Report for Department of Communications, Energy and Natural Resources

Corrib Pipeline

Statutory Assessment of Pipeline Design re: Application for Consent to Construct a Pipeline (Section 40 of the Gas Act, 1976, as amended)

January 2011
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Department of Communications, Energy and Natural Resources

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Final Report
January 2011

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Executive Summary

Purpose of this Report

This report has been produced for the purpose of performing a Statutory Assessment of the Corrib pipeline design documentation accompanying the Application for Consent to Construct a Pipeline (Dated 31st May 2010) in accordance with Section 40 of the Gas Act, 1976, as amended. The scope covers the whole pipeline from the wellheads to the Terminal.

Framework for Assessment

The principal author carried out a review of the Application for Consent to Construct (May 2010) and the accompanying documentation (principally the Corrib Onshore Pipeline Environmental Impact Statement, Volume 1 and Technical Appendices Volume 2, in particular Appendices M and Q but also the Offshore EIS and technical data) against industry practice, codes, standards and other regulators’ criteria. The author has sought additional comments from colleagues specialising in pipeline design and those familiar with tunnelling projects and slope stability issues.

Additional information and clarifications have been sought from Shell Exploration and Production Ireland Limited (SEPIL) on some matters (see Appendix B).

The review has been conducted against the safety requirements of:

- Good Industry Practice;
- Previous Recommendations of the Technical Advisory Group (TAG) set up to advise DCENR, and the Advantica Reports (which Entec considers appropriate);
- Codes and Standards Identified by National Standards Authority of Ireland, TAG and included in the Design Code Review by SEPIL;
- Social Responsibility in terms of addressing the concerns of Observers at the Oral Hearings and Submissions in response to Section 40 Application.

Scope of the Review

The review was required to examine the Section 40 submission (and accompanying EIA and other documents), review previous concerns and identify any new issues that may have significant impacts on safety and the local environment. The scope of the review is the whole pipeline from well-heads to the terminal at Bellanaboy.
Entec concludes that the pipeline may be considered safe and the Minister could, if he were so minded permit consent for construction subject to conditions that would ensure compliance with commitments made in the submissions, regulations and national / international standards.

Against each of the identified issues Entec lists how the proposed pipeline design addresses the concerns whether by avoidance or mitigation; finally Entec notes its opinion on the adequacy of the proposed solution.

The issues were grouped under four headings in the scope with some cross over between these areas, but are listed individually (in addition Entec has considered the requirements mentioned above):

**Pipeline Integrity Management Scheme**

Integrity Management includes all the processes by which the operator should ensure that the pipeline will not release any of its contents by having adequate procedures throughout the pipeline life-cycle, from specification and design, through construction, installation, commissioning, operation, modification to decommissioning.

Entec recognises that the SEPIL submissions demonstrate that SEPIL have a scheme which has:

- a specification and design that provides an onshore pipeline of greater strength and resilience than required by codes and standards by means of the pipe wall thickness, materials of construction and a pressure limitation system to ensure that the increased factor of safety is maintained;
- systems to protect against external corrosion and damage (although verification of the standards of installation of slabs at road and water course crossings will be required);
- a process of monitoring the pipeline and route to avoid or detect any damage before it gives rise to leaks which meets or exceed industry standards; and
- a high reliability pressure limitation system which has been verified by third parties.

Entec observes that the Integrity Management Scheme is not yet complete, in particular, the submissions have not provided full details of:

- safety management systems procedures for control of modifications (management of change, control of work) which will need to be in place before operations; and
- specific procedures for testing of isolation valves and emergency shut down valves although the test frequency has been given.

These items will need to be supplied before commissioning (introduction of gas) together with the other minor issues listed in this report. Therefore it would be appropriate to stipulate conditions to a consent to construct stating, that prior to commissioning the pipeline SEPIL must:
• complete the Safety Management System to ensure that modifications to the pipeline, including its instrumentation, control, operation, maintenance and testing are included within the Management of Change and Control of Work procedures for the whole Corrib Development Facilities; and,

• prepare test procedures for the isolation valves and emergency shutdown valves together with their control systems which will maintain the reliability of the pressure limitation and shut down systems, are approved.

Quantified Risk Assessment

The Quantified Risk Assessment (QRA) is the analysis that presents the likelihood of major accidents arising from leaks in the pipeline together with the effects that they might have and compares them with the regulators’ criteria or other standards of safety. The QRA should state clearly the assumptions that have been made in calculating the risks and therefore enable interested parties to identify the key features of the design, construction, operation, monitoring, testing, maintenance activities and equipment that are required to keep the risks within the required criteria.

The submission includes a Quantitative Risk Assessment that has been carried out in more detail than is normal for pipeline risk assessments. In particular it incorporates site specific hazards. However, the risks from any type of ground movement have been ruled out on the grounds of protection provided or the distance from any steep slopes with a history of land slips or similar terrain.

Entec agrees that the QRA demonstrates that the safety risks from the pipeline are extremely low and well within the “broadly acceptable” region of published criteria even in the open near the pipeline. The separation between pipeline and dwellings fulfils the criteria set by An Bord Pleanala (ABP) which go outside the framework of risk based separation (as described in codes and standards accepted by regulators elsewhere) and give a very conservative, protection based requirement for separation. The sensitivity analysis demonstrates that these are robust conclusions.

Entec recommends that the commitments made, some in the form of assumptions, in the QRA are required as conditions of any consent the Minister is minded to grant.

Landfall Valve Installation Design Overview

The Landfall Valve Installation (LVI) is a key component in the pressure limitation system to ensure that the pressure in the downstream, onshore pipeline does not exceed the Maximum Allowable Operating Pressure (MAOP) of 100 barg. Note that this does not imply that a leak will occur if the pressure limitation system fails because the pipeline is designed to withstand the test pressure of 504 barg, but the pressure limitation is designed as a mitigation measure to reduce both the likelihood of a leak and the consequences of a leak should it occur. The pressure limitation system has been designed as a very high reliability system which has been independently verified by an accredited body, and this verification has been reviewed by Entec.
Although the LVI was introduced as a safety system it does increase risk (over and above the pipeline risk) in its immediate vicinity because of the presence of additional equipment (pipework, valves and instrument connections). There is therefore a trade-off between risk close to the LVI and the reduction in risk downstream along the remainder of the pipeline. However the QRA has shown that the area of risk above the broadly acceptable level (according to the UK model proposed by ABP) is limited to less than 100 metres and even under worst case sensitivity analysis, the outer zone for land use planning restrictions would extend only to 132 metres from the LVI.

Entec considers that SEPIL have provided a justification of the design based on the availability of high reliability isolation valves which are capable of allowing the passage of pipeline inspection tools (PIGs). Given these concerns then the design of the facility represents the minimum level of equipment necessary to provide the highest level of reliability and allow for maintenance and testing.

**Corrib Pipeline Design Basis**

Entec finds that the pipeline design is based on the requirements of Irish and International Standards. It has also followed the advice of the Technical Advisory Group (which Entec considers appropriate). The use of the selected parts of the codes and standards is supported by analysis of codes by reputable international design companies, to combine aspects from different standards so that the most rigorous requirements have been applied and therefore, in Entec’s opinion, it meets the standard of Good Industry Practice.

**Other Issues**

Entec has also reviewed the submissions made by others in response to the SEPIL Planning Application and EIS which were received on 4th August 2010. In the course of the review of all these, the following additional issues have been identified concerning the construction of the tunnel:

A) At the time of submission (May 2010) the ground conditions in the sediments and bedrock beneath Sruwaddacon Bay had not been determined along the proposed tunnel alignment; therefore there was some uncertainty over the requirement for the Tunnel Boring Machine (TBM) to cope with the interface between sediments (sand and gravels) and the hard bedrock, together with the presence of hard rock inclusions within the sediments. More detailed information has become available which increases confidence in the knowledge of ground conditions and the ability of the TBM to operate successfully and avoid the need to initiate a contingency plan is to use intervention shafts, constructed in the Bay, for which no environmental assessment has yet been made. Entec has consulted with Atkins who agree that the construction of the tunnel as described in the SEPIL submissions is feasible and the likelihood of surface intervention being required is low.

B) Concerns have been expressed (in public submissions in response to the Planning Application and EIS) as to whether vibrations from tunnelling could trigger further land slips on Dooncarton Mountain. Although the vibrations are predicted to be much less than those from heavy traffic at the dwellings along the road
the tunnelling vibrations will be continuous. Nevertheless SEPIL has shown that by limiting vibration at the nearest dwellings the further attenuation with distance will reduce vibration in the areas of possible landslips far below the threshold for initiation. Entec has again consulted tunnelling experts at Atkins who agree that the vibrations arising from tunnelling should not give rise to any problems.

Submissions in Response to the Section 40 Application

Entec has reviewed additional submissions made concerning the integrity of the tunnel, its ability to protect the pipeline, the ventilation duct within the tunnel and the evidence of previous landslip effects, together with the responses from SEPIL. Entec recognises the concerns but is of the opinion that the approach taken by SEPIL in the design and construction will avoid the potential problems that they raised.

Conclusions of this Report

Entec considers that the pipeline design and its route are acceptable on the basis of international risk criteria as well as the risk criteria proposed by ABP and protection based separation distances.

The current proposal to place the pipeline in a tunnel beneath Sruwaddacon Bay satisfies distance separation criteria but raises some questions of feasibility and possible unwanted impacts if problems arise during tunnelling.

Entec has considered the public submissions and is of the opinion that none had any significant points that required changes to the EIS. Some of the concerns expressed have been taken into account in the proposed conditions which reinforce the commitments made by SEPIL in the EIS and during the assessment of it.

The outstanding matters which may be the subject of conditions are:

1. Surface intervention through the bed of Sruwaddacon Bay should not be included in the consent without further assessment of the impact of the specific intervention proposed. The consent should not be considered as an approval for such work.

2. Verification of the installed design of pipeline protection measures involving concrete slabs to ensure that there will be no adverse settlement. Also the design of other interfaces between sections of the pipeline in the tunnel, crossing the base of the shafts (at Glengad and Aghoos), boundaries of the LVI, trenched sections and sections in the stone road.

3. Confirmation of detailed measures to monitor slurry and grout in the TBM.

4. Other matters require clarification and are given in the report but would not constitute reasons for withholding a permit to construct.
Further information would be required before issuing a permit to operate but this is a normal approach in Safety Case Regimes where there are two separate stages of submissions, pre-construction and pre-commissioning.

Therefore Entec concludes that if the pipeline were to be constructed to the design submitted it would be safe in terms of any technical definition of the term. Hence, Entec recommends that the Minister could, if he were so minded, consent to the Corrib Application under section 40 of the Gas Act 1976 and Section 13 of the Petroleum and Other Minerals Development Act, 1960 on safety and design grounds.

Conditions are proposed to ensure that the pipeline is constructed to the specification in the Section 40 submission and commitments made in the EIS as well as during other regulatory processes.
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1. Introduction

1.1 Purpose of the Report

The purpose of this report is to record the scrutiny of all relevant documents which have been submitted as part of the application to construct the Corrib Gas Pipeline pursuant to section 40 of the Gas Act, 1976, as amended and associated amendment to the Plan of Development pursuant to Section 13 of the Petroleum and Other Minerals Development Act, 1960, as amended including:

- Pipeline Integrity Management Scheme;
- Quantified Risk Assessment;
- Landfall Valve Installation Design Overview;
- Corrib Pipeline Design Basis.

The scope of work dated 3rd June 2010 requires that the report:

- Critically examines these documents and concludes whether they contain sufficient information to form judgements on the issues below;
- Concludes whether or not, in the professional opinion of the consultant, the developer has, in the documents, met the relevant requirements as well as appropriate standards, codes of practice, regulations and operating procedures;
- Identifies any deficiencies in any respect relating to the above;
- Makes recommendations regarding any such deficiencies;
- Concludes whether or not, in the professional opinion of the consultant that the developer has demonstrated that the design and proposed construction and operation meet or exceed all relevant codes and standards and show best practice with regard to safety matters generally and further demonstrates that it meets the ALARP standard.

It is intended to provide a critical review which will endeavour to identify gaps and omissions in the material presented and give recommendations for further work (by the proponent or others) where appropriate.

The scope of the assessment is the whole pipeline from well-heads to the terminal at Bellanaboy.

The process for the Minister of Communications Energy and Natural to grant consent to construct under the Gas Act and Petroleum and Other Minerals Development Act is independent of the other regulatory processes requiring consents under other legislation, in particular Foreshore Licencing and Planning requirements.
1.2 Qualifications of the Author

Peter Waite is a Chartered Engineer with 29 years experience of world wide consulting on safety and risks from oil and gas installations, including pipelines. He has advised oil and gas companies, state and local governments as well as landowners and developers of land in the vicinity of installations and pipelines. He was a member of the Institution of Gas Engineers (IGE) working party revising edition 3 of the High Pressure Pipeline Design Code TD/1. He is registered as both a Safety Professional and an Environment Professional with the Institution of Chemical Engineers (IChemE). He has contributed to IChemE training packages and guidance on risk assessment and safety.

1.3 Brief Description of the Pipeline

1.3.1 Purpose and Design

The proposed Corrib Gas Pipeline is intended to transport the produced hydrocarbon fluids from the Corrib Gas Field off the west coast of Ireland to the treatment plant which will condition the plant to meet the required standards for natural gas supply. The subject of this report is the whole of the pipeline from the offshore, sea-bed wellheads to the Gas Terminal at Béal an Átha Bui (Bellanaboy) and including, in particular the proposed Onshore Gas Pipeline section to connect the previously permitted offshore pipeline to the Gas Terminal.

The length of the onshore pipeline section is now 8.3 kilometres from the landfall near Glengad in Broadhaven Bay to the Gas Terminal.

The pipeline fluids will comprise a mixture with a molecular weight of 16.9, the composition has been defined (Source EIA Volume 2 Appendix Q 2.1 Pipeline and LVI Integrated Design Chapter 4 Table 4.1):

- **Gas Fraction**
  - Methane 92.42 mole%
  - Ethane 2.99 mole%
  - Nitrogen 2.7 mole%
  - Propane and other heavier hydrocarbons 0.29 mole%
  - Carbon dioxide 0.25 mole%

- **Liquids**
  - Produced Water 1.09 mole %
  - Methanol Hydrate inhibitor added at well heads. 0.35 mole %
The proposed pipeline design parameters are:

- **Outside Diameter**: 508 mm (20 inch)
- **Maximum Allowable Operating Pressure**
  - Offshore: 150 barg
  - Onshore: 100 barg
- **Design Pressure**
  - Offshore: 345 barg
  - Onshore: 144 barg

(It is considered appropriate to define the design pressure for the onshore pipeline as 144 bar because of the high integrity pressure protection system to be provided at the Landfall Valve Installation which is designed to prevent the onshore pipeline pressure rising above 100 barg).

- **Test Pressure**: 504 barg (EIA Appendix Q9)
- **Wall thickness**: 27.1 mm
- **Material Grade**: Carbon Steel as specified in DNV code OS-F101, Allseas Material Data Sheet 208820 and supplemented by the Particular Specification Number H00/46/05 as agreed between Allseas and Corus. (API 5LX X70 equivalent)
- **Design Factor**: 0.3
- **Minimum depth of cover**: 1.2 m
- **Design Standards**:
  - “The overall design code for the pipeline will be IS EN 14161. However, where the provisions of IS 328 or PD 8010 exceed those of IS EN 14161, then these are to be applied (with IS 328 as the primary supplementary code). ”
- **Corrosion Allowance**: 1 mm
- **Manufacturing Tolerance Allowance**: 1 mm (in addition to the corrosion allowance).
Table 1.1 Summary of Relevant Pressures

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<th>Onshore (Downstream) Pipeline</th>
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<td>Design Pressure</td>
<td>345 barg</td>
<td>144 barg</td>
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<tr>
<td>(Maximum Allowable Operating Pressure) MAOP</td>
<td>150 barg</td>
<td>100 barg</td>
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<tr>
<td>Test Pressure</td>
<td>380 barg(^1) (minimum)</td>
<td>504 barg</td>
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1 Appendix Q2.1 section 5.4 states that the test pressure at the landfall end of the offshore pipeline is 380 barg, this implies a higher test pressure in sections of the pipeline in deep water where the hydrostatic pressure will increase.

2. The LVI is designed to withstand the upstream pipeline conditions and will be tested to 504 barg (05-2377-01-P-3-045 Rev 03 LVI Design Justification and Overview.doc Page 2 of 17 part of Section 40 Application).

1.4 Proposed Route

The offshore pipeline route and design remains as previously submitted but has been included in the submission currently under review (see Section 40 Submission: CORRIB FIELD DEVELOPMENT UPSTREAM PIPELINE APPLICATION FOR CONSENT TO CONSTRUCT SCOPE AND DRAWINGS SHELL E&P IRELAND LIMITED May 2010).

The onshore route proposed is reproduced in Appendix A (From DNV Appendix Q6.4 of EIA: “Corrib Onshore Pipeline QRA” May 2010).

The nearest occupied dwelling to the pipeline route is stated to be at 234 m from the pipeline. There is one building closer to the route but this is stated to be in SEPIL’s ownership.

The pipeline design codes would class the route as rural due to the low population density. It crosses one public road.

1.5 Areas of Concern

Several areas of concern have been raised previously with respect to earlier applications for consent to construct the Corrib Pipeline, particularly with respect to the onshore section, including (references in brackets to this report):

1. Proximity of the route to local houses; (Chapter 4);

2. Design of the Landfall Valve Installation; (Chapter 3);
3. Reliability of Pressure Limitation System; (Chapter 2 and Appendix F);

4. Methods of Monitoring and Maintaining Pipeline Integrity; (Chapter 2 and Appendix F);

5. Stability of Ground or Estuary Sediments through which pipe is to be laid. (Chapter 2 and Appendix F).

This review and submissions to DCENR¹ (and to ABP for the separate planning process²) have also raised some additional concerns. The complete list of questions raised by this review is given in Appendix B of this report, from which the major issues are:

   a. Safety of people outdoors;
   b. Emergency response in bad weather;
   c. Contingency plans if intervention pits are required for the tunnel beneath Sruwaddacon Bay;
   d. Potential for tunnelling induced vibration to affect the stability of Dooncarton Mountain.

These are also addressed in Chapters 2 to 5 below where additional matters from the review are also raised.

Details of SEPIL’s proposals and their assessments have been obtained from the Technical Appendices to the Onshore EIA which accompanied the Section 40 Application. In particular:

Appendix Q2 Integrated Design Description;

Appendix Q3 Code Requirements;

Appendix Q4 Technical Details;

Appendix Q5 Pipeline Integrity Management;

Appendix Q6 Safety Management;

Appendix M1-B Geotechnical Report;

Appendix M4 Geotechnical Risk Register.

¹ Received by Entec on 13th December 2010

² Received by Entec on 4th August 2010
1.6 Stages of Assessment by the DCENR

The DCENR safety assessment will not be complete until either the Department advises the Minister to issue a permit to operate, or the Department hands responsibility to CER who will be responsible for issuing a Safety Permit under PEES Act 2010. However the Department will also advise the Minister as to whether a permit to construct can be issued based on the PoD, EIS (Offshore and Onshore) and further information requested during the technical assessment of these submissions. At each stage the Department may impose conditions to ensure that the design, construction and operation of the pipeline will be within the limits and to the standards described either by the operator or determined during the assessment.
2. Pipeline Integrity Management Scheme

2.1 Introduction

The Integrity Management Scheme for the Corrib Pipeline consists of the arrangements being made to ensure that there are no leaks from the pipeline. This starts with the fabrication of the pipe and continues until final decommissioning of the pipeline. Entec recommends conditions to ensure that every part of the process is carried out according to the commitments made in the SEPIL submissions and requirements of the codes specified and the current regulations. This will include the provision of relevant certificates and inspection by third party certification bodies. The Entec review considered the scheme under the following headings:

1. The engineering design of the pipeline, in particular the materials of construction, protection (coating) and wall thickness;
2. The manufacturing standards and tolerances of the line pipe;
3. The proposed method of construction, installation and commissioning;
4. The instruments and limitation systems to ensure that the design pressure is not exceeded;
5. Ongoing monitoring and inspection of the pipeline, together with testing the pressure limitation and emergency shut down system;

It is understood that the Integrity Management System for the pipeline will be integrated with that of the Gas Terminal therefore it will be necessary to ensure that the definition of the overall Integrity Management System makes it clear that it applies to both.

In this context Integrity Management is the process by which the operator ensures that there will be no loss of containment, i.e. no release of fluids, nor any contravention of the declared operating parameters. It is a special case of a Safety Management System which applies to any operation where loss of containment of the materials being transported, stored or processed could lead to harm to people (workforce or public) or the environment.

Entec has carried out a detailed review of the proposals against the requirements of a good Safety Management System to ensure integrity, see Appendix F. This covered:

- Key Elements;
- Core Processes;
• Engineering Design (for Integrity Management);
• Manufacturing Standards;
• Construction, Installation and Commissioning;
• The Pressure Limitation System (including Safety & Reliability and Valve Testing);
• Monitoring and Maintaining Pipeline Integrity;
• Emergency Response.

In particular Entec commissioned Atkins tunnelling experts to review the feasibility and integrity of the proposed tunnel. Entec’s own reliability expert reviewed and validated the reliability assessment of the offshore pressure limitation system and verified the SIL calculations for the pressure limitation system at the LVI.

2.2 SEPII Corrib Pipeline Integrity Management

The current documents described within the SEPII submission will form part of the input into the Safety Case required under the PEES Act (2010) as stated in Appendix Q6.1 Section 4. However, prior to the introduction of the Safety Case Framework under this Act, DCENR will remain the Safety Authority and as such will require a justification of the safety of the pipeline which should be within the submissions for consents and maintained up to date during the operation of the pipeline. SEPII has committed to integrate the pipeline integrity / safety management system with the terminal’s system and for it to be described in a combined HSE Case (SEPII Appendix Q6.3 Section 1.3.4 Table 1.1 with details in Section 2.1) which will have to conform to the requirements of the COMAHDS regulations (lower tier) as well as the Shell Exploration & Production company standards. These cover many of the requirements discussed above and in Appendix F but they should specifically include the relevant offshore components, pipeline and LVI.

Entec considers that the Section 40 2010 application scope section 4.8 contains suitable commitments which should be verified before operation:

• “The PIMS will address the lifetime safeguarding of mechanical integrity through the mitigation of all threats that could compromise the pipeline and ancillary systems integrity and the monitoring of the effectiveness of risk barriers, and as such considers;

• Process safety, e.g. operating procedures, overpressure protection, emergency procedures and leak detection, as well as thorough training and supervision of personnel supported by up to date procedures explaining the work tasks and safe systems of work (permit to work system) to co-ordinate activities and ensure appropriate levels of control;

• Mechanical integrity, including general integrity, (e.g. fatigue, overstress, mechanical damage and threats from peat instability and other geotechnical instability), corrosion management, (e.g. corrosion and erosion), and flow assurance, (e.g. scaling, surge, slugging and hydrate formation);
• Management of change (e.g. design change, modifications and set points, hot work such as welding or grinding at the landfall installation) will be carried out under strict procedural controls and a permit system.”

For the pipeline SEPI has shown in the EIS Appendix Q5.2 Section 4 that it has a suitable Integrity Management Process.

Figure 3.2 in EIS Appendix Q5.2 Section 3.1 describes the management organisation and reporting lines, it does not show that the Technical Authorities for Safety and Integrity have a separate reporting line through a Corporate Safety organisation to the Shell International Board. SEPI should demonstrate that this recommendation is implemented in accordance with best practice following investigations into major incidents such as Texas City Refinery and Deep Water Horizon – Macondo.

2.3 Findings

Entec considers that the submissions demonstrate that SEPI has a scheme which has:

• A specification and design that provides an onshore pipeline of greater strength and resilience than required by codes and standards by means of the pipe wall thickness, materials of construction and a pressure limitation system to ensure that the increased factor of safety is maintained;

• Systems to protect against external corrosion and damage (although further details of the design of stream and debris channel crossings have been requested);

• A process of monitoring the pipeline and route to avoid or detect any damage before it gives rise to leaks which meets or exceed industry standards.

However Entec finds that the submissions have not provided details of:

• Safety management systems procedures for control of modifications (management of change, control of work) which will need to be in place before operations;

• Specific procedures for testing of isolation valves and emergency shut down valves although the test frequency has been given.

The combined Integrity Management System for both pipeline and terminal should state clearly that it applies to both in order that responsibility for the LVI and pipeline is clearly understood.

Entec recommends that these actions should be completed and verified prior to commissioning the pipeline.
3. Quantified Risk Assessment

3.1 Pipelines

Pipelines are generally the safest form of transport for large quantities of fluids such as oil and natural gas. They are designed and constructed to strict design codes developed over several decades taking into account developments in operating experience and materials of construction. Accidents to pipelines have occurred but the majority involve only damage to the pipeline coating or surface and if repaired these do not lead to any deterioration of the integrity of the pipeline over the long term. Major pipeline ruptures that have occurred have been due to loss of wall thickness in “standard wall” pipelines, external impact on standard wall pipelines and in exceptional cases extreme loading on a thick walled pipeline. It is Entec’s opinion that additional measures have been taken to ensure that these will not occur on the Corrib pipeline. The principal protection is afforded by the thickness of the pipe wall and the large safety factor between maximum allowable operating pressure and design pressure.

Although onshore natural gas transmission lines are normally designed to operate at less than 100 bar there are several examples of pipelines from offshore platforms in the North Sea to landfalls in the UK and Belgium with design pressures in excess of 150 barg (compared with the Corrib pipeline design pressure of 144 barg). Entec, and the author of this report, has experience of several such pipelines carrying both “raw gas” and treated gas. Some of these have significant (several kilometre) lengths from the beach landfall to the processing terminal; in particular Zeepipe (Zeebrugge) Belgium and CATS (Teesside) UK. It is common practice to increase the wall thickness in the vicinity of the beach crossing and along the onshore section if there are dwellings or other sensitive locations near the route.

3.2 Likelihood of Pipeline Failures

The application of modern design codes, coupled with the assurance of quality of materials (steel), manufacture and testing has resulted in a decline in the frequency of leaks, particularly in gas pipelines over the last 30 years (see EGIG data3). Leaks are so rare that the frequency has to be measured in chances per million per kilometre per year. Ruptures of pipelines have occurred but there is no record of rupture of pipelines with a wall thickness greater than 19 mm due to the ability of steel of such thickness to arrest cracks arising from minor damage or defects.

Entec consider that the likelihood of failure or failure frequencies quoted by Advantica and DNV are appropriate.

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3.3 **Consequences of Pipeline Leaks**

If an accidental release did occur then the hazards arising from a gas pipeline consist of fires (if the gas is ignited), and the effects of the pressure release in the immediate vicinity of a leak where a crater may be formed. Explosions will not occur unless the gas is confined (for example within a building) or the cloud burns through a congested area such as dense woodland and undergrowth. The pressure release from a buried pipeline may lead to the formation of crater up to 20 to 30 metres in diameter but there will be no significant over-pressure or blast from this.

In Entec’s experience, the distances for dangerous effects from releases calculated by Advantica⁴ and DNV are consistent with results for other pipelines and are consistent with the experience from the few accidents that have occurred (in thinner walled pipelines) when adjusted for pressure and pipeline diameter.

3.4 **Conclusion on Risk**

Entec agrees that the DNV report (Appendix Q6.4) demonstrates that the risks from the Corrib pipeline to residents and the general public are extremely low. This is despite the analysis allowing for the unlikely event of pipeline rupture and failure of the high integrity pressure limitation system. These risks are much lower than any used in international codes and other jurisdictions to determine the acceptability of pipeline routeing.

Although not accepted as necessary by Entec, the distance between the pipeline and houses conforms to the requirements of ABP in that, even in the extreme event of a pipeline rupture, people within dwellings would be protected and those outdoors near houses could escape indoors, notwithstanding that this event is not considered credible for the Corrib pipeline given its design and protection.

People outdoors, even if close to the pipeline for their whole life are at an extremely low risk from accidents arising to the pipeline. The risk levels are below those set out for residents in ABP’s letter of November 2009. Note that previous QRA studies have used different assumptions regarding the operating pressure and MAOP but even with an assumption of a leak at the maximum well head shut in pressure (i.e. assuming no pressure limitation) the largest estimate of Building Burn Distance was 230 m (DNV 2009).

The Advantica and previous DNV reports⁵ have demonstrated that the risks from the Corrib pipeline to residents and the general public are extremely low. This is despite the analysis allowing for the unlikely event of pipeline rupture and failure of the high integrity pressure limitation system. The Advantica report (D5.2 page 101) also shows that risks from an initial pressure of 345 bar (the maximum well head pressure with no flow to the terminal) is extremely low.

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⁴ Independent Safety Review of the Onshore Section of the Proposed Corrib Gas Pipeline, Advantica, R8391 17th January 2006.

⁵ Quantified Risk Analysis by DNV (2009) in the 2009 Corrib Onshore Pipeline EIS Appendix Q7.
would be lower than the criteria proposed by ABP (first paragraph (a) on page 2 of their letter) without the Landfall Valve Installation isolation valves which provide additional assurance.

The QRA contains a sensitivity analysis which demonstrates that the conclusions remain valid even when conservative (pessimistic) assumptions are applied to the calculation of frequencies and consequences.

It is Entec’s opinion that the QRA and hazard modelling has been performed to a good standard and the conclusion that risks to people are extremely low is robust.

If the Minister is minded to grant consent to the pipeline construction then the conditions should include the requirement to conform to the assumptions and risk mitigation used in the QRA.
4. **Landfall Valve Installation Design Overview**

4.1 **Introduction**

The Design of the Landfall Valve Installation (LVI) is described in the EIS Appendix Q2 and in more detail in Appendix Q4.3 with an appraisal of alternative arrangements for the LVI in Q4.4.

The LVI was originally designed as a means of isolation between the offshore and onshore sections of pipeline and not as an emergency shut-down or pressure limitation system.

Following the recommendations of Advantica (reference 6 above) and the requirement for consequence based separation distances from ABP (letter November 2009), the LVI design has developed to provide not only an emergency shutdown isolation valve station but also a high reliability pressure limitation function (see Section 6 of Appendix F). Although the onshore pipeline has a design pressure of 144 barg the LVI has been designed to ensure that the Maximum Allowable Operating Pressure of 100 barg is not exceeded. The reliability with which this control can be assured is addressed above in section 6 of Appendix F reviewing the analysis submitted by SEPIL based on Entec’s detailed examination reproduced in Appendix E.

The LVI has been designed to withstand the extreme well head shut in pressure of 345 barg, the same as the offshore pipeline (Q2.1 section 4.4.3). However the Maximum Allowable Operating Pressure (MAOP) is set at 150barg, also the same as the offshore pipeline (section 4.5). (See Appendix Q4.3 of the EIS for a full explanation of design pressures and MAOP at the LVI). The LVI pressure limitation facility works in conjunction with the offshore pressure limitation to ensure that the onshore section of the pipeline does not rise above the MAOP of 100 bar.

4.2 **Alternatives Considered**

4.2.1 **Pipework and Valve Configuration**

This has been discussed in Appendix Q4.4 of the EIS and the alternative straight through pipework configuration compared with the proposed “by-pass” arrangement. It is concluded that there is no noticeable reduction in risk for the straight through arrangement and that the required 20 inch, piggable, high integrity, safety shutdown valves are not field proven. In the absence of solids in the well fluids and because liquid slugs are unlikely to occur it is concluded that in this case the by-pass arrangement is more practical.

Entec considers this to be a reasonable conclusion but will place a requirement for integrity inspection of the LVI by-pass pipework and valves which will not be covered by the pipeline integrity monitoring with intelligent pigs.
4.2.2 Provision of a Cold Vent at the LVI

SEPIL has examined whether the provision of a flare or vent at the LVI would improve safety in Appendix Q4.5 section 7. As discussed in that section, the vent would only be required in the event of either:

- A shut down of the terminal AND failure of the offshore pressure limitation system to shut the offshore valves and one or more wells continues to flow;

Or (not discussed in the EIS):

- A leak in the onshore pipeline AND failure of the LVI pressure limitation system.

Both these scenarios have been shown to be extremely remote possibilities. In the case of the first it would be possible to organise venting through the terminal flare providing there was no problem with the inlet facilities. In addition it is noted that the most likely scale of this remote scenario is minor flow through an incompletely closed valve, in which case the flow rate and therefore pressure rise rate would be very slow and allow many days to rectify the problem or install a temporary vent at the terminal.

In the second case, again a very remote possibility because the likelihood of any leak is vanishingly small (see EIS Appendix Q 6.4, discussed in section 3.2 of this report) and the LVI shut down system is highly reliable, (see Appendix E of this report), venting at the LVI would require a manual intervention and therefore would not happen for some time. In the same time the operators should be able to close one or more of the valves at the LVI (remotely from the terminal) which would be more effective. Shut-in of the wells and venting the pipeline through the terminal would be another option for depressuring the pipeline although this would take some time to set up and achieve depressurisation.

Entec agrees that given the visual impact of a vent stack and the need for a protected sterile area around it, then the conclusion that it is not an effective safety measure is sound. In addition it should be noted that other landfall valve installations (or beach valves) that are remote from the terminal of the pipeline are not provided with such a facility, even where visual impact would not be an issue (for example Zeepipe landfall at Zeebrugge and CATS pipeline landfall at Redcar).

4.2.3 Visual and Protection Aspects

The LVI equipment is to be installed in a dished area to minimise the visual impact. The main equipment items, pipelines and valves, are to be buried beneath the surface and valve controls and instruments protected in cages.

Providing that the equipment is suitably protected against corrosion there is no problem with placing it below the surface. Corrib gas, being mainly methane is lighter than air so any small releases will become buoyant, rise and disperse. The lack of above ground equipment or buildings over the gas carrying equipment is an advantage as there is no congested or confined area for gas to accumulate.
Entec foresees no problems for this aspect of the LVI and considers that the equipment is provided with good protection against external interference.

4.2.4 Reliability of LVI Pressure Limitation System

Entec reviewed the LVI SIL (Safety Integrity Level) assessment report (see Appendix E) which establishes that the system is a SIL3 system. However, this depends very heavily on the isolation valve reliability data, specifically the Proof Test Coverage (PTC) value and the failure rate. A more conservative assessment may in fact give a SIL2 rating for the system (although it would probably be a “good” SIL2). Entec has identified potential improvements which should be considered but not required to make the pipeline safe.

The calculations provide justification for a SIL 3 system. However, some of the assumptions especially on the PTC and reliability of the isolation valves are critical to the overall calculated values. These overall values are given below:

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated PFD</td>
<td>0.00077</td>
</tr>
<tr>
<td>SIL 3 band PFD range</td>
<td>0.001 to 0.0001.</td>
</tr>
<tr>
<td>Estimated PFH</td>
<td>9.81 x 10^-8 /hr</td>
</tr>
<tr>
<td>SIL 3 band PFH range</td>
<td>&gt;= 10^-8 to &lt;10^-7 /hr.</td>
</tr>
</tbody>
</table>

Although technically the LVI system achieves SIL3, had a sensitivity analysis been undertaken specifically on the valve PTC and dangerous failure rate it is highly likely that some of the results would have fallen into the SIL2 band. It is Entec’s opinion that the valve system should be improved if it is required to meet SIL 3 status. This could potentially be done by:

- Using two different valves (from different valve suppliers) to significantly reduce or avoid Common Cause Failure (CCF);
- Use a partial stroking device to check for valve movement (such as “Valvguard”) if this can be fitted onto at least one of the valves although these valves are physically large;
- Increasing the test frequency.

Entec recommend that these improvements should be included in the SIL calculation and a sensitivity analysis conducted using a range of data for the valves.

The assessment above also assumes a full 12 monthly test. The test procedure should be assessed to ensure that this assumption is valid. The detailed design of some systems sometime prevents a full test on every component.
Notwithstanding these comments on the analysis Entec is of the opinion that the reliability of the pressure limitation system at the LVI is more than sufficient to meet the requirements of the relevant standard (IEC 61508 / 61511) in ensuring that the likelihood of a major incident affecting dwellings is extremely unlikely, and in practice highly improbable.

As mentioned in the Introduction to this section (2.1) the LVI pressure limitation system works in conjunction with the offshore shut down valve systems on each well. Again this system has been shown to be of high reliability and even with the more cautious calculations discussed in section 6 of Appendix F based on the detailed examination in Appendix E would have a reliability that Entec considers more than sufficient to meet the standard’s requirements for protection against major accidents.
5. Corrib Pipeline Design Basis

5.1 Design Codes

The scope of current relevant design codes means that no single code covers the whole length of the pipeline from the well heads / PLEM (Pipeline End Manifold) to the Terminal. Therefore the offshore code DNV-OS-F101:2007 applies to the offshore pipeline and up to the downstream valve of the LVI (see Appendix Q2 Figure 3.1 in Section 3.2). Appendix F of the DNV code covers landfall installations.

The onshore pipeline has been designed to Irish Standards, supplemented by European and UK standards where there are gaps or where they impose more stringent requirements. These are the TAG recommendations which have subsequently received endorsement from the National Standards Authority Ireland (NSAI) and Entec considers to be appropriate.

The relevant codes are reviewed in Appendix Q3.2. (Application of Irish and International Standards) of the EIS which concludes that:

“The pipeline codes IS EN14161, IS 328 and BS PD 8010 recommended by TAG and adopted for the Corrib onshore gas pipeline are applicable and relevant to the design of the Corrib onshore gas pipeline.

The application of the pipeline codes for design is clearly set out in the Design Code Review (Appendix Q3.3) referred to above.

The construction, installation, operation and maintenance of the onshore section of the onshore pipeline will be in accordance with IS 328 and the inspection and monitoring regime that will be applied to the Corrib onshore pipeline will be as per the relevant provisions of IS 328.”

National Standards Authority Ireland (NSAI) have endorsed this approach and confirmed the applicable codes by letter to the DCENR. Entec also considers this approach to be based on good engineering practice.

Where there appears to be an overlap between the codes (for example at the LVI) the code requirements are entirely consistent with the exception of the test pressure relative to the design pressure. In this case the LVI and downstream pipeline) will be tested to the higher, onshore test pressure of 504 barg.

5.2 Design Parameters

The design parameters are given in Section 1.3.1 of this report. The Design Pressure of the offshore pipeline section is set at 345 barg, the maximum well head shut in pressure6 which is an absolute maximum that the pipeline

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6 The 2010 s40 application states that the maximum well head shut in pressure is 320barg (Section 2.7, page 11)
could experience which with a design factor of 0.72 (a safety factor of 1.39 or 39%), corrosion allowance and manufacturing tolerance gives rise to the 27 mm wall thickness.

The offshore maximum allowable operating pressure of 150 barg is set to allow for the full flow pressure gradient from well heads to the Terminal but in practice the pressure upstream of the LVI would always be below this even in the case when well head isolation valves and LVI isolation valves are closed.

The onshore pipeline is protected by the offshore pressure limitation system and the LVI pressure limitation system to ensure the MAOP of 100 barg is not exceeded. The design pressure of 144 barg is comfortably in excess of this and results in a design factor of 0.3 with the pipe wall thickness of 27 mm. This implies a “safety factor” of 3.33 (or 233% above the strength required to withstand the design pressure). However, as the onshore pipeline pressure is limited to 100 barg (about 70% of design pressure) by the high reliability pressure limitation system the pipeline has a much higher excess strength than normal “thick wall” pipe used in more densely populated areas. (At a pressure of 100 barg the safety factor provided by the 27 mm wall thickness is about 4.5, compared with the normal thick wall pipe safety factor of 3.3 and a standard wall thickness pipe safety factor of about 1.3).

Entec considers that the design parameters of the pipeline have been set to give a greater than normal tolerance, or factor of safety, particularly with respect to the design pressure.

The SEPIL submission gives a design for protection at the single road crossing (DG701) and typical specification for drainage ditch and crossings (DG702 and DG703). The installation of these crossings needs to be verified during construction to ensure that the pipeline is lying on uniform strength material and not subject to differential settlement and that the protective concrete slabs are also on firm support so that additional loads will not be transmitted to the pipe.
6. Compliance with Codes and Standards

6.1 Offshore

The offshore pipeline is within the scope of DNV OS F101. According to Section 2 C 200 Corrib gas would be a Category D fluid (non-toxic single phase natural gas). The location classification would be mainly Class 1 for the offshore pipeline but Class 2 as it approaches the shore in the vicinity of Glengad (Section C 300). Thus most of the route would be Safety Class – Medium but the shore approach and onshore section to the LVI would be Safety Class – High.

Physical Protection

In-field flow lines are adequately protected see Section 3.5 of s40 2010 Design Premise. Sections 3.2, 3.3 and 3.6 describes the main offshore pipeline protection. All use an inherently strong pipeline but provide additional protection where appropriate by burying in trenches, rock dumping or sleeves (infield lines on entry to manifold / PLEM) and concrete coating (main offshore pipeline).

Pressure Protection

The code Section 3 B 302 states that the MAOP should be equal to the design pressure minus the pressure control system operating tolerance. However in this case the Design Pressure (345 barg) has been set higher than the maximum well head shut in pressure (320 barg). The code allows for an incidental pressure higher than the Design Pressure but in this case the maximum pressure would be the maximum well head shut in pressure (allowing for any pressure increase during valve closures). The MAOP for the offshore pipeline has been set at 150 barg giving a very large factor of safety between this and Design Pressure.

The pressure protection system has been shown to have a high reliability exceeding the code requirements for ensuring pressure does not exceed MAOP.

Hydraulic Analysis and Flow Assurance

The code (Section 3 B 400) requires this to demonstrate that the pipeline can safely transport the fluids in all circumstances including start-up, shut-down etc. Industry standard software, OLGA has been used to model pipeline flow (see Appendix Q4.5 of the EIS) and establish trip set points (to protect the pipeline against incidents where the design parameters might be exceeded).
Creating the environment for business

Route

The Offshore pipeline route has been selected in accordance with Section 3 C and takes into account sea bed topography, fishing activities and a suitable landfall site.

Environmental Conditions

The offshore pipeline has been designed to take account of the environmental conditions described in Section 3 D.

Pipe Condition

The pipeline design takes account of the external conditions listed in Section 3 E 100. The pipeline internal conditions have been monitored whilst in storage and prior to installation of the offshore line, they will be inspected by intelligent pigging prior to commissioning (E200). The internal corrosion potential of the Corrib fluids is low but has been taken into account in the design (E300) and corrosion monitoring will be undertaken as well as corrosion inhibitor added to the well fluids.

Design Loads and Design Limit State Criteria

This refers to sections 4 and 5 of the DNV Offshore Pipeline Code. The Section 40 2010 – Design Premise Section 2.10.1 states that the pressure containment and pressure collapse criteria govern the wall thickness of the offshore pipeline with a design pressure of 345 barg and a MAOP of 150 barg. The Stability requirements of each pipeline section have been calculated in accordance with code DNV RP E305. The offshore pipeline has been trenching between the landfall and 13 km offshore of the landfall for stability. Stabilisation and protection of the steel pipeline has been increased by means of the placement of a rock berm on top of the pipe in some sections.

8820-D100-01 E - Offshore Design Basis describes the design of the offshore pipeline and demonstrates that the loads defined in the standard have been taken into account, including:

- Stability (buoyancy);
- Mechanical protection against interaction with fishing gear or dropped objects; and,
- Free spans.

The basis of calculations for imposed loads during installation has not been presented and confirmation of calculations showing that these do not form the determining conditions for the pipeline design should be provided.

Corrosion Control

Section 6 of the DNV Offshore Pipeline Code covers the material selection and corrosion control. The offshore pipeline is provided with cathodic protection and a nominal corrosion allowance of 1mm. (Although the code...
Creating the environment for business

recommends 3 mm where free water is likely to be present the detailed assessments by SEPIL show that corrosion rates will be low even in the absence of inhibitor and given the intention to provide corrosion inhibitor and add excess methanol to ensure no free water is present this is conservative). The pipeline material is at least equivalent to the American Petroleum Industry’s standard API 5L grade X70 according to Chapter 2 of the 2010 Section 40 application.

Materials of Construction and Fabrication

This is covered in Section 7 of the DNV Offshore Pipeline Code and should have been the subject of third party verification and certification.

Construction and Installation

These matters are covered in Sections 8, 9 and 10 of the DNV Offshore Pipeline Code. Again, they should be covered by records of third party independent verification as these steps have already been carried out under previous consents.

Operations

Section 11 of the DNV Offshore Pipeline Code covers the operational requirements including the pipeline integrity management system discussed in Section 2, including the arrangements for inspection and monitoring. These matters should be completed before commissioning.

Documentation

The final required section of information under the DNV Offshore Pipeline Code, Section 12 describes the documents required to support the design, construction, installation and operation of an offshore pipeline which should be the subject of third party verification and therefore not part of this review.

Shore Approach and Onshore

Appendix F of the DNV Offshore Pipeline Code is of particular interest in this study as it provides complementary requirements for onshore sections of the pipeline to ensure compatibility with the offshore sections. Although this overlaps with the onshore pipeline codes used for the Corrib pipeline there is consistency in the requirements and references to ISO 13623, for example and the need to follow its more stringent requirements where necessary. In this case the overlap includes the whole Landfall Valve Installation (LVI) as the termination of the offshore section is defined as the downstream valve at the LVI.
6.2 Onshore

The onshore section of the pipeline (high water mark to terminal) has been designed in accordance with the codes recommended by TAG\(^7\) and confirmed by NSAI\(^8\), as shown in Appendix Q3 of the EIS. Entec considers these codes to be appropriate and to represent good practice. Note that IS EN 14161 adopts the international standard ISO 13623. The wording allows individual countries to apply their national requirements for public safety and the protection of the environment. Therefore the Corrib onshore pipeline applies the sections of I.S. 328 and PD 8010 for matters relating to public safety.

Advantica and TAG Requirements

The Advantica and TAG reviews have dealt with most concerns over compliance with the codes specified. SEPIL’s responses in Appendix Q3.1 of the EIS deal adequately with all these points except the following references from Attachments to EIS Appendix Q3.1.

<table>
<thead>
<tr>
<th>No</th>
<th>Topic</th>
<th>Entec Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>Impact protection: Concrete slabs for ditch and road crossings</td>
<td>Drawings are still generic and do not reflect actual ground conditions at the location of each crossing. The intentions and instructions are clear but the actual installation of the crossings should be verified by an independent third party to ensure that the excavations to firm foundations are made and the separations are achieved with no chance of differential settlement along the pipeline.</td>
</tr>
<tr>
<td>10</td>
<td>Interface between offshore and onshore CP systems</td>
<td>SEPIL has described separately (see response to Entec questions submitted to the ABP Oral Hearing) the method of ensuring there is no undue loss of material from the offshore sacrificial anodes due to the current from the onshore CP system</td>
</tr>
<tr>
<td>22</td>
<td>Pipeline Integrity Management System</td>
<td>Further points have been raised in this review see Section 2, above</td>
</tr>
<tr>
<td>23</td>
<td>Defect Assessment and repair</td>
<td>SEPIL has described separately (see response to Entec questions submitted to the ABP Oral Hearing) the methods for assessment of defects and if necessary repairs within the tunnel.</td>
</tr>
<tr>
<td>25</td>
<td>Repairs to the umbilical</td>
<td>Towards the end of the ABP Oral Hearing SEPIL proposed protecting the umbilicals and water discharge pipe with a narrow concrete slab. (This slab not to project over the pipeline). This would make the chance of damage to the umbilical much less but increase the difficulty of excavating to effect repairs without interfering with the pipeline. A detailed repair method statement needs to be developed in advance if this approach is adopted.</td>
</tr>
</tbody>
</table>

\(^7\) TAG; Report of the Corrib Technical Advisory Group to Minister Dempsey. 2006

\(^8\) Letter to DCENR August 2010
TABLE A1 (continued) (EIS Appendix Q3.1 Attachment A): Recommendations Arising from Independent Safety Review (Advantica)

<table>
<thead>
<tr>
<th>No</th>
<th>Topic</th>
<th>Entec Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>29</td>
<td>Proposed arrangements for pipeline monitoring and landowner liaison</td>
<td>These have not yet been produced.</td>
</tr>
<tr>
<td>31</td>
<td>Pipeline pressure limitation – reliability analysis</td>
<td>The reliability analysis (FTA and SIL verification) has been submitted separately and reviewed in detail by Entec see Section 3 above.</td>
</tr>
</tbody>
</table>

TABLE A2 (EIS Appendix Q3.1 Attachment A): Recommendations Arising from Independent Safety Review (TAG)

<table>
<thead>
<tr>
<th>No</th>
<th>Topic</th>
<th>Entec Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>Pipeline Integrity Management System</td>
<td>Further points have been raised in this review see Section 2, above.</td>
</tr>
<tr>
<td>4</td>
<td>Detailed Impact Protection Design</td>
<td>Drawings are still generic and do not reflect actual ground conditions at the location of each crossing. The intentions and instructions are clear but the actual installation of the crossings should be verified by an independent third party to ensure that the excavations to firm foundations are made and the separations are achieved with no chance of differential settlement along the pipeline.</td>
</tr>
<tr>
<td>6</td>
<td>Pipeline Slabbing in Peat Sections</td>
<td>New proposals for slab protection of umbilicals and water discharge pipe should include arrangements to ensure slabs are supported to avoid movement.</td>
</tr>
<tr>
<td>7</td>
<td>Assessment of pipe wall strain</td>
<td>Appropriate sections should include entry / exit to the LVI and entry to the tunneled section and the end of the exit ramp from the tunnel.</td>
</tr>
<tr>
<td>9</td>
<td>Monitoring of Settlement</td>
<td>As for 7 and the road / ditch crossings.</td>
</tr>
<tr>
<td>11</td>
<td>Repair work on umbilicals</td>
<td>Towards the end of the ABP Oral Hearing SEPIl proposed protecting the umbilicals and water discharge pipe with a narrow concrete slab. (This slab not to project over the pipeline). This would make the chance of damage to the umbilical much less but increase the difficulty of excavating to effect repairs without interfering with the pipeline. A detailed repair method statement needs to be developed in advance if this approach is adopted. Note detailed procedures within PIMS not yet available.</td>
</tr>
</tbody>
</table>

Additional concerns arise at the LVI and access pits at either end of the tunnel section and at the end of stone road sections where there will be a change in the ground support for the pipeline. The details of the pipeline entry and exit from the LVI and the transitions need to be established in the detailed method statements for construction.
Public Safety

The proposed onshore pipeline with a design pressure of 144 barg and MAOP of 100 barg exceeds the code (PD8010) requirements on pipeline wall thickness and separation distance from dwellings.

The QRA presented in Appendix Q6.4 of the EIS is in accordance with PD8010 part 3 and shows that risks are much lower than required by any regulatory body code or guidance.

Additional protection is provided at the road crossing in line with the code guidance.

Materials of Construction

The pipeline wall thickness gives the primary means of containment and protection against damage leading to leaks. The pipe is manufactured from X-70 carbon steel to meet the requirements of both onshore and offshore codes. An external corrosion protection coating is applied to the whole pipeline and internal corrosion to pipeline sections but not the area of the girth welds. Code requirements are met by this specification.

Instruments and Control Systems

The pressure protection system which maintains the onshore pipeline pressure below 100 barg constitutes a high integrity pressure protection system and conforms with section 5.4 of I.S. EN 14161 to ensure that both MAOP is kept to 100 barg or less during steady state and that the maximum incidental pressure (allowing for transients) is also kept within this pressure.

Physical Protection

The physical protection of the pipeline is provided by:

- Pipeline wall thickness (exceeding code requirements but giving a design factor of 0.3 at 144 barg design pressure);
- Depth of burial (minimum 1.2 m which meets or exceeds the code requirements);
- Slabs at crossings; and,
- Enclosure within tunnel for most of the onshore route.

These measures exceed code requirements.

Tunnel Construction

The tunnel design and construction should adopt the International Tunnelling Insurance Group (ITIG) ‘A Code of Practice For Risk Management of Tunnel Works’, January 2006 based on the Joint Code of Practice for Risk
6.3 **Landfall Valve Installation (LVI)**

The LVI is intended to be compliant with the offshore pipeline code (DNV OS F101) and the onshore pipeline codes (IS EN 14161 – section 7 is relevant to the LVI (ISO 13623) supplemented by I.S. 328 and PD 8010). Sections 7.7 and 7.8 of I.S. EN 14161 are replaced with Section 7.6 and 7.7 of PD 8010. Section 7.10 of I.S. EN 14161 is supplemented with Section 16.3 of I.S. 328 according to EIS Appendix Q3.3 following the TAG recommendations (with which Entec agrees). Appendix F of DNV-OS-F101 covers onshore facilities but remains concentrated on line pipe issues although the general requirements on materials and design parameters will apply they are consistent with the other codes (specifically referencing alignment with ISO 13623). It also states that the requirements of relevant national and international onshore standards should prevail where they have more onerous requirements, particularly regarding public safety, which is the case here considering the onshore codes referenced and the requirements of ABP. (Although the DNV code Appendix F section D 202 states “The need for lightening (sic) rod and means to avoid build-up of static electricity shall be considered”).

**LVI Location, Layout and Security**

The LVI is as close as practicable to the pipeline landfall high water mark and is located so that the nearest dwellings are out of range of life threatening effects of any accidents (including the largest possible (see EIS Appendix Q6.4). It is set back a short distance from the cliff to allow for cliff erosion and a suitable gradient for the buried pipeline to enter the installation. A dished area (depression) is to be created to house the LVI to minimise the visual impact of the installation. The main pipework and valves will be buried below the floor of the dished area and the valve controls and instruments will be protected with cages affording more protection than required by codes. There is provision for access for maintenance or replacement of equipment if required. There will be additional security measures at the LVI as well as the leak and interference detection for the pipeline. An emergency escape gate is provided in addition to a main gate.

Therefore Entec considers that the design presented in the EIS Appendix Q4.3 is in compliance with Sections 7.1 to 7.4 of I.S.EN 14161

**Configuration**

SEPIL has provided justification of the selected design configuration (EIS AppendixQ4.4) and this is discussed in Section 4 above.
The codes only require emergency shutdown arrangements for installations with pumps or compressors. There are no specific requirements for venting and isolation.

The codes do require stress analysis and vibration studies and these have been addressed in the EIS Appendix Q4.3 section 5.8.

Frost heave should be avoided through the use of the small by-pass around the downstream isolation valve which allows for a slow increase in pressure downstream of the isolation with low flow rates thus avoiding severe Joule-Thompson effects. However the design should also ensure that there are no other causes of differential movement or settlement of the pipeline particularly either side of the LVI where the pipeline moves from the LVI solid structures to the buried pipeline in a trench without a constructed foundation.

The instrumentation cabin should have appropriate signage and two outward opening doors for escape of personnel, if an escape route could be blocked in the event of a reasonably foreseeable accident.

Environmental

The LVI is a dished area and has to be provided with separate local drainage to a local separate outfall across the beach. The final design of this has not been completed and should be subject to a condition to ensure that no contaminated water is released. Although there are no normal activities leading to liquid discharges there may be maintenance or inspection activities which could lead to locally contaminated surfaces within the LVI and from which drains should not discharge directly. (Methanol is also supplied to the LVI and through the umbilicals, together with corrosion inhibitor and there is a remote (extremely unlikely) risk of a release at the LVI which should be contained and not discharge with any clean rain water).

Instruments and Control Systems

EN 14161 sections 7.13 and 7.14 defines requirements for monitoring pipeline conditions, in particular at the LVI and this is fundamental to the operation of the LVI as a pressure limitation facility. PD 8010 section 7.12 also requires monitoring the relevant parameters which in this case are pressure and temperature. It is noted that there is mention of temperature measurement offshore close to the well heads but no temperature measurement downstream of the LVI. As there is potential for a temperature drop across the LVI valves during start-ups (re-pressurisation of the onshore pipeline) it would be prudent to monitor temperature to ensure the pipeline remains within specification. Only one diagram refers to a temperature monitor at, or near the LVI, and that is in Appendix Q4.4 Figure 5.1 when discussing alternative designs of LVI.

Materials of Construction

The LVI pipework and valves are constructed of corrosion resistant alloys in order to protect against any flow inhomogeneity that could lead to ineffective distribution of corrosion inhibitor or appearance of free water.
The 16 inch isolation valves, main 20 inch pipeline and 20 inch valve within the LVI will be carbon steel overlay welded with corrosion resistant Alloy 625 and the pressure protection valves and by-pass valves are 22% Cr duplex stainless steel. The main 16 inch diameter loop pipework and 4 inch by-pass will be fabricated with 22% Cr duplex stainless steel (Appendix Q4.7 section 2).

Testing

I.S. 328 Section 17 requires hydrostatic testing of the installation pipework to 1.5 times the design pressure. If the installation upstream of the downstream valve is regarded as part of the offshore pipeline then this implies a test pressure of 1.5 times 345 barg, which is 517.5 barg compared with the proposed test pressure of 504 barg. The offshore design code has a different method of specifying the test pressure which may result in a lower value. However given the larger than normal difference between the design pressure and a maximum allowable operating pressure, and the maximum incidental pressure is equal to the maximum allowable operating pressure there is still considerable conservatism in the 504 barg test pressure selected.

Safety and Integrity Management

DNV-OS-F101 requires an Integrity Management System (Section 11C) and Integrity Management Process (Section 11D). Section 13 of EN 14161 and Section 12 of IS 328 require plans for ongoing monitoring maintenance and management of integrity related matters. The provisions discussed in Section 2 and Appendix F cover these aspects.
7. **Compliance with TAG Recommendations**

Although the current review has been conducted independently of previous reviews and is based on the revised 2010 submission many of the previous recommendations made to DCENR remain relevant. Indeed the SEPIL submission in Appendix Q3.1 of the pipeline EIS details the SEPIL responses to the Advantica and TAG recommendations which Entec considers appropriate to achieve a high standard of safety. These have been compared with the composite picture of the review of safety of the upstream, onshore section of the proposed Corrib gas pipeline given in “Corrib Gas Pipeline Safety Issues” (www.dcenr.gov.ie/NR/rdonlyres/96132992-6D9A-4D19-82D2C0DE05432847/0/CorribGasPipelineSafetyIssues.pdf)

All the issues have been addressed although some are not described fully in Appendix Q3.1:

7.1 **Formal Risk Framework for Major Projects in Ireland**

This is clearly not within SEPIL’s remit and is being addressed through the implementation of PEES (2010) for upstream oil and gas projects. Offsite risk has been addressed by HSA which has issued guidance on risks to the public from onshore installations falling under the COMAHDS Regulations (1999). This is not a requirement on SEPIL. (Note that ABP has proposed two different criteria, one based on the risk concepts used by the UK HSE for land use planning in the vicinity of Major Hazard fixed installations and pipelines; the other on a “protection concept” so that even in the event of a non-credible worst case accident residents in the nearest dwellings would not be seriously harmed. See Appendix D for Entec’s critique of this approach).

7.2 **Arrangements for Pipeline Monitoring**

The issues that are covered in Q3.1 include:

- Pipeline marking and position monitoring;
- Patrolling the route;
- Fatigue cycle count;
- Stress measurements;
- Intelligent pigging to monitor pipeline condition; and,
- Pressure monitoring.

Measures referred to elsewhere in the submission include:

- Interference and leak detection by optic fibre cable;
- Corrosion coupon monitoring;
- Checks on the cathodic protection system; and,
- Landowner liaison (see below).

Entec considers that these monitoring measures are adequate and should be incorporated into the routine tasks within the Pipeline Integrity Management System and responsibilities assigned for not only carrying them out but critical assessment of the results which should be used to update the risk assessments carried out whenever a change is detected.

### 7.3 Landowner Liaison

Advantica and TAG recommended that Shell should specify the arrangements for landowner liaison relating to pipeline monitoring in particular and Entec agrees that these should be in place prior to operations commencing. However, the exact mechanisms have not been described in the submissions. Entec recommends that SEPIL should present their proposed methods of communicating with landowners and local users of the land near the pipeline route. The communications should be directed at maintaining the integrity of the pipeline and reinforce the importance with respect to safety of:

- Avoiding damage to the pipeline or its coating or interference with the cathodic protection system;
- Maintaining marker posts and tape in position;
- Allowing access along the wayleave for visual inspection of the route;
- Reporting of any signs of disturbance, damage or incidents; and.
- Reminders of the arrangements for emergency response.
8. Other Stakeholder Safety Concerns

8.1 Concern that Pipeline might be Considered Unique or Experimental

It has been claimed (submissions received 4th August 2010) that the composition and pressure of the gas in the Corrib line makes the pipeline unique. Entec (and in particular the author) has experience (including risk assessment and safety specifications) of two pipelines designed in the 1980s which show that “raw gas” (i.e. not to sales gas specification) has been carried in onshore lines for many years, at least one at considerably higher pressure:

i) The Miller Gas St Fergus to Peterhead (18 km) pipeline is a sour gas line, designed to handle hydrogen sulphide content up to 1000 ppm, carbon dioxide up to 25% and free water up to 1 lb/mm3cf. The facility at St Fergus (essentially a complex LVI) has to drop the pressure from a maximum 174 barg in the offshore line to and provide pressure protection to the onshore line with an MAOP of 34 barg. (There are also heaters at St Fergus to cope with the temperature cooling associated with this pressure drop). It has an outside diameter of 26 inches and a wall thickness of 11.13mm. It was built to the CP 2010 series of codes which were the predecessors of PD 8010 current up to 1992.

ii) CATS Pipeline on Teesside runs onshore from the beach valves at Redcar about 8 km to the treatment terminal at Seal Sands, including a crossing beneath the Tees Estuary. It is 36 inches diameter, with an onshore wall thickness of 33.9 mm and a MAOP onshore of 125 barg (offshore 179.3 barg and wall thickness 28.4 mm). This line conveys rich gas, i.e. a mixture of natural gas and heavier hydrocarbons and has to be kept at high pressure to ensure that there is no phase separation. It copes with shut down and start-up conditions. It had a precautionary shut down after a super-tanker dropped and dragged its anchor across it, moving it by several metres, the pipeline coating was damaged but there was no loss of containment. This pipeline was also built to the requirements of CP2010.

The Corrib gas has a specification very close to that of Sales Gas (the gas conveyed by BGE pipes). It only differs in a tiny additional quantity of propane / butane fractions and the presence of a small quantity of water. In order to ensure that there is no free water in the pipe excess methanol will be added. The carbon dioxide content of the gas is very low (much lower than most North Sea gas) and therefore the potential for acidic corrosion (due to mixture of acid gases and water) is very low.

Most offshore reservoirs, particularly in the northern North Sea, contain mixtures of oil, gas and water. The processing offshore is very basic and separates the hydrocarbons from most of the water, then the hydrocarbons are separated into two or three streams, such as crude oil (containing pentane and heavier hydrocarbons), “natural gas liquids” (mainly propane and butane) and natural gas (mainly methane, but may contain significant fractions of other gases including nitrogen, carbon dioxide and hydrogen sulphide). All these streams may contain water and
other contaminants. Even if the three hydrocarbon streams are separated usually they are combined into two before being exported by pipeline or tanker. Therefore pipeline gas arriving at the beach often contains natural gas liquids, water, carbon dioxide and hydrogen sulphide and possibly other contaminants which need to be removed before being fed into “sales gas” distribution systems. Offshore processing to sales gas specification is rare.

Again the author has personal knowledge, from previous risk assessments, of another pipeline delivering natural gas to Belgium from Norway (814 km from Sleipner to Zeebrugge) which has a land fall valve facility 5 kilometres from the reception terminal. The Zeepipe 40 inch pipeline came into operation in 1993 and has a design pressure of 160 barg throughout. It passes within about 500m of the village of Ramskapelle and the nearest dwellings in Heist are within about 200 metres.

Therefore Entec considers that the assessment of safety can be carried out on the basis of criteria applied to the safety of other pipelines within the experience of the assessment team, applying the requirements of the most stringent codes and standards, to ascertain whether SEPIL’s assurance of the high standard of safety claimed is demonstrated in their submissions and the proposed methods of construction and operation.

8.2 Failures of Other “thick wall” Pipelines

Some pipeline failures in “thick walled” pipelines (wall thickness greater than 15 mm) have been identified:

- 1993 Moffatt pipeline rupture with wall thickness of 19mm – a concrete raft had been laid to protect the pipeline during construction but it was close to an existing road crossing. The pipeline crossing under the road had been laid on consolidated material but the raft had been laid over the pipe where the soil was not consolidated. Differential movement of the pipeline by 100 – 300 mm caused a high longitudinal stress which exceeded the specified minimum yield stress of the pipeline. This illustrates the need to ensure that concrete slab protection is properly designed and is laid on consolidated foundations;

- 1994 Edison, New Jersey 17.1 mm - the rupture was caused by a crack which formed in a gouge to the pipe made earlier, with growth ascribed to metal fatigue. (It was 36 inches in diameter, operating at 69.2 barg).

Therefore it would be more correct to state that there are no records of ruptures in pipelines with wall thickness greater than 19 mm. There is no record of third party interference leading to a rupture for wall thickness greater than 17 mm.

The Moffat incident does not affect the European records of failure due to third party interference as this was not the cause.

Both pipelines were considerably larger in diameter than the 20 inches of the proposed Corrib pipeline, which would have resulted in a greater wall thickness for the same design pressures. Design pressures were not given in the accident reports. Considering the relative diameters and wall thickness of these pipes it can be seen that the Corrib pipe would have much greater wall thickness and therefore reserve strength.
8.3 Safety at Road Crossing

Figure 12 in Appendix Q6.4 shows the variation in the risk of experiencing a dangerous dose or worse with distance from the pipeline. People in a road vehicle at the crossing would suffer a lower dose than those assumed to be escaping in the open air but even those would be exposed to a dangerous dose at a frequency of less than \(1 \times 10^{-8}\) per year, or less than once in a 100 million years. The general failure frequency of the pipeline can be used because the pipeline would have additional protection at a road crossing to prevent any localised loading on to the pipeline from road vehicles and to protect against damage during any road works.

These risk levels are two orders of magnitude below those proposed as acceptable risk criteria by ABP in their letter of November 2009 and well below other risk criteria set elsewhere.

8.4 Safety Risks near the Pipeline in the Open Air

People not in road vehicles or close to shelter in the vicinity of the pipeline may be considered to be at higher risk but due to the level of protection of the pipeline and the inherent safety provided by the pipe wall thickness the risk of any leakage is extremely small and therefore the risk from an ignited leak less than “extremely small”. A simple calculation may be made to show that an upper level of risk calculated very simply is well below the criteria set by ABP for risk at a dwelling.

The likelihood of an incident affecting a particular point on the pipeline is calculated for each hole size as:

\[
\text{Frequency of release (per metre) \times Probability of Ignition \times twice the maximum interaction length (where the interaction length is the maximum distance at which a dangerous dose may be received), \times proportion of time present (assume this to be 2 hours per day, every day). (Note Table 17 shows a range of distances for ruptures).}
\]

Table 9 of Appendix Q6.4 gives the frequency of each hole size, Table 12 gives the ignition probability and the maximum consequence distance for Dangerous Dose (1% risk of fatality from Table 17) 273 m rupture; the maximum consequence distance for Dangerous Dose from a hole ……………………..100 m (assumed); the maximum consequence distance for Dangerous Dose from a pin hole ……………………3 m (assumed);

\[
\begin{align*}
1.14 \times 10^{-5} \times 0.04 \times 2 \times 3 \times 0.084 & = 2.3 \times 10^{-7} \\
1.41 \times 10^{-6} \times 0.02 \times 2 \times 100 \times 0.084 & = 4.7 \times 10^{-7} \\
2.2 \times 10^{-9} \times 0.33 \times 2 \times 273 \times 0.084 & = 3.3 \times 10^{-8}
\end{align*}
\]

\[
\begin{align*}
\{ 7.4 \times 10^{-7} \}, \text{less than one in a million per year.}
\end{align*}
\]

Therefore a man on the centre line of the pipe 14 hours per week every week would still be within the ABP criteria described in the ABP letter of 2\textsuperscript{nd} November 2009.
8.5 **Vibration**

SEPIL has presented results of modelling vibrations from both tunnelling and the construction of access pits which show that the effects are below the threshold likely to cause damage to nearby housing. Vibration is measured in terms of the peak particle velocity generated in a vibration (mm/s).

The National Roads Authority (NRA) standard sets a threshold of 12.5 mm/s to prevent serious damage to houses and other structures. As the threshold peak particle velocity for triggering ground instability is about twice as high, (i.e. over 20 mm/s) the concerns over these vibrations triggering landslips on Dooncarton Mountain or the low cliffs around Sruwaddacon Bay should be assuaged by monitoring which shows the scale of further attenuation and non-detectable vibration at 300 m beyond the road. Nevertheless a condition on monitoring vibrations is proposed as a safeguard for SEPIL and residents.

Atkins, the tunnelling experts consulted, agree that the magnitudes of vibration are extremely low and are unlikely to generate adverse impacts within the wider locality (see Atkins Report⁹).

8.6 **Feasibility of Tunnel Construction**

Entec commissioned tunnelling experts at Atkins to give their opinion on the feasibility of constructing a bored tunnel to carry the pipeline beneath Sruwaddacon Bay in the manner defined by SEPIL and their consultants.

In the early stages of Entec’s preliminary review the following issues had been identified concerning the construction of the tunnel:

- The ground conditions in the sediments and bedrock beneath Sruwaddacon Bay have not been determined along the proposed tunnel alignment; therefore there is uncertainty over the requirement for the Tunnel Boring Machine (TBM) to cope with the interface between sediments (sand and gravels) and the hard bedrock, together with the presence of hard rock inclusions within the sediments. Should the TBM encounter difficulties then the contingency plan is to use intervention shafts, constructed in the Bay, for which no environmental assessment has yet been made.

The tunnelling experts at Atkins state in their report¹⁰ that the sampling regime and methods may underestimate the presence of cobbles and larger rock fragments, and that the investigations may not have reached sufficient depths to allow the tunnelling contractors to drive the tunnel at greater depths, but the overall assessment is that the need for surface intervention shafts is “highly unlikely” and the investigations are adequate on the proposed alignment.

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¹⁰ Corrib Onshore Pipeline: Review of Bored Tunnelling Proposals. Atkins November 2010
Concerns have been expressed as to whether vibrations from tunnelling could trigger further land slips on Dooncarton Mountain. Although the vibrations are predicted to be much less than those from heavy traffic at the dwellings along the road the tunnelling vibrations will be continuous.

The tunnelling experts consulted are of the opinion that the magnitudes of vibration from tunnelling are extremely low and are unlikely to generate adverse impacts within the wider locality.

8.7 Tunnel Construction

The current proposal to place the pipeline in a tunnel beneath Sruwaddacon Bay satisfies safety distance separation criteria but raises some questions of feasibility and possible unwanted impacts if problems arise during tunnelling. The tunnelling experts stated that these can be avoided by design and monitoring of the tunnelling operations.

However the Atkins tunnelling experts are satisfied that:

A) the tunnelling concept and construction method is feasible; and,

B) other than due to exceptional circumstances, surface intervention to access the TBM for repair during the drive under Sruwaddacon Bay is highly unlikely.

Entec has inferred from the Atkins report that the outstanding matters for SEPIL to confirm are:

1. The TBM specification addresses the key employer requirements with respect to the tunnel construction including:
   - Procedures for the control and monitoring of face support slurry (include salinity in the specification);
   - Procedures for the control and monitoring of grouting operations;
   - Obligations placed on the contractor as stated in the EIS;
   - Oil and grease leaks within the tunnel should be contained within the lining and along with nuisance water be pumped to the surface. Water disposal systems should be designed to deal with oil and solids. Any such oils should be specified as being biodegradable.
   - Variation of the tunnel horizontal and vertical alignment will be within the limits set in the EIS, in particular the minimum depth and the maximum horizontal deviation (8 m from the defined centreline).

2. Method to ensure no differential settlement between trenched pipeline sections and the tunnel shaft base or ramps.

8.8 Responses to Public Consultation on Section 40 Application

Three new issues have been raised in the submissions of Terence Conway and Michael O’Seighin (other safety related issues such as vibration have been dealt with elsewhere in this report):

a) The ventilation duct within the tunnel is not to be filled with grout and therefore forms a cavity which could be filled with an explosive gas mixture, ignite and then explode. SEPIL has responded\textsuperscript{11} that the ventilation duct will be filled with water glycol mix following the grouting of the tunnel. Entec agrees that the removal of the ventilation duct would risk damage to the pipeline, or at least its coatings, following the inspection and testing, therefore it is best left in place. Entec also agrees that the likelihood of a leak from the pipeline in the tunnel is vanishingly small but even if it did occur and somehow displace the liquid there would be no oxygen to create a flammable mixture within the duct.

b) The shallow sediments in Sruwaddacon Bay are not suitable for a tunnel and therefore the pipeline will not be protected within the tunnel bore. Entec, supported by Atkins have confirmed the feasibility of constructing a tunnel as proposed in the sediments above the bedrock. Other tunnels have been constructed in similar materials. Atkins has stated that it may be easier to construct wholly within the bedrock but this would take longer and require further investigations. The proposed tunnel does not rely on the support of the sediments but is formed by concrete segments completely lining the bore, which when grouted effectively form a concrete pipe within which the gas pipeline, umbilicals and water discharge pipes can be laid. The flexible grout gives further protection against any disturbance. Entec is of the opinion that this will provide a very resilient protection for the pipeline and is superior to a conventional buried pipeline laid in an open trench back filled with sand or other suitable fill which will not damage the pipeline or its coating.

c) There is evidence of disturbance due to landslips in 2003 within 40 metres of the proposed tunnel route according to the submission of Mr Terence Conway where he describes the disturbance as a crater. However the evidence from SEPIL is that this is local gulley erosion due to local surface water run-off (during the high rainfall that triggered the slides on the mountain) and not connected with the land slips on Dooncarton Mountain. This is discussed in Appendix M2 Section 7 of the EIS. Entec agrees with the conclusion that this is not, nor likely to be in future a debris channel for landslides originating on the steep slopes of Dooncarton as these are a considerable distance away and the gradient of the intervening land is not steep enough to sustain debris flow. The pipeline, some 40 metres beyond the end of this feature will be within the grouted concrete tunnel, the top of which is at least 5m below the surface. Therefore, in Entec’s opinion any further sediment flow or anticipated erosion would have no impact on the pipeline.

\textsuperscript{11} Responses to November 2010 Submissions to DoEHLG – J Ventilation Shaft
9. Conclusions

9.1 Design Codes

The Design Codes being used for the Offshore and Onshore Sections of the pipeline are entirely consistent and indeed the Offshore Code DNV OS F101 references other codes, particularly ISO 13623 or more stringent national requirements.

The Design Standards adopted for the onshore pipeline, are primarily those of I.S. EN 14161: 2004 Irish Standard – Petroleum and Natural Gas Industries - Pipeline Transportation Systems (ISO13623: 2000 modified); together with sections from I.S. 328: 2003 (Code of Practice for Gas Transmission Pipelines and Pipeline Installations (Edition 3.1)); and BS PD 8010-1: 2004 (Code of Practice for Pipelines – Part 1: Steel Pipelines on Land); where their requirements are more stringent. This is considered to be appropriate.

The main features resulting from the design codes are:

i) the pipeline is capable of withstanding the well head shut in pressure throughout its entire length from the well heads to the terminal, having a uniform wall thickness of 27mm and is manufactured from a consistent grade of steel;

ii) the entire onshore section to be constructed from the current termination of the offshore pipeline will be tested to 504 barg prior to commissioning.

Entec considers that the use of pipeline codes on the pipeline project is in line with Good Industry Practice and the recommendations of TAG and NSAI which are consistent with this level of design.

9.2 Pipeline Integrity Management Scheme

Entec considers that the submissions demonstrate that SEPI is has a scheme which has:

- A specification and design that provides an onshore pipeline of greater strength and resilience than required by codes and standards by means of the pipe wall thickness, materials of construction and a pressure limitation system to ensure that the increased factor of safety is maintained;

- Systems to protect against external corrosion and damage (although further details of the design of stream and debris channel crossings have been requested);

- A process of monitoring the pipeline and route to avoid or detect any damage before it gives rise to leaks which meets or exceed industry standards;

However Entec finds that the submissions have not provided details of:
• Safety management systems procedures for control of modifications (management of change, control of work) which will need to be in place before operations;

• Specific procedures for testing of isolation valves and emergency shut down valves although the test frequency has been given.

The combined Integrity Management System for both pipeline and terminal should state clearly that it applies to both in order that responsibility for the LVI and pipeline is clearly understood.

Entec recommends conditions that prior to commissioning the pipeline SEPIL must:

a. complete the Safety Management System to ensure that modifications to the pipeline, including its instrumentation, control, operation, maintenance and testing are included within the Management of Change and Control of Work procedures for the whole Corrib Development Facilities; and,

b. prepare test procedures for the isolation valves and emergency shutdown valves together with their control systems which will maintain the reliability of the pressure limitation and shut down systems, are approved.

9.3 Quantified Risk Assessment

The submission includes a Quantitative Risk Assessment that has been carried out in more detail than is normal for pipeline risk assessments. In particular it incorporates site specific hazards. However, the risks from landslides are ruled out on the grounds of protection provided although this has not been fully detailed, as mentioned above.

The QRA demonstrates that the safety risks from the pipeline are extremely low and well within the “broadly acceptable” region of published criteria even in the open near the pipeline. The separation between pipeline and dwellings fulfils the criteria set by ABP. The sensitivity analysis demonstrates that these are robust conclusions.

Entec recommends that any consent granted should be subject to conditions requiring completion of all the actions and commitments within the QRA.

9.4 Landfall Valve Installation Design Overview

The Landfall Valve Installation (LVI) is a key component in the pressure limitation system to ensure that the pressure in the downstream, onshore pipeline does not exceed the Maximum Allowable Operating Pressure (MAOP) of 100 barg. Note that this does not imply that a leak will occur if the pressure limitation system fails because the pipeline is designed to withstand the test pressure of 504barg, but the pressure limitation is designed as a mitigation measure to reduce both the likelihood of a leak and the consequences of a leak should it occur. The pressure limitation system has been designed as a very high reliability system which has been independently verified by an accredited body, and this verification has been reviewed by Entec.
Although the LVI was introduced as a safety system it does increase risk (over and above the pipeline risk) in its immediate vicinity because of the presence of additional equipment (pipework, valves and instrument connections). There is therefore a trade-off between risk close to the LVI and the reduction in risk downstream along the remainder of the pipeline. However the QRA has shown that the area of risk above the broadly acceptable level (according to the UK model proposed by ABP) is limited to less than 100 metres and even under worst case sensitivity analysis, the outer zone for land use planning restrictions would extend only to 132 metres from the LVI.

SEPIL have provided a justification of the design based on the availability of high reliability isolation valves which are capable of allowing the passage of pipeline inspection tools (PIGs). Given these concerns then the design of the facility represents the minimum level of equipment necessary to provide the highest level of reliability and allow for maintenance and testing.

Entec recommends that any consent granted should be subject to conditions to ensure that the measures described in the EIS are adopted, a satisfactory regime of testing the valves is in pace and that the method of installing the pipeline across the boundaries of the LVI does not give rise to possible differential settlement.

9.5 Corrib Pipeline Design Basis

Entec finds that the pipeline design is based on the requirements of Irish and International Standards. It has followed the advice of the Technical Advisory Group, supported by analysis of codes by reputable international design companies, to combine aspects from different standards so that the most rigorous requirements have been applied. Entec endorses this approach.

9.6 Other Issues

In the course of the review the following issues have been identified concerning the construction of the tunnel:

- The ground conditions in the sediments and bedrock beneath Sruwaddacon Bay have not been determined along the proposed tunnel alignment; therefore there is uncertainty over the requirement for the Tunnel Boring Machine (TBM) to cope with the interface between sediments (sand and gravels) and the hard bedrock, together with the presence of hard rock inclusions within the sediments. Should the TBM encounter difficulties then the contingency plan is to use intervention shafts, constructed in the Bay, for which no environmental assessment has yet been made.

The tunnelling experts at Atkins (see Report\textsuperscript{9}) are of the opinion that the sampling regime and methods may underestimate the presence of cobbles and larger rock fragments, and that the investigations may not have reached sufficient depths to allow the tunnelling contractors to drive the tunnel at greater depths, but the overall assessment is that the need for surface intervention shafts is “highly unlikely”.

- Concerns have been expressed as to whether vibrations from tunnelling could trigger further land slips on Dooncarton Mountain. Although the vibrations are predicted to be much less than those from heavy traffic at the dwellings along the road the tunnelling vibrations will be continuous. An analysis
of the conditions under which slips are likely together with monitoring of vibrations along the route before the sections nearest to the Mountain are reached would provide additional assurance. A condition is proposed to ensure that vibrations are well below those likely to trigger any landslips or indeed damage to houses. This monitoring would also provide SEPIL with evidence that their activities did not initiate any incidents which may occur due to other causes. Namely:

- Monitoring in the vicinity of housing along the road on both northern and southern sides of Sruwaddacon Bay, noting that SEPIL have demonstrated further attenuation by more than an order of magnitude will occur a further 300 m away from the tunnel route:
- 0.5 mm/s warning level - at the proposed monitoring points, representing dwellings closest to the pipeline route and well above any model predictions but below the thresholds likely to cause damage or the thresholds for human tolerability;
- 2.5 mm/s action level - which should result in immediate mitigation measures;
- 12.5 mm/s the absolute upper limit to prevent damage as proposed by SEPIL following the NRA standard.

Note that the tunnelling experts consulted are of the opinion that the magnitudes of vibration from tunnelling are extremely low and are unlikely to generate adverse impacts within the wider locality.

9.7 Tunnelling

The current proposal to place the pipeline in a tunnel beneath Sruwaddacon Bay satisfies distance separation criteria but raises some questions of feasibility and possible unwanted impacts if problems arise during tunnelling. These can be avoided by design and monitoring of the tunnelling operations.

The outstanding matters for SEPIL to demonstrate are:

1. The TBM specification addresses the key employer requirements with respect to the tunnel construction including:
   - Requirement for a closed face tunnelling machine;
   - Requirements with respect to maintenance of cutter head and TBM. Stating that all maintenance for the TBM and cutter head should be able to be carried out within the TBM;
   - Tool wear indication;
   - Water proofing requirements of the lining;
   - Procedures for the control and monitoring of face support slurry (include salinity in the specification);
   - Procedures for the control and monitoring of grouting operations;
Creating the environment for business

- Obligations placed on the contractor as stated in the EIS;
- Oil and grease leaks within the tunnel should be contained within the lining and along with nuisance water be pumped to the surface. Water disposal systems should be designed to deal with oil and solids. Any such oils should be specified as being biodegradable.
- Design requirements of the shafts and tunnel with respect to allowable differential movement;
- Variation of the tunnel horizontal and vertical alignment within the limits specified in the EIS.

2. The TBM should not be halted for intervention in the vicinity of the ground investigation boreholes to avoid potential for fluid loss during tunnelling through the boreholes sunk along the tunnel centre line which appear not to have been backfilled with cement bentonite grout above rock head;

3. Construction of the shaft and tunnel junctions founded on rock will ensure that any differential settlement is minimised;


9.8 Conclusions of this Report

Therefore Entec concludes that if the pipeline were to be constructed to the design submitted it would be safe in terms of any technical definition of the term. Indeed in many aspects the design exceeds existing good industry practice and would be considered as safe without the additional safety measures. However to achieve the stated performance within the submissions and other Shell documents some conditions are required. Hence, Entec recommends that the Minister could, if he were so minded, consent to the Corrib Application under section 40 of the Gas Act 1976 and Section 13 of the Petroleum and Other Minerals Development Act, 1960 on safety and design grounds, subject to conditions listed below.

The pipeline design and its route are acceptable on the basis of the ABP proposed risk criteria and all other similar criteria used internationally. The ABP proposed criteria for separation based on protection against the worst case accident is not recognised by international codes and standards nor used by other regulators. Nevertheless the proposed design meets this requirement also.

Other matters require clarification are given in the report but would not constitute reasons for withholding a permit to construct. Further information would be required before issuing a permit to operate but this is a normal approach in Safety Case Regimes where there are two separate stages of submissions, pre-construction and pre-commissioning.

Proposed conditions are listed in Section 9.9 (pre-construction) and Section 9.10 (pre-operation).
Absolute safety cannot be guaranteed in any human activity, so it is often suggested that separation can be increased between a hazardous material and people until the risk of harm becomes vanishingly small. Quantified risk analysis is often used to estimate the level of risk, but judgement must be applied to determine what level of risk is vanishingly small or at least generally tolerated. Given a pipeline diameter and pressure the worst case accident is determined and has been calculated in the QRA reports presented by Advantica and DNV. The range of effects is greater than the distance to the nearest dwelling for all pipeline pressures above 100 bar. However, the analysis in all three previous reports on pipeline risks (JP Kenny, Advantica and DNV) agree that risks arising from pipeline leaks and ruptures have been reduced to less than one in ten million per year (JP Kenny) and below one in a thousand million per year (US billion) at the nearest dwelling in the Advantica and DNV reports assuming additional high pressure protection of the pipeline. Entec considers these risk assessments represent the actual risks, based on the assumptions in the analysis, and can be considered accurate to within the limits of current risk analysis techniques (i.e. better than a factor of ten). These estimates would apply for the first four years of operation, following this, the reservoir pressure falls below 100 bara, the consequences of failure would be less and the building burn distance less than the distance to the nearest dwelling. The protection measures also have the advantage that they will reduce the likelihood of accidents affecting areas closer to the pipeline, particularly road crossings (at least one is unavoidable to reach the terminal). By comparison the UK HSE view an individual risk of fatality below one in a million per year as ‘broadly acceptable’ and for land use planning purposes place no restriction on developments (even of high density or sensitive nature) where even the risk of a dangerous dose is less than three in ten million per year (roughly equivalent to a risk of death of one in ten million per year). According to the DNV analysis, the current proposal gives rise to risks less than 1 % of this criterion, i.e. the risks are a hundred times lower at the nearest dwelling.

The pipeline design and its route are acceptable on the basis of the ABP proposed risk criteria and all other similar criteria used internationally. The risks are so low that any significant effort to reduce risk further would not be required under these criteria.

Further, additional conditions beyond the proposed design features already incorporated following the Independent Review by Advantica are not warranted.

The two sets of safety and risk criteria quoted by ABP in their letter of 2 November 2009 are inconsistent, in that:

- The consequence based criteria imply that only a zero level of risk can be tolerated, whereas;
- The risk based criteria recognise that zero risk is not possible but specify that the risk from a pipeline should be extremely low and much smaller than risks from other commonly encountered hazards.

The pipeline as specified, incorporating improvements since the Advantica Independent Review, presents such low risks that further conditions attached to a planning approval are not necessary by international standards on risk criteria, or those proposed by ABP. Similarly re-routing the pipeline is not required by international standards.
9.9 Proposed Conditions for Consent to Construct

The pipeline shall be designed to offshore pipeline code (DNV OS F101) and the onshore pipeline code IS EN 14161 (ISO 13623) supplemented by I.S. 328 and PD 8010, where their requirements are more stringent as detailed in the EIS.

The operator shall ensure that (and provide records or other documentation where appropriate):

1. MAOP of offshore section of pipeline (upstream of downstream valve on LVI) shall be 150 barg.
2. MAOP of onshore section of pipeline (downstream of downstream valve on LVI) shall be 100 barg.
3. Verification of pipeline material quality, construction certificates and current condition.
4. Verification that imposed loads during construction of offshore pipeline did not exceed requirements of other design conditions.
5. Clarification of beach crossing depth of cover (3m cover according to s40 2010 section 2. But scope (4.6.1) states 2m). 2m would be adequate but clearly 3m provides better protection but in any case it is necessary to know the installed depth in order to be able to monitor changes.
6. Verification that all issues arising during design and changes post submission of s40 application have been closed in a satisfactory manner.
7. Approval and verification process for field welding, including certification of welders.
8. Verification process for installation of concrete slab protection, oversight of this and other aspects of pipeline installation where cover or support of the pipeline changes.
10. The methods adopted for tunnelling should follow BS6164; Code of Practice for safety in Tunnelling in the Construction Industry.
11. Approval of method statement for final works in the tunnel following hydrostatic test and visual inspections to ensure that no activities take place which could lead to pipeline or coating damage. In particular the grouting operation does not involve any movement of equipment or moving parts which could impact on the pipe or its coating.
12. Demonstration that Technical Authorities responsible for Safety and Integrity have reporting lines to the corporate board (i.e. Shell International) independent of Asset Management and Operations.

13. Approval of final drainage arrangements at the LVI to ensure any surface contamination is not drained directly to the sea.

14. Temperature monitoring at the downstream side of the LVI confirmed as in Figure 5.1 (Appendix Q4.4).

15. Monitoring of vibrations from tunnel boring and the construction of access pits should be carried out at the locations proposed by Shell, on either side of Sruwaddacon Bay and near both Glengad and Aghoos. A warning level should be set at 0.5mm/s ppv, an action level should at 2.5mm/s ppv (to initiate mitigation) and a stop level at 12.5mm/s ppv to ensure no damage to property and levels well below any regarded to initiate ground instability.

16. SEPIL should specify to DCENR the arrangements for liaison with landowners as detailed in the Advantica and TAG recommendations, particularly with regard to ensuring no interference with the pipeline, umbilicals, markers, marking tape and cathodic protection. These arrangements should be agreed with DCENR.

9.10 Additional Requirements before Commissioning

1. The terminal Safety Case (SEPIL’s own requirement) shall be expanded to include the pipeline, LVI and offshore systems identified in the s40 application as being part of the safety assurance for the pipeline, LVI and terminal.

2. Identification and evaluation of major hazards — adoption and implementation of procedures for systematically identifying major hazards arising from normal and abnormal operation and the assessment of their likelihood and severity (as covered in Appendix Q6) should be linked to a demonstration of the adequacy of safety controls (as would be required for in the Safety Report for a top-tier COMAHDS site). Although the terminal is only lower tier SEPIL have undertaken to provide their own comprehensive Safety Case, covering the pipeline as well as terminal, and this demonstration should be included prior to operation.

3. Means of detection of unsafe conditions to be included in the Safety Report and together with the monitoring (see Appendix Q3.1 onshore EIS and Section 7.2 of this report and Section 11 of DNV OS F101 for offshore) and audit schedules. This includes the sensitivity of the leak detection systems and the leak rates at which they are each capable of giving a reliable alarm.

4. A process and schedule for testing all components of the shutdown system and pressure limitation systems shall be established which conforms with the assumptions on testing in the FTA and SIL Verification reports.
5. Procedures and schedule for integrity monitoring of the LVI by-pass pipe-work and equipment need to be included in the monitoring, inspection and testing schedule.

6. Monitoring of safety indicators shall include leading indicators to ensure the preservation of process safety standards and these should include rectification of faults and adherence to the testing or inspection schedules to assure safety system reliability and integrity.

7. Verification that all issues arising during design and changes post submission of s40 application, including changes introduced during construction have been closed in a satisfactory manner.

8. SEPIL shall agree criteria for the review of its Safety Case to allow for incremental change to Plant, Procedures or People as well as “significant” modifications (or step changes) and the five yearly reviews under COMAHDS. Note that accidents occurring elsewhere may give rise to a change in knowledge which would affect the safety case.

9. SEPIL shall demonstrate that there is a system to ensure that core safety management competencies and technical knowledge are developed and retained.

10. Process safety shall be managed with sufficient independence to avoid bias and assist in resolving conflicts.

11. An emergency response plan should be complete and have been subjected to test by at least one emergency exercise.

12. If the umbilicals and water discharge pipe are protected with a narrow concrete slab then a detailed repair method statement needs to be developed in advance to ensure that excavation for repair of these lines does not damage the main pipeline coating.
Appendix A
Corrib Onshore Pipeline Route Map
Appendix B
Issues Raised in this Review
Issues Raised in this Review

Appendix B

Section 1 Issues Raised Before Oral Hearing (Answers received by 31/08/2010)

Section 2 Issues Arising from Technical Review (non-Planning Issues)
<table>
<thead>
<tr>
<th>Ref</th>
<th>Subject</th>
<th>Issue</th>
<th>Rank</th>
<th>Proposed Action / Response</th>
<th>Potential Action</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1. Tunnel</td>
<td>Construction – do tunnel boring machines exist which meet the</td>
<td>2</td>
<td>Additional Information</td>
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<tr>
<td></td>
<td>Construction</td>
<td>specifications given Page M1-13? Can the TBM manage all the</td>
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<td>Slurry TBM tendering for new build underway. SEPIL identified several examples of similar mixed conditions</td>
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<td>foreseeable ground conditions (including possible igneous intrusions,</td>
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<td>including Ems Tunnel 4,015 m long, 3 m diameter Yes. A mixed shield slurry type TBM has been chosen as</td>
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<td>large boulders etc) over the 4.9km length, what compromises need</td>
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<td>being the most versatile TBM type presently available to cope with the expected ground conditions. These</td>
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<td>to make and what are the associated risks, - examples of successful</td>
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<td>are ranging from gravel, medium and fine sand as well as rock of considerable strength (up to &gt; 250</td>
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<td>TBM’s on other projects in similar ground conditions would assist?</td>
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<td>MPa). Bidders for tunnelling contract currently being evaluated have confirmed the suitability of Slurry TBM</td>
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<td>use for the Corrib project.</td>
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<td>The tools of the TBM cutter head used to excavate the soil or break the rock are fitted to the cutter head</td>
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<td>by bolted connections. This allows regular inspection and replacement (if required) by means of compressed</td>
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<td>air work, a task that is commonly executed for long distance tunnelling projects. This way it is ensured,</td>
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<td>that mining and rock cutting will be equally efficient over the complete length of the tunnel.</td>
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<td>Projects that have been completed with a slurry type TBM include:</td>
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<td></td>
<td></td>
<td>Germany</td>
<td>Sewer tunnel Berlin</td>
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<td>Sand, Stone, Marl</td>
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<td>Europipe</td>
<td>tunnel</td>
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<td></td>
<td>Clay, Marl, Sand</td>
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<td></td>
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<td></td>
<td>Han River</td>
<td>Rock, Gravel</td>
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<td>Korea</td>
<td>Cable tunnel Seoul</td>
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<td>Rock, ground water</td>
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<td></td>
<td>China</td>
<td>Pearl River</td>
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<td>Weathered rock, Loam</td>
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<td>Sand, Gravel</td>
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<td></td>
<td>East-West-Pipeline</td>
<td>Weathered Rock, Ground water</td>
</tr>
</tbody>
</table>

Confirm TBM specification meets conditions found in detailed survey and contractor and staff have experience of these conditions.
| 2 | Tunnel Construction | Can the cone crusher manage the range of rock strengths that can be foreseen? - range of rock strengths and capabilities of crusher would assist | 2 | Additional Information | Upper surface of bedrock is weathered old metamorphic sandstone some rock strength up to 250 MPa but most less than 100 MPa. Access available to replace if necessary. Yes. The TBM will be equipped with tools to effectively excavate lose soil and cut rock and boulders. Only those boulders or stones that are cut small enough to pass through the openings in the cutter head will be further diminished in size by the rock crusher. Due to the abrasivity of the soil it is envisaged that also the cutting tools of the crusher will require maintenance and/or replacement. For this purpose a jaw crusher will be used on the TBM instead of a cone crusher. The jaw crusher is located in a separate chamber behind the cutter head, which can be closed to allow safe access under compressed air without the need for a full face compressed air intervention. | Confirm TBM specification |
| 3 | Tunnel Construction | What ‘exceptional circumstances’ will halt the TBM and how are Shell planning to investigate that these have a very low risk of being present? | 2 | Additional Information | SEPIL has identified two reasons that could halt progress: Large peat layer causing settlement Blockage by large metallic object or large extremely hard rock Based on the information of the geotechnical and geophysical investigations to date there is no evidence of any circumstances that would lead to a complete stop of the tunnelling works. Theoretically the following scenarios could result in a complete stop of the works, in case it should not be possible to resolve them from inside the TBM or by means of compressed air work at the face of the TBM: - Soft peat layers of significant thickness. These layers would not provide sufficient bearing capacity for the weight of the TBM. However, there has not been any evidence, that such layer will be encountered at the depth of the tunnel alignment. In addition, calculations have shown that the weight of the TBM is not significantly higher than the soil that will be excavated along the alignment. This means that there will be no significant net vertical downward loading on the peat layers. In addition the peat layers have already been consolidated due to the load of the current overburden. As such there will be no excessive settlement of the TBM. - Large man made (steel) obstacles or large tree logs that could not be handled from inside the TBM. As stated | Confirm by detailed survey that these do not exist. Reviewed by third party – low likelihood |
Above, information of the geotechnical and geophysical investigations to date geophysical show no evidence of any such obstacles.

4 Tunnel Construction
Are there any risks of 'blow out' of the bentonite from the tunnel face or grout from the annulus onto the estuary bed - how will the pressures be designed and monitored - what impact could this have on the estuary - is there a requirement for monitoring the estuary bed?

2 Additional Information
Slurry and counter-pressure air compressor earth plus hydrostatic regulator adjust pressure – alarm at low level + flow meter for mass balance calculation and alarm. Maximum release 7m³
Grout fill annulus between bore and lining from small portable tanks 2-2.5 m³ capacity. The pressure gradient would drive flow to the front of machine (TBM) The volume of grout required is 1.8 m³/segment.
Impact of release is said to be assessed in EIS Chapter 12 but no specific mention of bentonite slurry is made.

In order to prevent a break-out of circulating bentonite slurry or excessive settlements at the surface the pressure and flow of the bentonite slurry is controlled at the soil face in front of the TBM. For this purpose, a slurry type TBM will be deployed, allowing an individual adjustment of slurry flow rate and pressure.

The pressure of the slurry at the soil face will be controlled by a compressed air cushion inside the TBM, which allows for rapid changes of the slurry volume in mixed ground conditions, while automatically maintaining a pre-set face support pressure (slide). The pressure at the soil face will be continuously measured, monitored and alarmed when limit values are met. The maximum allowable and minimal required slurry pressures have been calculated at critical locations. For the tunnelling operation, detailed slurry pressure calculations will be carried out for any position along the alignment.

The slurry volume inside the working chamber of the TBM will be continuously monitored and the flow will be shut down automatically in case a low or high level alarm is triggered. In addition to monitoring the slurry pressures, feed and return lines of the slurry system will be equipped with flow meters, continuously measuring the flow of slurry to and from the excavation chamber. Thus, in the unlikely event of a slurry break-out due to unforeseen ground conditions, only a limited amount of slurry suspension may be lost before the system is shut down and mitigation measures can be deployed.

The injection of grout to the tunnel annulus is controlled in a similar manner as the slurry flow. The risk of a grout breakout however, is substantially less than that of slurry, since on the one hand a much smaller amount of grout is available at the TBM (approx. 2 m³ at any time). Also, it is very unlikely that the grout would break out to

2 Additional Information
Verify measurements, alarms and shut-off provided.
the surface, since it will follow the path of least resistance along the TBM outside to the front of the TBM, where it will enter the slurry system and be fed back to the separation plant. Since the cutter head is slightly larger in diameter than the TBM shield diameter, there will be a small bentonite slurry filled annulus between the front of the TBM and the rear tail skin at which the grout is injected. If the grout was injected at a pressure significantly higher than the slurry pressure, it would not break through the soil, but find its way along the TBM to the front.

### 5 Tunnel Construction

**The final mitigation in case of an obstruction to tunnelling is intervention from the surface with a sheet piled pit with coffer dam page M1-13 – has the impact of this been assessed?**

2 **Additional Information**

- See EIS Chap 5, 12, 13, 14 App P
- Yes, see Chapters 5, 12, 13 and 14 of the Onshore Pipeline EIS and associated technical reports (Appendix)

**Assessment**

- not complete
- but likelihood of activity very low

### 6a Tunnel Construction

**A - potential settlement of tunnel / entrapment of TBM by subsidence**

2 **Additional Information**

- Peat layer identified up to 700 mm thick could be throughout Bay at 100-200mm thick.
- But weight of TBM and tunnel replace soil and so peat loading remains similar after construction (17 kN/m$^3$ sediment cf fill with grout and concrete 12 kN/m$^3$ + steel pipe)

  The geotechnical and geophysical information available at the time of application was considered sufficient to assess the feasibility of the tunnel construction. The tunnel boring machine (TBM) has been specified for the construction tenders – choosing the most versatile TBM type presently available for this type of geology.

  The most significant risks to a tunnelling project of this type that would require a surface intervention have been outlined in Item 3 above and there is no evidence contained in the ground investigation data that would indicate the presence of such a situation. Further detailed geotechnical investigations are underway and on-going review of this data confirms the original ground investigation data.

  The tunnel alignment under the bay is essentially within superficial sediments that are typical of estuarine deposits, and which comprise a relatively consistent material comprising dominantly sand and gravel. The presence of igneous intrusions within the bedrock is therefore not considered an issue for the tunnel alignment under the bay (see below for further discussion). Notwithstanding this, the TBM will be equipped to mine through the rock expected in the bay area.

  Based on geotechnical review of SruwaddaconBay, boulders where present are more likely to be encountered at the interface of the bedrock and superficial sediments. Where there is a significant cluster of boulders present (though this not evident from the ongoing investigations) then this may affect the progress rate of

**Monitoring during construction – calculations and survey show not likely to be an issue.**
the tunnelling works, but as described above the TBM will be equipped to mine rock and boulders of the type to be expected within the bay.

The presence of possible igneous intrusions was indicated by the geophysical survey within the bedrock under the bay. These intrusions within the bedrock under the bay will not be encountered by the tunnel as the tunnel will be located within the bay sediments. At either end of the tunnel alignment the tunnel over short lengths is within rock (App M1A, drawings 401 to 404). Whilst igneous intrusions within the rock sections of tunnel cannot be discounted the effect on the works would not be considered significant given the short length of intrusions and the fact that the TBM will be equipped to mine through such rock.

The ongoing detailed geotechnical site investigation campaign is being conducted to verify the information that has been obtained by the earlier geotechnical and geophysical investigations. The ongoing investigation comprises further intrusive techniques which includes rotary and percussive boring and cone penetration testing.

| 6b Tunnel Construction | B – is knowledge of ground conditions adequate to ensure that tunnel can be constructed without any remedial action from the surface? Normally prefer to construct tunnel through uniform layer – could be problems at surface of bedrock or if igneous inclusions encountered. Page M1-13 | 2 Additional Information | Investigation going ahead boreholes & rotary drill into bedrock. Current penetration test – towards base organics and weathered rock. Sediments consistent and igneous inclusions are in bedrock. Bedrock on land sections of tunnel strength of most <100 MPa. Tunnel alignment based on geophysics line – totally within sediments under the Bay rises through bedrock at each end. Survey will give maximum 150 m spacing boreholes closer when going across interface which is critical zone
  
The ongoing investigations will also provide a verification of the interface between bedrock and sediments. Where the TBM will leave/enter the bedrock the investigations spacings are have been decreased in order to optimize the tunnel alignment at the interface of bedrock/ sediments (within the corridor specified in the application).

It is not uncommon to select an alignment that does not follow a uniform layer. For the tunnel alignment decisions have been made to align the tunnel within the sediments for the majority of the tunnel length in order to minimize the overall impact of the project by reducing the execution time to a minimum. These sediments comprise a relatively consistent material that comprises dominantly sand and gravel. A deeper alignment within bedrock over a larger distance would significantly affect the project duration and additionally require more frequent cutting tool changes under compressed air and at higher pressures. The risks associated with these tasks are therefore also minimized by the choice of shallower alignment.

Investigation now adequate if tunnel alignment remains as stated. If contractor wishes to take tunnel to a greater depth then additional data required.
<table>
<thead>
<tr>
<th>7a</th>
<th>Tunnel Construction</th>
<th>Vibration M1-15 the tunnel boring will be a continuous operation whereas traffic vibration will be intermittent is there any significance in the duration of a vibration rather than its intensity with respect to ground stability?</th>
<th>2</th>
<th>Additional Information</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Landslide risk due to vibration from tunnelling is assessed as being negligible</td>
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<td>Road traffic considered in 9.2.3.2</td>
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<td>Susceptible areas on Dooncarton Mountain 350m from road where section 9.3.1.3 gives vibration due to traffic at 0.175 - 0.275 mm/s</td>
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<tr>
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<td>Tunnel vibrations (sec 9.4.4) 0.02 mm/s at 240m from tunnel where the assessment uses highest ppv infinite duration</td>
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<td>The vulnerable slopes are 800m SW of tunnel works The typical safe range 15-20mm/s independent of soil type to avoid vibration induced instability so predicted vibrations are more than three orders of magnitude lower (a thousand times lower) than the range of concern.</td>
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<td>App M2 other contributors</td>
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<td>Assessment of vibration affects on ground instability, particularly on Dooncarton Mountain, would take into account the greatest magnitude of vibration (measured in ppv or g) at the site of sensitive slopes irrespective of the duration of the vibration event. In this regard, the duration of the vibration would not be considered significant.</td>
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<td>Ground vibration produce by road traffic are unlikely to cause perceptible structural vibrations in properties located near well maintained and smooth road surfaces. As such, road traffic vibrations can be largely minimised by maintenance of the road surface (EIS vol 1 9.2.3.2).</td>
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<td>Baseline vibration readings taken at roadside locations were in the range 0.175 to 0.275 mm/s (EIS vol 1 9.3.1.3).</td>
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<td>Notwithstanding the above, with respect to the vibration affect from tunnel works on the surrounding slopes:</td>
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<td>(1) The calculated vibration (in peak particle velocity, ppv) induced by tunnelling at a house 240m distance from the tunnel has been determined as 0.02mm/s (EIS, vol 1, 9.4.4). The more sensitive steeper upper parts of the Dooncarton Mountain slopes where previous failures are located are some 800m distance from the tunnel. (The nearest main road is about 350m distance from the sensitive steeper upper slopes of Dooncarton Mountain)</td>
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<td>(2) At a distance of 800m, the ppv would be notably less than 0.02mm/s, which would not be considered significant. For comparison purposes, a door slamming within a room with a wooden floor would generate a ppv of about 2mm/s.</td>
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<td>Ambient vibrations will be reported when drilling boreholes</td>
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<td>Proposed conditions to prevent damage to houses and then by inference to present undetectable vibration at vulnerable slopes.</td>
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<tr>
<td>7b</td>
<td>Tunnel Construction</td>
<td>Piling of access chambers (launch and reception shafts) will also create noise and vibration. Has this been assessed? Note that sheet piles may not penetrate bedrock unless it is excavated – bored or secant piles may be required</td>
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<td>2 Additional Information</td>
<td>Evidence presented shows piling could be more significant than tunnelling but within tolerable limits.</td>
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<tr>
<td>7c</td>
<td>Tunnel Construction</td>
<td>Vol 2 Book 5 M4 Employees will be familiar with tunnelling in similar conditions – where will such staff be recruited and how does it mitigate the risks?</td>
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<td>2 Additional Information</td>
<td>Part of PQQ process and a contract requirement</td>
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<td>Yes this is assured through tender prequalification procedures which have confirmed that potential contractors have the necessary experienced staff.</td>
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<tr>
<td>8</td>
<td>Debris Channel Crossing</td>
<td>How far has the design of concrete slabs progressed to protect the pipeline from impact and erosion where it crosses the debris channels? What is the process for determining horizontal spread of the slabs and has the need for vertical support / &quot;toe&quot; walls both up and downstream to protect against scour under the slabs? M2 page vii M” page 178 refers to JPK drwg</td>
<td></td>
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<td></td>
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<td>2 Additional Information</td>
<td>Channel 2 debris at head of channel not in downstream, flatter areas near pipeline route.</td>
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<td></td>
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<td></td>
<td>Slab spans 2.15 m either side of pipe &amp; services DG0702 below cleaned bottom of channel bears on intact ground depending 1m inspection of load bearing soils investigated. Construction will be supervised to ensure slab is founded on stable layer.</td>
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<td>Photographs of channel 2 has been provided.</td>
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<td>Channel 2 is essentially a field drain boundary comprising an upstanding bund and drainage ditch. The ditch is about 1m wide and infilled with natural vegetation. Depth of channel is estimated at less than 1m. Based on the size and condition of the channel it appears unlikely that there was any significant erosion and incision of the channel bed or passage of debris along the channel during the 2003 landslide event. The topography is also relatively flat at Critical point for inspection during construction.</td>
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<td></td>
<td>Some judgement required during installation needs to be covered by 3rd party verification.</td>
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<tr>
<td>Corrosion Protection</td>
<td>Can the CP operate effectively in fully grouted tunnel? 4.3.1 says yes but is this system the same as used in grouting sleeves at road crossings etc?</td>
<td>Additional Information</td>
<td>Monitoring as proposed</td>
<td></td>
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<td>9</td>
<td></td>
<td>JP Kenny &amp; Dr Steve Patterson confirmed that there was no interference on the Ems pipeline which is 38” diameter grout filled there will be monitoring inside the tunnel to ensure the effectiveness.</td>
<td></td>
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<tr>
<td>10</td>
<td>Where is the interface between onshore (impressed current) and offshore (sacrificial anode) protection? What</td>
<td>Additional Information</td>
<td>Solution is appropriate but</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Holloway consultants report fewer isolation joints better – key is to balance onshore &amp; offshore CP to avoid using up offshore</td>
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</table>
sacrificial anodes. Monitoring up to edge of beach current balance checked see Appendix Q5 PIMS - bracelets some distance offshore checked yearly). Intelligent Pig after 0-8 months initial run, checking aqueous/iron counts dependent ~ 5 yearly pigging. Continuous corrosion monitoring at Higher Temperature upstream end (near well heads).

The onshore impressed current system will be monitored through checks on the transformer/rectifier up-time and output, standard test posts and coupon polarisation probes, close interval potential surveys (CIPS) and direct voltage current gradient (DCVG) surveys. The cathodic protection design for the section of onshore pipeline in the tunnel is still to be defined but will include cathodic protection monitoring facilities.

Particular attention is required for the interface between the offshore and onshore pipelines to ensure that there is no current drain from the offshore pipeline anodes to onshore. Following a detailed assessment it was concluded that the installation of an isolation joint between the offshore and onshore pipeline was not necessary, but potential monitoring coupons/probes will be installed close to the LVI to allow potentials to be accurately measured. This satisfies the recommendation of the Advantica Independent Safety Review (see section Q3.1 of this Appendix).

An isolation spool is fitted between the onshore pipeline and the Terminal facilities and this will be subject to monitoring to assure isolation and absence of any degradation.

Balancing of the offshore and onshore CP systems is needed to prevent one system becoming a drain on the other with current flowing say from the offshore anodes to protect the onshore section or vice versa.

The main objective of balancing the offshore and onshore pipeline potentials is to ensure that the offshore CP system does not protect the onshore section, as if this occurs it could result in early depletion of the sacrificial bracelet anodes installed close to the landfall.

In order to monitor CP potentials along the onshore pipeline section, test stations will be installed at regular intervals, including one installed very close to the offshore/onshore interface.

Permanent reference electrodes and coupons will also be installed at each test station that will allow measurement of pipeline on and coupon instantaneous off potentials.

To balance the offshore and onshore pipeline voltage potentials and prevent the passage of CP current onshore, first the voltage potential imposed from the offshore anodes onto the onshore pipeline (with all onshore CP switched off) is measured. Then the
The level of potential needed from the onshore CP system to make the onshore system slightly more negative than the offshore voltage potential is calculated. This means that a small current will flow from the onshore system to the offshore pipeline, and not vice versa. Prior to commissioning of the permanent impressed current CP, this will be achieved by adjusting the current output of the temporary, sacrificial magnesium anodes (with variable resistors installed within test stations). Once the permanent CP system has been commissioned, the current output from the Transformer Rectifier is adjusted to achieve the same objective and then set to automatic current control.

<table>
<thead>
<tr>
<th>11</th>
<th>Pipeline and service Repair in Tunnel</th>
<th>2</th>
<th>Additional Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Repair: If any defects are discovered after filling the tunnel with grout then how would remedial measures be undertaken? Defects might include:</td>
<td>100% weld and 504 barg hydrotest and coating checked before grouting commences. 95% fill tubes stay in situ after grouting so no movement of equipment during process. Potential defect – internal corrosion only (ph of grout inhibits external, pressure test should eliminate material defect and tunnel provides protection against ground movement and external impact.) Repair method would be to insert smaller diameter pipe within the existing line which would not constrain field production if it occurred some years after start, which would be expected from internal corrosion due to corrosion allowance being included in design and very slow rates expected.</td>
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<tr>
<td>• Higher than anticipated internal corrosion;</td>
<td>It is unlikely that defects will be discovered after filling the tunnel with grout as before grouting the pipe in the tunnel will be hydrotested to 504barg, the coating will be checked and there will be UT testing of the welds.</td>
<td></td>
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<tr>
<td>• Manufacturing defects / inclusions growing post commissioning;</td>
<td>1. Higher than anticipated internal corrosion; Corrosion modelling and subsequent corrosion testing under simulated onshore pipeline conditions indicate very low internal corrosion rates (&lt; 0.02 mm/yr) even without corrosion inhibition. Should higher than anticipated corrosion occur then this will be assessed using the damage assessment map given in Appendix Q4.8 of the EIS. This map shows that relatively large areas of corrosion with a depth of 10mm can be safely tolerated. Smaller areas with an approximate depth of 20mm can be tolerated. This damage would be discussed and agreed with the regulatory authority should significant corrosion occur. If the corrosion were to become intolerable then the envisaged repair would be to pull a new smaller diameter 16&quot; pipeline through the 20&quot; pipe</td>
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<tr>
<td>• Damage to pipe coating during the grouting operation;</td>
<td>2. Manufacturing defects / inclusions growing post commissioning The linepipe has been subject to extensive testing and inspection during manufacture. The girth welds in the pipeline will also be</td>
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<td></td>
<td>Explain that grout will be injected via fixed pipes that will not be removed. There is a scheme described verbally for pipe repair (via insertion of smaller pipe) Need confirmation of method statement by contractor.</td>
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</tbody>
</table>
subject to extensive testing and inspection during fabrication including automatic ultrasonic testing. This is a very effective technique for discovering even small defects. All defects which do not meet the strict specification requirements will be repaired.

Furthermore the completed pipeline will be subject to a hydrostatic test at 504 bar which is considerably above that required for a design pressure of 144 bar. This test will confirm the absence of any significant defects. There are two generic types of weld defects, planar and volumetric. Volumetric defects are not prone to growth and if within code requirements can be considered benign. Planar defects such as lack of fusion require some form of mechanism such as fatigue to initiate growth. Our assessments indicate no credible growth mechanism such as fatigue in the pipeline. Given the level of inspection and hydrostatic test pressure and the absence of any growth mechanism such as fatigue there is negligible risk of defect growth post commissioning.

3. Damage to pipe coating during the grouting operation
A thorough inspection of the coating system will be carried out following installation and any damage will be repaired. Once installation is complete the tunnel will be filled with a cementitious grouting compound. The grout typically has shrinkage of 2 to 5% and normally takes over 24 hours to harden. As it shrinks on to the pipe it will not damage the coating and will form a protective layer which will, to a large extent, exclude free water and oxygen. The grout also has a pH of 12 which is alkaline and would effectively passivate the steel against corrosion if exposed to water. The grout is conductive which will allow the pipeline cathodic protection system to protect any exposed steel should water penetrate the grout.

### Additional Information

<table>
<thead>
<tr>
<th>12</th>
<th>Isolation Valves</th>
<th>Q2 6 page 23. In the UK offshore industry the HSE require an operator to specify an “acceptable” passing rate for tests of isolation valves. How will the operator ascertain the acceptability of tests on the isolation valves? Standard passing rates have been quoted in the calculation are these the maximum acceptable? SEPIL sensitivity analysis shows higher rates would be acceptable.</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Additional</td>
<td>Subsea 14.7 scf/min API 14b No sand / proppant production / can replace valves. LVI HIPS Valve App Q4.5 p33 0.25 mmsec?d removed every 5yrs with terminal shutdown. DEGV test capability Always 2oo3 barriers available – 2 valves leaking shut down rates to be defined SEPIL will ascertain the acceptability of tests on the isolation valves via our Verification system and the associated performance standards – they are based on detection of pressure build-up &amp; decay during pressure tests. A number of passing rates have been used, and a number of cases developed to demonstrate the potential for pipeline pressure to increase due to valves passing. For a more detailed analysis, please see section 4 in Appendix Q4.5 (The question is based on detection of pressure build-up &amp; decay during pressure tests.</td>
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</table>

There will need to be testing and monitoring of the performance of isolation valves. Whereas a degree of “leakage” may be acceptable the concern is that this should not be relaxed later in the pipeline life to render the
<table>
<thead>
<tr>
<th>Q6.4</th>
<th>ORA</th>
<th>Q6.4 Section 6.4 identifies land slide debris risk but has not included it in discussion analysis. Given additional design measures proposed would expect a justification of those protection measures.</th>
<th>Q6.4 Section 6.4 identifies land slide debris risk but has not included it in discussion analysis. Given additional design measures proposed would expect a justification of those protection measures. See answer to Q8 above. Debris impact risk negligible because even flow of debris down water channels has not reached pipeline route. Extent of protection proposed will give adequate protection ok. Clarification has been provided in relation to the issue of landslide risk and mitigation at watercourse crossings. Accepted</th>
</tr>
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<tbody>
<tr>
<td>Q4.5</td>
<td>Galvanic App</td>
<td>The tubing in the control system is fabricated from stainless steel (austenitic or duplex) throughout and there are no significant galvanic couples. The termination assemblies (UTA) and subsea distribution units (SDU) are fabricated from carbon steel but are protected by coating and cathodic protection. All metallic components in the control system are electrically bonded and the cathodic protection system will ensure that no galvanic corrosion will occur in the system including couplings. Electrical continuity checks on subsea control systems prior to installation to ensure that all metallic components are electrically bonded were carried out. During operation regular checks will be made to ensure that the cathodic protection system is functioning as intended. Galvanic corrosion in subsea control systems is not common.</td>
<td>Galvanic App Q4 fail close. Tubing ss term uta terms cs but protected – continuity bonding checks during commissioning. The tubing in the control system is fabricated from stainless steel (austenitic or duplex) throughout and there are no significant galvanic couples. The termination assemblies (UTA) and subsea distribution units (SDU) are fabricated from carbon steel but are protected by coating and cathodic protection. All metallic components in the control system are electrically bonded and the cathodic protection system will ensure that no galvanic corrosion will occur in the system including couplings. Electrical continuity checks on subsea control systems prior to installation to ensure that all metallic components are electrically bonded were carried out. During operation regular checks will be made to ensure that the cathodic protection system is functioning as intended. Galvanic corrosion in subsea control systems is not common. Galvanic App Q4 fail close. Tubing ss term uta terms cs but protected – continuity bonding checks during commissioning.</td>
</tr>
<tr>
<td>13</td>
<td>Page 44 use of 58mm diam hole to represent 20 -80 mm range is not conservative under all assumptions. 2 Additional Information</td>
<td>Representative size of EGIG – not affecting hazards at nearest houses and negligible impact on risk. Verified by taking rule of thumb that hazard range varies with square of diameter.</td>
<td>Representative size of EGIG – not affecting hazards at nearest houses and negligible impact on risk. Verified by taking rule of thumb that hazard range varies with square of diameter.</td>
</tr>
</tbody>
</table>

upon Appendix Q2 – but this is only a summary of the work that has been performed and presented in Q4.5. Further information on testing is also given in Appendix Q4.5 (see Page 26 in this Appendix, Section 4.2.5: Valve In Situ Testing Regime). The acceptable leakage rates for A) the subsea valves are determined from the Well Integrity Management System. This sets the acceptable leak rate at 14.7 scfm. Note: see page 31 for the absolute worst case scenario where all of the subsea valves are leaking at their maximum allowable leakage rate as per testing (highly unlikely). This results in a period of 80 days for offshore pipeline to increase to its MAOP. B) the acceptable leakage rates for the HIPPS valves and the 20” DEGV at the LVI will be based upon the applicable performance standard for pipeline isolation valves. This will ensure that the maximum acceptable rate will be lower than the absolute worst case sensitivity (which is stated one page 33, indicating it would take approximately 10 hours for the onshore pipeline to reach its MAOP with a leakage rate of 0.25 MMSCFD).
| Q4.7 s4.4.1.1 where are temperature sensors located? | 2 | Additional Information | Just downstream and about 1 km downstream, i.e. upstream of transition to higher minimum temperature specification. The temperature sensors are located at the wells, at the LVI and, at the point where the design temperature of the pipeline changes from -20°C to -10°C, i.e. 1150m downstream of the LVI. | OK |

| Stone Road Construction Method: Does the detailed specification refer to choice of backfill to ensure no damage to pipeline or coating | 1 | Clarification | Yes | OK |

| Tunnel Construction | 1 | Clarification | See 7b | HOLD |

| Pipeline Safety Management Q1 7.1.2 Building Proximity Distance is not normally a distance from dwellings but is the distance within which no building activity is allowed to protect the pipeline. However in the case of thick walled pipelines with a low design factor and where the risk can be shown to be below 1x10^-6 per year, the separation from occupied dwellings may be reduced to the BPD – see PD 8010. See also App Q6.2 p1 3rd & 4th bullets. | 1 | Clarification | The applicant should make this distinction clear. Our understanding is that for the design stage, which is stage we are at, the purpose of the Code based Building Proximity Distance (BPD) is to define the distance from existing normally occupied dwellings. It is when the pipeline is in operation that the BPD can be used to define the distance within which no building activity is permitted (refer also to Land Use Planning clarifications provided below). For most pipelines, including the Corrib onshore pipeline, the 1 x 10^-6 distance is considerably less than the Code based BPD. | Evidence read by Jane Haswell indicates Entec interpretation correct. |

<p>| Pipeline Safety Management Q1 7.3 There are three risk levels quoted by the UK HSE, these differ from the risk levels used in Land Use Planning advice by the HSA, who use 1x10^-7 for the outer zone but expressed as risk of fatality not dangerous dose. | 1 | Clarification | The applicant should make this difference clear. Our remit in carrying out the QRA was the content of the letters from the Board which made no reference to HSA criteria or, in fact, mentioned the term “Land Use Planning”. As stated in the QRA document: &quot;An Bord Pleanála’s letter of 29th November 2009, Page 3, item (j) requests: (j) Provide details separately of the inner zone, middle | Correct – the HSA has no remit for public safety (except for duties as the CA under COMAHDS which do not apply to pipelines). The |</p>
<table>
<thead>
<tr>
<th>No.</th>
<th>Category</th>
<th>Question</th>
<th>Clarification</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>19</td>
<td>LVI</td>
<td>Q2 2.1.3 does not make it clear that the mainline isolation valve is to be a special type that effectively provides the “Double Block and Bleed” level of protection.</td>
<td>Appendix Q2 is an overall summary of the technical aspects presented in the various Appendices comprising Appendix Q. The detail of the type of valves incorporated in the LVI is included in Appendix Q4.3 Section 5.1. The 20” mainline isolation valve and the 16” and 4” isolation valves are all double expanding gate valve types. It is agreed that these valves effectively provide a level of isolation that is equivalent to a double block and bleed arrangement. However, for clarity we have not used the term double block and bleed as it implies use of two valves with an independent bleed valve whereas the DEGV is a single valve.</td>
<td>OK – however the intent is the same as DBB in that isolation can be verified by monitoring the section between the valves.</td>
</tr>
<tr>
<td>20</td>
<td>Pipeline Integrity Management</td>
<td>Q2 9 Legislation does not give any assurance of integrity but can specify that the assurance process can take place. The operator must accept responsibility for the calculations, quality of manufacturing etc.</td>
<td>Appendix Q2 is an overall summary of the technical aspects presented in the various Appendices comprising Appendix Q. The detail of the type of valves incorporated in the LVI is included in Appendix Q4.3 Section 5.1. The 20” mainline isolation valve and the 16” and 4” isolation valves are all double expanding gate valve types. It is agreed that these valves effectively provide a level of isolation that is equivalent to a double block and bleed arrangement. However, for clarity we have not used the term double block and bleed as it implies use of two valves with an independent bleed valve whereas the DEGV is a single valve.</td>
<td>OK – however the intent is the same as DBB in that isolation can be verified by monitoring the section between the valves.</td>
</tr>
<tr>
<td>21</td>
<td>Pipeline Integrity Management</td>
<td>Q4.5 Table 2.2 shows 6 layers of protection but they are not all independent.</td>
<td>Appendix Q2 is an overall summary of the technical aspects presented in the various Appendices comprising Appendix Q. The detail of the type of valves incorporated in the LVI is included in Appendix Q4.3 Section 5.1. The 20” mainline isolation valve and the 16” and 4” isolation valves are all double expanding gate valve types. It is agreed that these valves effectively provide a level of isolation that is equivalent to a double block and bleed arrangement. However, for clarity we have not used the term double block and bleed as it implies use of two valves with an independent bleed valve whereas the DEGV is a single valve.</td>
<td>Covered in reliability assessments</td>
</tr>
<tr>
<td>22</td>
<td>Pipeline Integrity Management</td>
<td>Q4.5 Hydrate plug removal strategy, is it necessary to depressurise upstream of a plug, if so can SEPIL explain how?</td>
<td>Appendix Q2 is an overall summary of the technical aspects presented in the various Appendices comprising Appendix Q. The detail of the type of valves incorporated in the LVI is included in Appendix Q4.3 Section 5.1. The 20” mainline isolation valve and the 16” and 4” isolation valves are all double expanding gate valve types. It is agreed that these valves effectively provide a level of isolation that is equivalent to a double block and bleed arrangement. However, for clarity we have not used the term double block and bleed as it implies use of two valves with an independent bleed valve whereas the DEGV is a single valve.</td>
<td>OK</td>
</tr>
<tr>
<td>23</td>
<td>Testing Shutdown</td>
<td>Q4.5 s 4.2.5 Testing Regime a more complete description / procedure will be needed and a demonstration of how</td>
<td>This is required</td>
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<td>24</td>
<td>Reliability</td>
<td>Q4.6 critical to reliability of pressure control. Can SEPIL state who the independent verification authority was and the qualification of the personnel involved? Summary does not introduce terminology of IEC 61508 / 61511 but is in effect stating that systems are better than SIL3</td>
<td>1</td>
<td>Clarification</td>
</tr>
<tr>
<td>25</td>
<td>Consequence</td>
<td>Building Burn Distance is 180m for worst-case scenario. The 216m is the calculated “appropriate hazard distance” as required by the Board in their letters of November 2009 and January 2010. 216m is based on the governing factor for “appropriate hazard distance” being the closest a person may be to such an event without receiving a dose of thermal flux in excess of 31.5 kW/m2. Is this correct -I thought 216 m corresponded to 1000 tdu?</td>
<td>1</td>
<td>Clarification</td>
</tr>
<tr>
<td>26</td>
<td>Potential Damage to Pipe</td>
<td>The denting and gouging analysis is intended to address the risk of pipeline failure leading to loss of containment; it is not intended to address the risk of coating damage. Although not stated, the analysis was made on the basis that the polypropylene external corrosion protection coating would not provide any mechanical protection to the pipeline against denting and gouging, which indeed it will not. The approach to repair of coating damage during the operational phase will be to repair damage. Note that any damaged areas will be protected by the cathodic protection until a repair can be effected. In the unlikely event of 3rd party related damage being undetected then our pipeline integrity management activities such as inspection and cathodic protection system monitoring would identify any anomalies. OK</td>
<td>1</td>
<td>Clarification</td>
</tr>
<tr>
<td>27</td>
<td>Case for Safety</td>
<td>We have been informed that there are no planning applications for new building development within the vicinity of the Corrib onshore pipeline currently lodged with Mayo County Council. Any future applications would be dealt with by Mayo County Council and take into account any Land Use Planning restrictions that they, as the planning authority, would establish. SEPIL do not consider themselves to be in a position to predict any sensitivities in this respect as Land Use Planning is the remit of the appropriate authority, however SEPIL would of course be willing to liaise with the planning authority in the future OK</td>
<td>1</td>
<td>Clarification</td>
</tr>
<tr>
<td>28</td>
<td>Case for Safety</td>
<td>The Safety Management System presented in Q6.3 is not intended as a fully detailed description of the operational phase Safety Management System, but rather a simple introduction to what an SMS is and its relation to the bowtie analysis. A fully detailed description of the SMS will be submitted as part of the Safety Case in accordance with the requirements of the PEES Act and will include reference to Management of Change, Permit to Work and other workplace safety controls. SEPIL confirms that Management of Change, Permit to Work and other essential safety control Report text goes into details of SMS requirements.</td>
<td>1</td>
<td>Clarification</td>
</tr>
<tr>
<td>Page</td>
<td>QRA Q6.4</td>
<td>Clarification</td>
<td>SEPIL response is in agreement with Entec's view.</td>
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<tr>
<td>29</td>
<td>P13 risk of construction and extended period increases risk to workforce</td>
<td>This observation is correct in that rerouting in a tunnel (where environmental impact is a driver) leads to additional construction phase exposure to risk (higher level of activity, longer duration) leading to a combination of a higher potential for accidents at the workplace and a higher statistical likelihood of road accidents that may affect workers and public. Our QRA only looks at residual risk to the public during the operational phase as per PD 8010-3:2009. However, we have acknowledged in our QRA that: “……., it cannot be claimed that the reduction in risk is a step towards achievement of ALARP as the costs associated with the re-routing of the tunnel and the safety risks associated with the extended construction period and the more hazardous nature of tunnel construction will outweigh the benefit of the reduction in risk associated with the operation of the pipeline.” SEPIL has not carried out a quantitative ALARP assessment based on a comparison of construction and operational phase potential losses of life for the 2009 and 2010 design proposals (primarily because this would involve putting a value on the life of members of the public). However, such an assessment would be somewhat academic as the additional cost and project effort associated with the 2010 design proposal is significant and the construction safety risk has increased to an extent that may be seen as disproportional to the decrease in operational phase risks to the public.</td>
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<td></td>
<td>P14 UK HSE define 1x10-3 as limit of tolerability for workforce and 1x10-4 for members of the public. Some authorities (e.g. in Australia) define 1x10-5 as a limit at the site boundary for a fixed plant.</td>
<td>The QRA has been prepared to align with the approach to QRA contained in PD 8010-3:2009 Part 3. It has provided predictions against criteria specified by ABP. These are exclusively addressing risks to the public. Risks to workers during the operational phase have not been calculated as part of this submission. The Australian criteria for the limiting risk level at the site boundary for a fixed plant mentioned by DCENR is the type of risk tolerance criteria that could be reviewed as part of an integrated Bellanaboy Bridge Gas Terminal and incoming pipeline QRA currently being prepared separate to this submission, although care would need to be taken as the stated criteria are likely to be associated with a defined methodology which may be different from the methodology used for the terminal QRA. The 1x10-3 and 1x10-4 per year levels being referred to by DCENR presumably relate to the UK HSE document ‘Reducing Risks, Protecting People’ which states: (p. 46) “Nevertheless, in our document on the tolerability of risks in</td>
<td>Agreed</td>
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nuclear power stations, we suggested that an individual risk of death of one in a thousand per annum should on its own represent the dividing line between what could be just tolerable for any substantial category of workers for any large part of a working life, and what is unacceptable for any but fairly exceptional groups. For members of the public who have a risk imposed on them ‘in the wider interest of society’ this limit is judged to be an order of magnitude lower – at 1 in 10000 per annum.”

A key factor in comparing risk tolerance criteria for workers and members of the public is that workers receive benefit for working with the risk; the public invariably do not.

The risk of fatality per year for workers is calculated taking into account the duration that an individual worker is actually at work and on the basis that a) the actual individual may be doing inherently hazardous tasks, and b) that the locations where he or she does these tasks are, in themselves, hazardous. The fatal accident rate applicable to their inherently hazardous tasks (covering accidents such as falling, hit by machinery, electrocution) is thus applied to the length of time in a typical year these tasks are undertaken. The contribution to a workers risk due to working in an environment that is higher risk, such as a gas plant, is determined by estimating their cumulative exposure to this risk as they move around the plant over their working year; this is where ‘individual risk contours’ derived from QRA are used as these are the contours associated with a ‘major accident’ for a hypothetical individual.

Risks to the public, calculated within the Corrib Pipeline QRA as Individual Risk, only indicate the risk to a hypothetical individual as a result of a ‘major accident’. This is the part of an individual’s risk that they, as a member of the public, can personally have little or no influence over.

The contribution of pipeline major accident risk to the overall risk to workers during the operational phase would be extremely low as the Individual Risks predicted at or near the pipeline are very low and the presence of any worker near the pipeline would be infrequent. Similarly for the LVI.

<p>| P15 Quoting from ABP requirement should point out this is UK HSE not HSA which is 1x10-7 | Refer previous response to item 18 [Q1 7.3 There are three risk levels quoted by the UK HSE, these differ from the risk levels used in Land Use Planning advice by the HSA, who use 1x10-7 for the outer zone but expressed as risk of fatality not dangerous dose.] wherein we have described why we chose to make no reference to HSA criteria in this respect. | See above |
| P31 has the effect of hydrate partial blockage giving cooling been considered? | See elsewhere |
| P32 6.3.2.5 note that 504 barg is nearly 1.5 times well head shut in pressure and 6.3.2.6 peat fire discussion | It is confirmed that 504 barg is approximately 1.5 times well head OK |</p>
<table>
<thead>
<tr>
<th>Section</th>
<th>Question</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.3.2.6</td>
<td>Peat fire discussion different to Risktec?</td>
<td>This is a question of different styles as, whilst the discussion is different, the principles being discussed and conclusions reached do not differ.</td>
</tr>
<tr>
<td>6.3.2.8</td>
<td>Pipeline expansion in grout – any issues?</td>
<td>Explained in Briefs of evidence that grout is flexible.</td>
</tr>
<tr>
<td>6.3.2.10</td>
<td>Umbilical and water discharge pipeline in tunnel as well as gas line – which has plastic wrap – different sizes but would unskilled operative appreciate differences?</td>
<td>This refers to hot-tapping of the wrong pipeline, e.g. hot tapping into a gas pipeline that was thought to be a lower pressure oil pipeline. The argument for excluding this as a credible failure mode is that the need to hot tap will never arise. The possibility of hot-tapping into the water line thinking it might be the gas line would thus not arise (and anyway not be a loss of containment of gas risk). Hot-tapping, indeed any safety critical operation or activity, would simply not be carried out by an ‘unskilled operative’ as there will be competency management systems in place coupled with task/activity risk management systems. OK – will refer to competency and Control of Work aspects of SMS.</td>
</tr>
<tr>
<td>6.3.2.14</td>
<td>How have all liquid slugs been ruled out in all circumstances? (Commissioning fluids, methanol, and future conditions?)</td>
<td>Slugging issues are not predicted to occur for the Corrib production facilities. The hydraulic behaviour of the Corrib pipeline, the liquid drainage capacity and liquid buffer volume of the receiving facilities resulted in: 1. An operating envelope for normal operations (steady-state operations). The pipeline flow within the operating envelope shows no slugging issues as observed by steady-state and dynamic pipeline simulations. For operations that may lead to a liquid surges within the operating envelope (a production ramp-up) procedures are in place (as determined by dynamic pipeline simulations) to limit the liquid outflow from the pipeline within the capacity of the receiving facilities. Operations outside the operating envelope (start-up) are guided by procedures (as determined by dynamic pipeline simulations) to limit the liquid surges within the capacity of the receiving facilities. OK – need to verify appropriate monitoring and controls in place for start-up etc.</td>
</tr>
</tbody>
</table>

**ADDITIONAL POINTS**

| 30 | EIA Vol 2 Drawings | P17 AG14 is 159m from the pipeline is this owned by SEPIL? App Q Introduction says nearest housing 234m Also Q6.2 p1 nearest house 234m. | 1 Clarification | Yes, AG14 is a house owned by SEPIL and unoccupied. See Fig. 5.1 in Appendix Q6.5(i) | OK |

**ADD LUTION POINTS**

<p>| 31 | Land Use Planning | Q6.2.3.4 p5 states that restrictions on Land Use will be explained in Q6.4 but it does not. | 1 Clarification | See LUP and SEPIL to advise Mayo as above. |
| 32 | Safety Case | Q6.3 Critical aspect of a Safety Case Framework is how Internal safety case Shell auditors will use and it will be kept as a | 2 Additional | OK |</p>
<table>
<thead>
<tr>
<th>QRA</th>
<th>Q6.3</th>
<th>Within the description of the Safety Management System to address Major Accident Hazards would expect to see procedures/processes for Management of Change (People and Processes as well as Plant), Control of Work, Contractors, PTW etc.</th>
<th>Additional Information</th>
<th>App 6.3 page 8 Table 2.1</th>
<th>May be left to Permit to Operate BUT need MoC post Engineering Design.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q6.2</td>
<td>1.3” and 4” bullets – BPD is for normally occupied buildings – not dwellings. In this case risks are low enough so that dwellings would be allowed up to BPD but not generally true.</td>
<td>Clarification</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q6.4 p 13</td>
<td>Offshore section 50m from landfall to LVI - would expect contributions to risk for the “interaction distance upstream of the landfall low water mark – may be different ignition probabilities and risks of flash fire rather than jet fire.</td>
<td>Additional Information</td>
<td>na</td>
<td>Explained in Briefs of Evidence / Questioning at Oral Hearing</td>
<td></td>
</tr>
<tr>
<td>P15</td>
<td>Societal Risk Criteria focus on Broadly Acceptable / ALARP boundary could mention this is two orders of magnitude below the intolerable level set in R2P2.</td>
<td>Clarification</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>P39 6.4.3.1</td>
<td>References to de Stefani should be to 6.4.2.1</td>
<td>Clarification</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6.4.5</td>
<td>Does not consider debris slide from Doonarton Mountain – design of protection needs to be justified as protecting against all potential debris slides</td>
<td>Additional Information</td>
<td>At lvi increased by x10 frequency</td>
<td>Possible Condition on protection design</td>
<td></td>
</tr>
<tr>
<td>6.4.7</td>
<td>Quoting a risk per km for intentional damage does not seem appropriate – those of malicious intent would seek out a weak point on target that; exposed above ground equipment, or easily excavated areas would be preferred. This is a short but contentious pipeline however the likelihood of a malicious attack leading to loss of containment is unlikely given suitable level of precautions.</td>
<td>Additional Information (may be secret due to nature of installation)</td>
<td>Beyond normal precautions caging / intruder detection Fibre optic link detects vibration etc</td>
<td>Maintained</td>
<td></td>
</tr>
<tr>
<td>P66 Figure 13</td>
<td>Outer Contour is Risk of Dangerous Dose of 1x10E-07 rather than ABP/UK HSE 3x10E-07</td>
<td>Clarification</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q6.5(i)</td>
<td>goes beyond original ABF requirement for building burn distance governing separation between pipeline and dwellings.</td>
<td>Clarification</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
well as those in “occupied buildings” not clear.

Note 1: Significance Classification based on:
   1 = minor deficiency, not sufficient to impede approval, although a clarification (see below) may be requested
   2 = significant deficiency that needs to be resolved prior to approval (through Proposed Resolution – see Note 2)

Note 2: Proposed Resolution Types are:
   i. **Clarification**: Request for clarification from the developer but not of a sufficient level to require a formal submission of Additional Information under the Gas Act Section 40. Note that final resolution can only be determined once the clarification is received.
   
   ii. **Additional Information**: Request for significant Additional Information (data or assessment) that would constitute a formal new submission under the Gas Act Section 40.
Section 2 Additional Issues Arising from Technical Review:

1. Completion of Pipeline Integrity Management System and integration with Terminal SMS in overall Safety Case.

2. Have ground investigation boreholes been adequately sealed?

3. Would increasing the depth of the launch and recovery access shafts be a cost effective method of improving the schedule and practicality of tunnelling?

4. If the tunnel needs to be aligned deeper than planned along the Bay then it will be in strata not subject to the detailed ground investigations. What constraints are placed on the tunnelling contractor?

5. How is the risk arising from ground conditions shared between the contractor and SEPIL and how might the agreement proposed affect performance of the contract?

6. How will the commitments made in the EIS and other environmental protection be managed between SEPIL and the Contractor(s)?
Appendix C
Protection against Identified Hazards
Distances are measured from the PLEM offshore – hence km 19 is 19 km from the offshore end of the pipeline.

<table>
<thead>
<tr>
<th>Component</th>
<th>Hazard</th>
<th>Protection</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>Pressure</td>
<td>Wall Thickness 27mm for 345 bara (well head shut-in pressure) and design factor of 0.72 originally</td>
<td>PoD 2001</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Offshore shut down valves SCSSV, MV, WV and (on each well) in-field flow line shut down valve close on high pressure (&gt;93barg) at the terminal end of pipeline (or on loss of power or loss of hydraulic fluid / pressure).</td>
<td>Appendix Q2.1 section 5.3.1 &amp; 5.4</td>
</tr>
<tr>
<td>Well heads</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Protection cage against dropped objects, over-traversable and snag resistant</td>
<td>Chapter 2 of 2001 PoD</td>
</tr>
<tr>
<td>Flow lines</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Buried or covered</td>
<td>Section 3.5 &amp; 3.8 of s40 2010 Design Premise</td>
</tr>
<tr>
<td>Manifold &amp; PLEM</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Protection cage against dropped objects, over-traversable and snag resistant</td>
<td>Chapter 2 of 2001 PoD</td>
</tr>
<tr>
<td>Offshore Pipeline</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Concrete coated from km 19 to shore (also for negative buoyancy). Rock dump pre- and post – lay with video and side scan sonar surveys every two years to confirm in place (also prevents free spans)</td>
<td>Fig 2.17 of 2001 PoD and rock armour specified in section 2 of 2010 PoD</td>
</tr>
<tr>
<td>Shore Approach</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Trenching as nears shore starts at km 69 and depth increases to km 73</td>
<td>2001 PoD</td>
</tr>
<tr>
<td>Beach Crossing</td>
<td>Accidental and deliberate Impact (Including third party damage)</td>
<td>Trench to give minimum 3m cover</td>
<td>S40 2010 section 2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Trench with 2m minimum cover</td>
<td>S40 2010 scope(4.6.1)</td>
</tr>
<tr>
<td>Landfall Valve Installation</td>
<td>Accidental and deliberate Impact (Including third party damage)</td>
<td>Main pipe work buried. Exposed valve controls and instruments in protective cages. LVI contained within high security compound</td>
<td>EIS Appendix Q4.3 Section 4.2.6 EIS Appendix Q4.3 Section 4.2.6 S40 2010 section 4.6.5.2</td>
</tr>
<tr>
<td>Onshore</td>
<td>Pressure</td>
<td>High reliability safety system with LVI isolation valves closed when pressure reaches 99 barg at downstream side of LVI.</td>
<td>EIS Appendix Q2.1 section 5.3.2 &amp; 5.4</td>
</tr>
<tr>
<td>Onshore – trenched</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Minimum 1.2 m cover over pipe</td>
<td>EIS Appendix Q4.1 Section 3</td>
</tr>
<tr>
<td>Onshore at crossings</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Reinforced concrete slabs at road and river / stream crossings with minimum depth of cover of pipe 1.6 m; slab &gt; 600mm above pipe.</td>
<td>S40 2010 scope 4.6.4</td>
</tr>
<tr>
<td>Onshore - tunnel</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Pipe entirely within grouted concrete tunnel. No moving equipment in tunnel after inspection and hydrotect.</td>
<td>Additional information received in response to request.</td>
</tr>
<tr>
<td>Component</td>
<td>Hazard</td>
<td>Protection</td>
<td>Reference</td>
</tr>
<tr>
<td>------------------------------</td>
<td>---------------------------------------</td>
<td>-----------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Whole pipeline</td>
<td>Accidental Impact (Including third party damage)</td>
<td>Pipeline wall thickness resists all but most severe impacts.</td>
<td>Section 2 of 2010 POD Addendum DNV – OS-F101 requirement is 21 – 27 mm wall thickness.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Demonstration of size of excavator required to cause hole.</td>
<td>Onshore EIS Appendix Q2.1 Section 8.4</td>
</tr>
<tr>
<td>Well heads</td>
<td>Ground Movement</td>
<td>Flexible Flow lines</td>
<td>Section 2.6.3 of 2010 POD Design Premise</td>
</tr>
<tr>
<td>Flow lines</td>
<td>Ground Movement</td>
<td>Flexible Flow lines</td>
<td>Section 2.6.3 of 2010 POD Design Premise</td>
</tr>
<tr>
<td>Manifold &amp; PLEM</td>
<td>Ground Movement</td>
<td>Flexible Flow lines and dog leg in pipeline Manifold to PLEM dog leg</td>
<td>Section 2.6.3 of 2010 POD Design Premise (for flow lines). Figure 2.2 Section 02 Corrib Offshore EIS 2001</td>
</tr>
<tr>
<td>Offshore Pipeline</td>
<td>Ground Movement</td>
<td>Monitoring of Free spans (video &amp; sonar every two years), rock dumping to support and protect pipeline</td>
<td>Offshore Design Basis Section 8.7 DNV GN14 refers. PoD 2001 Concrete coat from km 19</td>
</tr>
<tr>
<td>Shore Approach</td>
<td>Ground Movement</td>
<td>Increased burial and concrete coat</td>
<td>PoD 2010 Addendum added rock protection. PoD 2001 trenching increasing from km69 to full at km73</td>
</tr>
<tr>
<td>Beach Crossing</td>
<td>Ground Movement</td>
<td>Increased burial and concrete coat</td>
<td>3m cover according to s40 2010 section 2. But scope (4.6.1) states 2m.</td>
</tr>
<tr>
<td>Landfall Valve Installation</td>
<td>Ground Movement</td>
<td>Buried and away from cliff edge</td>
<td>EIS AppQ2 and Q4.3 section 4.2</td>
</tr>
<tr>
<td>Onshore - transitions</td>
<td>Ground Movement</td>
<td>Need to establish assurance of avoidance of differential settlement at Glengad end of tunnel; ends of stone road sections and either sides of water and road crossings.</td>
<td>Requires condition to ensure verification during construction</td>
</tr>
<tr>
<td>Onshore – trenched</td>
<td>Ground Movement</td>
<td>Only use this method in stable soils. Otherwise pipeline laid in stone road</td>
<td>EIS Appendix M and Q2</td>
</tr>
<tr>
<td>Onshore at crossings</td>
<td>Ground Movement</td>
<td>Establish firm ground (avoiding mobile sediments and peat) for slab foundation AND for the ground containing the pipe.</td>
<td>Requires condition to ensure verification during construction</td>
</tr>
<tr>
<td>Onshore - tunnel</td>
<td>Ground Movement</td>
<td>Protection afforded by concrete tunnel and flexible grout fill although demonstration also given that differential settlement will be negligible.</td>
<td>EIS AppQ2 and EIS Addendum data used to establish no significant differential settlement. See answers to Entec queries in Appendix B</td>
</tr>
<tr>
<td>Whole pipeline</td>
<td>Ground Movement</td>
<td>Inherent strength of 27 mm thick pipe wall</td>
<td>Free span calculation</td>
</tr>
<tr>
<td>Well heads</td>
<td>External Corrosion</td>
<td>Materials of Construction</td>
<td>PoD 2001 and 2010 Addendum</td>
</tr>
<tr>
<td>Flow lines</td>
<td>External Corrosion</td>
<td>Materials of Construction</td>
<td>PoD 2001 and 2010 Addendum</td>
</tr>
<tr>
<td>Manifold &amp; PLEM</td>
<td>External Corrosion</td>
<td>Materials of Construction and Cathodic Protection (CP)</td>
<td>PoD 2001 and 2010 Addendum</td>
</tr>
<tr>
<td>Offshore Pipeline</td>
<td>External Corrosion</td>
<td>Protective Coatings and CP</td>
<td>PoD 2001 and 2010 Addendum CP in EIS Appendix Q4.1 section 4.15</td>
</tr>
<tr>
<td>Component</td>
<td>Hazard</td>
<td>Protection</td>
<td>Reference</td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-------------------------</td>
<td>----------------------------------------------------</td>
<td>----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Shore Approach</td>
<td>External Corrosion</td>
<td>Protective Coatings and CP</td>
<td>As Offshore Pipeline</td>
</tr>
<tr>
<td>Beach Crossing</td>
<td>External Corrosion</td>
<td>Protective Coatings and CP</td>
<td>As offshore pipeline with check on balance between onshore and offshore - See answers to Entec queries in Appendix B</td>
</tr>
<tr>
<td>Landfall Valve Installation</td>
<td>External Corrosion</td>
<td>Materials of Construction and Protective Coatings Underground</td>
<td>EIS AppQ2 and Q4.3 section 4.2</td>
</tr>
<tr>
<td>Onshore pipeline</td>
<td>External Corrosion</td>
<td>Protective Coatings and Cathodic Protection</td>
<td>EIS Appendix Q2</td>
</tr>
<tr>
<td>Whole system</td>
<td>Internal Corrosion</td>
<td>Corrosion Inhibitor</td>
<td>EIS Appendix Q2 8.1.1</td>
</tr>
<tr>
<td>Offshore components and LVI</td>
<td>Internal Corrosion</td>
<td>Materials of Construction</td>
<td>S40 2010 Pod EIS Appendix Q2</td>
</tr>
<tr>
<td>Offshore and Onshore Pipeline</td>
<td>Internal Corrosion</td>
<td>Corrosion Allowance in pipe wall thickness</td>
<td>EIS Appendix Q2 8.1.3</td>
</tr>
<tr>
<td>Whole System</td>
<td>Material Defects</td>
<td>Verification of materials quality and welding quality through manufacturing process</td>
<td>3rd party verification Pipeline Inspection Hydrostatic Tests EIS Appendix Q2 Section 9</td>
</tr>
<tr>
<td>Whole System</td>
<td>Pipeline failure causes classified as “other”</td>
<td>Systematic hazard studies to identify issues; Third Party Reviews</td>
<td>See references to deliberate interference and differential settlement referred to above</td>
</tr>
</tbody>
</table>

Appendix C
Appendix D
Strengths and Weaknesses of Risk Based and Consequence Based Separation Distances
1. Purpose
This note is intended to provide a background to the setting of separation distances between pipelines conveying high pressure flammable gas and dwellings. The context of the note is the proposal to construct an Onshore Gas Pipeline to connect the permitted offshore pipeline and Corrib Gas Field off the west coast of Ireland to the Gas Terminal at Béal an Átha Búi (Bellanaboy). The length of the proposed onshore pipeline is 9.2 km from the proposed Landfall Valve Installation (LVI) at Gleann an Ghad (Glengad) to the Gas Terminal.

2. Regulations, Codes and Standards
There are no regulations in Ireland (according to the brief) governing the separation between pipelines and dwellings in order to protect the dwellings and their residents from harm in the event of an accident which releases the pipeline fluids. There is a requirement (under the EU Seveso 2 Directive Article 12) for Member States to have Land Use Planning Policies to prevent fixed installations handling hazardous materials from being located too close to existing developments (where vulnerable populations may be located) or new developments encroaching too close to major hazard installations.

Pipeline design codes and standards do make reference to public safety but ISO 13623:2000 and IS 328:2003 only consider it necessary to decrease the design factor (increase the pipeline wall thickness) as the population density around the pipeline increases.

Two recently published codes PD 8010 (Part 3) and IGEM/TD/2 describe the use of quantified risk assessment to determine the separation distance between pipelines and dwellings or other forms of development. In the UK these codes are designed to interact with the UK Pipelines Safety Regulations (1996) which allow the UK to extend the land use planning system for compliance with Seveso 2 to pipelines carrying dangerous fluids. This approach does not apply in Ireland because there are no equivalent Pipeline Safety Regulation requirements.

It is recognised within the codes that it is not always possible to find a pipeline route that is ideal, that is, one which avoids imposing risk from an accident to any member of the public. However, the codes and their related design requirements specify increased protection of a pipeline so that an accident becomes less likely in the areas where there may be interaction with the public, such as road or railway crossings and where are there are dwellings or other buildings with more sensitive occupants within areas that could be affected by a major accident.

3. Corrib Onshore Pipeline
3.1 Design Operating Conditions
The Corrib pipeline is designed to transport gas from the offshore sub sea well heads to the on shore terminal. The total pipeline length is over 90 km but only about 9km of this is onshore. The offshore section of pipeline is about 82 km long. The initial pressure at the well heads, with
the valves closed is 345 bara (1 bara = atmospheric pressure). However as soon as the valves
are opened and the well fluids start to flow the pressure is reduced as the pressure is used to
overcome friction in both the wells and the pipeline. The friction in the wells alone will cause a
drop to 272 bara, the pipeline wall friction reduces this further so that for the last 10% of the
pipeline’s length (the onshore section) the pressure will be about 110 barg when the wells are
first producing, and the gas is flowing. However as the well fluids are removed from the
reservoir the reservoir pressure will drop, until after about four years the pressure in the
reservoir will fall to about 100 bara and the pressure in the onshore pipeline to about 66 barg
when the gas is flowing.

3.2 Maximum Pressure

If there were no valves in the pipeline between the offshore reservoir and the terminal then,
when the terminal was shut down and its inlet valves closed, the pipeline pressure could rise
until it was the same as the wellhead pressure. (There would be no flow and no friction losses).
However, even the original design had a number of valves that could be shut to enable the
pressure in the pipeline to be controlled. In common with all wellheads the Corrib field wells
will be equipped with control valves, which act as taps so that the flow from the wells can be
matched with the requirement for gas at the Bellanaboy Terminal. If processing stopped at the
terminal then the control valves would be closed and the pressure in the pipeline would not rise
even though the pressure in the wells would rise to the reservoir pressure. In addition to a
control valve all wells are normally fitted with a master isolation valve in the main body of the
valve and a further isolation or wing valve near the outlet. As a precaution against damage to
the well head (which is protected by a cage) there is normally also a down-hole sub-sea isolation
valve located several metres below the sea bed. Therefore there are three safety isolation valves
in series in addition to the control valve. Following the Advantica Independent Safety Review
and report in 2006 it was decided to add to these safety systems a further pair of isolation valves
at the landfall valve installation at Glengad. These are also fail safe valves which will close if
the control system is lost or if the pressure in the onshore pipeline approaches 144 barg. The
system of protecting the onshore pipeline by limiting its maximum operating pressure is known
as a high integrity pressure protection system (HIPPS). This allows the maximum operating
pressure or design pressure to be considered as 144 barg. However, the pipeline design has
remained the same as when it was originally designed to 345 bara, in particular the wall
thickness, so that it can be stated that there is a much greater factor of safety in the design. The
pipeline will still contain the well head pressure should the HIPPS fail. Indeed it will withstand
the 504 barg test pressure that it will be subjected to before commissioning. As time passes and
the reservoir pressure falls the factor of safety will increase.

3.3 “Safe” Separation Distances

Absolute safety cannot be guaranteed in any human activity, so it is often suggested that
separation can be increased between a hazardous material and people until the risk of harm
becomes vanishingly small. Quantified risk analysis is often used to estimate the level of risk,
but judgement must be applied to determine what level of risk is vanishingly small or at least
generally tolerated. Given a pipeline diameter and pressure the worst case accident is
determined and has been calculated in the QRA reports presented by Advantica and DNV. The
range of effects is greater than the distance to the nearest dwelling for all pipeline pressures
above 100 barg. However, the analysis in all three previous reports on pipeline risks (JP Kenny,
Advantica and DNV) agree that risks arising from pipeline leaks and ruptures have been
reduced to less than one in ten million per year (JP Kenny) and below one in a thousand million
per year (US billion) at the nearest dwelling in the Advantica and DNV reports assuming additional high pressure protection of the pipeline. These estimates would apply for the first four years of operation, following this, the reservoir pressure falls below 100 bara, the consequences of failure would be less and the building burn distance less than the distance to the nearest dwelling. The protection measures also have the advantage that they will reduce the likelihood of accidents affecting areas closer to the pipeline, particularly road crossings (at least one is unavoidable to reach the terminal). By comparison the UK HSE view an individual risk of fatality below one in a million per year as ‘broadly acceptable’ and for land use planning purposes place no restriction on developments (even of high density or sensitive nature) where even the risk of a dangerous dose is less than three in ten million per year (roughly equivalent to a risk of death of one in ten million per year). According to the DNV analysis, the current proposal gives rise to risks less than 1% of this criterion, i.e. the risks are a hundred times lower at the nearest dwelling.

4. Opinion

The risk assessments presented are in accordance with good industry practice for such analysis although differ in detail from the approach used by the UK HSE or specified in the relevant codes (PD 8010 Part 3 and IGEM/ID/2 which were published after the analysis was performed). They are unlikely to differ from other competent analyses in their broad conclusions and show that the design of the Corrib pipeline provides a sound basis for risk reduction to ensure that the risks it poses are within limits found to be ‘broadly acceptable’ elsewhere. The author of this note has personal experience of onshore pipeline landfall sections with design pressures and maximum operating pressures in excess of 110 barg up to 160 - 180 barg and design factors greater than 0.3, which have been in operation for 20 years.

This note has been produced following a rapid review of the Corrib Gas pipeline EIA web site http://www.corribgaspipelineapplication.ie/ and Appendix Q in particular as well as the Advantica Independent Safety Review (R 8391 17th January 2006). No documents have been reviewed which support a single fixed separation distance based on a “worst case” consequence analysis.

Author: P J Waite

Reviewer: R J Smyllie

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Appendix E
Review of Corrib Pipeline FTA and SIL reports
E-1 Objective and Scope

Entec is carrying out Statutory Assessment of the Pipeline Design in relation to the Application for Consent to Construct a Pipeline (Section 40 of the Gas Act, 1976, as amended) on behalf of the Department of Communications, Energy and Natural Resources under the parallel process of submissions under s40 of the Gas Act and part of this support includes a technical review of the design of the system. The objective of this technical note is to undertake an independent review of the following two documents:

1. SIL Verification Report LVPLS by Safety Solutions Consultants BV Corrib Field Development Project


It should be noted that the SIL report was self contained – an appropriate description of the system including diagrams was available. However, the FTA report, although it referred to a drawing “05-2377-01-H-0-015”, no overview schematic was provided. A simplified schematic, “COR-25-SH-0011” was available and has been used and is attached at the end of this technical note (Addendum A).

E-2 Overview of Corrib Pipeline Project

The pipeline system for the Corrib Field Development Project is 83km long and 20 inch diameter from the offshore manifold to a Landfall Valve Facility (LVF) at Broadhaven Bay County Mayo. The onshore section of the pipeline is protected from pressure rising above its Maximum Allowable Operating Pressure (MAOP) of 100 barg by a high integrity safety system commonly referred to as the Land Valve Installation (LVI). When the LVI closes all the subsea wells should also close to prevent the pressure in the subsea pipeline rising to its design pressure of 345 barg. The maximum allowable operating pressure (MAOP) of the offshore pipeline (upstream of the LVI) is 150 barg.

E-3 Review of the SIL Report

E-3.1 Purpose of the SIL report

The LVI is a safety system designed to protect the onshore section of the pipeline from overpressure generated within the wells. The specification of the LVI ESD system (not within the scope of this review) has identified that it should have a Safety Integrity Level (SIL) of 3.
E-3.2 Review of the SIL Report

E-3.2.1 Methodology

The scope of the SIL report is comprehensive and is compliant with the international standard IEC 61511. The report complies with the methods presented in this and other standards.

The demand rate on the LVI is high for an emergency shut-down system. As a result they have examined in section 6.4 whether the Low or High Demand mode criteria apply. They have calculated the SIL for both criteria. They have considered architectural criteria in section 6.3.

They have concluded that the system is a SIL3 system based on a 12 monthly proof test. The system is SIL3 based on the criteria for both Low and High Demand mode and for architectural requirements.

It should be noted that the shut-off valves are the most unreliable components in the system accounting for 69% of the unreliability of the PFD value (Table 10, 6.4.1.) and 83% of the PFH value (Table 11, 6.4.2.). This is what would normally be expected.

E-3.2.2 Assumptions – Degree of Conservatism

Throughout the calculations Beta factor and Proof test coverage (PTC) factor have been included (these are discussed in the following section).

The potential problems associated with hydrate formation are considered in the report, page 5. They believe this should not be a problem and this is a reasonable assumption provided the injection of methanol is reliable and that the trace heating system functions in a satisfactory way.

The basic reliability data (section 5.3) used appears appropriate with the exception of the comments in the following section.

E-3.2.3 Areas of Concern

There are three areas of concern two which are often the cause of disagreement because they are difficult to quantify accurately but have a significant effect on the calculated result. These two areas are: Common Cause Failure (“Beta Factor”) and Proof Test Coverage (PTC) factor.

Common Cause Failure

Where a system has redundant components (e.g. two pressure transmitters activating one shut-down system) there is the potential for Common Cause Failure (CCF) – i.e. both components (transmitters) fail in the same way. There are two general areas where CCF can play a significant role. The first is where there is redundancy built into the trip system as in the above example. The second is where a utility, design feature or even a human action (such as a maintenance action) can cause separate devices to fail for the same reason.
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For utility failure it appears that the system fails closed.

CCF usually dominate the unreliability of redundant systems. Calculations usually use the “Beta factor” method for CCF. This is the standard approach and is described in Annex D of 61508-6:2002 or in “Functional Safety”, 6.2.2.1.

If a simple system is considered where two duplicate devices are used in parallel, the reliability block diagram becomes:

Figure 1 Reliability Block Diagram

This indicates that the units have redundancy but also a common cause element. In simple terms the formula, assuming \( PFD_d \) is the device PFD is (which each block having them same PFD):

\[
PFD_{sys} = (PFD_d \times PFD_d) + \beta \times PFD_d
\]

Where, \( \beta \) is the Beta factor typically with a value between 0.01 and 0.3.

In the SIL report on some occasion they have estimated a Beta Factor using IEC 61508-6 Annex D, “A methodology for quantifying the effect of hardware-related common cause failures in E/E/PE system”. This Annex contains a scoring table for the following subjects: separation / segregation, diversity / redundancy, complexity / design / application / maturity / experience, feedback of data, procedures / human interface, competence / training / safety culture, environmental control & testing. For the valves a filled in score leads to Beta factor of 5%. It is stated that this is also commonly used for similar redundant equipment. However, in other occasions a Beta factor has been assumed with little or no justification.

Proof Test Coverage

Proof test coverage (PTC) is the measure of effectiveness of the testing method. When a device is tested, the test cannot be assumed to detect all un-revealed failures. The PFD formula makes a correction for proof test coverage which, when less than 100%, increases the PFD. The value of Proof Test Coverage chosen may have a major effect on the overall PFD.

---

In the SIL report the PTC is assumed to be 95% in all cases, including the emergency valves. However, this has not been justified and it can have a significant effect on the calculations. It is not considered to be a conservative value. Entec have seen figures as low as 60% used for emergency valves.

Valve Reliability Data

This is provided in Appendix 6 in a certificate and report by TUV. The reliability data within the report is given in Table 2 (page 7 of 10). It is data supplied by the manufacturer based on field experience. In general terms the most accurate reliability data is operational data where all the faults have been fully analysed and recorded and the equipment is exposed to the same operating conditions (process and environmental) as required in the project and is also subject to the same maintenance regime. This is almost never available. This is especially true for suppliers. They depend on users to feedback to them operational problems (claims / returns). Often the suppliers will quote figures which are in fact quite optimistic because they do not know of all the faults. However, their valves do get blamed for other faults which could have occurred (or hardware faults, bad installation, inadequate maintenance...). If they record customer complaints during the warranty period after the valve sale then it may not have been installed or (on a new site) the plant may not yet be operational for a period of several months after the sale. In the TUV report the data is quoted as “time of operation (years)” with an average value of 18 years per valve. This certainly extends past any warranty period. If this is accurate, i.e. that the manufacturer has been able to collect “operational” data excluding other non-operational time etc., then the values should be good. It has been reported\(^\text{13}\) that, as a general statement, suppliers’ data could be too low (i.e. optimistic) by a factor of 5 to 10. So field data is best IF it is accurate.

However, comparison with data in the Faradip 6.1 database for a “HIPS valve, failure to operate normal” suggested that the quoted valve failure rate was not unreasonable.

E-3.3 Summary

The calculations provide justification for a SIL 3 system. However, some of the assumptions especially on the PTC and reliability of the isolation valves are critical to the overall calculated values. These overall values are given below:

- Estimated PFD: 0.00077
- SIL 3 band PFD range: 0.001 to 0.0001.
- Estimated PFH: 9.81 x 10\(^{-8}\) /hr
- SIL 3 band PFH range: \(\geq 10^{-8}\) to \(< 10^{-7}\) /hr.

Although technically the LVI system achieves SIL3, had a sensitivity analysis been undertaken specifically on the valve PTC and dangerous failure rate it is highly likely that some of the results would have fallen into the SIL2

\(^{13}\) Technis Report T 263.
band. It is Entec’s opinion that the valve system should be improved if it is required to meet SIL 3 status. This could potentially be done by:

- Using two different valves (from different valve suppliers) to significantly reduce or avoid CCF.
- Use a partial stroking device to check for valve movement (such as “Valvguard”) if this can be fitted onto at least one of the valves although these valves are physically large.
- Increasing the test frequency.

These improvements should be included in the SIL calculation and a sensitivity analysis conducted using a range of data for the valves.

The assessment above also assumes a full 12 monthly test. The test procedure should be assessed to ensure that this assumption is valid. The detailed design of some systems sometime prevents a full test on every component.

**E-4 Review of FTA Report**

**E-4.1 Purpose of the FTA Report**

The FTA report calculates the probability of “Failure to Isolate One or More Wells”. If this occurs when the LVI is closed the subsea pipeline pressure could rise to its design pressure of 345 barg. There is no target probability set for this event, i.e. the system has not been given a required reliability such as SIL2 or SIL3.

The system itself is understood to have several component parts:
- Initiating systems such as: High Pressure at the LVI on at 2 out of 3 voting (2oo3) system. Limit switches on the LVI valves to indicate they are closed;
- Logic (control system);
- Sub-sea isolation systems: There are 7 wells in a manifold together and all must be isolated. But each individual well has four isolation valves of which at least one must operate.

**E-4.2 Review of the FTA Report**

**E-4.2.1 Methodology**

The assessment of the probability of “Failure to Isolate One or More Wells” was undertaken by using a Failure Mode and Effects Analysis (FMEA) to identify the relevant modes of failure and then by a Fault Tree Analysis (FTA) to calculate the probability of “Failure to Isolate One or More Wells”.

The method employed is generally robust and the data sources are well documented.
E-4.2.2 Assumptions – Degree of Conservatism

The following assumptions should be considered conservative (but appropriate):

<table>
<thead>
<tr>
<th>Section</th>
<th>Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.3.1</td>
<td>No credit is taken for the operator identifying a problem before the critical event occurs.</td>
</tr>
<tr>
<td>4.3.2.1</td>
<td>Operator response to alarms will be within 1 hour.</td>
</tr>
<tr>
<td>4.5</td>
<td>Choke valve on the Christmas Tree not considered to give isolation as it is in practice a control valve.</td>
</tr>
</tbody>
</table>

The Manifold Isolation Valve Tree (MVV Fault tree) has not been included in the analysis as the valves are not subject to a test procedure (report 5.2.1 page 16). This is a justified approach. If, however, the desired reliability for the complete system has not been achieved some form of test procedure should be developed. Inclusion of these valves will improve the reliability as in effect they cannot currently be considered to be an emergency shut-down system.

E-4.2.3 Areas of Concern

The numerical assessment of the system, presented in 5.2.1, indicates that the key critical issues as a percentage of the total PFD are:

- Loss of ABB Logic Solver node: 44.8%
- Any manifold valve failed to close: 39.1%

The main areas of concern considered in the SIL report should also be considered in the FTA report: CCF, PTC and reliability data.

Common Cause Failure

CCF applies where a system has redundant components (e.g. two pressure transmitters both activating one shut-down system) as discussed in section 3. There are areas of redundancy (e.g. LVI pressure transmitters and valve limit switches). The wells themselves (although there are 7 feeding into the manifold) are not in a redundant configuration: all the wells must be isolated to make the system safe.

In the report CCF (or Common Cause Failures) are consider in 5.2.1 with common equipment listed in 4.4.1 and 4.4.2. However, in the calculations no use is made of a “Beta factor” (as described in section 3) and there occasions where it should have been, for example, in the Low Pressure system tree (LPT) the “Loss of Comms A” and “Loss of Comms B” appear to be redundant systems.

It is not clear if this would significantly alter the estimated PFD. If the assumption is made that the most unreliable components are the process valves there are 4 in each well system and provided one operates (closes fully) the
system is safe. From the data used it appears that the Master and Wing valves may be similar and this issue should be considered.

Proof Test Coverage
Proof test coverage (PTC) has not been considered in this report. This should be included in the analysis.

Reliability Data

The Logic solver has been estimated to contribute almost half of the PFD of the system. This is not typical. The data has been taken from the OREDA database and should be considered good data. However, with the advent of IEC 61508 (in the mid 90s) and similar standards more reliable systems have been developed. It is normally possible to have high reliability PLCs with built in redundancy. In this case the supplier may well have been able to provide certified reliability data which would have been more reliable than the generic / historic data used in the calculation.

The data on the sub-sea isolation valves is generally taken from the OREDA data – this is historical data collected from a range of North Sea oil and gas operations which can only be considered a good data source. One item is from an ABB source.

E-4.3 Summary

The system has no reliability target so it has not failed or achieved a specified objective. In 5.2.1 the PFD is estimated at 0.00045. This is described as “band 3 or less than one occurrence in five thousand years”. However, in 4.1 the demand rate is estimated at 4 times per year. Assuming there are no spurious demands in this rate, the unsafe condition will occur on average once every 555 years \[ \frac{1}{(4 \times 0.00045)} \]. It is unclear what is meant in the report.

The reliability of the ABB logic solver should be examined in more detail as this is currently the most unreliable component of the system. It should be possible to either improve the design of this part of the system or possibly to review the reliability data and justify a more reliable value.

The FTA has not included PTC or CCF. These will make the system less reliable but it is not clear if this is significant. This is especially true of the isolation valves on each well.

The assessment above also assumes a full 6 monthly test for the sub-sea equipment. The test procedure should be assessed to ensure that this assumption is valid. The detailed design of some systems sometime prevents a full test on every component. Testing of the manifold isolation valves may need to be considered.

E-5 Conclusions

The LVI SIL assessment report establishes that the system is a SIL3 system. However, this depends very heavily on the isolation valve reliability data, specifically the Proof Test Coverage value and the failure rate. A more conservative assessment may in fact give a SIL2 rating for the system (although it would probably be a “good”
SIL2). Potential improvements are suggested. However the Entec conservative analysis already shows that the reliability is sufficiently high to provide a good level of additional protection and the standard would not normally require a SIL 3 system to protect against an already low risk event.

The FTA report estimates that the PLC and the valves are the most unreliable components of the sub-sea isolation system. However, the PLC reliability may be overly conservative and should be considered further. PTC and CCF on the valves should be evaluated in more detail. There is no target PFD or frequency quoted for this system. Entec's conclusion is that the offshore valves control system provides a high level of reliability of preventing pressures in excess of MAOP throughout the whole pipeline.

The reliability of the combined pressure limitation system is more than adequate to render the risk to the public tolerable even if based on the Entec conservative assumptions.

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Addendum A
Simple System Schematic

Drawing COR-25-SH-0011.

See following Page
Figure 2.1: A schematic of some of the main elements of the pipeline process safeguarding system
1 Introduction

The Integrity Management Scheme for the Corrib Pipeline consists of the arrangements being made to ensure that there are no leaks from the pipeline. The review considered the scheme under the following headings:

1. The engineering design of the pipeline, in particular the materials of construction, protection (coating) and wall thickness;
2. The manufacturing standards and tolerances of the line pipe;
3. The proposed method of construction, installation and commissioning;
4. The instruments and limitation systems to ensure that the design pressure is not exceeded;
5. Ongoing monitoring and inspection of the pipeline, together with testing the pressure limitation and emergency shut down system;

It is understood that the Integrity Management System for the pipeline will be integrated with that of the Gas Terminal therefore it will be necessary to ensure that the definition of the overall Integrity Management System makes it clear that it applies to both.

In this context Integrity Management is the process by which the operator ensures that there will be no loss of containment, i.e. no release of fluids, nor any contravention of the declared operating parameters. It is a special case of a Safety Management System which applies to any operation where loss of containment of the materials being transported, stored or processed could lead to harm to people (workforce or public) or the environment.

The essential requirements of any Safety Management System are that it should:\n
1. Include the processes considered core for effective safety management;
2. Facilitate issues being taken from identification (e.g. problem recognition) through planning, implementation, monitoring, review and revision;
3. Place sufficient weight on management factors shown to be important by previous incidents and relevant research;
4. Measure and track the key indicators and symptoms of safety management effectiveness;
5. Lead to risks from hazards being reduced to “as low as reasonably practicable” (ALARP);
6. Be suitable for the variety of organisational units it is applied to;

7. Avoid placing unnecessary emphasis and constraints on how satisfactory levels of safety are achieved;

8. Be alert and adapt to the health & safety management issues associated with new ways of working, technology and new information; and,

9. Be sufficiently specified to ensure consistent application.

These 9 items are addressed in sub-sections 2.1.1 to 2.1.9 below.

2 Safety Management System

2.1.1 Core Processes

Any management system is expected to include processes to:

- Identify needs;
- Plan;
- Control:
  - Obtain feedback;
- Review and revise.

This often summarised as Plan/Do/Check/Act but in terms of safety and integrity management the POPMAR acronym is appropriate:

- Set Policy;
- Organise staff;
- Plan and set standards;
- Measure performance;
- Learn from experience: Audit; and
- Review.

A safety management system for complex hazardous activities should also have processes to ensure:

i) Policy objectives are set, planned for and communicated;

ii) Hazards are identified and the risks assessed in a systematic and structured manner in the development of safety controls;
iii) Resources are organised and allocated responsibilities so as to exert control;

iv) Potentially conflicting interests are managed. This includes sufficient independence of the management of safety to avoid bias and assist in resolving conflicts;

v) Core safety management competencies and technical knowledge are developed and retained;

vi) Safety controls are implemented;

vii) Unsafe conditions and deviations arising during operations are detected and rectified;

viii) Emergency circumstances are foreseen, prepared for and responded to, (preparation includes rehearsals);

ix) Performance is monitored and reviewed;

x) Changes to the system are planned and implemented safely, and;

xi) The system is continuously improved, both in an incremental manner (e.g. fixing problems) and stepwise (e.g. major revisions in the light of new knowledge or new control processes).

Processes for all these should be in place for the terminal; in particular COMAHDS\textsuperscript{15} requires that sites prepare a Major Accident Prevention Policy (see Schedule 2 of Reference 15) which must include:

- The major accident prevention policy should be established in writing and should include the operator's overall aims and principles of action with respect to the control of major-accident hazards (item i above);

- Identification and evaluation of major hazards — adoption and implementation of procedures for systematically identifying major hazards arising from normal and abnormal operation and the assessment of their likelihood and severity (partly satisfies item ii above) but also needs link to show adequacy of safety controls (which is required for top-tier COMAHDS sites in the Safety Report) this should be included in the overall SEPIL Safety Case prior to operation. (The demonstration of ALARP can be based upon the QRA submitted with the application);

- Organisation and personnel — the roles and responsibilities of personnel involved in the management of major hazards at all levels in the organisation. (item iii above);

- Operational control — adoption and implementation of procedures and instructions for safe operation, including maintenance, of plant, processes, equipment and temporary stoppages (item vi);

- Planning for emergencies — adoption and implementation of procedures to identify foreseeable emergencies by systematic analysis and to prepare, test and review emergency plans to respond to such emergencies and to provide specific training for the staff concerned (item viii);

- Management of change — adoption and implementation of procedures for planning modifications to, or the design of new installations, processes or storage facilities (item x – although it should be noted that best practice is to broaden the requirement from plant to include people and procedures as well);

\textsuperscript{15} European Communities (Control of Major Accident Hazards involving Dangerous Substances) Regulations, 2006
Monitoring performance — adoption and implementation of procedures for the ongoing assessment of compliance with the objectives set by the operator's major-accident prevention policy and safety management system, and the mechanisms for investigation and taking corrective action in case of non-compliance (parts of vii, ix and xi need to consider detection of unsafe conditions under it to ensure there is satisfactory linkage between the assessed risk and the mitigation planned – which is normally included in the safety report);

Audit and review — adoption and implementation of procedures for periodic systematic assessment of the major-accident prevention policy and the effectiveness and suitability of the safety management system; the documented review of performance of the policy and safety management system and its updating by senior management (this should complete item vii in that examining timely rectification of all faults should be included in the audit, and also item ix and whether they lead to improvement on a regular basis).

The condition is therefore that prior to operation the Safety Management System and Safety Case should be expanded to include all the above aspects for the pipeline as well as the statutory requirement for the Terminal under COMAHDS.

The Management of Change Process should be implemented immediately so that any changes subsequent to the information reviewed for the s40 Application and approval of the amended PoD are subject to it.

Item v) does not appear to be completely covered by the MAPP requirements but is closely linked with iii) and the MAPP requirement on Organisation and Personnel, a specific condition at operation stage would be appropriate.

Item iv is a key consideration which has been identified following the Texas City and Deepwater Horizon accidents. The process safety specialist at the terminal should have a direct independent reporting line, and be accountable to the head of the process safety discipline within Shell’s corporate leadership team. This may well be the current situation but a condition of the permit to operate should be the maintenance of this to ensure that no compromise is taken on safety in the interest of some other objective.

### 2.1.2 Close Out of Issues

For a permit to construct this requirement implies that all issues identified during the design process have been addressed and improvements either implemented or demonstrated to be unnecessary. At the operation stage there should be a system in place to monitor the identification of hazards, risk assessment and closure of actions arising (see 2.1.1). Issues arising from the operation of the Management of Change process shall be included in the verification of closure.

### 2.1.3 Management Improvement Process

A significant proportion of the lessons to be learned from past major accidents in the oil and gas industry are related to organisational and management factors which have a major impact on safety.

Changes to management, organisation, roles and responsibilities need to be included in the management system for assessment alongside the control of changes to plant and procedures.
There should be a mechanism for acting on the lessons learned from accidents (including those occurring in other companies and locations) and using near miss reports to improve management as well as plant and procedures.

External influences such as economic factors and market forces determining the modes of operation may also impact on the safety of the plant unless management adapts to the change in a manner which ensures maintenance or improvement of safety. Therefore the SEPIL Safety Case should be subject to review both for changes listed in COMAHDS and the potential incremental changes introduced by such external influences.

2.1.4 Measurement – Leading and Lagging Indicators

A key input to the review and improvement of the management system is the measurement of performance achieved. This is not only in respect of compliance with the management system but also the indicators of safety management performance.

Lagging indicators such as lost time injuries and quantities of materials released have been used to measure performance but are generally not helpful in improving the integrity management system, the former because lost time injuries are rarely related to process safety issues (such as loss of containment of process fluids) and the latter because pipeline systems in particular should not experience any leaks. Therefore leading indicators should be developed to demonstrate that integrity is being managed effectively. These can be derived from the industry benchmarks or set locally to include for example, percentages of –

- Safety inspections carried out on time;
- Defects rectified within required time;
- Safety training needs met in the quarter;
- Posts filled with properly qualified staff;

which cover both safety critical equipment and safety critical tasks.

2.1.5 Reduction of Risk to ALARP

The management system should stimulate the on-going search for, and appraisal of, new and cost effective risk controls in the organisation and risk mitigation in procedures and equipment.

The attention paid to risk reduction should be focussed upon the main contributors to risk. Therefore the system should ensure that all risks are properly considered but attention is not distracted from major hazard risks.

2.1.6 Appropriate to Offshore, Pipeline, LVI and Terminal

Pipeline integrity will be managed through the Safety Management System covering the terminal and will need to integrate with the management of integrity for the offshore wells and LVI. Therefore it is essential that there are no gaps or conflicts between the systems for each component and that the design intentions are consistent across the interfaces between the different parts of the Corrib project. Only the terminal will be permanently manned,
although the other parts will be continuously monitored, therefore the management system needs to ensure that these other parts receive the appropriate monitoring, testing and maintenance.

### 2.1.7 Overall objective is safe operation

It is often believed that it is easier and clearer to follow a set of prescriptive rules which will ensure safety. However this relies on the rules being perfect and their authors having 100% foresight. In practice rules will be changed as external circumstances and perhaps other factors change. It should be clear that the overall objective is safe operation with no loss of containment which could damage people or the environment. Procedures may be challenged but only changed after careful assessment and authorisation. However the pipeline is a relatively simple system and therefore the operating, monitoring, inspection, testing and maintenance procedures should be clear and not require change. This would normally be included in the Major Accident Prevention Policy.

### 2.1.8 Responsive to change

If change is required then the system (procedures or process) for identification of hazards and assessment of risks should be used to ensure that change does not lead to a deterioration of safety and integrity standards. Change should generally bring an improvement by means of improved equipment (e.g. higher reliability), procedures (clarity or ease of use), or people (training, easier workload). The risk assessment process should be available to review the management of organisational and procedure change as well as changes to equipment.

### 2.1.9 Consistent application

The Integrity Management System should not be open to variable personal interpretation or judgement. For example it should set performance standards for leak tightness on valves under test.

### 3 Engineering Design

The Design Basis is addressed in Chapter 5 as a separate heading in the scope of work, but for the purpose of integrity management it is important to recognise that the primary means of assuring integrity is in the specification of the pipeline, its material, wall thickness and protection against possible failure mechanisms. The design codes and standards are addressed in Chapter 5. This Section reviews the design against the potential hazards, both external from the local environment to the pipeline and possible internal causes of leaks.

The generic potential hazards are leaks of gas caused by:

- Pipeline failures;
  - Third Party Accidental Impact
  - Ground Movement
  - External Corrosion
  - Internal Corrosion
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Material Defects
- Other (which may include causes of additional stress during installation or as a result of additional structures near a pipeline)

- Offshore (Wellhead and Flow Lines)
  - Damage to valves, (Christmas trees), flow lines or flanges.

- Landfall Valve Installation
  - Defective valves, flanges or small instrument connections.

The proposed design includes protection against all of the above and for the sake of completeness and for ease of use in any verification audit the proposed protection is listed in Appendix C:

The details of some protection measures are not given in the EIA nor the supporting Technical Appendices. Some are subject to the provision of satisfactory method statements by contractors and verification of installation to meet ground conditions but this is to be expected in a project of this nature.

Note that hydrate formation is not seen as a threat to pipeline integrity but removal of hydrates needs a prepared contingency plan to avoid any unsafe conditions. Prevention of hydrate formation is a key requirement to ensure reliability of gas supply and therefore excess methanol will be injected at the well heads and provision made for methanol injection at the LVI during start-up or re-start.

4 Manufacturing Standards

The pipeline specification (discussed in Section 5) requires the pipe to be manufactured from material suitable for the temperatures and pressures that could be expected. The manufacturing standards require assurance that there are no defects within the metal that could grow and lead to failure. Similarly welding of the pipe should be carried out by qualified welders and subject to 100% examination for any defects. This is in addition to final testing at 504 barg.

The allowable manufacturing tolerance in the pipe wall thickness is 1 mm and this has been allowed for in the wall thickness calculation in addition to the corrosion allowance.

These matters are all properly covered by the third party verification body and checked by KOIL on behalf of the Department.

5 Construction, Installation and Commissioning

The main concerns during these activities are normally:

i) to maintain the standard of construction in welding sections of the pipe together;

ii) to avoid damage to the pipeline and its protective coatings during installation;
iii) to ensure that sections of the pipeline are not affected by differential settlement; and,

iv) to carry out hydrostatic pressure testing safely.

In addition, for the Corrib onshore pipeline and the tunnelled section in particular, construction activities may have the potential to affect the local environment with some possible risk to people and property, although this appears to be unlikely. In particular:

- Vibration from the continuous operation of the Tunnel Boring Machine (TBM) which concerns the local residents in case vibrations from tunnelling affect the stability of the steep slopes of Dooncarton Mountain which have been the location of previous landslips following exceptional heavy rain, or cause damage to their property (structural damage to houses or collapse of steep banks);

- Uncertainty over the bedrock – sediment interface, and presence of hard rock inclusions or other obstructions beneath Sruwaddacon Bay at the proposed depth of the tunnel which may either
  - Affect the ability of the Tunnel Boring Machine (TBM) to maintain the required line (possibly rising too close to the bed of the estuary and leading to bentonite mud breakthrough to the estuary waters); or,
  - Block progress of the TBM and require intervention from the surface using a pit, for which there is limited analysis of the environmental impact;

- Settlement and Stability of Ground or Estuary Sediments through which pipe is to be laid, particularly peat layers which may be compressed or move laterally.

These issues have been addressed by tunnelling specialists (from Atkins) whose report concludes with the following observations

- A review of the tunnelling proposals furnished has concluded that the concept of this construction method is feasible;

- The magnitudes of vibration from tunnelling are extremely low and are unlikely to generate adverse impacts within the wider locality;

- Given that the prevailing ground conditions are non-cohesive fine to medium sands the use of slurry TBM methodology would appear to be appropriate;

- The critical tunnel construction project requirements are to complete the construction safely, on programme with no significant impact on Sruwaddacon Bay or the local environment. The proposed tunnel construction methodology and tunnel size affords the opportunity to equip a TBM such that the risk of a surface intervention in Sruwaddacon Bay are rated (by Atkins) to be very low or highly unlikely;

- Appropriate specification for the management of face support slurry and grout will prevent inadvertent release into Sruwaddacon Bay;

- The tunnel vertical alignment has been designed to ensure a minimum of 5.5m of cover remains under Sruwaddacon Bay. The tunnel gradient as the tunnel leaves and enters the launch/reception shafts is 4% and is straight. Horizontal and vertical curves are based on a minimum radius of 1000m which should be easily accommodated by a 4m diameter TBM;
A documented design process upon which option decisions and proposed arrangements have been
developed, has not been inspected, rather proposed arrangements are described in the EIS and Brief of
Evidence;

The excavated rock and soil is expected to be abrasive and work is below the water table in permeable
strata. Tool replacement during the 4.9km drive will be required and need to be undertaken in
compressed air;

Shafts as outlined, indicate that TBM launch and recovery is within a mixed face of soil and rock;

Sufficient data has been obtained to identify a tunnel concept with the preferred alignment.

All ground investigation boreholes sunk along the tunnel centre line appear not to have been backfilled
with cement bentonite grout above rock head. The potential for fluid loss during tunnelling via these
borehole paths cannot therefore be ruled out but the boreholes are placed more than 10 metres from
the preferred route and the maximum deviation allowed is 8 metres so the tunnel bore should not
intersect these boreholes (intervention from the TBM should be avoided near these locations);

Bulk sampling of material for particle size analysis has been from boreholes, which limits sample size.
This can lead to an underestimation of the larger sizes ranges such as cobble and boulder but the
methods adopted should be able to cope with these;

Construction of the shaft and tunnel junctions in rock or founded on the rock and adoption of
appropriate designs of the tunnel shaft interface will ensure any differential settlement is minimised;

The review has not included oversight of tunnel design and construction procurement documentation;

The exact installation methods or spatial requirements have not been provided with respect to the gas
pipeline, service ducts and water discharge line;

Construction of a tunnel on the proposed alignment is feasible provided a tunnelling machine is
designed to cope with these expected ground conditions and facilities are provided to enter the head
chamber and inspect or replace cutting tools;

The commitments of the EIS in terms of construction–related impacts are clear, and it is expected that
they will be passed down to the contractor via the EMP, (an explicit statement to this effect may allay
third party concerns).

Atkins has made the following recommendations:

A TBM specification should be developed that addresses the key employer requirements with respect
to the tunnel construction including:-

- Requirement for a closed face tunnelling machine;
- Requirements with respect to maintenance of cutter head and TBM. Stating that all maintenance
  for the TBM and cutter head should be able to be carried out within the TBM;
- Minimum internal diameter of tunnel lining;
- Tool wear indication;
Creating the environment for business

- Water proofing requirements of the lining;
- Procedures for the control and monitoring of face support slurry (include salinity in the specification);
- Procedures for the control and monitoring of grouting operations;
- Obligations placed on the contractor as stated in the EIS;
- Oil and grease leaks within the tunnel should be contained within the lining and along with nuisance water be pumped to the surface. Water disposal systems should be designed to deal with oil and solids. Any such oils should be specified as being biodegradable.
- Design requirements of the shafts and tunnel with respect to allowable differential movement;
- Variation of the tunnel horizontal and vertical alignment as specified in the EIS.

• Atkins recommend that the development of this tunnel project is subject to the risk management systems and processes identified within the International Tunnelling Insurance Group (ITIG) ‘A Code of Practice For Risk Management of Tunnel Works’, January 2006 based on the Joint BTS/ABI Code of Practice for Tunnelling;

• In subsequent procurement, very close consideration should be given to contractors’ proposals for TBM specification and for their proposals for planned maintenance and intervention at the tunnel head during the tunnel construction;

• Investigate limitations on the movement of heavy abnormal loads on the road network leading to the construction site with respect to loading and gauge. Alternatively the risk could be passed to the potential contractor and he be made responsible for supplying plant and equipment to site. Such movements should be agreed with the Local Authority.

Entec raised the issue of possible damage to the pipeline coating in the tunnel, after hydrostatic testing and visual examination, for example during removal of equipment from the tunnel or grouting operation. SEPIL informed Entec that the intended method of grouting avoids moving any equipment in the tunnel following these inspections. This needs to be confirmed as being complied with when the final method statements are available.

An intelligent PIG (Pipeline Inspection & Gauging tool) will be run through the pipe to verify the fitness for purpose and to establish the baseline for future inspection (SEPIL Appendix Q5.1).

The EIS Appendix Q5.3 Hydrostatic Pressure Test describes the rigorous testing of the onshore pipeline and LVI pipework. It is understood that the offshore pipeline has already been hydrotested satisfactorily. Given the interval between hydrotest of the offshore pipeline test and commissioning may be over three years it would be reasonable to add a final step of testing the full pipeline at least from manifold to terminal to the offshore test pressure, following the separate test of the onshore pipeline, (prior to pigging the whole line) as this would also include the “golden weld” upstream of the LVI (the final weld between upstream (offshore) and the onshore downstream portion of the pipeline (including LVI) which is to be tested separately.
6 Pressure Limitation System

Under normal operating conditions the operators will control flow and pressure in the pipeline using control valves at the terminal and the choke valves on each well head offshore. Appendix Q4.6 Reliability of Pressure Protection System summarises the reliability studies which have been the subject of third party verification reports which Entec has reviewed as described in Appendix E of this report.

6.1 Safety & Reliability of Pressure Protection (Shutdown System)

Notwithstanding the pipeline’s ability to contain the maximum well head shut in pressure it is intended to install pressure protection systems offshore and at the LVI to ensure that the Maximum Allowable Operating Pressure (MAOP) of 150 barg at the LVI and upstream of it, and 100 barg downstream is not exceeded. The reliability of these systems has been specified as equivalent to or better than systems elsewhere which protect pipework which may not withstand the maximum pressure in the well. There is also a considerable margin (greater than normal) between MAOP and design pressures both onshore and offshore.

SEPIL has described the reliability assessments of the systems to shut the valves offshore and at the LVI in the event that the pipeline limits approach the MAOP of the onshore pipeline. The LVI valves and offshore valves together with their control systems are the subject of independent verification by suitably qualified organisations and personnel. The reports have been subject to detailed review by Entec staff with suitable qualifications from an accredited training organisation. A detailed report is provided in Appendix E.

Note that the “operational valve” which controls flow (and therefore pressure) under normal conditions (i.e. below 93 barg at the terminal) is the choke valve which does not form part of the pressure protection system (the valves in this are the SCSSV, master valve, wing valve and well isolation valve).

The offshore shut-down valves are designed to close under fault conditions such as loss of the umbilicals, loss of hydraulic or electrical power. Hydraulic or electrical power is necessary to hold them open against springs which would close them. However even if the offshore valves failed to close and the terminal inlet valve was closed so that the pipeline pressure would ultimately rise to the well head shut-in pressure the pipeline wall thickness is such that it would contain the maximum well head shut in pressure (initially 345 barg), which is less than the hydrostatic test pressure of the onshore pipeline (504 barg). SEPIL has examined the time taken for pressure to rise in the pipeline following shutting of the terminal inlet valves in the unlikely event of the offshore valves failing to provide a tight seal. In all realistic scenarios the time to reach the MAOP is long enough for a temporary route to vent to be provided at the terminal.

6.2 Valve Testing

The procedure for testing both the offshore valves and the LVI valves involved in the pressure limitation systems needs to be defined so that conformity with the assumptions in the reliability analysis can be confirmed.

In particular it may be possible to propose simple modifications to the testing regime which enhance the demonstrated reliability to give more assurance that the claimed figures are reached. However in some cases it has proved difficult to ensure full testing of all parts of the system without interrupting the gas flow and also giving rise
6.3 Conclusions of Entec Review of Reliability

The reliability of the LVI and offshore pressure limitation systems has been assessed on behalf of SEPIL in two separate third party verification reports. Whilst some of the assumptions used in these assessments may not be conservative these are both shown to have high reliability levels which justify the claims made in the EIS, in particular Appendix Q.

LVI

The LVI SIL (Safety Integrity Level) assessment report\(^{16}\) establishes that the system is a SIL3 system. However, this depends very heavily on the isolation valve reliability data, specifically the Proof Test Coverage (PTC) value and the failure rate. A more conservative assessment may in fact give a SIL2 rating for the system (although it would probably be a “good” SIL2). Potential improvements are considered but not required.

The calculations provide justification for a SIL 3 system. However, some of the assumptions especially on the PTC and reliability of the isolation valves are critical to the overall calculated values. These overall values are given below:

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated PFD</td>
<td>0.00077</td>
<td>(Probability of Failure per Demand)</td>
</tr>
<tr>
<td>SIL 3 band PFD range</td>
<td>0.001 to 0.0001</td>
<td></td>
</tr>
<tr>
<td>Estimated PFH</td>
<td>$9.81 \times 10^{-8}$/hr</td>
<td>(Probability of Failure per Hour of operation)</td>
</tr>
<tr>
<td>SIL 3 band PFH range</td>
<td>$\geq 10^{-8}$ to $&lt;10^{-7}$/hr.</td>
<td></td>
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</tbody>
</table>

Although technically the LVI system achieves SIL3, had a sensitivity analysis been undertaken specifically on the valve PTC and dangerous failure rate it is highly likely that some of the results would have fallen into the SIL2 band. It is Entec’s opinion that the valve system should be improved if it is required to meet SIL 3 status. This could potentially be done by:

- Using two different valves (from different valve suppliers) to significantly reduce or avoid Common Cause Failure (CCF).
- Use a partial stroking device to check for valve movement (such as “Valvguard”) if this can be fitted onto at least one of the valves although these valves are physically large.
- Increasing the test frequency.

\(^{16}\) SIL Verification Report LVPLS by Safety Solutions Consultants BV, Corrib Field Development Project

January 2011
These improvements should be included in the SIL calculation and a sensitivity analysis conducted using a range of data for the valves.

The assessment above also assumes a full 12 monthly test. The test procedure should be assessed to ensure that this assumption is valid. The detailed design of some systems sometime prevents a full test on every component.

Nevertheless Entec concludes that the reliability of the LVI pressure limitation system is high and more than adequate for the purpose of protecting public safety.

**Offshore**

The FTA report\(^\text{17}\) estimates that the PLC and the valves are the most unreliable components of the sub-sea isolation system. However, the PLC reliability may be overly conservative and should be considered further. PTC and CCF on the valves should be evaluated in more detail. There is no target PFD or frequency quoted for this system.

The system has no reliability target so it has not failed or achieved a specified objective. In 5.2.1 of the FTA report the PFD is estimated at 0.00045. This is described as “band 3 or less than one occurrence in five thousand years”. However, in 4.1 the demand rate is estimated at 4 times per year. Assuming there are no spurious demands in this rate, the unsafe condition will occur on average once every 555 years \([1 / (4 \times 0.00045)]\). It is unclear what is meant in the report.

The reliability of the ABB logic solver should be examined in more detail as this is currently the most unreliable component of the system. It should be possible to either improve the design of this part of the system or possibly to review the reliability data and justify a more reliable value.

The FTA has not included PTC or CCF. These will make the system less reliable but it is not clear if this is significant. This is especially true of the isolation valves on each well.

The assessment above also assumes a full 6 monthly test for the sub-sea equipment. The test procedure should be assessed to ensure that this assumption is valid. The detailed design of some systems sometimes prevents a full test on every component. Testing of the manifold isolation valves may need to be considered.

Nevertheless Entec concludes that the reliability of the offshore pressure limitation system is high and more than adequate for the purpose of protecting public safety.

### 7 Monitoring and Maintaining Pipeline Integrity

SEPIL propose several methods of monitoring the pipeline to ensure that any of the precursors to failure are identified before there is a threat to the pipeline integrity. These include:

1. Physically walking the pipeline route to check for any third party activity which may pose a threat;

2. Monitoring for third party activity using the fibre optic cable which is also a leak detection sensor;

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\(^{17}\) FMEA & FTA of Corrib Gas Isolation System, DNV Report for Shell Exploration & Production Ireland Limited. Report No. 214658, Rev 2, 17 August 2010-09-10
3. Video and sonar scans of the offshore pipeline to check for damage, free spans, movement of rock dumping or mattress protection or other disturbance;

4. Corrosion and defect monitoring, principally by intelligent pigging the whole line to examine for any loss of wall thickness;

5. Precautionary shut down of the wells if the hydraulic umbilical or power system fails – the valves will fail closed automatically as they are only held open by the presence of these services.

Should there be a loss of integrity and a pipeline leak there are a number of systems to detect it and lead to a shutdown of the pipe:

1. A major leak would cause a pressure drop and automatic closure of the Emergency Shut Down Valves (offshore and at the LVI). The leak should also be detected by the mass balance system which may be more sensitive than a check on loss of pressure. The sensitivity of the leak detection system should be determined and specified.

2. Smaller leaks may be detected by the fibre optic cable;

3. Very small leaks that do not affect the flow in the pipeline would only be detected by portable gas detectors carried by the pipeline monitoring personnel or, if they persisted for some days by discoloration of vegetation affected by methane.

The difficulties in detecting small leaks are common to all gas pipelines and have not caused any significant problems in the UK’s high pressure network which is no longer odorised as the occurrence of leaks is so rare that the additional benefit of easier detection is outweighed by the risk from large quantities of toxic odorants (mercaptans).

8 Emergency Response

Appendix Q6.6 Emergency Response Planning and Provisions describes the proposed approach. It is appropriate that arrangements are not finalised until immediately prior to commissioning but it should be a condition of the permit to operate that a full emergency response plan is in place.

Other related contingency procedures should be in place, for example repair and rectification of defects in case of damage not leading to imminent danger.

SEPIL explained how it would wish to deal with damage within the tunnel after installation, including determining critical sizes of defects that would require remedial action – up to and including replacing sections of pipe or, in the case of the tunnel providing an inner pipe lining.

9 SEPIL Corrib Pipeline Integrity Management

The current documents will form part of the input into the Safety Case required under the PEES Act (2010) as stated in Appendix Q6.1 Section 4. The pipeline integrity / safety management system is intended to be integrated with the terminal and described in a combined HSE Case (Appendix Q6.3 Section 1.3.4 Table 1.1 with details in
Section 2.1) which will have to conform to the requirements of the COMAHDS regulations (lower tier) as well as the Shell Exploration & Production company standards. These cover many of the requirements discussed above but they should specifically include the relevant offshore components, pipeline and LVI.

The Section 40 2010 application scope section 4.8 contains suitable commitments which should be verified before operation:

- “The PIMS will address the lifetime safeguarding of mechanical integrity through the mitigation of all threats that could compromise the pipeline and ancillary systems integrity and the monitoring of the effectiveness of risk barriers, and as such considers;

- Process safety, e.g. operating procedures, overpressure protection, emergency procedures and leak detection, as well as thorough training and supervision of personnel supported by up to date procedures explaining the work tasks and safe systems of work (permit to work system) to co-ordinate activities and ensure appropriate levels of control;

- Mechanical integrity, including general integrity, (e.g. fatigue, overstress, mechanical damage and threats from peat instability and other geotechnical instability), corrosion management, (e.g. corrosion and erosion), and flow assurance, (e.g. scaling, surge, slugging and hydrate formation);

- Management of change (e.g. design change, modifications and set points, hot work such as welding or grinding at the landfall installation) will be carried out under strict procedural controls and a permit system.”

For the pipeline SEPIL has shown in the EIS Appendix Q5.2 Section 4 that it has a suitable Integrity Management Process.

Figure 3.2 in EIS Appendix Q5.2 Section 3.1 describes the management organisation and reporting lines, it does not show that the Technical Authorities for Safety and Integrity have a separate reporting line through a Corporate Safety organisation to the Shell International Board. SEPIL should demonstrate that this recommendation is implemented in accordance with best practice following investigations into major incidents such as Texas City Refinery and Deep Water Horizon – Macondo.