1 Qualifications and Experience

My name is Steve Paterson and I am Head of Materials and Corrosion Engineering with Shell Upstream Europe based in Aberdeen since 2001. I am a Chartered Engineer and hold Bachelor of Science and Doctor of Philosophy degrees in Metallurgy. I am a Professional Member of the Institute of Mining, Minerals & Materials, a Senior Member of the Welding Institute, and a Member of the Institute of Corrosion. I have worked for Shell for a total of twenty-seven years in the disciplines of materials, welding, corrosion and quality management. My experience includes work on major subsea pipeline projects, onshore pipeline projects, and onshore processing facilities, and I have been directly involved in pipeline integrity management in the Netherlands and the UK.

2 Knowledge of the Site and Related Activities

I have been involved in the Corrib Gas project since 2002. My involvement has included provision of technical advice to the project teams engaged with the subsea facilities & pipeline, the onshore pipeline and LVI, and the gas terminal. I have been a frequent visitor to the pipe storage site at Killybegs and I am familiar with the proposed onshore pipeline route. I have conducted an in-depth assessment of the integrity of the proposed Corrib pipeline.

3 Evidence

1. This statement is intended to respond to the request for further information from An Bord Pleanála and specifically, with regard to input to the QRA:

- the effect of wet gas and CO2 in the pipeline,
- the relevance of the database to wet gas,
- the assessment of the possibility of third party damage,
- and the potential for methane hydrate in the pipeline.

The statement will also address other corrosion related matters raised by the Bord in their communication of August, 2010.

3. 1 Effect of wet gas and CO2

2. The integrity of a carbon steel pipeline with respect to corrosion requires a thorough assessment of the corrosivity and the implementation of an effective corrosion management system. This involves identifying all possible degradation threats and defining mitigation, monitoring and control

measures to manage the risk during operation. The main internal corrosion threat for the Corrib pipeline system is acidic carbon dioxide corrosion.

3. Carbon dioxide corrosion can occur when carbon dioxide dissolves in water to form carbonic acid which is corrosive to steel. Water will be present in the pipeline primarily through condensation from the gas at the subsea end of the pipeline. At around 0.3% the carbon dioxide content of the Corrib gas is relatively low compared to many gas fields and is not very corrosive. There will be some contribution to acidity from organic acids such as acetic acid but the organic acid content of the Corrib gas of 10 parts per million is also very low.

4. The risk of internal corrosion for the Corrib pipeline system is addressed in Appendix Q4.7 and Q4.9 of the EIS. It was assessed using the latest Shell carbon dioxide corrosion prediction tool. This tool has been developed following many years of research, development and application by Shell and has been externally validated by the Institute for Energy in Norway. Unlike many other modelling tools, the Shell tool is able to model the corrosion along the whole length of the pipeline.

5. There is a marked temperature drop along the pipeline which significantly decreases the likelihood of corrosion in the onshore section of the pipeline. This will be at ambient temperature and therefore the kinetics of any corrosion mechanism in this section of pipeline would be very slow.

6. To mitigate internal carbon dioxide corrosion we will inject corrosion inhibitor which forms a barrier to protect the internal pipe wall against the corrosive fluids. The presence of methanol also helps inhibit corrosion because it is miscible with water and reduces its corrosivity.

7. Two corrosion inhibitor pumps will be installed at the gas terminal to ensure that the corrosion inhibitor barrier is continuously applied. The corrosion inhibitor will be mixed with the methanol which will be injected in the pipeline to avoid formation of hydrates thus ensuring that the corrosion inhibitor is always present in the pipeline.

8. The flow regime for the Corrib pipeline is annular dispersed for the full field life as described in Appendix 4.5 of the EIS. This means that any liquids are fully distributed in the gas flow allowing protection of the whole circumference of the internal surface of the pipeline by the corrosion inhibitor and avoiding any significant accumulation of liquids in the bottom of the pipeline. At the LVI and immediately downstream of the subsea manifold system where protection by the corrosion inhibitor

could not be guaranteed because of flow effects, such as turbulence, a corrosion resistant alloy has been used.

9. The corrosion inhibitor for the Corrib pipeline system is currently undergoing final verification testing. The results show that the corrosion rate in the onshore pipeline without inhibitor is less than 0.02 mm/yr in condensed water. This will be even lower with corrosion inhibitor. Therefore there will be no significant internal corrosion in the onshore pipeline.

10. To allow for any residual corrosion the original design of the onshore pipeline provided a corrosion allowance of 1mm. The suitability of this corrosion allowance for the service life of the pipeline has been confirmed by the SEPIL corrosion rate calculations given in Appendix Q4.9 of the EIS and it is consistent with good industry practice described by the European Federation of Corrosion. Monitoring of the wall thickness of the pipe stored in Killybegs has confirmed that the pipe has not suffered from significant corrosion and meets the specified requirements, as described in Appendix Q5.4 of the EIS. Our assessment confirms that the corrosion allowance of the onshore pipeline is more than sufficient for the full field life.

11. An assessment has also been made of the risk of erosion of the pipeline by hard solids. The Corrib reservoir is a tight formation and no sand is expected. To ensure that there is no significant solid production from the wells an acoustic monitor that detects hard particles has been fitted to the subsea manifold. If this indicates significant solids production the relevant well will be closed-in.

12. An essential element of corrosion management is the application of appropriate corrosion monitoring. For the Corrib pipeline system this will include continuous on-line corrosion monitoring equipment incorporating an offshore corrosion monitoring spool that allows monitoring of the corrosion rate around the circumference of the pipeline, together with ultrasonic measurement mats and corrosion probes at the inlet to the gas terminal which are representative of the conditions of the onshore pipeline. The monitoring equipment will identify any significant upsets to the corrosion mitigation system as well as providing long term corrosion rate information. The produced fluids will also be sampled in the gas terminal and analysed for iron and residual inhibitor to indicate any significant changes or events. This integrated approach to monitoring will allow immediate action to be taken should the corrosion mitigation system not meet the defined targets.

13. In addition to continuous corrosion monitoring, all the corrosion management information, together with the relevant production data, will be subject to an annual assessment and

independent peer review as defined in the Pipeline Integrity Management Scheme (PIMS). This is described in Appendix Q5.2 of the EIS. As part of this process, a calibrated risk based assessment model will be used to determine the frequency of inspection for the LVI and the pipeline.

14. As outlined in Appendix Q4.2 of the EIS, the wall thickness of the onshore pipeline will be measured using specialised intelligent pig equipment. Shell will utilize the combined CDX tool intelligent pig with SIC (Shallow Internal Corrosion) sensor unit from the Rosen company. This tool combines the well established magnetic flux leakage (MFL) sensor technology for measuring metal loss defects with eddy current sensor technology for measuring shallow internal corrosion. MFL has a defect detection capability of approximately 10% wall loss. Eddy current sensor technology has a high sensitivity for detecting internal wall loss features as shallow as 0.8 to 1 mm. Shell has qualified this technology and applied the CDX tool for the inspection of the Ormen Lange 30-inch 35mm thick subsea pipeline and the eddy current (SIC) tool for the Gannet-Fulmar pipeline. This technology has also been used within the past 18 months for another 10 pipelines belonging to other operators. Statoil has used the tool for their main gas export pipelines with positive feedback. Shell therefore considers eddy current inspection to be an established technology which can be used to detect initial signs of corrosion within the corrosion allowance. A baseline survey will be made during pre-commissioning of the pipeline to assist with subsequent interpretation of intelligent pig inspection.

15. In the unlikely event that corrosion in excess of the corrosion allowance should occur, a defect assessment will be made using the damage assessment methodology described Appendix Q4.8 of the EIS which follows the industry recommended DNV RP F-101 code. This calculates the defect acceptability taking account of the design factor of 0.3. The assessment shows that there is a factor of 3 between defect assessment acceptability and MFL detection sensitivity, and a factor of about 10 with respect to the eddy current detection sensitivity. It means that corrosion will be detected by intelligent pig inspection long before it exceeds the DNV code requirements.

3.2 Relevance of the Database to upstream wet gas

16. Shell has extensive global experience with the successful operation of wet gas pipelines. A recent review of our experience is given in Appendix Q4.9. These data demonstrate the validity of the corrosion modelling and methodology adopted for operation of wet gas pipelines and also the absence of failures. The total Shell experience with wet gas pipelines in Europe without a loss of containment incident amounts to over 40,000 km years which provides a high degree of confidence in Shell's capability with this type of operation.

17. Our assessment and testing have shown that the inhibited corrosion rate for the onshore pipeline will be only slightly higher than the rate that might be expected for a dry gas line, and it is significantly less than might be expected for a pipeline transporting oil where additional threats such as flow effects, under-deposit corrosion and microbial induced corrosion can also affect the degradation rate. For this reason we have used the CONCAWE pipeline failure database for liquid pipelines as an overly conservative approach to internal corrosion assessment for the QRA which is described in Appendix Q6.4 of the EIS. The CONCAWE database is therefore considered relevant to the Corrib pipeline with respect to internal corrosion.

3.3 Third Party interference

18. Where the pipeline is not installed in a tunnel, in the Glengad and Aghoos areas, there is a potential risk from third party interference, especially unauthorised excavation. Primary controls such as the use of minimum 1.2m cover, concrete slab protection and deeper cover at crossings and ditches, and regular line patrols and liaison with landowners are used to safeguard against this. Furthermore, only 242m of the on-land pipeline route is through privately owned farmland and this land is used for grazing. Any authorised excavation along the pipeline way-leave will be subject to supervision by SEPIL. Unauthorised excavation should be observed by the line surveillance but is also likely to be detected by the noise and vibration from digging by the fibre optic leak detection system.

19. The thick walled construction of the pipeline also makes it very resistant to damage from most agricultural and earth moving equipment. Our specialists in Shell Global Solutions have calculated the impact resistance of the pipeline against external damage. This is described in Appendix Q4.10 of the EIS. It is based on extensive research done by the European Pipeline Research Group (EPRG) into the impact resistance of pipelines against external damage, and included experimental trials with excavators.

20. The EPRG and other best Industry models have been used to calculate the puncture and denting resistance of the Corrib pipeline. It was concluded that:

- To puncture the pipe an excavator of the order of 150 tonnes weight would be required. Puncturing by a smaller excavator or plough would not occur.
- To cause denting or gouging of the pipeline that may not immediately lead to loss of containment but may result in failure should the pressure in the pipeline subsequently increase to the MAOP, would require an excavator in excess of 65 tonnes.

21. An average excavator used for agricultural works is in the range 15 to 20 tonnes. Roadbridge have used excavators in the range of 20 to 60 tonnes for excavations on the landfall project. The 60 tonne excavator was used for excavating the near shore trench for the offshore pipeline. These 60 tonne excavators are big machines and not normally used on agricultural or peat lands. Given the bearing capacity in peat lands it would be very difficult to get a 65 tonne excavator onto peat lands without significant works such as a stone road or large quantity of supporting mats to enable this.

22. The output of this evaluation provided specific input to the QRA with respect to assessing the possibility of accidental third party damage to the Corrib pipeline.

3.4 Potential for Methane Hydrate

23. The Corrib gas can form methane hydrate in the pipeline if no hydrate inhibitor is used. Methane combines with water to form a crystalline solid which can quickly accumulate to cause a blockage in the pipeline. Methanol will be continuously injected in sufficient quantities in the pipeline system to ensure that hydrates do not form. A robust hydrate management strategy has been developed for Corrib to cover all operating scenarios including normal operation and start-up. This is described in Appendix Q4.5 of the EIS.

24. Formation of methane hydrate is not expected in the Corrib pipeline because of the continuous injection of methanol. A methanol injection system has been designed that meets the reliability required by the pipeline system. The operating strategy for Corrib is to immediately stop production at the wells should methanol injection become unavailable. A surveillance and monitoring plan will be in place and operators will be trained to detect the formation of hydrates from identification of changes in key operating parameters.

25. In the unlikely event that a full bore impermeable methane hydrate plug forms in the pipeline it must be emphasised that the integrity of the pipeline is not at risk because the formation of a hydrate plug will not result in loss of containment. Hydrates are complex gas water crystalline formations and unlike ice cannot cause a pipeline to fail by expansion and excessive hoop stress. Should hydrates accumulate to form a complete blockage of the pipeline, the wells will be shut in and the pressure protection system will ensure that the MAOP's in the offshore and onshore sections of the pipeline are not exceeded. It is important to note that, should the hydrate management system fail, hydrate formation is more likely to occur offshore near the manifold, rather than in the onshore pipeline.

26. Outline hydrate remediation procedures have been developed to remove a blockage, as described in Appendix Q4.5 of the EIS. If faced with the necessity to remove a hydrate blockage, a team of specialists from the Corrib organisation and the global hydrate expert group in Amsterdam will perform the detailed operational procedure that is specific to the situation at hand.

3.5 Responses to specific ABP questions 15 &16 (communication of August, 2010)

27. The LVI will be constructed with corrosion resistant alloys and no degradation is expected. The LVI pipework can be inspected by ultrasonic wall thickness testing if required. During maintenance of the pressure protection valves an internal visual inspection will be carried out. Inspection requirements for the LVI are defined in the PIMS. Should any significant event occur, such as unexpected production of solid particles, ultrasonic inspection of the pipework, in particular at the bends and T-pieces, will be carried out. This is described in Appendix Q4.7 of the EIS.

28. External corrosion of the pipeline will be prevented by a robust 3 layer polypropylene coating and cathodic protection (CP). The impressed current CP system for the onshore pipeline will be continually monitored through checks on the transformer-rectifier output and polarisation coupons which will be installed at defined locations along the pipeline, including one very close to the offshore/onshore interface at Glengad. This will enable measurement of the on-potential of pipeline and the instantaneous off-potentials of the coupons, and will allow calibration of the transformer-rectifier output such that there is no current drain to the onshore pipeline resulting in early depletion of the sacrificial anodes on the offshore pipeline close to the landfall. It should be noted that significant draw of current from the CP system will only occur if there is damage to the pipeline coating which is not expected with the robust polypropylene coating system.

3.6 Summary

29. In summary I would like to re-iterate the following key messages:

a) the CO2 content of the Corrib gas is relatively low and testing has confirmed the low predicted corrosion rate. There will be no significant corrosion in the onshore pipeline with wet gas and CO2,

b) continuous corrosion monitoring and regular fluid sampling will ensure that corrosion mitigation is operating as intended and will be used to define the frequency of in-line inspection,

c) the assessment is supported by the extensive and successful Shell experience with operating wet gas pipelines,

d) the selected failure database for internal corrosion for the QRA is conservative and is therefore relevant for an upstream wet gas,

e) third party damage will be prevented by the use of appropriate controls for the pipeline. Furthermore damage by an excavator or similar which could result in loss of containment would require very heavy equipment which is not normally used in the area of the pipeline,
f) formation of methane hydrate in the pipeline is highly unlikely but should it occur it will not cause a threat to the integrity of the pipeline or the associated facilities.

This concludes my witness statement.