidays’ (exclusions or defects in the pipeline coating) as a result of the impact of AC induction near powerlines. The mechanism for the process is not clearly understood, but is more likely to occur under the presence of specific conditions including high current density and low soil resistivity.

The impact of AC corrosion will be assessed in the next design stage in order to mitigate the load current levels to values that are below the critical value which would result in a high likelihood of impact. Inclusion of resistance probes to monitor AC corrosion will be considered.

Notwithstanding, AC corrosion is considered to be of low likelihood and no increase in the failure rate for this failure mode was included in the frequency analysis.

12.1.3. Potential Consequences

Ignited gas release from the pipeline could result in:

- Jet fire, if ignited immediately
- Flash fire, if ignition is delayed
- Vapour Cloud Explosion (VCE) if a flash fire occurs within a congested or confined plant area.

As discussed in Section 10.3, a methane release could result in a jet fire if ignited immediately, or a flash fire if ignition is delayed (allowing a vapour cloud to form following release). As for releases from the well-sites, CPF and HDS, explosion events (VCEs) from pipeline releases have not been considered in this analysis, given the low potential for vapour cloud congestion along the gathering line and transmission pipeline routes.

12.1.4. Pipeline Safeguards

The proposed Export Sales Pipeline will be designed and operated in accordance with AS 2885-2007. The design will meet the requirements for T1 locations, classed as areas developed for residential, commercial or industrial use, where allotments are less than 1 hectare in area and buildings do not exceed 4 floors. The guidelines of AS2885.1 specify that the design for pipelines in T1 locations satisfy a requirement that failure by rupture will not occur and that the maximum energy release rate from the failure will not exceed 10 GJ/s.

The selection and design of the safeguards for protection of pipelines are based on the requirements of AS2885.1 and from previous experience. The following engineered and procedural safeguards are typical of pipeline designs and will be in place).

Protection Against External Damage

- Marker signs
- 'One-Call'/ 'Dial-before-dig' services
- Pipeline patrols
- Marker tape

Corrosion Protection

- External coating of pipeline
- 'Holiday' detection (testing of coating integrity) prior to burial
- Sacrificial anode or impressed current cathodic protection system

- Gas quality with minimal corrosion enhancing components
- Intelligent pigging (transmission pipeline only) to assess pipeline condition

Ground Movement/ Subsidence

The proposed pipeline route would not cross any known areas of mine subsidence. However, as this may change in the future, it is recommended that AGL liaise with the Mine Subsidence Board to determine likely future mining activity and the potential for subsidence.

Resistance to Penetration

The design of the proposed gathering lines and transmission pipeline eliminates the likelihood of rupture from external impact by providing the pipe grades described in Section 6.

Any construction undertaken in the proposed routes designated as location class T1, would not use excavators larger than 30-40 tonnes. Larger equipment would only possibly be used for major industrial developments. In this case, additional procedural controls would be implemented to minimize the likelihood of external impact.

Road & Rail Crossings

The design of the proposed gathering lines and transmission pipeline near road and rail crossings is described in Section 6.

Scour Damage

The likelihood of scour damage near watercourses is minimal because of the small catchment area available near the pipeline. There is also a potential for pipeline floatation near swampy land. The potential for pipe exposure due to scouring and floatation is low because of the structural integrity of the large-diameter, heavy-walled transmission pipeline and because of the regular pipeline patrols.

Vehicle Loading

The likelihood of impact from high vehicle loads is negligible due to the inherent structural integrity of the transmission pipeline (which is much higher compared with typical vehicle loading); gathering lines will not be exposed to significant roads and rail crossing loads.

Construction and Material Defects

The gathering lines and transmission pipeline will be hydrostatically tested to a stress level equal to 100% of Specified Minimum Yield Strength (SMYS). This will provide assurance that the integrity is not compromised by residual flaws that could grow to failure as a result of fatigue.

Acid-Sulphate Soils

Acid sulphate soils occur predominantly in coastal areas where the soils formed underwater and the sea level later receded, leaving behind underground concentrations of iron-sulphide-rich soil. Acid sulphate soils are typically found in coastal plains, wetlands and mangroves.

When the soils remain in an undisturbed and waterlogged state, they remain relatively inactive. However, when the soil is excavated and exposed to oxygen through drainage or excavation, sulphuric acid is produced in large quantities. This results in an environmental impact due to releases of concentrated acid. During the operational phase of the pipeline, residual acid may result in pipeline corrosion.

The effect of acid sulphate soils is mitigated by appropriate management procedures, including limited excavation to minimise the length of open trenches and the time exposed in affected areas; lime neutralisation; and spoil management, including segregated storage of acidic spoil stockpiles and appropriate treatment/ disposal methods.

13. CONSEQUENCE ASSESSMENT

The subsequent sections summarise the consequences analyses undertaken in the PHA. Detailed findings are provided in APPENDIX 2.

13.1. Effect Modelling

Release rates and consequence effects were calculated using the proprietary consequence modelling package Shell FRED Version 5 (Ref. 10).

The assessment took into account the orientation of the release. For buried pipeline, a horizontal jet would be less likely to occur as the jet release would tend to be directed upwards, with the majority of releases in a vertical direction since external impacts would be more likely to occur from above the pipe. Therefore, the assessment of buried pipeline leaks was based on an assumption of 80% of releases being vertical and 20% at 45º.

13.2. Releases from Aboveground Facilities

The hazard identification tables were reviewed to select a set of credible release scenarios and hole sizes to be carried forward for consequence modelling. The following leak scenarios and hole sizes were carried forward for the well-sites, CPF, power station and HDS:

13.2.1. Station Equipment

- Flange gasket leaks – 6 mm equivalent hole size
- Valve body leaks – 10 mm equivalent hole size
- Instrument fitting leaks – 25 mm equivalent hole size

13.2.2. Station Pipework

- Pipework pinhole release (corrosion) - 3 mm equivalent hole size
- Pipework puncture release - 25 mm equivalent hole size

Full bore pipework releases for station pipework were not considered credible as per Section 9.2 and was not carried forward to the risk assessment.

The process data used to evaluate the consequences of releases are summarised in Table 9.1. The distance to jet fire heat radiation levels and flash fire impact zones are provided in APPENDIX 2.

13.3. Releases from Gathering/ Spine Lines and Export Sales Pipeline

The gathering line and transmission pipeline release scenarios carried forward for consequence assessment are jet fires and flash fires resulting from a leak or rupture.

As discussed in APPENDIX 2, the European Gas Pipeline Incident Data Group collects data on the frequency of pipeline failures and reports statistical data by a number of factors including hole sizes (Ref. 9). The data broadly categorises releases in a range of hole sizes:

- pinholes or small holes
- medium holes or punctures
- ruptures

Pinholes can occur due to mechanisms such as corrosion, weld defects, material defects in the pipe itself. The resistance of the pipeline material to crack propagation (its fracture toughness) is an important feature in determining whether the release could propagate, resulting in a full bore rupture of the pipeline. There is a potential for small holes or cracks to propagate, potentially leading to extensive longitudinal cracking with an equivalent hole size equal to the full bore rupture.

Townsend and Fearnehough (Ref. 11) indicate that the majority of leaks are small (pinholes and small holes) and would be less than 10 mm. They also indicate that small leaks from pinholes and small holes do not generally constitute a significant hazard due to the low release rates involved.

Hole sizes in the range from 20 mm to 80 mm are predominantly caused by puncture from external interference. A statistical analysis of hole size from puncture events indicated 40 mm as the mean hole size for punctures (Ref. 12).

As discussed in Sections 6.1 and 12.1.4, the ESP will be designed to meet the requirements of the AS2885.1-2007, which requires that the pipeline eliminate the risk of pipeline rupture in T1 location class areas. The pipeline design will also require that the maximum energy release rate should not exceed 10GJ/s, which, at the MAOP, is greater than the proposed flow through the gathering lines and transmission pipeline.

Based on this data, the following hole sizes were selected for release incidents:

- 10 mm diameter for pinholes and small holes.
- 50 mm for medium holes (selected for conservatism over the 40 mm average hole size determined by Fearnehough, Ref. 6).
- Full-bore rupture, which would not exceed the maximum credible leak rate to meet the requirement for a maximum energy release rate for pipeline in T1 locations.

The process data used to evaluate the consequences of releases are summarised in Table 9.1. The distance to jet fire heat radiation levels and flash fire impact zones are provided in APPENDIX 2.

14. FREQUENCY ANALYSIS

14.1. Aboveground Facility Incident Frequencies

Details of the frequency assessment for the well-sites, CPF, power station and HDS are given in APPENDIX 3. The frequency of jet and flash fire incidents was estimated based on:

- generic failure rates for component releases
- the probability of ignition of the release (which is dependent on the release rate).

A parts count of components was undertaken to determine the total release frequency at each location within each facility.

14.2. ESP Incident Frequencies

Details of the frequency assessment for the Export Sales Pipeline are given in APPENDIX 4, including details regarding the effect of pipeline safeguards on the leak/ failure frequencies.

Frequencies for jet and flash fires were derived from published historical records of pipeline incidents. The frequencies of jet fire and flash fire incidents were estimated based on the:

- frequency of the initiating leak
- probability of immediate ignition for jet fires
- probability of delayed ignition for flash fires.

14.3. Gathering Line and Spine Line Incident Frequencies

Details of the frequency assessment for the Gathering/ Spine Lines and Transmission Pipeline are given in APPENDIX 5.

15. QUANTITATIVE RISK ASSESSMENT

15.1. Overview

The quantitative risk levels for the aboveground facilities are presented as risk contours. The contours indicate the risk level at any point around the facility.

The quantitative risk profile resulting from the operation of the gathering and spine lines and the ESP are presented as risk transects, i.e. a graph of estimated risk level versus the lateral distance from the centreline of the pipe. The graph shows the risk level that a receiver would be exposed to at any lateral distance from the pipe. The graph can also be used to estimate the distance to the relevant risk criteria and to show whether there is adequate separation from the pipeline to adjacent land uses.

15.2. Well-Sites Risk Profile

Risk contours were generated for the well-sites. There are approximately 110 identical well-sites, each with provision for up to 4 well-heads, and a typical risk contour is shown in Figure 15.1. The following were the results of the assessment of the risk contours:

- The 0.5 x 10^{-6} per year individual fatality risk contour (sensitive land-use) was found to extend by about 40m from the centre of the well site. This will not extend to any sensitive land-uses.
- The 1 x 10^{-6} per year individual fatality risk contour (residential areas) was found to extend by about 38m from the centre of the well site. This will not extend to any residential areas as well sites will be located to provide a minimum exclusion zone
- The 5 x 10^{-6} per year individual fatality risk contour (commercial areas) was found to extend by about 20m from the centre of the well site and will not extend to any commercial land-uses.
- The 10 x 10^{-6} per year individual fatality risk contour (active open spaces) was found to extend by about 15m from the centre of the well site and will not extend to any active open spaces.
- The 50 x 10^{-6} per year individual fatality risk contour (industrial areas) was not generated by the well-site hazard scenarios.

The radius of the risk contours for the well-sites depends on a number of factors with a predominant factor being the pressure assumed for the well-site equipment. For the well-sites at the Gloucester coal seam locations, a pressure of 10.2 MPa was assumed based on design rating of well-site equipment upstream of the well-head shutdown valve. The actual operating pressure will be much less than this early in the wellhead life (typically 4 MPa) and will degrade over the operating life of the wellhead. The assumption of a 10.2 MPa pressure will give a conservative estimate of risk level compared with similar facilities where a lower operating pressure is assumed.

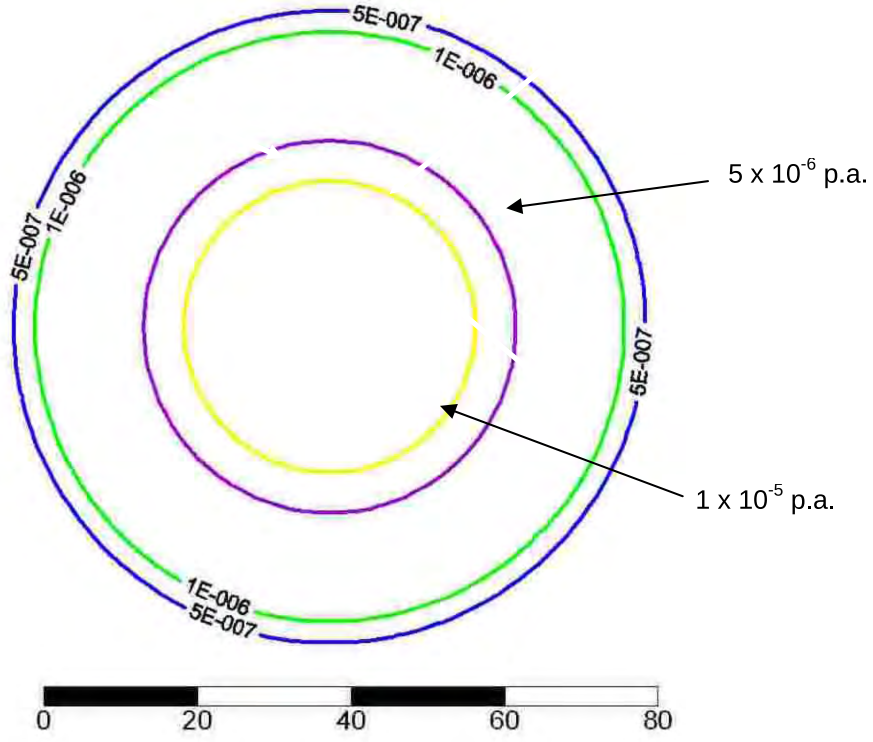

FIGURE 15.1: TYPICAL INDIVIDUAL FATALITY RISK CONTOURS FOR WELL-SITES

15.3. Gas Gathering and Spine Lines Risk Profile

Risk transects were produced, for the gas gathering and spine lines, showing the individual risk of fatality versus the distance from the centreline of the pipe. A number of cases are considered taking into account a range of pipe diameters and process flow rates.

15.3.1. Gathering Line Risk Transects

A number of cases were assessed for the gathering lines as follows:

- Case 1 - 110mm diameter lines with a design flow rate of 2 TJ/day
- Case 2 - 160mm diameter lines with a design flow rate of 4 TJ/day
- Case 3 - 200mm diameter lines with a design flow rate of 6 TJ/day

The risk transects calculated for the gathering lines showed that the risk of fatality would not be expected to exceed about 2×10^{-7} p.a. for all cases. The risk transects are shown in Figure 15.2.

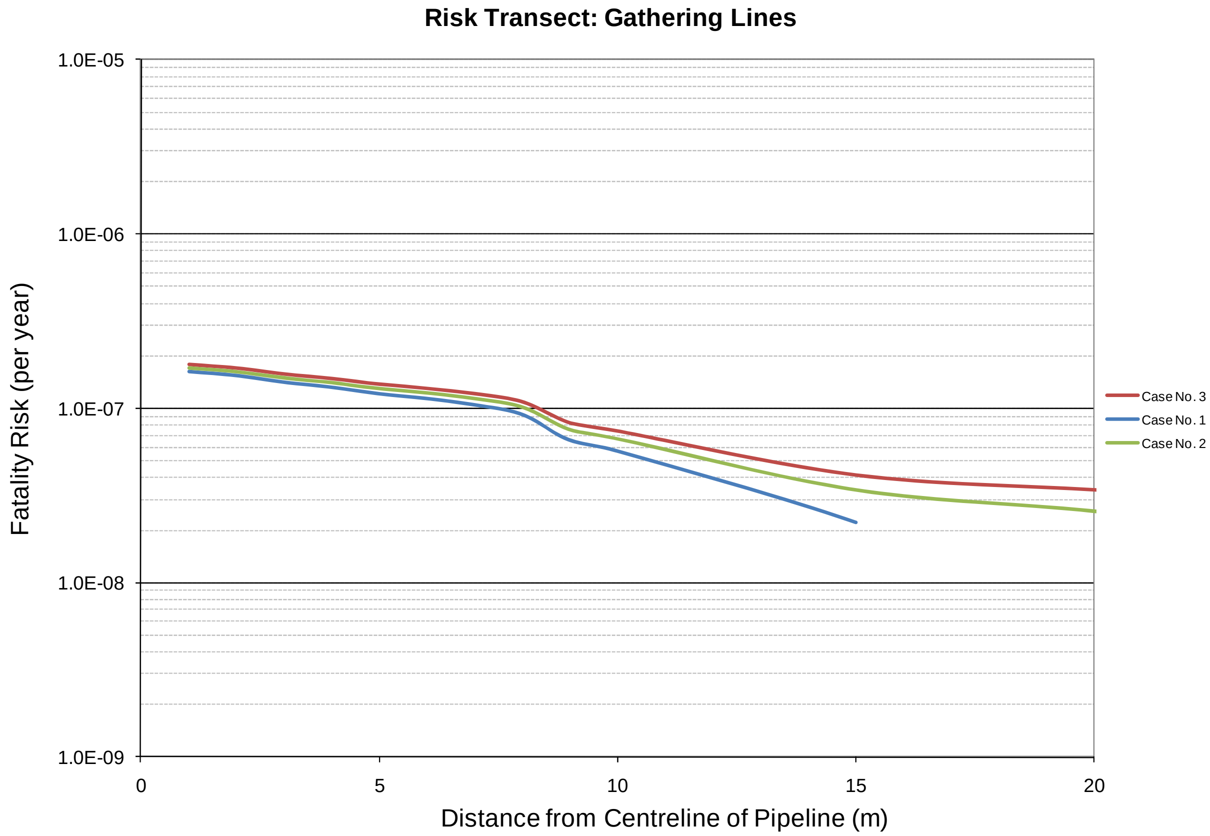

FIGURE 15.2: GATHERING LINE RISK TRANSECT

15.3.2. Spine Line Risk Transects

A number of cases were assessed for the spine lines as follows:

- Case 1 - 315mm diameter lines with a design flow rate of 10 TJ/day
- Case 2 - 315mm diameter lines with a design flow rate of 20 TJ/day
- Case 3 - 450mm diameter lines with a design flow rate of 10 TJ/day
- Case 4 - 450mm diameter lines with a design flow rate of 20 TJ/day
- Case 5 - 450mm diameter lines with a design flow rate of 40 TJ/day
- Case 6 - 450mm diameter lines with a design flow rate of 60 TJ/day
- Case 7 - 540mm diameter lines with a design flow rate of 40 TJ/day
- Case 8 - 540mm diameter lines with a design flow rate of 60 TJ/day
- Case 9 - 630mm diameter lines with a design flow rate of 40 TJ/day
- Case 10 - 630mm diameter lines with a design flow rate of 60 TJ/day

The risk transects calculated for the spine lines showed that the risk of fatality would not be expected to exceed about 3×10^{-7} p.a. for all cases. The risk transects are shown in Figure 15.3.

Risk Transect: Spine Lines

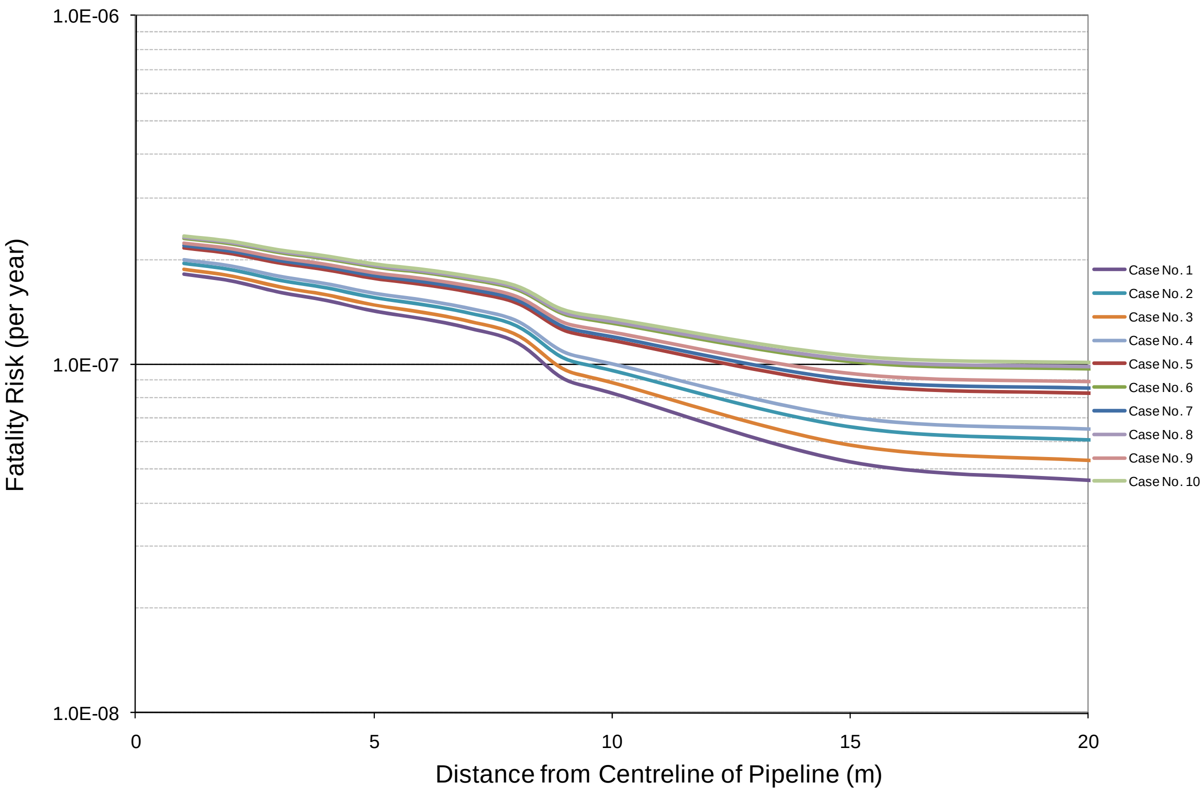

FIGURE 15.3: SPINE LINE RISK TRANSECT

15.3.3. Results of Risk Assessment for Gathering/ Spine Lines

Table 15.1 summarises the distances estimated for the gathering and spine lines to risk criteria levels for other land uses as measured from the centreline of the pipe. This shows that risk levels near the gathering and spines lines do not reach levels which would exceed the risk criteria for all land use types considered by the NSW DoP.

TABLE 15.1: DISTANCES TO CRITERIA OF INDIVIDUAL RISK OF FATALITY – GATHERING LINES AND SPINE LINES

Case	Distance to Individual Risk of Fatality (m)				
	Sensitive (hospitals, nursing homes)	Residential	Commercial	Active Open Spaces	Industrial
	(5×10^{-7} per year)	(1×10^{-6} per year)	(5×10^{-6} per year)	(1×10^{-5} per year)	(5×10^{-5} per year)
Gathering Line Cases					
Case 1 (110mm 2TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 2 (160mm 4TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 3 (200mm 6TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Spine Line Cases					
Case 1 (315mm 10TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 2 (315mm 20TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 3 (450mm 10TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 4 (450mm 20TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 5 (450mm 40TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 6 (450mm 60TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 7 (540mm 40TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 8 (540mm 60TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 9 (630mm 40TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached
Case 10 (630mm 60TJ/d)	Not Reached	Not Reached	Not Reached	Not Reached	Not Reached

15.4. Central Processing Facility (CPF) Risk Profile

Risk contours were generated for two CPF location options:

- CPF-1 (Figure 15.4)
- CPF-7 (Figure 15.5)

15.4.1. CPF-1 Risk Assessment Results

The following were the results of the assessment of the risk contours for **CPF-1**:

- The 0.5×10^{-6} per year individual fatality risk contour (sensitive land-use) was located within the boundary of the site and does not extend to sensitive land uses.
- The 1×10^{-6} per year individual fatality risk contour (residential areas) was located within the boundary of the site and does not extend to residential areas.

- Risk levels for other land use types (commercial, active open spaces, industrial) were located within the boundary of the site and do not extend to the relevant land use types.

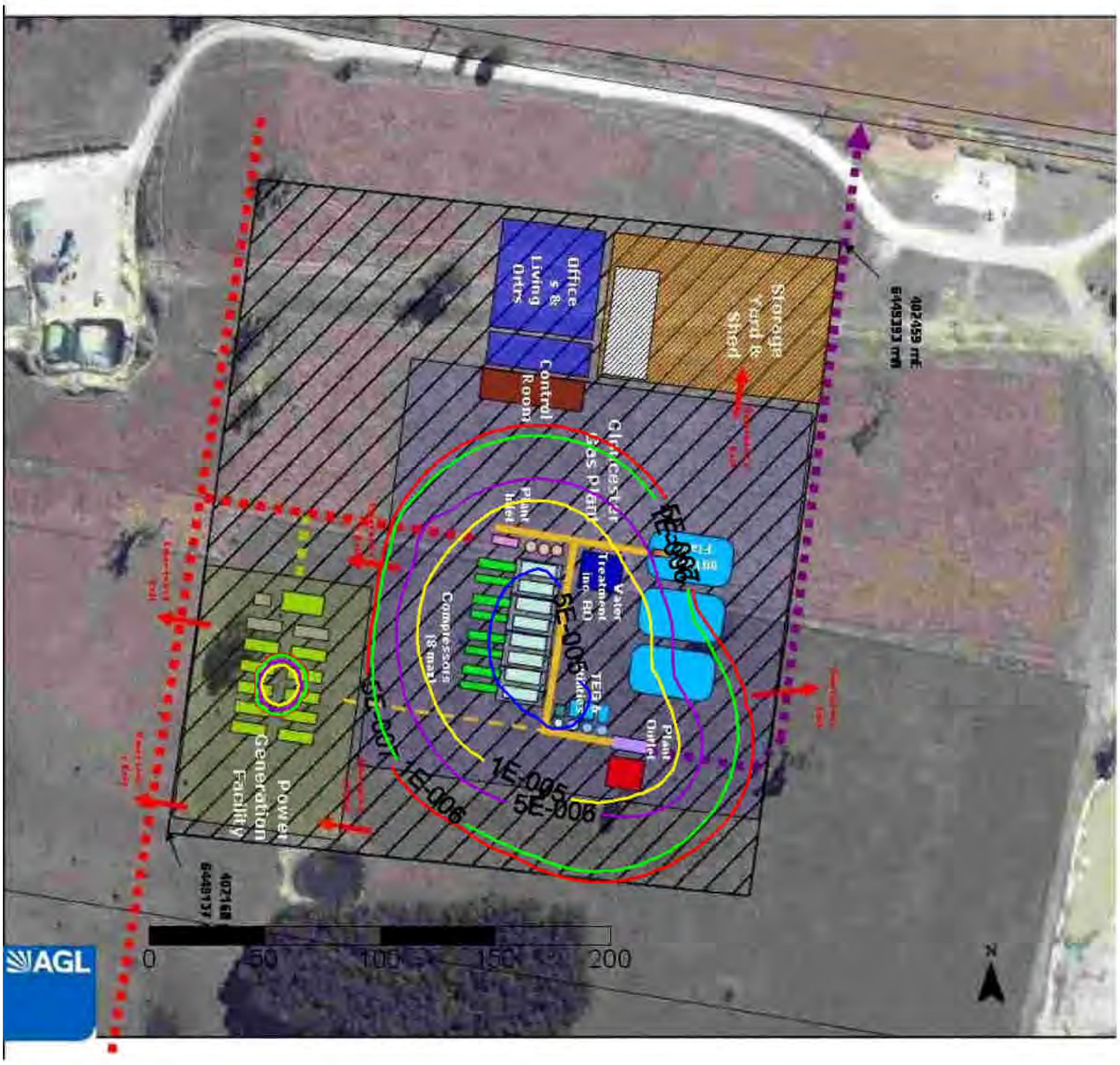

FIGURE 15.4: CPF OPTION 1 INDIVIDUAL FATALITY RISK CONTOURS

15.4.2. CPF-7 Risk Assessment Results

The following were the results of the assessment of the risk contours for **CPF-7**:

- The 0.5 x 10^{-6} per year individual fatality risk contour (sensitive land-use) was located within the boundary of the site and does not extend to sensitive land uses.
- The 1 x 10^{-6} per year individual fatality risk contour (residential areas) was located within the boundary of the site and does not extend to residential areas.
- Risk levels for other land use types (commercial, active open spaces, industrial) were located within the boundary of the site and do not extend to the relevant land use types.

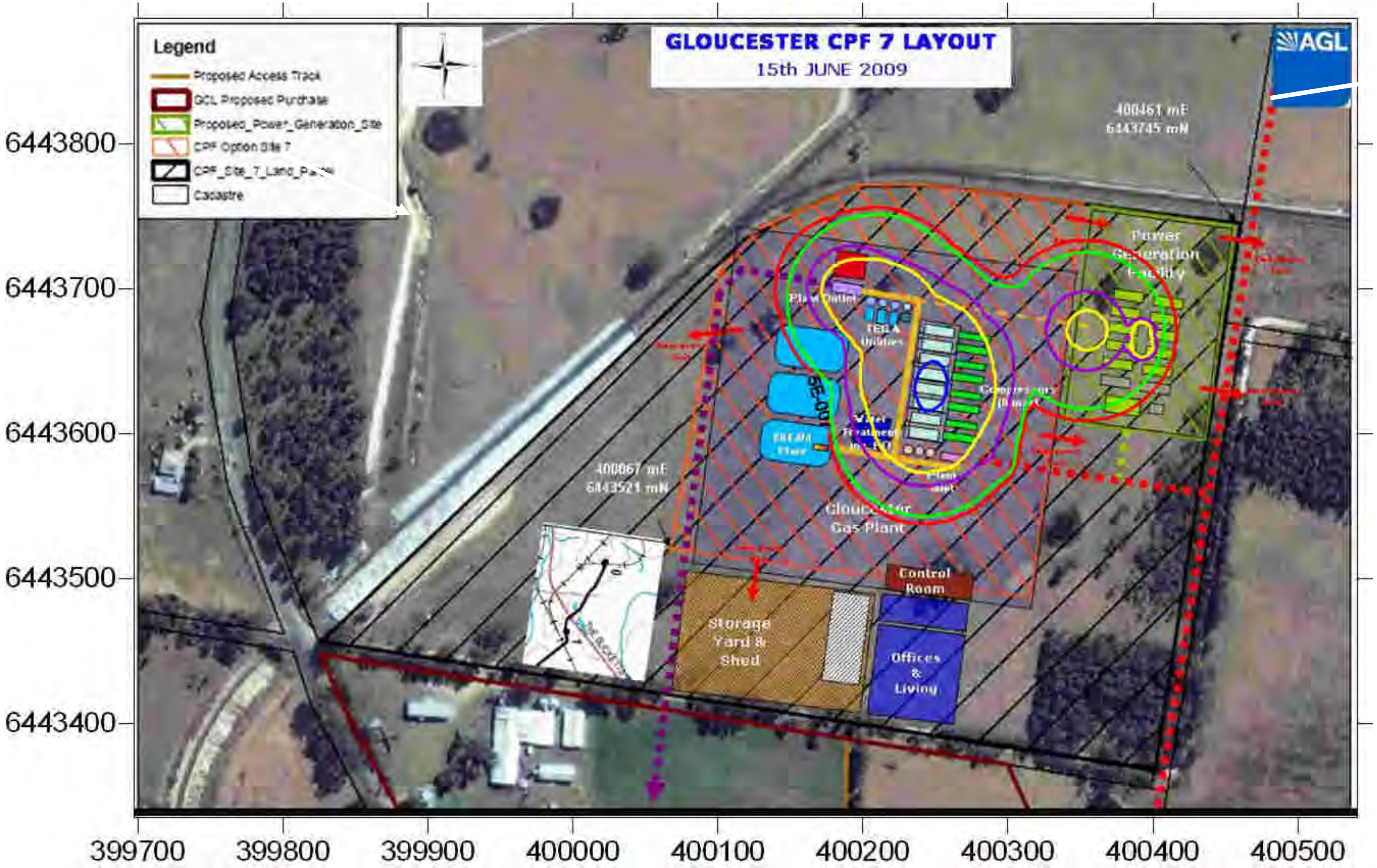

FIGURE 15.5: CPF OPTION 7 INDIVIDUAL FATALITY RISK CONTOURS

15.5. Export Sales Pipeline Risk Profile

A number of sensitivity cases have been assessed taking into account a range of design parameters and safeguards:

- Pipeline diameter (DN 450/250)
- Location class (R1/T1)
- Depth of Cover
- Wall Thickness
- Marker Tape

The following cases have been assessed:

- Case No. 1 – DN 450, R1, 750mm DOC, 11mm WT, no marker tape
- Case No. 2 – DN 450, T1, 900mm DOC, 11mm WT, marker tape
- Case No. 3 – DN 250, R1, 750mm DOC, 5mm WT, no marker tape
- Case No. 4 – DN 250, T1, 900mm DOC, 12.7mm WT, marker tape
- Case No. 5 – DN 250, Road/Rail Crossings, 1200mm DOC, 7.5mm WT, marker tape
- Case No. 6 – DN 250, Intermediate water courses, 1500mm DOC, 7.5mm WT, no marker tape
- Case No. 7 – DN 250, Major water courses, 2000mm DOC, 7.5mm WT, no marker tape

15.5.1. Results of Risk Assessment for Export Sales Pipeline

Risk transects were produced for these cases showing the individual risk of fatality versus the distance from the centreline of the pipe. The DN 450 cases are shown in Figure 15.6 (Cases 1-2) and the DN 250 cases in Figure 15.7 (Cases 3-7).

Table 15.2 summarises the distances estimated for the ESP to risk criteria levels for land uses as measured from the centreline of the pipe. This shows the minimum separation distances required for various land use types to ensure compliance with the risk criteria of the NSW DoP.

DN 450 Pipeline – R1 Locations

For the DN 450 pipeline in R1 locations (Case 1), the fatality risk contour level for sensitive land uses (5×10^{-7} per year) was found to extend up to 190 m from the centreline of the pipe, however, sensitive land uses (including hospitals, schools, child care facilities, aged care housing, etc.) were not identified to exist within a this distance from the centreline of the pipeline.

Risk levels with the potential for significant impact to residential areas (1×10^{-6} per year) were shown to extend 35m from the centreline of the ESP. From a review of the separation distances to the nearest residences identified near the pipeline (Section 6.3), the nearest residences are located as close as 15 m from the pipeline.

These locations are within the first 16km of the pipeline, in R1 locations. Therefore, Case 1 (with 750 mm DOC and no marker tape) will not comply with the NSW DoP risk criteria. Therefore, additional measures will be required near these locations, such as additional depth of cover and/or marker tape.

DN 450 Pipeline – T1 Locations

For the DN 450 pipeline for T1 locations (Case 2, including marker tape), the fatality risk contour level for sensitive land uses (5 x 10^{-7} per year) was found to extend up to 41 m from the centreline of the pipe, however, sensitive land uses (including hospitals, schools, child care facilities, aged care housing, etc.) were not identified to exist within a this distance from the centreline of the pipeline.

Risk levels with the potential for significant impact to residential areas (1 x 10^{-6} per year) were not reached at any distance from the centreline of the ESP.

TABLE 15.2: DISTANCES TO CRITERIA OF INDIVIDUAL RISK OF FATALITY – EXPORT SALES PIPELINE

Case	Distance to Individual Risk of Fatality (m)				
	Sensitive (hospitals, nursing homes)	Residential	Commercial	Active Open Spaces	Industrial
	(5 x 10^{-7} per year)	(1 x 10^{-6} per year)	(5 x 10^{-6} per year)	(1 x 10^{-5} per year)	(5 x 10^{-5} per year)
DN 450 Pipeline					
Case No. 1	190	35	Not Reached	Not Reached	Not Reached
Case No. 2	41	Not Reached	Not Reached	Not Reached	Not Reached
DN 250 Pipeline					
Case No. 3	230	215	20	Not Reached	Not Reached
Case No. 4	35	Not Reached	Not Reached	Not Reached	Not Reached
Case No. 5	43	Not Reached	Not Reached	Not Reached	Not Reached
Case No. 6	45	12	Not Reached	Not Reached	Not Reached
Case No. 7	10	Not Reached	Not Reached	Not Reached	Not Reached

DN 250 Pipeline – All Cases

The risk assessment for the DN 250 cases was undertaken to compare the distances to risk criteria levels for a number of cases.

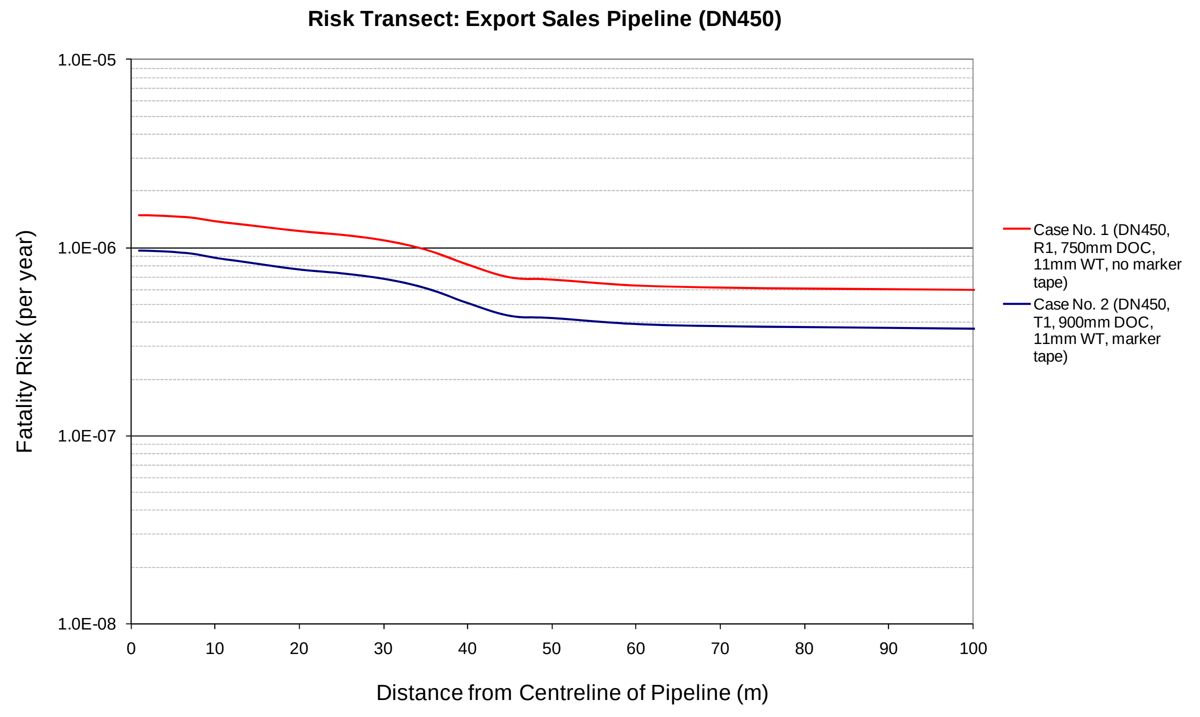

FIGURE 15.6: EXPORT SALES PIPELINE RISK TRANSECT – DN 450 (CASES 1 AND 2)

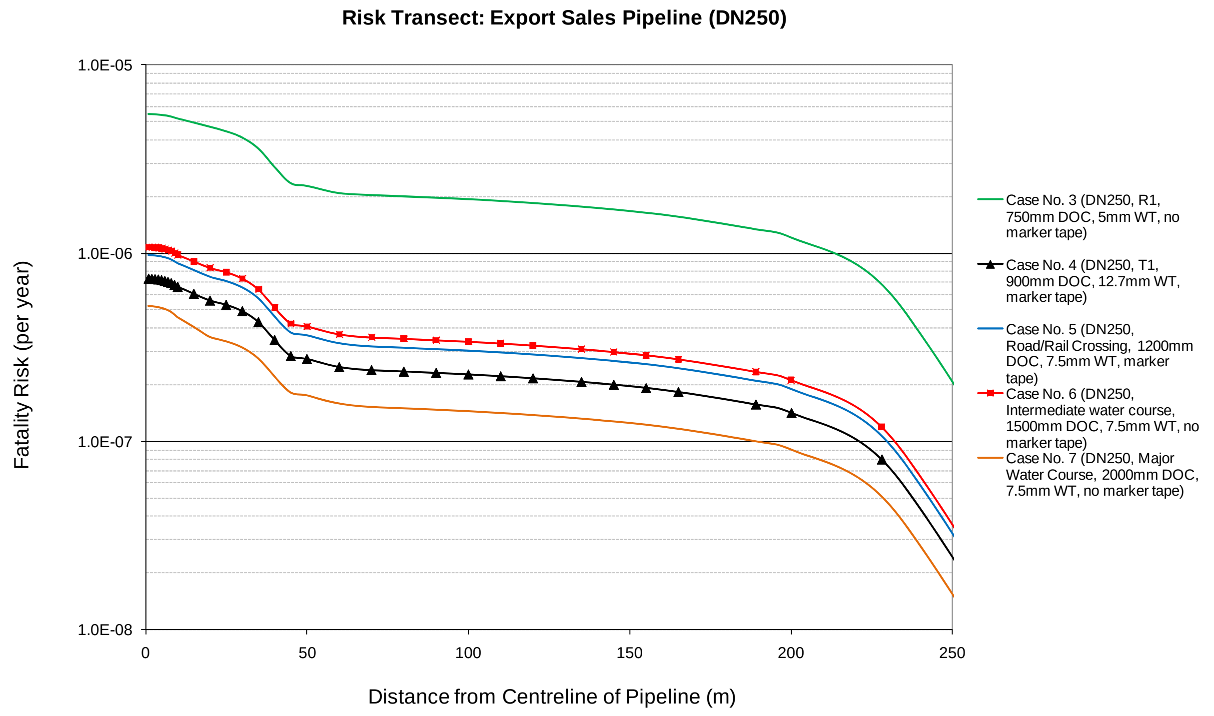

FIGURE 15.7: EXPORT SALES PIPELINE RISK TRANSECT – DN 250 (CASES 3 - 7)

15.6. Hexham Delivery Station (HDS) Risk Profile

The HDS will be located within the Hexham Port and Industry Zone which is Zone 4a as per the Newcastle Local Environment Plan 2003 - Ref. 13), in which there are no sensitive, residential or commercial land-uses (as defined in Table 2 of HIPAP 4, Ref. 4). Risk contours were generated for the HDS and are shown in Figure 15.8.

The findings are as follows:

- The 0.5×10^{-6} per year individual fatality risk contour (sensitive land-use) was found to extend off-site by a maximum of about 30m. The contour remains within the Zone 4a Industrial Area, and does not reach any sensitive land-uses.
- The 1×10^{-6} per year individual fatality risk contour (residential areas) was found to extend off-site by a maximum of about 20m to the southern boundary of the HDS site. The contour remains almost entirely within the Zone 4a Industrial Area and does not reach any residences.
- The 5×10^{-6} per year individual fatality risk contour (commercial) was found to be contained within the boundary of the HDS site and therefore will not extend to adjacent commercial zones (i.e. retail centres, office or entertainment centre).
- The risk levels for other land use types (active open spaces, industrial) were not generated for the site, i.e. risk levels at the HDS did not reach the criteria levels for these land use types at any point on the HDS site.
- The 50×10^{-6} per year injury risk contours were not generated on the site.
- The 50×10^{-6} per year escalation (accident propagation) risk contours were not generated on the site.

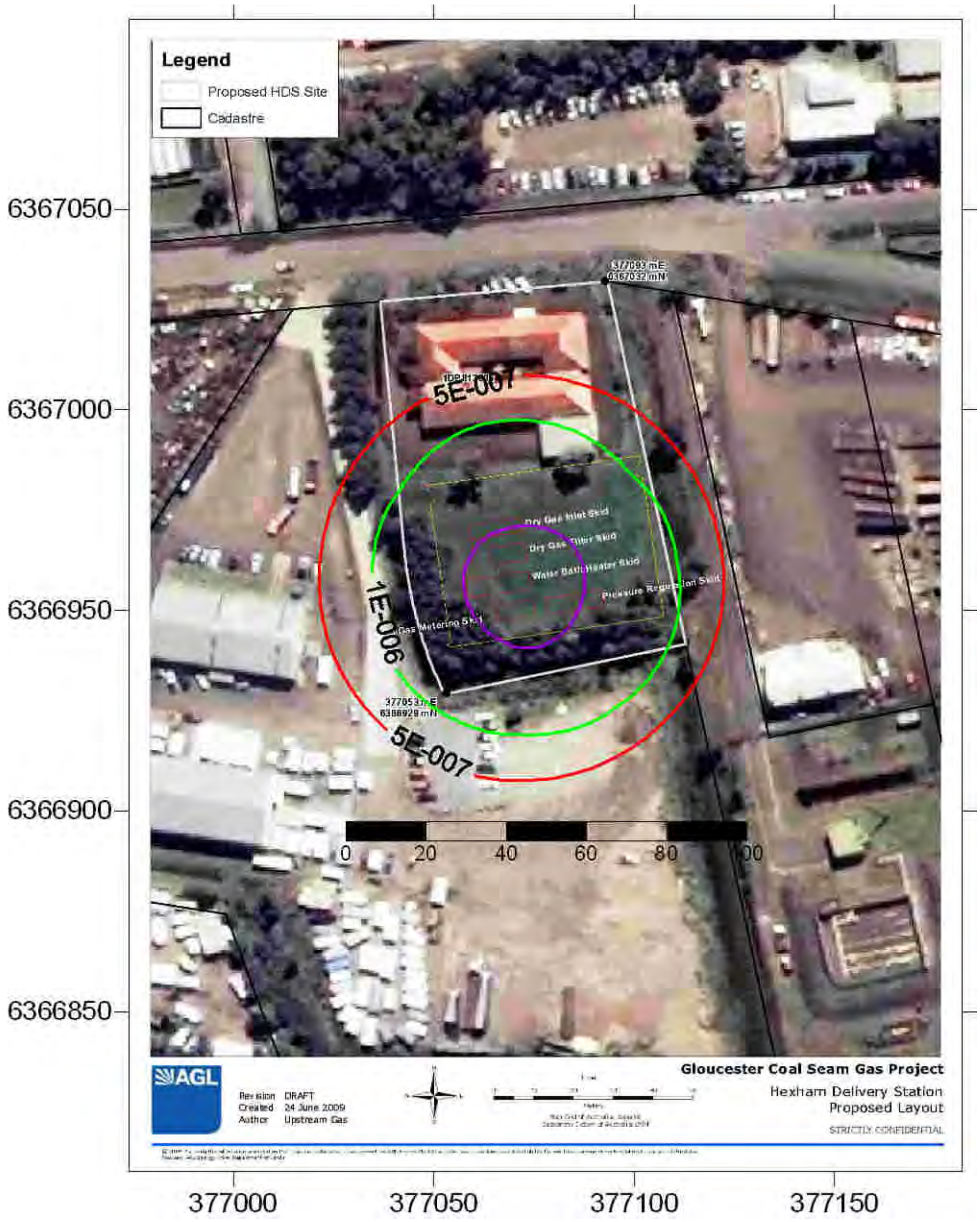

FIGURE 15.8: HDS INDIVIDUAL FATALITY RISK CONTOURS

15.7. Societal Risk

Due to the low off-site risk levels at each facility, societal risk was not evaluated.

15.8. Bio-Physical Effects

The following general comments concerning biophysical and environmental impacts were made as a result of the assessment:

- The effects of an accidental emission of methane gas are unlikely to threaten the long-term viability of the ecosystem or any species within any sensitive natural environmental areas which may exist near the proposed development.

- The potential biophysical effects of produced-water (including accidental emission) are evaluated in the Environmental Assessment (EA, Ref. 3).

15.9. Conclusions

A PHA was undertaken to determine the off-site risk profile of the proposed Gloucester Coal Seam Gas (GCSG) Project, including the well-sites, gathering lines, processing facility, transmission pipeline and delivery station.

The PHA found that the off-site risk of fatality, injury and accident propagation posed by the GCSG project meets the requirements of the NSW Department of Planning Risk Criteria for Land-Use Safety Planning (Ref. 4).

The effects of an accidental emission of methane gas are unlikely to threaten the long-term viability of the ecosystem or any species within any sensitive natural environmental areas which may exist near the proposed development. The potential biophysical effects of produced-water are evaluated in the EA (Ref. 3).

15.10. Recommendations

1. It is recommended that, near existing residences in R1 locations (or land identified for future residential use) that are within 35 m of the centreline of the Export Sales Pipeline, safeguards in addition to those provided for Case 1 (DN 450mm pipeline in R1 locations) should be implemented. These additional safeguards may include marker tape and/ or additional depth of cover.

2. The proposed Export Sales Pipeline would not cross any known areas of mine subsidence. However, as this may change in the future, it is recommended that AGL liaise with the Mine Subsidence Board to determine likely future mining activity and the potential for subsidence.

3. The PHA should be updated when final design details are known, particularly for the operation of the flare.

4. Once final design details are known, the design should be HAZOPed, particularly to assess abnormal operating modes such as flare and blowdown operations.

As the design develops, the project is generally required to complete a number of other safety and risk studies, as part of the NSW Department of Planning Seven Stage Approval Process, which are to be undertaken in accordance with the relevant Departmental guidelines.

APPENDIX 1. HAZARD IDENTIFICATION TABLES

A 1.1. HAZARD IDENTIFICATION

The hazard identification undertaken for the Gloucester Coal Seam Gas Project is summarised in the following tables:

- Well sites – Table A1.1
- Gathering lines and spine lines – Table A1.2
- Central Processing Facility – Table A1.3
- Export Sales Pipeline – Table A1.4
- Hexham Delivery Station – Table A1.5

TABLE A1.1: HAZARD IDENTIFICATION TABLE FOR WELL-SITES

No.	Accident/Event	Cause	Consequence	Safeguards	Comments/Recommendations
1	General leaks and ignition	• Miscellaneous failures • Gasket leak • Instrument fitting leak • Weld failure • Vibration	• Gas release • Jet fire if ignited	• Isolation valves • Pressure monitoring via SCADA system • Electrical design for equipment in hazardous areas • Spiral wound gaskets on flanged equipment	Carried forward to quantitative risk analysis
2	Release from station pipework and ignition	• External damage by third party interference or vehicle impact	• Gas release • Jet fire if ignited	• Pipework is aboveground • Permit to work system for maintenance • Site fenced off	Carried forward to quantitative risk analysis
3	Pinhole leaks and pipework failure	• Internal corrosion • External corrosion • Weld failure • Material defects	• Gas release • Jet fire if ignited	• Corrosion protection • Painting of aboveground pipework • Construction and material defects protection • 100% radiography of all circumferential welds • Hydrostatic test	Carried forward to quantitative risk analysis
4	Valve leaks	• Leak from valve stem • Pinhole or hole in valve body • Hole or rupture in smaller diameter pipework or from leaks in fittings in smaller diameter pipework	• Gas release • Jet fire if ignited	• Robust nature of valve body • Regular inspection of station • Low corrosion potential due to dry gas • Some valves welded into line • Valve specifications • Routine maintenance	Carried forward for further analysis
5	Vessel/ equipment leaks	• Gasket / fitting leaks	• Gas release • Jet fire if ignited	• Station equipment fully monitored by the SCADA system • Maintenance • Flanges fitted with spiral wound gaskets	Carried forward for further analysis
6	Pipework failure/ rupture	• Ground movement • Well blow-out	• Gas release • Jet fire if ignited	• Pipeline integrity • Wall thickness • Stress relief at tie-in points	Low likelihood of causing a loss of containment. Not carried forward to quantitative risk analysis.

No.	Accident/Event	Cause	Consequence	Safeguards	Comments/Recommendations
7	Equipment damage – External events	• Bushfire / grass fire	• Damage to surface facilities leading to leak • Jet fire if ignited	• Bushfire / grass fire protection • Vegetation well cleared from above ground facilities • Security fencing around station in line with hazardous area classification (AS2430/ API RP500) • Gravel or hardstand area within fenced area	Not carried forward to quantitative risk analysis
8	Equipment damage – External events	• Lightning	• Damage to surface facilities leading to leak and ignition and jet fire	• Lightning protection system	Low likelihood of impact. Not carried forward for further analysis
9	High Pressure	• Overpressure	• Pipeline / equipment damage	• Pipework design to MAOP • Monitoring of pressure	Not carried forward to quantitative risk analysis
10	High Temperature	• Over-temperature	• Pipeline / equipment damage	• Design temperature above normal operating temperature	Not carried forward to quantitative risk analysis
11	Release during normal operation/ maintenance	• Releases from operation and maintenance activity (venting)	• Gas release, jet fire if ignited	• Small quantities released • Operating procedures and monitoring • Permit to work system	Not carried forward for further analysis
12	Vandalism	• Location of well-sites	• Equipment damage • Uncontrolled release	• Security fencing • Alarms in buildings • Monitoring of stations	Not carried forward to quantitative risk analysis
13	Diesel fires	• Spills from diesel genset	• Impact to equipment	• No storage at well sites	Not carried forward to quantitative risk analysis

TABLE A1.2: HAZARD IDENTIFICATION TABLE FOR GATHERING AND SPINE LINES

No.	Component	Hazardous Incident	Consequence	Protection or Safety Measure	Comments/Recommendations
1	Pipeline	External interference	Potential impact on pipeline causing leak of natural gas. Jet fire if ignited. Potential injury/fatality	• Depth of cover • Wall thickness • Pipeline patrols	Carried forward to risk assessment
2	Pipeline	Scouring / erosion at waterways / drains leading to exposure of pipeline	Exposed pipeline may be subject to external impact	• Depth of cover provided at waterways/drain crossings • Pipeline patrols	Not carried forward to quantitative risk assessment
3	Pipeline	Floatation of pipeline near swamp	• Exposed pipeline may be subject to external impact • Pipe stress	• Pipeline patrols • High integrity pipeline	Not carried forward to quantitative risk assessment
4	Pipeline	High vehicular loading on pipeline due to roadways (highway) / railway powerline easement roads	• Potential impact on pipeline causing leak of natural gas. • Jet fire if ignited. • Potential injury/fatality	• Depth of cover at road / rail crossings • Pipeline patrol • One-call system	Not carried forward to quantitative risk assessment
5	Pipeline	Pipeline leaks due to weld/ material defects	Potential leak, jet fire if ignited	• Welding procedures • Material Certificates • Hydrostatic testing • QA/QC	Carried forward to quantitative risk assessment
6	Pipeline	Overpressure	Pipeline / equipment damage	• Pipeline designed to meet full 0.5MPa MAOP • Monitoring of system pressure	Not carried forward to quantitative risk assessment
7	Pipeline	Over-temperature	Pipeline / equipment damage	• Monitoring of compressor outlet temperature. • Compressor aftercoolers	Not carried forward to quantitative risk assessment
8	Pipeline	Mine subsidence	Pipeline damage	• The proposed routes would not cross any known areas of mine subsidence.	Not carried forward to quantitative risk assessment

TABLE A1.3: HAZARD IDENTIFICATION TABLE FOR CENTRAL PROCESSING FACILITY

No.	Accident/Event	Cause	Consequence	Safeguards	Comments/Recommendations
1	General leaks and ignition	• Miscellaneous failures • Gasket leak • Weld failure • Vibration	Gas release, jet fire if ignited.	• Isolation valves • Pressure monitoring via SCADA system • Electrical design for equipment in hazardous areas in Compressor Station and Delivery facility • Spiral wound gaskets on flanged equipment • Gas detectors	Carried forward to quantitative risk analysis
2	Pipe impact, hole release and ignition	External damage by third party interference or vehicle impact	Gas release, jet fire if ignited	• Pipework within station is aboveground • Permit to work system for maintenance • Site fenced off	Carried forward to quantitative risk analysis
3	Pinhole leaks (including pipeline)	• Internal corrosion • External corrosion • Weld failure • Material defects	Gas release, jet fire if ignited	• Corrosion protection • Painting of aboveground pipework in station	Carried forward to quantitative risk analysis
4	Pipework failure/rupture	Ground movement	Gas release, jet fire if ignited	• Pipeline integrity • Wall thickness • Stress relief at tie-in points	Low likelihood of causing a loss of containment. Not carried forward to quantitative risk analysis
5	Pipework failure	Construction and material defects	Gas release, jet fire if ignited	• Construction and material defects protection • 100% radiography of all circumferential welds • Hydrostatic test	Carried forward to quantitative risk analysis
6	Equipment damage	Bushfire / grass fire	Damage to surface facilities leading to leak Jet fire if ignited	• Bushfire / grass fire protection • Vegetation well cleared from above ground facilities • Security fencing around station in line with hazardous area classification (AS2430) • Gravel or hardstand area within fenced area	Not carried forward to quantitative risk analysis

No.	Accident/Event	Cause	Consequence	Safeguards	Comments/Recommendations
7	Equipment damage	Lightning	Damage to surface facilities leading to leak and ignition and jet fire	• Lightning protection system	Low likelihood of impact. Not carried forward for further analysis
8	Pipeline	Overpressure	Pipeline / equipment damage	• Pipework design to MAOP • Monitoring of station pressure	Not carried forward to quantitative risk analysis
9	Pipeline	Over-temperature	Pipeline / equipment damage	• Design temperature above normal operating temperature • Compressor Intercooler/ aftercooler	Not carried forward to quantitative risk analysis
10	Valve leaks	• Leak from valve stem • Pinhole or hole in valve body • Leaks from pinhole • Hole or rupture in smaller diameter pipework or from leaks in fittings in smaller diameter pipework	Gas release Jet fire if ignited	• Robust nature of valve body • Regular inspection of station • Low corrosion potential due to dry gas • Some valves welded into line • Valve specifications • Routine maintenance	Carried forward for further analysis
11	Vessel/ equipment leaks	Gasket / fitting leaks	Gas release, jet fire if ignited	• Station equipment fully monitored by the SCADA system • Maintenance • Flanges fitted with spiral wound gaskets	Carried forward for further analysis
12	Release during normal operation/ maintenance	Releases from operation and maintenance activity (venting)	Gas release, jet fire if ignited	• Small quantities released/ Controlled operation • Operating procedures and monitoring • Permit to work system	Not carried forward for further analysis
13	Vent operations (ESD operations)	Auto venting / blowdown operation on ESD	Gas release Fire Explosion	• Gas lighter than air and disperses rapidly • Separation distance from plant area • Gas being discharged at a controlled rate	Carried forward for dispersion analysis
14	Vandalism	Location of stations	Equipment damage Uncontrolled release	• Security fencing • Alarms in buildings • Monitoring of stations	Not carried forward to quantitative risk analysis
15	Compressor Enclosure	Release into enclosure	Gas buildup Explosion	• Ventilation • Gas / fire detection	Not carried forward to quantitative risk analysis

TABLE A1.4: HAZARD IDENTIFICATION TABLE FOR EXPORT SALES PIPELINE

No.	Component	Hazardous Incident	Consequence	Protection or Safety Measure	Comments/Recommendations
1	Pipeline	External interference	Potential impact on pipeline causing leak of natural gas. Jet fire if ignited. Potential injury/fatality	• Depth of cover • Wall thickness • Pipeline patrols	Carried forward to risk assessment
2	Pipeline	Scouring / erosion at waterways /drains leading to exposure of pipeline	Exposed pipeline may be subject to external impact	• Depth of cover / extra wall thickness provided at waterways/drain crossings. Pipeline patrols	Not carried forward to quantitative risk assessment
3	Pipeline	Floatation of pipeline near swamp	Exposed pipeline may be subject to external impact Pipe stress	• Pipeline patrols • High integrity pipeline	
4	Pipeline	High vehicular loading on pipeline due to roadways (highway) / railway powerline easement roads	Potential impact on pipeline causing leak of natural gas. Jet fire if ignited. Potential injury/fatality	• Depth of cover at road / rail crossings • Pipeline patrol • One-call system	Not carried forward to quantitative risk assessment
5	Pipeline	Corrosion due to stray currents	Potential impact on pipeline coating Pinhole leaks Jet fire if ignited	• Pipeline coating • Cathodic protection • Holiday coating checks • Inspection of cathodic protection (probes)	Carried forward to quantitative risk assessment
6	Pipeline	Stress corrosion cracking	Potential leak, jet fire if ignited	• Pipeline coating • Pressure cycling not to exceed design criteria • Welding procedures • Material Certificates • Weld joints radiographed (100%) • Hydrostatic testing • QA/QC	Not carried forward to quantitative risk assessment

No.	Component	Hazardous Incident	Consequence	Protection or Safety Measure	Comments/Recommendations
7	Pipeline	Pipeline leaks due to weld/material defects	Potential leak, jet fire if ignited	• Welding procedures • Material Certificates • Weld joints radiographed (100%) • Hydrostatic testing • QA/QC	Carried forward to quantitative risk assessment
8	Pipeline	Overpressure	Pipeline / equipment damage	• Pipeline designed to meet full MAOP • Monitoring of system pressure	Not carried forward to quantitative risk assessment
9	Pipeline	Over-temperature	Pipeline / equipment damage	• Monitoring of compressor outlet temperature. • Compressor aftercoolers	Not carried forward to quantitative risk assessment
10	Pipeline	AC Induction impact on pipeline from adjacent powerlines	Pipeline damage (corrosion impact) Personnel impact	• AC induction safeguards as proposed • Powerline can be shut off during maintenance	Not carried forward to quantitative risk assessment
11	Pipeline	Stray current and DC voltage impact from railway line	Corrosion and induction	• Design to include control devices, for example, Transformer Rectifier Assisted Drainage (TRAD) unit to divert stray currents	Not carried forward to quantitative risk assessment
12	Pipeline	Mine subsidence	Pipeline damage	• The proposed pipeline route would not cross any known areas of mine subsidence.	Not carried forward to quantitative risk assessment

TABLE A1.5: HAZARD IDENTIFICATION TABLE FOR HEXHAM DELIVERY STATION

No.	Accident/Event	Cause	Consequence	Safeguards	Comments/Recommendations
1	General leaks and ignition	• Miscellaneous failures • Gasket leak • Weld failure • Vibration	Gas release, jet fire if ignited.	• Isolation valves • Pressure monitoring via SCADA system • Electrical design for equipment in hazardous areas in Compressor Station and Delivery facility • Spiral wound gaskets on flanged equipment • Gas detectors	Carried forward to quantitative risk analysis
2	Pipe impact, hole release and ignition	External damage by third party interference or vehicle impact	Gas release, jet fire if ignited	• Pipework within station is aboveground • Permit to work system for maintenance • Site fenced off	Carried forward to quantitative risk analysis
3	Pinhole leaks (including pipeline)	• Internal corrosion • External corrosion • Weld failure • Material defects	Gas release, jet fire if ignited	• Corrosion protection • Painting of aboveground pipework in station	Carried forward to quantitative risk analysis
4	Pipework failure/ rupture	Ground movement	Gas release, jet fire if ignited	• Pipeline integrity • Wall thickness • Stress relief at tie-in points	Low likelihood of causing a loss of containment. Not carried forward to quantitative risk analysis
5	Pipework failure	Construction and material defects	Gas release, jet fire if ignited	• Construction and material defects protection • 100% radiography of all circumferential welds • Hydrostatic test	Carried forward to quantitative risk analysis

No.	Accident/Event	Cause	Consequence	Safeguards	Comments/Recommendations
6	Equipment damage	Bushfire / grass fire	Damage to surface facilities leading to leak Jet fire if ignited	• Bushfire / grass fire protection • Vegetation well cleared from above ground facilities • Security fencing around station in line with hazardous area classification (AS2430) • Gravel or hardstand area within fenced area	Not carried forward to quantitative risk analysis
7	Equipment damage	Lightning	Damage to surface facilities leading to leak and ignition and jet fire	• Lightning protection system	Low likelihood of impact. Not carried forward for further analysis
8	Pipeline	Overpressure	Pipeline / equipment damage	• Pipework design to MAOP • Monitoring of station pressure	Not carried forward to quantitative risk analysis
9	Pipeline	Over-temperature	Pipeline / equipment damage	• Design temperature above normal operating temperature	Not carried forward to quantitative risk analysis
10	Valve leaks	• Leak from valve stem • Pinhole or hole in valve body • Leaks from pinhole • Hole or rupture in smaller diameter pipework or from leaks in fittings	Gas release Jet fire if ignited	• Robust nature of valve body • Regular inspection of station • Low corrosion potential due to dry gas • Some valves welded into line • Valve specifications • Routine maintenance	Carried forward for further analysis
11	Vessel/ equipment leaks	Gasket / fitting leaks	Gas release, jet fire if ignited	• Station equipment fully monitored by the SCADA system • Maintenance • Flanges fitted with spiral wound gaskets	Carried forward for further analysis
12	Release during normal operation/ maintenance	Releases from operation and maintenance activity (venting)	Gas release, jet fire if ignited	• Small quantities released • Operating procedures and monitoring • Permit to work system	Not carried forward for further analysis
14	Vandalism	Location of stations	Equipment damage Uncontrolled release	• Security fencing • Alarms in buildings • Monitoring of stations	Not carried forward to quantitative risk analysis

APPENDIX 2. CONSEQUENCE ASSESSMENT

A 2.1. Introduction

This appendix documents the consequence assessment of the Gloucester Coal Seam Gas Project, including the well-sites, gathering lines, processing facility, transmission pipeline and delivery station. In particular, the following activities undertaken for the consequence analysis are described:

- Selection of release scenarios and hole size
- Jet fire modelling approach
- Flash fire modelling approach
- Dispersion modelling approach
- Results of consequence assessment and associated heat radiation effects

A 2.2. Modelling Approach

A 2.2.1. Leak and Effect Modelling

The consequence modelling for the jet fire scenarios was undertaken using Shell FRED 5.0, which was developed by Shell Global Solutions (Ref. 10).

The impact from flash fire incidents is modelled in Shell FRED as the dispersion distance to half the lower flammability limit (LFL). It is assumed that in a flash fire there is a 100% chance of fatality occurring within the fireball.

A 2.2.2. Meteorological Conditions

The following typical weather conditions were assumed for the consequence assessment:

- "D" Pasquill stability class and 5m/s wind speed for jet fires and flash fires
- "F" Pasquill stability class and 2m/s wind speed for flash fires
- 20^{o}C ambient temperature
- 70% relative humidity

For the assessment of impact from flash fires, the greatest distance for downwind impact was carried forward.

A 2.2.3. Orientation of Release

The angle of release from the gathering lines and transmission pipeline was specified as follows:

- Vertical where the release is 90 degrees to the horizontal plane. Releases due to third party impact will tend to occur on the top of the pipeline.

- Horizontal releases will tend to scour the ground around the pipeline resulting in a crater which will deflect the jet upwards. The release is modelled as a jet flame at 45 degrees to the horizontal plane.

NOTE: In the consequence distance tables, the flame length reported is the total length including flame lift-off from the release point and length of the flame, not the lateral distance from the pipeline. For releases at an angle from vertical, the flame length reported (which results in 100% chance of fatality) may be greater in some cases than the distance to heat radiation levels which result in fatality. This will result in conservative risk levels near the pipeline.

The well-site, CPF and HDS pipework is a mixture of aboveground and underground. In the worst case, it was assumed that the angle of release for station pipework was horizontal. Similarly, fitting releases could occur in any direction, depending on the leak location and the placement of the fitting. Horizontal releases result in the furthest impact distances and would give the worse case results for releases from the stations.

A 2.3. Summary of Findings

A 2.3.1. Gathering and Spine Lines

The release rates, jet fire and flash fire impact distances evaluated for the gathering and spine lines are summarised in Table A2.1.

A number of cases are considered for the consequence assessment of gathering and spine line releases as follows:

Gathering Lines

- 110mm diameter lines with a design flow rate of 2 TJ/day
- 160mm diameter lines with a design flow rate of 4 TJ/day
- 200mm diameter lines with a design flow rate of 6 TJ/day

Spine Lines

- 315mm diameter lines with a design flow rate of 10 TJ/day
- 315mm diameter lines with a design flow rate of 20 TJ/day
- 450mm diameter lines with a design flow rate of 10 TJ/day
- 450mm diameter lines with a design flow rate of 20 TJ/day
- 450mm diameter lines with a design flow rate of 40 TJ/day
- 450mm diameter lines with a design flow rate of 60 TJ/day
- 540mm diameter lines with a design flow rate of 40 TJ/day
- 540mm diameter lines with a design flow rate of 60 TJ/day
- 630mm diameter lines with a design flow rate of 40 TJ/day
- 630mm diameter lines with a design flow rate of 40 TJ/day

A 2.3.2. Well-Sites, CPF and HDS

The release rates, jet fire and flash fire impact distances evaluated for the Well-Sites, CPF and HDS are summarised in Table A2.2.

Design flow rates for equipment are assumed as follows:

- Maximum overall flow rate – 80 TJ/day
- Filter coalescers (2 off) – 2 x 40 TJ/day
- Compressors (8 off, 7 duty, 1 standby) – 7 x 11.4 TJ/day
- TEG Contactor towers (2 off) – 2 x 40 TJ/day

A 2.3.3. Export Sales Pipeline

The release rates, jet fire and flash fire impact distances evaluated for the Gloucester-Hexham Transmission Pipeline are summarised in Table A2.3.

A number of cases are considered for the consequence assessment of export sales pipeline as follows:

- 450mm diameter lines with a design flow rate of 80 TJ/day
- 250mm diameter lines with a design flow rate of 80 TJ/day

A 2.3.4. Power Station

The release rates, jet fire and flash fire impact distances evaluated for the power station located adjacent to the CPF are summarised in Table A2.4.

The following assumptions are made for the power station consequence assessment:

- Station maximum inlet gas pressure – 4.5 barg
- Station inlet operating temperature – 47°C
- Station flow rate – 714 kg/h
- Gas engine flow rate – 8 x 89 kg/h
- Fuel gas letdown pressure – 0.45 barg

TABLE A2.1: GATHERING AND SPINE LINE CONSEQUENCE MODELLING RESULTS

ID Tag	Release Description	Press	Temp	Hole Size	Design Flow Rate	Release Rate	Release Orient'n	Jet Fire						D5 Flash Fire (to Half LFL)		F2 Flash Fire (to Half LFL)	
								Flame Length	4.7 kw/m^2	6 kw/m^2	10 kw/m^2	14 kw/m^2	23 kw/m^2	Length	Width	Length	Width
		barg	ºC	(mm)	(TJ/d)	(kg/s)		(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)
Gathering Lines																	
1	Pinhole	7	30	10	All	0.09	45º	5	6	5	5	4	4	2	0.4	3.0	0.5
2	Puncture	7	30	50	All	2.14	45º	17	22	20	18	16	15	10	2	13.6	2.4
3	110mm Rupture - No Isolation	7	30	110	2	3.10	45º	19	27	25	22	20	18	13	3	17.8	3.6
4	160mm Rupture - No Isolation	7	30	160	4	6.30	45º	25	37	34	30	27	25	19	4	24.0	4.8
5	200mm Rupture - No Isolation	7	30	200	6	9.40	45º	30	44	41	35	32	29	24	5	29.0	6.0
6	Pinhole	7	30	10	All	0.09	Vertical	4	4	3	3	2	2	0.5	0.5	0.4	0.5
7	Puncture	7	30	50	All	2.14	Vertical	15	16	14	11	9	7	3.0	2.4	2.4	2.5
8	110mm Rupture - No Isolation	7	30	110	2	3.10	Vertical	18	21	19	15	13	10	4.2	3.4	3.7	3.6
9	160mm Rupture - No Isolation	7	30	160	4	6.30	Vertical	24	28	25	20	17	14	6.0	4.8	5.5	5.2
10	200mm Rupture - No Isolation	7	30	200	6	9.40	Vertical	28	34	30	24	21	17	7.7	5.8	6.7	6.4
Spine Lines																	
1	Pinhole	7	30	10	All	0.09	45º	5	6	5	5	4	4	2.0	0.5	3.0	0.5
2	Puncture	7	30	50	All	2.14	45º	17	22	20	18	17	15	10.7	2.2	13.6	2.4
3	Rupture - No Isolation	7	30	315	10	15.6	45º	37	57	53	46	42	38	32.0	7.2	39.0	8.2
4	Rupture - No Isolation	7	30	315	20	31.3	45º	48	71	65	57	53	47	40.0	8.6	47.3	9.7
5	Rupture - No Isolation	7	30	450	10	15.6	45º	37	64	59	51	47	43	35.0	8.0	41.7	9.8
6	Rupture - No Isolation	7	30	450	20	31.3	45º	48	77	71	61	56	50	43.4	5.8	48.5	11.4
7	Rupture - No Isolation	7	30	450	40	62.6	45º	64	94	88	76	69	62	54.5	12.2	64.0	13.3
8	Rupture - No Isolation	7	30	450	60	93.8	45º	75	110	102	88	81	73	66.8	13.6	71.4	15.1
9	Rupture - No Isolation	7	30	540	40	62.6	45º	64	97	91	77	72	64	55.0	13.1	64.7	14.6
10	Rupture - No Isolation	7	30	540	60	93.8	45º	75	111	103	89	82	73	67.3	14.9	76.5	15.9
11	Rupture - No Isolation	7	30	630	40	62.6	45º	64	102	95	81	74	67	61.0	14.0	70.0	15.4
12	Rupture - No Isolation	7	30	630	60	93.8	45º	75	115	106	92	84	75	68.0	16.0	76.8	16.5
1	Pinhole	7	30	10	All	0.09	Vertical	4	4	3	3	2	2	0.5	0.5	0.4	0.5
2	Puncture	7	30	50	All	2.14	Vertical	15	16	14	11	9	7	2.8	2.4	2.3	2.5

ID Tag	Release Description	Press	Temp	Hole Size	Design Flow Rate	Release Rate	Release Orient'n	Jet Fire						D5 Flash Fire (to Half LFL)		F2 Flash Fire (to Half LFL)	
								Flame Length	4.7 kw/m^2	6 kw/m^2	10 kw/m^2	14 kw/m^2	23 kw/m^2	Length	Width	Length	Width
		barg	ºC	(mm)	(TJ/d)	(kg/s)		(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)
3	Rupture - No Isolation	7	30	315	10	15.6	Vertical	34	46	42	34	29	25	12.4	4.0	10.4	9.2
4	Rupture - No Isolation	7	30	315	20	31.3	Vertical	45	53	48	38	33	26	12.9	9.9	10.9	10.6
5	Rupture - No Isolation	7	30	450	10	15.6	Vertical	34	57	51	42	37	32	18.0	9.0	14.8	10.9
6	Rupture - No Isolation	7	30	450	20	31.3	Vertical	45	62	56	46	40	33	17.9	11.4	15.2	12.8
7	Rupture - No Isolation	7	30	450	40	62.6	Vertical	60	72	64	51	45	36	18.8	13.7	15.0	14.5
8	Rupture - No Isolation	7	30	450	60	93.8	Vertical	70	81	72	59	50	40	20.9	15.9	17.1	16.5
9	Rupture - No Isolation	7	30	540	40	62.6	Vertical	60	77	69	56	49	40	21.9	14.6	18.0	16.0
10	Rupture - No Isolation	7	30	540	60	93.8	Vertical	70	85	76	60	52	43	22.3	16.4	18.2	17.3
11	Rupture - No Isolation	7	30	630	40	62.6	Vertical	60	83	75	61	53	44	25.0	15.5	20.9	17.2
12	Rupture - No Isolation	7	30	630	60	93.8	Vertical	70	89	81	65	55	45	25.0	17.5	21.2	18.6

TABLE A2.2: WELL-SITES, CPF & HDS CONSEQUENCE MODELLING RESULTS

ID Tag	Plant Area	Hole Size	Press	Temp	Process Rate	Process Rate	Release Rate	Release Orient'n	Jet Fire						D5 Flash Fire (to Half LFL)		F2 Flash Fire (to Half LFL)	
									Flame Length	4.7 kw/m^2	6 kw/m^2	10 kw/m^2	14 kw/m^2	23 kw/m^2	Length	Width	Length	Width
		mm	barg	°C	(TJ/day)	(kg/s)	(kg/s)		(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)
Well-Sites																		
WH1	Well-head	6	102	30	2	40	0.5	Vertical	8	8	7	6	5	4	1	1	1	1
WH2	Well-head	10	102	30	2	40	1.3	Vertical	13	13	11	9	8	6	2	2	2	2
WH3	Well-head	25	102	30	2	40	8.0	Vertical	26	28	25	20	17	13	6	5	5	5
WH4	Well-head	80mm (FB)	102	30	2	40	40	Vertical	50	54	48	38	33	26	9	7	10	10
WS1	Water Separator	6	7	30	2	3.1	0.03	Horizontal	3	4	4	4	4	3	2	0.3	3	0.3
WS2	Water Separator	10	7	30	2	3.1	0.1	Horizontal	5	6	6	6	5	5	3	0.4	4	0.5
WS3	Water Separator	25	7	30	2	3.1	0.5	Horizontal	10	13	12	12	11	11	9	2	8	2
WS4	Water Separator	80mm (FB)	7	30	2	3.1	3.1	Horizontal	20	28	26	25	24	23	26	5	18	5
CPF																		
SH1	Suction Header	6	7	30	40	63	0.03	Horizontal	3	4	4	4	4	3	2	0.3	3	0.3
SH2	Suction Header	10	7	30	40	63	0.1	Horizontal	5	6	6	6	5	5	3	0.4	4	0.5
SH3	Suction Header	25	7	30	40	63	0.5	Horizontal	10	13	12	12	11	11	9	2	8	2
IS1	Inlet Separator	6	7	30	80	125	0.03	Horizontal	3	4	4	4	4	3	2	0.3	3	0.3
IS2	Inlet Separator	10	7	30	80	125	0.1	Horizontal	5	6	6	6	5	5	3	0.4	4	0.5
IS3	Inlet Separator	25	7	30	80	125	0.5	Horizontal	10	13	12	12	11	11	9	2	8	2
FC1	Inlet Filter Coalescer	6	7	30	80	125	0.03	Horizontal	3	4	4	4	4	3	2	0.3	3	0.3
FC2	Inlet Filter Coalescer	10	7	30	80	125	0.1	Horizontal	5	6	6	6	5	5	3	0.4	4	0.5
FC3	Inlet Filter Coalescer	25	7	30	80	125	0.5	Horizontal	10	13	12	12	11	11	9	2	8	2
C11	Compressor 1	6	168	55	11.4	348	0.7	Horizontal	11	15	14	13	13	12	11	2	9	2
C12	Compressor 1	10	168	55	11.4	348	2	Horizontal	17	23	22	20	19	19	19	4	14	4

ID Tag	Plant Area	Hole Size	Press	Temp	Process Rate	Process Rate	Release Rate	Release Orient'n	Jet Fire						D5 Flash Fire (to Half LFL)		F2 Flash Fire (to Half LFL)	
									Flame Length	4.7 kw/m^2	6 kw/m^2	10 kw/m^2	14 kw/m^2	23 kw/m^2	Length	Width	Length	Width
		mm	barg	^oC	(TJ/day)	(kg/s)	(kg/s)		(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)
C13	Compressor 1	25	168	55	11.4	348	12	Horizontal	35	49	48	44	42	40	50	10	36	9
-	Other Compressors as for Comp 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DH1	Discharge Header	6	153	55	80	2225	1	Horizontal	11	14	14	13	12	12	10	2	9	2
DH2	Discharge Header	10	153	55	80	2225	2	Horizontal	16	22	21	19	19	18	18	3	14	3
DH3	Discharge Header	25	153	55	80	2225	11	Horizontal	33	48	46	42	40	39	49	9	34	9
TEG1	TEG Inlet Coalescer TEG Contactor TEG Outlet Coalescer	6	168	55	80	2442	1	Horizontal	11	15	14	13	13	12	11	2	9	2
TEG2	TEG Inlet Coalescer TEG Contactor TEG Outlet Coalescer	10	168	55	80	2442	2	Horizontal	17	23	22	20	19	19	19	4	14	4
TEG3	TEG Inlet Coalescer TEG Contactor TEG Outlet Coalescer	25	168	55	80	2442	12	Horizontal	35	49	48	44	42	40	50	10	36	9
CV1	Regulator/SDV	6	153	55	80	2225	1	Horizontal	11	14	14	13	12	12	10	2	9	2
CV2	Regulator/SDV	10	153	55	80	2225	2	Horizontal	16	22	21	19	19	18	18	3	14	3
CV3	Regulator/SDV	25	153	55	80	2225	11	Horizontal	33	48	46	42	40	39	49	9	34	9
EX1	Scraper Launcher Gas Analysers Export Metering	6	168	55	80	2442	1	Horizontal	11	15	14	13	13	12	11	2	9	2

ID Tag	Plant Area	Hole Size	Press	Temp	Process Rate	Process Rate	Release Rate	Release Orient'n	Jet Fire						D5 Flash Fire (to Half LFL)		F2 Flash Fire (to Half LFL)	
									Flame Length	4.7 kw/m^2	6 kw/m^2	10 kw/m^2	14 kw/m^2	23 kw/m^2	Length	Width	Length	Width
		mm	barg	^{o}C	(TJ/day)	(kg/s)	(kg/s)		(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)
EX2	Scraper Launcher Gas Analysers Export Metering	10	168	55	80	2442	2	Horizontal	17	23	22	20	19	19	19	4	14	4
EX3	Scraper Launcher Gas Analysers Export Metering	25	168	55	80	2442	12	Horizontal	35	49	48	44	42	40	50	10	36	9
UG1	Utility Gas Skid	6	19.65	30	4	16	0.08	Horizontal	4.6	5.9	5.7	5.3	5.2	5.1	3.0	0.4	3.5	0.5
UG2	Utility Gas Skid	10	19.65	30	4	16	0.23	Horizontal	7	9.1	8.7	8.1	7.9	7.7	5.5	0.8	5.5	0.9
UG3	Utility Gas Skid	25	19.65	30	4	16	1.4	Horizontal	14	20	19	18	17	16	16	3	12	3
CPF Station Pipework																		
PIPE-LP1	Low Pressure Pipework	3	7	30	80	125	0.0077	Horizontal	2	2	2	2	2	2	1	0.14	1	0.16
PIPE-LP2	Low Pressure Pipework	25	7	30	80	125	0.54	Horizontal	10	13	12	12	11	11	9	2	8	2
PIPE-HP1	Low Pressure Pipework	3	168	55	80	2442	0.2	Horizontal	6	8	8	8	7	7	5	1	5	1
PIPE-HP2	Low Pressure Pipework	25	168	55	80	2442	12.44	Horizontal	35	49	48	44	42	40	50	10	36	9
PIPE-UG1	Utility Gas Pipework	3	19.65	30	4	16	0.02	Horizontal	3	3	3	3	3	3	1.8	0.2	2.0	0.2
PIPE-UG2	Utility Gas Pipework	25	19.65	30	4	16	1.42	Horizontal	14	20	19	18	17	16	16	3	12	3
HDS																		
IN1	Inlet/Scraper Receiver	6	153	30	80	2409	0.65	Horizontal	11	14	14	13	12	12	10	2	9	2
IN2	Scraper Receiver Dry Gas Filters Custody Meters	10	153	30	80	2409	1.81	Horizontal	16	22	21	19	19	18	18	3	14	3
IN3	Scraper Receiver Dry Gas Filters Custody Meters	25	153	30	80	2409	11.30	Horizontal	33	48	46	42	40	39	49	9	34	9

ID Tag	Plant Area	Hole Size	Press	Temp	Process Rate	Process Rate	Release Rate	Release Orient'n	Jet Fire						D5 Flash Fire (to Half LFL)		F2 Flash Fire (to Half LFL)	
									Flame Length	4.7 kw/m^2	6 kw/m^2	10 kw/m^2	14 kw/m^2	23 kw/m^2	Length	Width	Length	Width
		mm	barg	°C	(TJ/day)	(kg/s)	(kg/s)		(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)
DGF1	Dry Gas Filters	6	153	30	80	2409	0.65	Horizontal	11	14	14	13	12	12	10	2	9	2
DGF2	Dry Gas Filters	10	153	30	80	2409	1.81	Horizontal	16	22	21	19	19	18	18	3	14	3
DGF3	Dry Gas Filters	25	153	30	80	2409	11.30	Horizontal	33	48	46	42	40	39	49	9	34	9
HEAT1	Water Bath Heaters	6	153	30	80	2409	0.65	Horizontal	11	14	14	13	12	12	10	2	9	2
HEAT2	Water Bath Heaters	10	153	30	80	2409	1.81	Horizontal	16	22	21	19	19	18	18	3	14	3
HEAT3	Water Bath Heaters	25	153	30	80	2409	11.30	Horizontal	33	48	46	42	40	39	49	9	34	9
METER1	Custody Meters	6	153	30	80	2409	0.65	Horizontal	11	14	14	13	12	12	10	2	9	2
METER2	Custody Meters	10	153	30	80	2409	1.81	Horizontal	16	22	21	19	19	18	18	3	14	3
METER3	Custody Meters	25	153	30	80	2409	11.30	Horizontal	33	48	46	42	40	39	49	9	34	9
REG1	Regulator Skid	6	153	30	80	2409	0.65	Horizontal	11	14	14	13	12	12	10	2	9	2
REG2	Regulator Skid	10	153	30	80	2409	1.81	Horizontal	16	22	21	19	19	18	18	3	14	3
REG3	Regulator Skid	25	153	30	80	2409	11.30	Horizontal	33	48	46	42	40	39	49	9	34	9

TABLE A2.3: EXPORT SALES PIPELINE CONSEQUENCE MODELLING RESULTS

ID Tag	Release Description	Pressure	Temp	Hole Size	Process Rate	Process Rate	Release Rate	Release Orient'n	Jet Fire						D5 Flash Fire (to Half LFL)		F2 Flash Fire (to Half LFL)	
									Flame Length	4.7 kw/m^2	6 kw/m^2	10 kw/m^2	14 kw/m^2	23 kw/m^2	Length	Width	Length	Width
		barg	ºC	(mm)	(TJ/day)	(kg/s)	(kg/s)		(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)
1	Pinhole	153	30	10	80	2409	2	45º	16	21	20	17	16	15	9.9	2.1	13.8	2.4
2	Puncture	153	30	50	80	2409	50	45º	58	83	77	67	62	55	46.4	10.1	56.1	11.0
3	Rupture - No Isolation	153	30	Full Bore (450mm)	80	2409	2409	45º	275	412	385	329	303	268	n/a	n/a	n/a	n/a
6	Rupture - No Isolation	153	30	Full Bore (250mm)	80	2409	1247	45º	211	317	292	251	231	206	232.5	49.2	233.0	45.0
1	Pinhole	153	30	10	80	2409	2	Vertical	15	15	14	11	9	7	2.8	2.4	2.3	2.5
2	Puncture	153	30	50	80	2409	50	Vertical	54	61	55	43	37	30	14.4	11.3	12.1	11.9
3	Rupture - No Isolation	153	30	Full Bore (450mm)	80	2409	2409	Vertical	256	306	274	221	188	150	101.5	35.8	93.4	66.8
5	Rupture - No Isolation	153	30	Full Bore (250mm)	80	2409	1247	Vertical	197	232	209	166	144	116	75.4	26.8	67.0	25.5

TABLE A2.4: POWER STATION CONSEQUENCE MODELLING RESULTS

ID Tag	Plant Area	Hole Size	Press	Temp	Process Rate	Release Rate	Release Orient'n	Jet Fire						D5 Flash Fire (to Half LFL)		F2 Flash Fir (to Half LFL	
								Flame Length	4.7 kw/m^2	6 kw/m^2	10 kw/m^2	14 kw/m^2	23 kw/m^2	Length	Width	Length	Wic
		mm	barg	^{o}C	(kg/s)	(kg/s)		(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m)	(m
Power Station Equipment																	
PSIN1	SDV/Isol Valves Meter/Bypass Valves	6	4.5	47	0.4	0.02	Horiz.	3	3	3	3	3	3	2	0.2	2	0.
PSIN2	SDV/Isol Valves Meter/Bypass Valves	10	4.5	47	0.4	0.06	Horiz.	4	5	5	5	5	4	2	0.4	3	0.
PSIN3	SDV/Isol Valves Meter/Bypass Valves	25	4.5	47	0.4	0.36	Horiz.	8	11	10	10	10	9	7	1	7	1
ENG1HP1	Inlet Filter (Combine 10 Units at one Location) Meter/Bypass	6	4.5	47	0.1	0.02	Horiz.	3	3	3	3	3	3	2	0.2	2	0.
ENG1HP2	Inlet Filter (Combine 10 Units at one Location) Meter/Bypass	10	4.5	47	0.1	0.06	Horiz.	4	5	5	5	5	4	2	0.4	3	0.
ENG1HP3	Inlet Filter (Combine 10 Units at one Location) Meter/Bypass	25	4.5	47	0.1	0.10	Horiz.	5	7	6	6	6	6	4	1	5	1
ENG1LP1	Regulator (all 10 combined) Relief Valve	6	0.45	47	0.1	0.005	Horiz.	2	2	2	2	2	2	1	0.2	2	0.
ENG1LP2	Regulator (all 10 combined) Relief Valve	10	0.45	47	0.1	0.014	Horiz.	2	3	3	3	3	3	2	0.3	3	0.
ENG1LP3	Regulator (all 10 combined) Relief Valve	25	0.45	47	0.1	0.088	Horiz.	5	6	6	6	6	5	4	1	5	1
Power Station Pipework																	
PIPE-PSHP1	PS HP Pipework	3	4.5	47	0.4	0.005	Horiz.	2	2	2	2	2	2	1	0.1	1	0.
PIPE-PSHP2	PS HP Pipework	25	4.5	30	0	0.36	Horiz.	8	11	10	10	10	9	7	1	7	1

APPENDIX 3. ABOVEGROUND FACILITY INCIDENT FREQUENCIES

A 3.1. General

This appendix summarises the results of the frequency assessment for the following:

- Frequency of releases from station equipment and pipework
- Probability of immediate ignition of release and frequency of jet fire
- Probability of delayed ignition of release and frequency of flash fire

A 3.2. Well-Site, CPF and HDS Facilities Release Frequencies

A 3.2.1. Probability of Loss of Containment

Release frequencies were categorised as:

Station Equipment

- Flange gasket leaks – 6 mm equivalent hole size
- Valve body leaks – 10 mm equivalent hole size
- Instrument fitting leaks – 25 mm equivalent hole size

Station Pipework

- Pipework pinhole release (corrosion) - 3 mm equivalent hole size
- Pipework puncture release - 25 mm equivalent hole size

The UK Health and Safety Executive (Ref. 14) reports the frequency of valve, flange and pipework failures, as follows:

- Flange/gasket leaks
- Valve body leaks
- Pipework releases (both small and large release sizes)

Cox, Lees and Ang (Ref. 15) reports the frequency of instrument tapping failure as 1 x 10^{-4} per fitting-year for a rupture leak.

The release frequency data used for the QRA is summarised in Table A3.1..

TABLE A3.1: COMPONENT LEAK FREQUENCIES

Equipment	Failure Mode	Release Frequency (x 10^{-6} per year)
Flange gasket leak	6 mm spiral wound gasket leak	50 x 10^{-6} per flange
Valve body leak	10 mm gland leak	170 x 10^{-6} per valve
Instrument fitting leak	25 mm leak	100 x 10^{-6} per fitting
Pipework pinhole release	3 mm leak	7.6 x 10^{-6} per m
Pipework puncture	25 mm leak	7.6 x 10^{-6} per m

A 3.2.2. Event Frequencies

Cox, Lees and Ang (Ref. 15) estimates the probability of ignition of leaks in plants, as shown in Table A3.2 (the event tree for release rates between 1 and 50 kg/s is shown below), which is applicable to aboveground facilities.

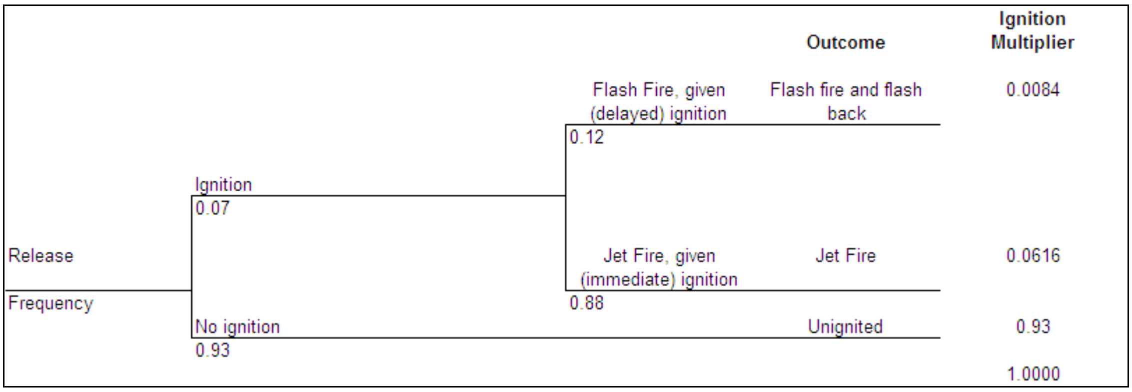

TABLE A3.2: CONDITIONAL PROBABILITIES OF IMMEDIATE AND DELAYED IGNITION GIVEN GAS RELEASE

Leak Size	Ignition Probability (Gas or Mixture)	Conditional Probability of Flash Fire	Immediate Ignition (Jet Fire) Probability	Delayed Ignition (Flash Fire) Probability
<1 kg/s	0.01	0.04	0.0096	0.0004
1 - 50 kg/s	0.07	0.12	0.0616	0.0084
50 kg/s	0.3	0.3	0.21	0.09

A 3.2.3. Parts Count

The parts counts for the well-sites, CPF and power station, and HDS are shown in Table A3.3. The parts count was undertaken using preliminary (concept-phase) drawings and conservative assumptions were made in the absence of detailed information.

TABLE A3.3: COMPONENT PARTS COUNT

Plant Area	Parts Count		
	Flanges	Valves	Instrument Fittings
Well-Sites			
Wellhead (4 off per well-site)	24	12	12
Water Separator (4 off per well-site)	64	44	8
Central Processing Facility			
Suction header	12	16	1
Inlet Separator	10	5	1
Inlet filter coalescers (3 units)	54	27	3
Compressors (per compressor unit)	20	6	5
Discharge header	4	0	2
TEG inlet coalescer, contactor, outlet coalescer	36	18	6

Plant Area	Parts Count		
	Flanges	Valves	Instrument Fittings
Regulator/SDV	4	2	0
Scraper launcher, Gas analysers, Export metering	16	8	2
Utility gas skid	10	4	4
Power Station			
Inlet SDV, isolation valves, meter/bypass valves	32	12	4
Engine inlet Filter and meter/bypass (per engine unit)	17	6	1
Regulator and relief valves (per engine unit)	11	5	1
Hexham Delivery Station			
Inlet/Scraper Receiver	8	4	2
Dry Gas Filters	8	4	4
Water Bath Heaters	12	4	4
Custody Meters	20	7	4
Regulator Skid	12	6	2

TABLE A3.3: WELL-SITE, CPF POWER STATION & HDS FREQUENCIES

Incident Tag No.	Plant Area	Release Description	Leak Frequency (per year)	Probability Jet Fire Given Ignition	Jet Fire Frequency (per year)	Probability Flash Fire Given Ignition	Flash Fire Frequency (per year)
Well-Sites							
WH1	Well-head	Gasket Leak	1.20E-03	0.0096	1.15E-05	0.0004	4.80E-07
WH2	Well-head	Valve Leak	2.04E-03	0.0616	1.26E-04	0.0084	1.71E-05
WH3	Well-head	Fitting Leak	1.20E-03	0.0616	7.39E-05	0.0084	1.01E-05
WH4	Well-head	Pipework Rupture	6.08E-05	0.0616	3.75E-06	0.0084	5.11E-07
WS1	Water Separator	Gasket Leak	3.20E-03	0.0096	3.07E-05	0.0004	1.28E-06
WS2	Water Separator	Valve Leak	7.48E-03	0.0096	7.18E-05	0.0004	2.99E-06
WS3	Water Separator	Fitting Leak	8.00E-04	0.0096	7.68E-06	0.0004	3.20E-07
WS4	Water Separator	Pipework Rupture	3.04E-04	0.0616	1.87E-05	0.0084	2.55E-06
CPF Equipment							
SH1	Suction Header	Gasket Leak	6.00E-04	0.0096	5.76E-06	0.0004	2.40E-07
SH2	Suction Header	Valve Leak	1.02E-03	0.0096	9.79E-06	0.0004	4.08E-07
SH3	Suction Header	Fitting Leak	1.00E-04	0.0096	9.60E-07	0.0004	4.00E-08
IS1	Inlet Separator	Gasket Leak	5.00E-04	0.0096	4.80E-06	0.0004	2.00E-07
IS2	Inlet Separator	Valve Leak	8.50E-04	0.0096	8.16E-06	0.0004	3.40E-07
IS3	Inlet Separator	Fitting Leak	1.00E-04	0.0096	9.60E-07	0.0004	4.00E-08
FC1	Inlet Filter Coalescers	Gasket Leak	2.70E-03	0.0096	2.59E-05	0.0004	1.08E-06
FC2	Inlet Filter Coalescers	Valve Leak	4.59E-03	0.0096	4.41E-05	0.0004	1.84E-06
FC3	Inlet Filter Coalescers	Fitting Leak	3.00E-04	0.0096	2.88E-06	0.0004	1.20E-07
C11	Compressor Unit (per compressor)	Gasket Leak	1.00E-03	0.0096	9.60E-06	0.0004	4.00E-07
C12	Compressor Unit (per compressor)	Valve Leak	1.02E-03	0.0616	6.28E-05	0.0084	8.57E-06

Incident Tag No.	Plant Area	Release Description	Leak Frequency (per year)	Probability Jet Fire Given Ignition	Jet Fire Frequency (per year)	Probability Flash Fire Given Ignition	Flash Fire Frequency (per year)
C13	Compressor Unit (per compressor)	Fitting Leak	5.00E-04	0.0616	3.08E-05	0.0084	4.20E-06
DH1	Discharge Header	Gasket Leak	2.00E-04	0.0096	1.92E-06	0.0004	8.00E-08
DH2	Discharge Header	Valve Leak	0.00E+00	0.0616	0.00E+00	0.0084	0.00E+00
DH3	Discharge Header	Fitting Leak	2.00E-04	0.0616	1.23E-05	0.0084	1.68E-06
TEG1	TEG Inlet Coalescer TEG Contactor TEG Outlet Coalescer	Gasket Leak	1.80E-03	0.0096	1.73E-05	0.0004	7.20E-07
TEG2	TEG Inlet Coalescer TEG Contactor TEG Outlet Coalescer	Valve Leak	3.06E-03	0.0616	1.88E-04	0.0084	2.57E-05
TEG3	TEG Inlet Coalescer TEG Contactor TEG Outlet Coalescer	Fitting Leak	6.00E-04	0.0616	3.70E-05	0.0084	5.04E-06
CV1	Regulator/SDV	Gasket Leak	2.00E-04	0.0096	1.92E-06	0.0004	8.00E-08
CV2	Regulator/SDV	Valve Leak	3.40E-04	0.0616	2.09E-05	0.0084	2.86E-06
CV3	Regulator/SDV	Fitting Leak	0.00E+00	0.0616	0.00E+00	0.0084	0.00E+00
EX1	Scraper Launcher Gas Analysers Export Metering	Gasket Leak	8.00E-04	0.0096	7.68E-06	0.0004	3.20E-07
EX2	Scraper Launcher Gas Analysers Export Metering	Valve Leak	1.36E-03	0.0616	8.38E-05	0.0084	1.14E-05
EX3	Scraper Launcher Gas Analysers Export Metering	Fitting Leak	2.00E-04	0.0616	1.23E-05	0.0084	1.68E-06
UG1	Utility Gas Skid	Gasket Leak	5.00E-04	0.0096	4.80E-06	0.0004	2.00E-07

Incident Tag No.	Plant Area	Release Description	Leak Frequency (per year)	Probability Jet Fire Given Ignition	Jet Fire Frequency (per year)	Probability Flash Fire Given Ignition	Flash Fire Frequency (per year)
UG2	Utility Gas Skid	Valve Leak	6.80E-04	0.0096	6.53E-06	0.0004	2.72E-07
UG3	Utility Gas Skid	Fitting Leak	4.00E-04	0.0616	2.46E-05	0.0084	3.36E-06
CPF Pipework							
PIPE-LP1	Low Pressure Pipework (per m)	Pinhole Leak	3.00E-06	0.0096	2.88E-08	0.0004	1.20E-09
PIPE-LP2	Low Pressure Pipework (per m)	Pipeline Puncture	3.00E-07	0.0096	2.88E-09	0.0004	1.20E-10
PIPE-HP1	High Pressure Pipework (per m)	Pinhole Leak	3.00E-06	0.0096	2.88E-08	0.0004	1.20E-09
PIPE-HP2	High Pressure Pipework (per m)	Pipeline Puncture	3.00E-07	0.0616	1.85E-08	0.0084	2.52E-09
PIPE-UG1	Utility Gas Pipework (per m)	Pinhole Leak	3.00E-06	0.0096	2.88E-08	0.0004	1.20E-09
PIPE-UG2	Utility Gas Pipework (per m)	Pipeline Puncture	3.00E-07	0.0616	1.85E-08	0.0084	2.52E-09
Power Station Equipment							
PSIN1	SDV/Isol Valves Meter/Bypass Valves	Gasket Leak	1.60E-03	0.0096	1.54E-05	0.0004	6.40E-07
PSIN2	SDV/Isol Valves Meter/Bypass Valves	Valve Leak	2.04E-03	0.0096	1.96E-05	0.0004	8.16E-07
PSIN3	SDV/Isol Valves Meter/Bypass Valves	Fitting Leak	4.00E-04	0.0096	3.84E-06	0.0004	1.60E-07
ENG1HP1	Inlet Filter (All) Meter/Bypass	Gasket Leak	8.50E-03	0.0096	8.16E-05	0.0004	3.40E-06
ENG1HP2	Inlet Filter (All) Meter/Bypass	Valve Leak	1.02E-02	0.0096	9.79E-05	0.0004	4.08E-06

Incident Tag No.	Plant Area	Release Description	Leak Frequency (per year)	Probability Jet Fire Given Ignition	Jet Fire Frequency (per year)	Probability Flash Fire Given Ignition	Flash Fire Frequency (per year)
ENG1HP3	Inlet Filter (All) Meter/Bypass	Fitting Leak	1.00E-03	0.0096	9.60E-06	0.0004	4.00E-07
ENG1LP1	Regulator (per unit) Relief Valve	Gasket Leak	5.50E-03	0.0096	5.28E-05	0.0004	2.20E-06
ENG1LP2	Regulator (per unit) Relief Valve	Valve Leak	8.50E-03	0.0096	8.16E-05	0.0004	3.40E-06
ENG1LP3	Regulator (per unit) Relief Valve	Fitting Leak	1.00E-03	0.0096	9.60E-06	0.0004	4.00E-07
Power Station Pipework							
PIPE-PSHP1	PS HP Pipework (per m)	Pinhole Leak	3.00E-06	0.0096	2.88E-08	0.0004	1.20E-09
PIPE-PSHP2	PS HP Pipework (per m)	Pipeline Puncture	3.00E-07	0.0096	2.88E-09	0.0004	1.20E-10
HDS Equipment							
IN1	Inlet/Scraper Receiver	Gasket Leak	4.00E-04	0.0096	3.84E-06	0.0004	1.60E-07
IN2	Inlet/Scraper Receiver	Valve Leak	6.80E-04	0.0096	6.53E-06	0.0004	2.72E-07
IN3	Inlet/Scraper Receiver	Fitting Leak	2.00E-04	0.0096	1.92E-06	0.0004	8.00E-08
DGF1	Dry Gas Filters	Gasket Leak	4.00E-04	0.0096	3.84E-06	0.0004	1.60E-07
DGF2	Dry Gas Filters	Valve Leak	6.80E-04	0.0096	6.53E-06	0.0004	2.72E-07
DGF3	Dry Gas Filters	Fitting Leak	4.00E-04	0.0096	3.84E-06	0.0004	1.60E-07
HEAT1	Water Bath Heaters	Gasket Leak	6.00E-04	0.0096	5.76E-06	0.0004	2.40E-07
HEAT2	Water Bath Heaters	Valve Leak	6.80E-04	0.0096	6.53E-06	0.0004	2.72E-07
HEAT3	Water Bath Heaters	Fitting Leak	4.00E-04	0.0096	3.84E-06	0.0004	1.60E-07
METER1	Custody Meters	Gasket Leak	1.00E-03	0.0096	9.60E-06	0.0004	4.00E-07
METER2	Custody Meters	Valve Leak	1.19E-03	0.0096	1.14E-05	0.0004	4.76E-07
METER3	Custody Meters	Fitting Leak	4.00E-04	0.0096	3.84E-06	0.0004	1.60E-07

Incident Tag No.	Plant Area	Release Description	Leak Frequency (per year)	Probability Jet Fire Given Ignition	Jet Fire Frequency (per year)	Probability Flash Fire Given Ignition	Flash Fire Frequency (per year)
REG1	Regulator Skid	Gasket Leak	6.00E-04	0.0096	5.76E-06	0.0004	2.40E-07
REG2	Regulator Skid	Valve Leak	1.02E-03	0.0096	9.79E-06	0.0004	4.08E-07
REG3	Regulator Skid	Fitting Leak	2.00E-04	0.0096	1.92E-06	0.0004	8.00E-08
HDS Pipework							
PIPE-HDS1	HDS Pipework (per m)	Pinhole Leak	3.00E-06	0.0096	2.88E-08	0.0004	1.20E-09
PIPE-HDS2	HDS Pipework (per m)	Pipeline Puncture	3.00E-07	0.0096	2.88E-09	0.0004	1.20E-10

APPENDIX 4. ESP INCIDENT FREQUENCIES

A 4.1. Pipeline Release Frequencies

A 4.1.1. Generic Pipeline Failure Data

The failure rate data used for the assessment of the frequency of pipeline releases was derived from the European Gas Pipeline Incident Data Group (EGIG, Ref. 9). The European data are useful because of the significant exposure in terms of kilometre years experienced (approximately 2.4 million kilometre-years from 1970-2001). The large exposure provides a statistically significant basis, particularly when estimating the frequency of different causes of failure. The data also includes factors such as wall thickness, depth of cover, probability of ignition, etc.

The EGIG data, however, are considered conservative when applied to pipelines in Australia. This is because there is a higher density of pipelines and higher population densities along pipeline routes in Europe than in Australia. This will tend to result in higher failure rates for European pipelines compared with the experience of pipelines in Australia, particularly for incidents caused by external interference.

The EGIG database is continually updated and summary data are periodically reported. The data show that the failure rates for pipeline failures are gradually reducing over time, reflecting the improvements in pipeline technology and safeguards. The overall failure frequency reported for the period 1970-2004 was 0.41 incidents per 1000 km-yr compared with a failure frequency of 0.17 incidents per 1000 km-yr for the years 2000-2004.

A 4.1.2. Steel Pipe Failure Frequencies

While the EGIG data are expected to be quite conservative for the Export Sales Pipeline, the data are useful to estimate the frequency of different causes of failures such as corrosion, external interference, material defects, etc.

Table A4.1 summarises the data derived from the EGIG report (Figure 18, Ref.9) for the period 1970-2004. The data are categorised by the identified cause of the incident and show the relative frequency of each cause. The most frequent cause of pipeline failures is due to external interference (52%) with the next most likely causes being construction/ material defects (18%) and corrosion (17%).

The incidence of hot-tap errors (taken as the likelihood of tapping into the wrong pipeline or inadvertently impacting an adjacent pipeline) will be insignificant as there will only be one off-take in the vicinity on the existing main gas pipeline. Therefore the frequency for hot-tap errors has been set to zero.

Pipeline rupture is less likely to occur due to ground movement (e.g. at locations near mining leases due to subsidence or seismic impact from blasting). Whilst the proposed pipeline route would not cross any known areas of mine subsidence, the frequency for ground movement was conservatively carried forward.

TABLE A4.1: BASE FREQUENCIES FOR STEEL PIPELINE FAILURES

Cause	Pipeline Base Frequency by Cause and Hole Size (per 1000 km-yr)		
	Pinhole-Crack (d<10 mm)	**Hole (10 mm<d<50 mm)**	**Maximum Hole Size (d>50 mm)**
External Interference	0.05	0.12	0.03
Construction/ material	0.045	0.02	0.005
Corrosion	0.06	0.004	0
Ground Movement	0.008	0.008	0.001
Hot tap error	0	0	0
Other/Unknown	0.025	0.003	0
Total	**0.188**	**0.155**	**0.036**

The base frequencies given in Table A4.1 were then adjusted to take account of the proposed design for the Export Sales Pipeline. The safeguards proposed for the Export Sales Pipeline include:

- Depth of cover
- Wall thickness
- Marker tape

The safeguards proposed for the Export Sales Pipeline and the modifications to failure frequency are discussed in more detail in the following sections.

A 4.1.3. Pipeline Depth of Cover

Table A4.2 summarises the risk reduction factors from the testing reported by Corder (Ref. 16). Note that a reduction factor of 1.0 resulted for depths of cover of 1.11 m and that lower depths of cover result in a reduction factor greater than 1, i.e. there is an increase of the relative frequency of external impact.

TABLE A4.2: REDUCTION FACTORS FOR DEPTH OF COVER

Depth of Cover (m)	Reduction Factor
0.6	1.49
0.75	1.35
0.9	1.21
1	1.11
1.1	1.02
1.2	0.92
1.4	0.73

The various pipeline depth of cover at various locations has been assessed in a number of sensitivity cases.

A 4.1.4. Wall Thickness

The EGIG database also summarises pipeline failure frequencies by wall thickness. Based on the data, the following factors are used for pipe with varying wall thickness.

TABLE A4.3: FREQUENCY MULTIPLYING FACTOR FOR WALL THICKNESS

Pipewall Thickness (mm)	Pinhole	Puncture	Rupture (Full Bore Release)
2.5 (0-5mm)	4.0	2.4	5.8
7.5 (5-10mm)	1.0	1.0	1.0
12.5 (10-15mm)	0.5	0.5	0.5

A 4.1.5. Marker Tape

Corder (Ref. 16) has reported that a damage reduction factor of 1.67 was achieved when marker tape is provided above pipelines based on experimental data derived from testing undertaken by British Gas. Marker tape may not be provided at all locations of the pipeline route, therefore a number of sensitivity cases were assessed with different levels of safeguards.

A 4.1.6. Pipeline Failure Cases Assessed

A number of sensitivity cases have been assessed taking into account:

- Pipeline diameter (DN 450/250)
- Location class (R1/T1)
- Depth of Cover
- Wall Thickness
- Marker Tape

The following cases have been assessed:

- Case No. 1 (DN 450, R1, 750mm DOC, 11mm WT, no marker tape)
- Case No. 2 (DN 450, T1, 900mm DOC, 11mm WT, marker tape)

- Case No. 3 (DN 250, R1, 750mm DOC, 5mm WT, no marker tape)
- Case No. 4 (DN 250, T1, 900mm DOC, 12.7mm WT, marker tape)
- Case No. 5 (DN 250, Road/Rail Crossing, 1200mm DOC, 7.5mm WT, marker tape)
- Case No. 6 (DN 250, Intermediate water course, 1500mm DOC, 7.5mm WT, no marker tape)
- Case No. 7 (DN 250, Major Water Course, 2000mm DOC, 7.5mm WT, no marker tape)

A 4.1.7. Revised Failure Frequencies

The revised failure frequencies incorporating risk reduction factors are summarised in Tables A4.4 for Case 1 for the Export Sales Pipeline (without and with marker tape, respectively). The failure frequencies for the other cases are calculated in a similar

TABLE A4.4: SUMMARY OF FINAL RELEASE FREQUENCIES FOR: EXPORT SALES PIPELINE (CASE 1)

Cause	Pipeline Base Frequency by Cause and Hole Size (per 1000 km-yr)		
	Pinhole-Crack (d<10 mm)	Hole (10 mm<d<50 mm)	Rupture (d>50 mm)
External Interference	0.018	0.043	0.011
Construction/ material	0.045	0.020	0.005
Corrosion	0.030	0.004	0.000
Ground Movement	0.008	0.008	0.001
Hot tap error	0.000	0.000	0.000
Other/Unknown	0.025	0.003	0.000
Total	**0.126**	**0.078**	**0.017**

A 4.1.8. Pipeline Ignition Probabilities

The probability of ignition used in the frequency assessment was based on the EGIG 2005 Report (Ref. 9).

TABLE A4.5: PROBABILITY OF IGNITION FOLLOWING PIPELINE GAS RELEASE

Hole Size	Ignition Probability
Pinhole (10 mm)	3%
Hole (50 mm)	2%
Full Bore Rupture	30%

A 4.1.9. Probability of Leak Detection

The Export Sales Pipeline will be provided with a remote shutdown capability consisting of automatic line break facilities located at the inlet to the CPF and at the inlet to the HDS. The stations will be provided with telemetry which will allow remote monitoring of the pipeline operating conditions. A pipeline rupture would be readily detected by a sudden drop in pipeline pressure which would initiate closure of the shutdown valves.

Due to the large capacity in the line, the rupture release will continue for some time and the release rate will only reduce slowly. This reduces the effectiveness of the isolation in minimising the consequences of rupture.

It is unlikely that pinholes and punctures would be readily detected by remote monitoring and may depend on the operating conditions at the time of the leak. Small releases in remote locations may not be readily detected until a routine patrol of the pipeline occurs. It was assumed that pinhole and puncture releases would not be detected for some time and the release rate was modelled as a steady-state release at the maximum allowable operating pressure.

APPENDIX 5. GATHERING AND SPINE LINE INCIDENT FREQUENCIES

A 5.1. Background

Polyethylene (PE) pipes were introduced to the gas industry in the late 1960s, offering corrosion resistance, resistance to the effects of gas constituents, ease of installation and cost-effectiveness. British Gas (BG) commenced using PE in 1969 and the Gas & Fuel Corporation of Victoria (G&FC) in 1973. In Australia the older "first generation" HDPE was initially used because of local manufacture of raw materials and concerns about the reliability of supply of imported polymers. Although MDPE was known to confer superior properties in terms of resistance to crack growth and long term strength, G&FC, along with Allgas and Sagasco, continued to successfully use "first generation" HDPE. The transition to MDPE commenced during the 1980s.

PE almost totally replaced metallic pipe materials within the material's size and pressure range, such that in 1988, G&FC reported annual usage of 280 km of Class 250 (250 kPa) and 1162 km of Class 575 (575 kPa) in sizes up to 50mm. At the time, it was reported that the failure rate was approximately 200 to 300 p.a.[1], with the highest percentage in 1983 being due to point loading (64%), whereas the highest percentage in 1986 was due to mechanical damage (66%). Mechanical damage and point loading have accounted for the vast majority of identified PE pipe failures over the period reported. The reduction in point loading failures was attributable to improved installation standards and the use of thicker walled Class 575 HDPE pipe, with its improved resistance to localised loads, such as rock impingement.

In 1989, BG commenced use of PE 100 HDPE for higher pressure applications (up to 7 bar) and larger diameters, the key attributes being improved long term strength, stress crack resistance, and resistance to rapid crack propagation.

In 1993, new Australian Standards, AS 4130(Int) and AS 4131(Int) were introduced for PE pipes and compounds to incorporate the new grades and appropriate performance requirements. In 1995, AS/NZS 4130 and AS/NZS 4131 were introduced, covering all pressure applications, including fuel gas.

In 2001, these Standards were revised to reflect the latest developments and test requirements were increased to reflect the improved material properties, especially for PE 100 grades. In addition, resistance to slow crack growth requirements were increased for both PE 80 and PE 100 in order to reflect requirements of the U.K. gas industry and latest ISO proposals. These increased levels provide further assurance of

[1] Reported by M. Stahmer, Chairman, PIPA Polyolefins Technical Committee December, 2008, in *Polyethylene - The Optimum Gas Pipe Material?* It is not clear what measure applies (presumably per the population exposed, i.e. 280km) nor what level of incident occurred. Therefore it is not possible to derive meaningful failure frequencies.

long term performance under adverse conditions, such as surface damage and localised loading.

PE 100 materials are now being frequently used in Europe and Scandinavia for fuel gas applications at pressures up to 10 bar, with both pipes and fittings available in PE 100 material. In Australia, PE 100 systems have been designed to operate at pressures up to 1050 kPa (Tumut Pipeline Project).

Developments in polyethylene pipe and fitting materials continue to improve already outstanding properties and afford the asset owner confidence in long term durability.

A 5.2. Failure Modes: PE versus Steel

The predominant failure modes for steel pipelines (in decreasing order of prevalence) are[2]:

- external interference (e.g. excavation works)
- construction/ material problems
- corrosion
- design flaws
- ground movement
- hot tap errors

By comparison, the predominant failure mode for plastic pipework has also been external impact, usually due to excavation works. However, it has been shown that PE piping has a larger resistance to external force than steel pipe and impact tends to result in smaller puncture sizes[3]. Visco-elastic materials such as PE deform under load, allowing stresses to relax and stresses to be shed.

Construction and material problems in plastic piping tend to lead to brittle-like failures, which are the second most frequent failure mode in polyethylene pipeline systems; although, mainly in older-generation piping which tended to fail prematurely due to brittle cracking. Brittle-like cracking has been linked to stress intensification generated by external forces acting on the pipe[4]. Examples of conditions that can generate stress intensification include differential earth settlement (particularly at connections with more rigidly anchored fittings), excessive bending (as a result of installation configurations, especially at fittings), and point contact with rocks or other objects. Limiting shear and bending forces at plastic service connections to steel mains via steel tapping tees was deemed to be a major contributor to minimising stress intensification.

Corrosion is not an issue for PE piping, as it is for steel pipe.

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[2] 6th Report of the European Gas Pipeline Incident Data Group - EGIG

[3] Synnerholm, L., *Gas Pipes – Qualification of Plastic Pipes for 10 Bar*, Proceedings of Plastic Pipes XI, Munich Germany 3 September 2001

[4] US National Transportation Safety Board Pipeline Special Investigation Report NTSBISIR-98101

The performance of PE during ground-movement situations (earthquake) was demonstrated during the 1995 earthquake in Kobe, Japan, following which Osaka Gas found failures in steel/ iron pipework but none in PE systems.

Hot tapping is an inherently hazardous process and errors are mainly a function of human error (poor workmanship); both steel and PE piping is susceptible to hot tap error leading to pipe failures.

A 5.3. PE Pipe Failure Data

Failure/ reliability data for new-generation PE pipework is not readily available in the open literature. Although the American Gas Association began undertaking leak surveys for US gas distribution networks), the data comprises significant sections of old-generation PE piping which cannot be readily applied to third-generation (PE100: higher crack-resistant, higher-pressure) pipework.

Based on the preceding discussion, it is considered that the performance (integrity) of PE pipe is as good as, if not better than, steel for the pipe size and rating indicated above. Therefore, it is proposed that the EGIG pipe failure data is representative of, if not conservative for, PE piping with the following modifications (to account for physical limitations):

Failure Mode	**Pipeline Failure Frequency (per 1000km-yr)**	**Comment**
External Interference	0.2	The frequency of external interference was carried forward as the likelihood of interference does not depend on pipe material.
Construction/ Material	0.07	Although there has been a reduction in point loading failures (attributable to improved installation standards) failure due to construction issues was carried forward.
Corrosion	-	PE is not vulnerable to corrosion.
Ground Movement	0.017	Whilst PE has performed effectively under earthquake situations, this value was conservatively carried forward.
Hot tap error	0.02	Carried forward.
Other/Unknown	0.028	Carried forward.
Total	**0.315**	**-**

Table A5.1 summarises the data derived from the EGIG report for the period 1970-2004, as applied to PE piping.

TABLE A5.1: BASE FREQUENCIES FOR PE PIPELINE FAILURES

Cause	Pipeline Base Frequency by Cause and Hole Size (per 1000 km-yr)		
	Pinhole-Crack (d<10 mm)	**Hole (10 mm<d<50 mm)**	**Maximum Hole Size (d>50 mm)**
External Interference	0.05	0.12	0.03
Construction/ material	0.045	0.02	0.005
Corrosion	-	-	-
Ground Movement	0.008	0.008	0.001
Hot tap error	-	0.02	-
Other/Unknown	0.025	0.003	0
Total	**0.128**	**0.171**	**0.036**

The base frequencies given in Table A5.1 were then adjusted to take account of the proposed design for the Gathering and Spine lines.

The safeguards proposed for the Gathering and Spine lines include:

- Marker tape at a minimum of 200 mm above the buried pipeline.
- Depth of cover: 600 mm (depth of cover for roadway and creek crossings was not assessed as this will be lower risk).
- Wall thickness: 12 mm for DN 125 Gathering Lines and 43 mm for DN 450 Spine Lines (Note: EGIG analyses are provided for up to 15 mm wall thickness; hence application to 43 mm-thick spine lines is conservative).

The provision of these safeguards will result in a reduction in the likelihood of external interference leading to pipeline damage.

The minimum depth of cover for the Gathering and Spine lines is 600 mm therefore an increase in the relative frequency of external interference by a factor of 1.49 was used (based on the risk reduction factors listed in Table A4.22).

The revised failure frequencies incorporating risk reduction factors are summarised in Table A5.2 for the Gathering Lines and Table A5.3 for the Spine lines.

TABLE A5.2: SUMMARY OF FINAL GATHERING LINE FAILURE FREQUENCIES

Cause	Pipeline Base Frequency by Cause and Hole Size (per 1000 km-yr)		
	Pinhole-Crack (d<10 mm)	Hole (10 mm<d<50 mm)	Rupture (d>50 mm)
External Interference	0.024	0.058	0.014
Construction/ material	0.045	0.020	0.005
Corrosion	-	-	-
Ground Movement	0.008	0.008	0.001
Hot tap error	0.000	0.020	0.000
Other/Unknown	0.025	0.003	0.000
Total	**0.102**	**0.109**	**0.020**

TABLE A5.3: SUMMARY OF FINAL SPINE LINE FAILURE FREQUENCIES

Cause	Pipeline Base Frequency by Cause and Hole Size (per 1000 km-yr)		
	Pinhole-Crack (d<10 mm)	Hole (10 mm<d<50 mm)	Rupture (d>50 mm)
External Interference	0.022	0.054	0.013
Construction/ material	0.045	0.020	0.005
Corrosion	-	-	-
Ground Movement	0.008	0.008	0.001
Hot tap error	0.000	0.020	0.000
Other/Unknown	0.025	0.003	0.000
Total	**0.100**	**0.105**	**0.019**

A 5.3.1. Pipeline Ignition Probabilities

The probability of ignition for gathering and spine line release is as for the ESP (Table 4.5).

TABLE A4.5: PROBABILITY OF IGNITION FOLLOWING PIPELINE GAS RELEASE

Hole Size	Ignition Probability
Pinhole (10 mm)	3%
Hole (50 mm)	2%
Full Bore Rupture	30%