STATEMENT OF EVIDENCE

ABP Ref. No: PL16.GA0004

John Gurden, J P Kenny Ltd

Onshore Pipeline and the Landfall Valve Installation (LVI) Design

Qualifications and Experience

1. My name is John Gurden and I am a Senior Project Manager with J P Kenny Ltd. My responsibilities comprise overall management and control of individual engineering and design projects undertaken by J P Kenny.

2. I am a graduate engineer BSc Eng and a member of the Institute of Engineering and Technology. I have over thirty years experience in the International Oil and Gas industry with particular emphasis towards onshore pipelines and facilities.

3. As an experienced Senior Project Manager I have undertaken many projects on behalf of major Oil & Gas companies in a number of countries including the United Kingdom, Russia and within the Middle East.

4. These multi-discipline projects have included all stages of implementation from initial feasibility studies, through design and procurement to final commissioning and hand-over.

Knowledge of the Corrib Onshore Pipeline Project

5. I have worked on the Corrib Field Gas Development Project since 2005 and for the last three years I have focused on the detailed engineering and design of the Landfall Valve Installation or LVI at Glengad together with the design of the onshore pipeline, the outfall pipeline and associated services.

Scope of Evidence

6. Inspector, I explained in my previous statement of evidence of 2009,

    - The reason why the LVI is required.
    - How the LVI is an integral part of the onshore pipeline over pressurisation protection system.
    - How the LVI safety shutdown system operates,

    and

    - What are the other main features of the LVI.

7. Today I will address the changes in design resulting from the clarifications requested in An Bord Pleanála's letter dated 2nd November 2009 items a), b), c), h) and n), together with the letter dated 29th January 2010, item 4.

8. The statement therefore presents

    - Clarification of the pipeline codes applicable to the design of the Corrib pipeline and the LVI, items a) and b).

- Clarification of the hydrostatic test pressures for the Corrib pipeline, item a).
- A summary of the development of the design of the Landfall Valve Installation and in particular any changes at the LVI in the revised EIS 2010, item h).
- A comparison of the alternative straight pipe configuration and the bypass configuration as proposed in the EIS, item h).
- The effect of vertical movement of the stone road on the gas pipeline, outfall pipeline and associated services, item n)

9. Design details regarding the LVI are included in the Corrib Pipeline EIS, Volume 1 Chapter 4 and Volume 2 Book 6 of 6, Appendix Q4.3.

10. Design details of the onshore pipeline are included in the Corrib Pipeline EIS 2010 Volume 1 Chapter 4 and Volume 2 Book 6 of 6, Appendix Q4.2.

11. Subsequent references to Appendix Q will be found in the Volumes and Books as referred to above.

Application of the Pipeline Codes

12. An Bord Pleanála's letter dated 2nd November 2009, items a), b) and c) requested clarification regarding the application of the pipeline codes as they are applied to the Corrib pipeline.

13. The design, construction, operation and maintenance of the Corrib pipeline system is in accordance with a series of designated pipeline codes which were recommended by the Corrib Technical Advisory Group (TAG) and adopted by Shell E&P Ireland Ltd (SEPIL).

14. Appendix Q3.2 of the EIS sets out the context of these pipeline codes within the overall framework of International Codes and specifically in relation to Irish pipeline codes.

15. Appendix Q3.2 also identifies the application of other key pipeline codes in relation to the Corrib onshore pipeline.

16. The TAG reports and the Advantica Independent Safety Review are referenced in Appendix Q3.2, Section 12.

17. The pipeline codes referenced within the TAG recommendations for the design of the Corrib onshore gas pipeline are:

18. I.S. EN 14161:2004 Petroleum and Natural Gas Industries – Pipeline Transportation Systems (ISO 13623:2000 Modified)

19. I.S. 328:2003 Code of Practice for Gas Transmission Pipelines and Pipeline Installations.

20. BS PD 8010-1:2004 Code of Practice for Pipelines – Part 1: Steel Pipelines on Land.

21. These pipeline codes reflect the requirements of the European Union, gas pipelines in Ireland and the pipeline design practices adopted in the United Kingdom to supplement the European Code, EN 14161.

22. The TAG recommendations required that a pipeline code compliance document be submitted by SEPIL to demonstrate compliance with the designated codes. The application of the codes was then set out in a Design Code Review, which was accepted by TAG and is included in Appendix Q3.3.

This evaluated the three respective pipeline codes and established a basis for design compliance with the codes. This enabled potential misunderstanding or misinterpretation to be avoided.

23. Furthermore, TAG recommended that I.S. 328 be adopted for construction, testing, commissioning and operation of the onshore section of the Corrib Gas Pipeline.

24. For the Corrib offshore pipeline the pipeline code adopted for design and construction is DNV-OS-F101: 2000: Submarine Pipeline Systems.

25. At the landfall of the offshore pipeline at Glengad, an interface arises between the primary onshore code I.S. EN 14161 and the primary offshore code DNV-OS-F101.

26. The interface at Glengad and the application of the various codes for design is illustrated in Appendix Q2.1 Figure 3.1 which is illustrated on Slide 1.

27. The offshore pipeline code DNV-OS-F101 was reissued in 2007 and Appendix F paragraph A101 specifies the requirements for design, construction and operation of parts of the offshore pipeline systems going onshore.

28. The guidance given in Appendix F is that the submarine pipeline system is defined to end at a weld beyond the first flange or valve onshore.

29. Appendix F, paragraph A 301 further states that Appendix F is fully aligned with the requirements given in ISO 13623 (and thus I.S. EN 14161).

30. Therefore the design code specification break at the Landfall between the design codes DNV-OS-F101 and I.S. EN 14161, I.S. 328 and BS PD 8010 was selected at the weld between the downstream barred tee of the LVI and the onshore pipeline. This is illustrated on Slide 1 as point A

31. From the above application of the pipeline design codes, the section of offshore pipeline between the High Water Mark and the LVI, illustrated on Slide 1 as line B, falls within the offshore pipeline code DNV-OS-F101 and furthermore complies with the relevant onshore pipeline codes.

Application of Hydrostatic Test Pressures

32. An Bord Pleanála’s letter dated 2nd November 2009, item a) requested clarification regarding the application of the hydrostatic test pressures for the Corrib pipeline.

33. For clarity, the adopted hydrostatic test pressures for the offshore pipeline, the LVI and the onshore pipeline are marked on the diagram illustrated in Appendix Q2.1 Figure 3.1 which is illustrated in Slide 2.

34. For the offshore pipeline the hydrostatic test pressure is 380 barg as stated in Appendix Q2.1 Section 9.4.1 and is in accordance with DNV-FS-101.

35. For the onshore pipeline the hydrostatic test pressure is 504 barg, as stated in Volume 2 Appendix Q5.3 and is in accordance with I.S. 328.

36. As stated previously, the LVI is designed to DNV-OS-F101 and therefore the test pressure for the LVI would be normally 380 barg. However, it has been concluded that the LVI, including the section of pipe up to the tie-in with the installed offshore pipe should be hydrostatically pressure tested to 504 barg.

37. The pipeline code specification break at the Landfall between the design codes DNV-OS-F101 and I.S. EN 14161, I.S. 328 and BS PD 8010 is illustrated on Slide 2 as point A

38. The application of the onshore hydrostatic test pressure of 504 barg is illustrated on Slide 2 from the tie-in with the already installed offshore pipeline, point C, through to the Gas Terminal.

39. The application of the DNV pipeline code and hydrostatic test pressure as illustrated in Slides 1 and 2 were confirmed to be in accordance with the requirements set out by TAG in 2006 via Department of Communications Energy and Natural Resources letter dated 13th May 2010.

PROPOSED DESIGN OF THE LANDFALL VALVE INSTALLATION

40. An Bord Pleanála's letter dated 2nd November 2009, item h) requested SEPIL provide a full justification for the proposed design of the Landfall Valve Installation.

41. Appendix Q4.3 provides the design justification and an overview of the Landfall Valve Installation.

42. An Bord Pleanála's letter dated 2nd November 2009, item h) also requested that further consideration be given to adopting a straight pipe configuration for the LVI with a potential for increase in safety at Glengad. This will be addressed later in this statement.

43. I will now briefly recap on the requirements of the Landfall Valve Installation at Glengad.

44. From the recommendations of the Corrib Technical Advisory Group in 2006, the Advantica report re-classified the onshore pipeline as a Class 2, Suburban pipeline, with a 0.3 design factor, and reduced the design pressure of the onshore pipeline section from its original 345 barg to a lower design pressure of 144 barg.

45. An Bord Pleanála's letter dated 2nd November 2009, item c) requested that the maximum allowable operating pressures (MAOP) be stated for the two sections of the Corrib pipeline. The selected MAOP values are:

46. Offshore pipeline and Landfall Valve Installation 150 barg

47. Onshore pipeline 100 barg.

48. The respective onshore pipeline codes require that a pressure protection system is in place to prevent the onshore pipeline MAOP being exceeded.

49. As the onshore pipeline MAOP is lower than the offshore pipeline MAOP, then onshore pipeline design code require that there shall be provision to prevent the operating pressure exceeding the MAOP of 100 barg under normal steady-state operating conditions.

50. Thus provision of a high reliability over-pressurisation protection system needs to be installed at the landfall at Glengad.

51. The purpose of this facility is to ensure that the pressure in the onshore section does not exceed 100 barg by isolating the flow of gas from the offshore pipeline to the onshore pipeline.

52. In addition TAG required that there were facilities to initiate, from the Gas Terminal, remote isolation between the offshore and the onshore pipeline sections at the landfall.

53. These two requirements resulted in a Landfall Valve Installation (LVI) being established at the landfall. The configuration of the LVI is presented in Appendix Q4.3 Figure 5-1 and is illustrated in Slide 3.

54. It should be noted that, at the LVI, there is no continuous control, reduction or regulation of gas pressure between the upstream offshore pipeline and the downstream onshore pipeline. The LVI is a pressure limitation and isolation system.

55. As indicated previously in this statement, the break between the two pipeline codes, namely DNV-FS-101 and I.S. EN 14161 is at the weld between the downstream barred tee of the LVI and the onshore pipeline. This location is marked on Slide 3 as Point A.

56. The constraints influencing the design of the LVI were:

- Selection of the safety shutdown system and the optimum pipe configuration.
- Offshore to onshore pipeline interface at the LVI to be suitable for intelligent pigging.
- Maximise safety at the LVI.
- Mitigate visual impact at Glengad.
- Minimise the footprint of the LVI site.
- Site security and lighting.

57. Each of these constraints is discussed in further detail in Appendix Q4.3 Section 4.2.

58. For the purposes of clarity I will now recap on the operation of the LVI.

59. The prime function of the LVI is to ensure that the pressure in the onshore section does not exceed 100 barg by positively isolating flow of gas from the offshore pipeline to the onshore pipeline.

60. The mainline valve (V1) is locked closed and only used when intelligent pigging of the Corrib pipeline is underway. This is an infrequent event which is subject to the Gas Terminal permit to work system. The LVI will be fully manned 24/7 during such an operation.

61. Normal flow of gas at the LVI is through a shutdown spool located around the mainline valve V1.

62. Isolation between the offshore and onshore pipelines is achieved by the two high integrity safety shutdown valves (V3 and V4) in the shutdown spool. Both of these valves are axial flow type which means that the valve piston moves in the direction of flow against an internal orifice with a metal to metal seal.

63. Each safety shutdown valve is equipped with a spring powered actuator mounted on the valve, thus enabling each valve to close in less than 12 seconds.

64. Each safety shut down valve is maintained in the open position by internal hydraulic fluid pressure pushing against the spring and thus opening the valve. When hydraulic pressure is released, the valve will close. To open the valve the hydraulic system is re-pressurised using a hand pump fitted to the valve.

65. Automatic closure of the safety shutdown valves is initiated should any 2 out of 3 (2oo3) pressure transmitters exceed a prescribed trip pressure which is below the 100 barg MAOP. In such a case the control unit (or logic solver)

immediately causes the hydraulic pressure in both valves to be released resulting in the two safety shutdown valves automatically closing under the force of the spring to close actuators.

66. Should there be any loss of hydraulic pressure or loss of electrical power, then the two safety shutdown valves will both fully close; that is they fail to the fully closed position.

67. As required by the TAG recommendations, the operator at the Gas Terminal has facilities to remotely close both safety shutdown valves located at the LVI. The safety shutdown valves can only be re-opened at the LVI.

68. The two double expanding gate valves V2 and V5 enable the shutdown spool to be isolated for maintenance.

69. A 4” start-up spool is located around isolation valve V5. This comprises a downstream isolation valve and a restart globe valve. This is used to manually adjust the gas flow rate into the onshore pipeline during restart to equalise the pressure over the two safety shutdown valves should these have closed. Methanol will also be injected into the gas flow during restart to mitigate any possible hydrate formation.

70. The 20” diameter mainline valve is normally locked closed during daily operation of the Corrib pipeline system. Consequently the short section of 20” diameter pipe between the upstream and downstream barred tees is not subject to continuous flow of gas and is not afforded protection via the internal corrosion inhibitors dosed into the gas subsea. Corrosion protection is therefore provided on this section in the form of clad carbon steel pipe. In addition the valve internals of the 20” diameter DEGV are also clad carbon steel with a duplex stainless steel gate.

71. The shutdown spool and the restart spool are non-piggable sections of pipe and the materials selected provide corrosion resistance. This is achieved by using both duplex stainless steel and clad carbon steel materials.

72. The design adopted for the LVI is such that any vibration that may occur during operation will be within the design limits of the pipe work.

LVI ALTERNATIVE CONFIGURATIONS

73. An Bord Pleanála’s letter dated 2nd November 2009 item (h) and subsequent clarification in letter dated 29th January 2010 item 4, requested that further consideration be given to adopting a straight pipe configuration for the LVI with a potential for increase in safety at Glengad.

74. The proposed configuration of the LVI, the bypass configuration, is illustrated in Appendix Q4.3 Figure 5-1, included as Slide 3.

75. A schematic of a straight pipe configuration is illustrated in Appendix Q4.4 Figure 4-1 and in Slide 4.

76. The straight pipe configuration locates the two safety shutdown valves S1 and S2 in line with the offshore and onshore pipelines. To enable the safety system to be inspected and maintained, upstream and downstream double expanding gates valve, DEGV1 and DEGV 2 will be required.

77. To facilitate restart following closure of the safety shutdown valves, a restart spool and methanol injection will be required around DEGV2.

78. Flow of gas therefore passes directly from the offshore pipeline through DEGV1, S1, S2 and DEGV2 into the onshore pipeline.

79. If the pressure on the onshore pipeline exceeds a prescribed trip pressure which is below the 100 barg MAOP, then S1 and S2 are closed.

80. The two pipe work and valve configurations have been assessed and the evaluation is presented in Appendix Q4.4.

81. The evaluation concluded that the bypass configuration was preferred for the following reasons:

82. Pigging of the offshore and onshore pipelines is an integral part of verifying the integrity of the overall pipeline system. In the straight line configuration the pigs would pass directly through both safety shutdown valves S1 and S2. There is therefore potential for the passing pigs to affect the safety shutdown valves which could increase their probability of failing to close on demand. In addition, pigging of high integrity safety shutdown valves is not in compliance with the design practice adopted by SEPIL.

83. From an evaluation of the current market there was insufficient evidence to establish the availability of field proven piggable, 20” diameter, 345 barg design pressure, high integrity safety shutdown valves. The 16” diameter safety shutdown valve selected for the proposed bypass arrangement has an extensive field proven operational track record.

84. When assessing the individual risk per year for the two alternative configurations, the difference in the level of risk at Glengad was found to be negligible. This is illustrated in Appendix Q4.4 Figure 6-1 which is included in Slide 5.

85. The graph shows a plot of Individual Risk per Year against distance from the LVI. There are two plots, one for the straight pipe arrangement in blue and the second for the proposed bypass arrangement in purple. As can be seen there is no discernable difference between the plots which means from a safety perspective there is no reduction in risk to an individual when adopting the straight pipe arrangement.

86. Therefore the bypass configuration has been adopted in preference to the straight pipe configuration for the following reasons:

- The axial flow safety shutdown valves have a proven field track record for the pressure and diameters required for the LVI.
- Pigging of the LVI can be accommodated by use of the locked closed 20” diameter mainline valve.
- The difference in individual risk per year for the two alternative configurations at Glengad was found to be negligible.

MOVEMENT OF THE STONE ROAD

87. An Bord Pleanála’s letter dated 2nd November 2009, item n) requested an assessment of the potential impact of the estimated stone road settlements on the umbilical pipeline and service ducts that will also be constructed within the stone road.

88. As the route of the onshore pipeline has changed, the assessment of stone road settlements on the gas pipeline has also been updated to reflect the proposed route.

89. The method of construction of the stone road through areas of peat is presented in Volume 1, Chapter 5.

90. The potential for movement of the stone road has been evaluated and this is presented in Volume 2, Book 5 of 6, Appendix M.

91. The evaluation of the stone road in areas of peat established that there would be no horizontal movement of the stone road in the peat. Small changes in vertical movement may occur and these have been quantified. The worst case vertical movement was 0.5 metre.

92. An analysis was performed to ensure that any such vertical movement would not result in loss of containment from the gas pipeline and that the displacements would not affect the outfall line, the umbilical, the fibre optic cable and the signal cable.

93. The analysis took into consideration the worst case vertical displacements that could be considered along the route of the stone road.

94. The results of the analysis are presented in Appendix Q4.1, Attachment Q4.1A. This established that the effects on the outfall pipeline and the associated services were within the specified design parameters and thus no consequential effects result from the worst case vertical displacement.

95. For the gas pipeline the calculations established that the resultant pipeline combined stress is within the allowable limits stated by the respective pipeline code. The highest values were identified as occurring during hydrostatic testing of the onshore pipeline. (Refer Attachment Q4.1A for further details).

96. It is noted that the extent of vertical movement considered within the analysis was the worst case and the modelling of the gas pipe adopted a stringent evaluation of the pipe movement under a number of potential scenarios.

97. The analysis concluded that the onshore gas pipeline routed through areas of peat and installed in the stone road would not be subject to loss of containment due to the predicted worst case vertical settlement of the stone road.

CONCLUSION

98. Inspector, in conclusion I consider that the submitted documents within the EIS and this statement provide a transparent response to the points raised in An Bord Pleanála's letters dated 2nd November 2009 and the 29th January 2010 as identified as follows:

99. Items a), b)and c). I confirm that the onshore pipeline, the outfall pipeline and associated services, together with the LVI have been designed in full compliance with the required pipeline codes and standards as recommended by TAG and used within the Industry. Furthermore the design code DNV-FS-101 is applicable to the section of pipeline from approximate chainage 83+380 (HWM) to chainage 83+470 (downstream weld at the LVI).

100. Item a). The hydrostatic test pressures for the offshore pipeline, the LVI and the onshore pipeline have been defined in accordance with the respective offshore and onshore pipeline codes. In particular the hydrostatic test pressure applicable to the section of pipeline from approximate chainage 83+380, the High Water Mark, to chainage 83+470, the downstream weld at LVI is as follows. To chainage ~83+440 the test pressure will be 380 barg and from chainage ~83+440, the test pressure will be 504 barg.

101. Item h), I confirm that the proposed bypass configuration is the optimum design which is based upon field proven equipment and will ensure that the

pressure in the onshore pipeline does not exceed the onshore pipeline MAOP of 100 barg.

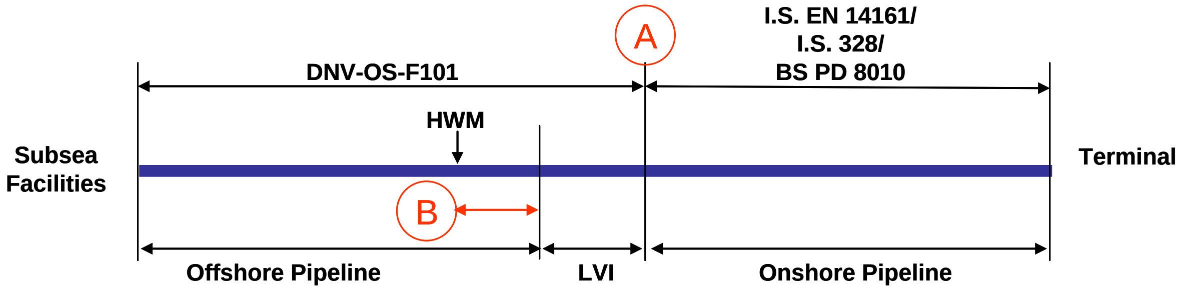
102. Item n), I confirm that the predicted worst case vertical movement of the gas pipeline in the stone road will not result in a loss of containment of gas.

103. Item n), I confirm that the predicted worst case vertical movement of the outfall pipe, umbilicals and service ducts that will also be constructed within the stone road are within their respective design parameters and thus no consequential effects result from the worst case vertical displacement.

104. Finally, the Corrib pipeline has been designed to the stringent requirements of the pipeline codes and fully complies with best industry practice.

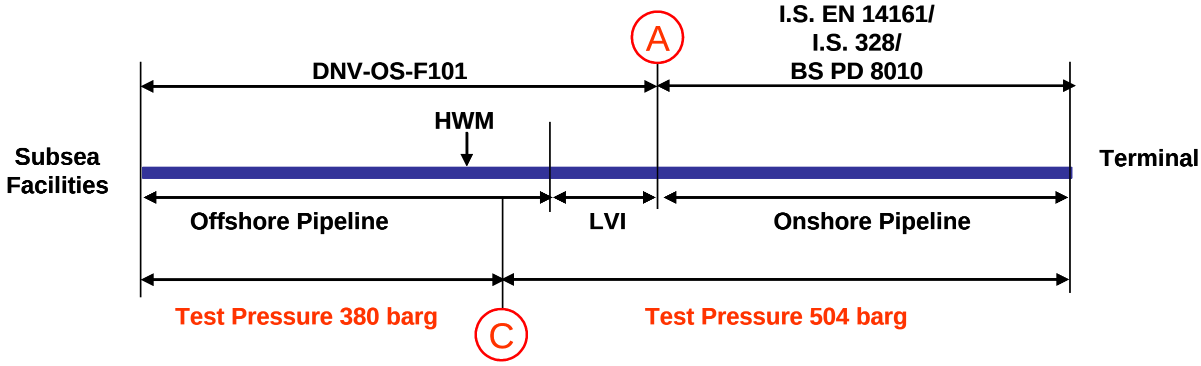
105. This concludes my statement

Slide 1



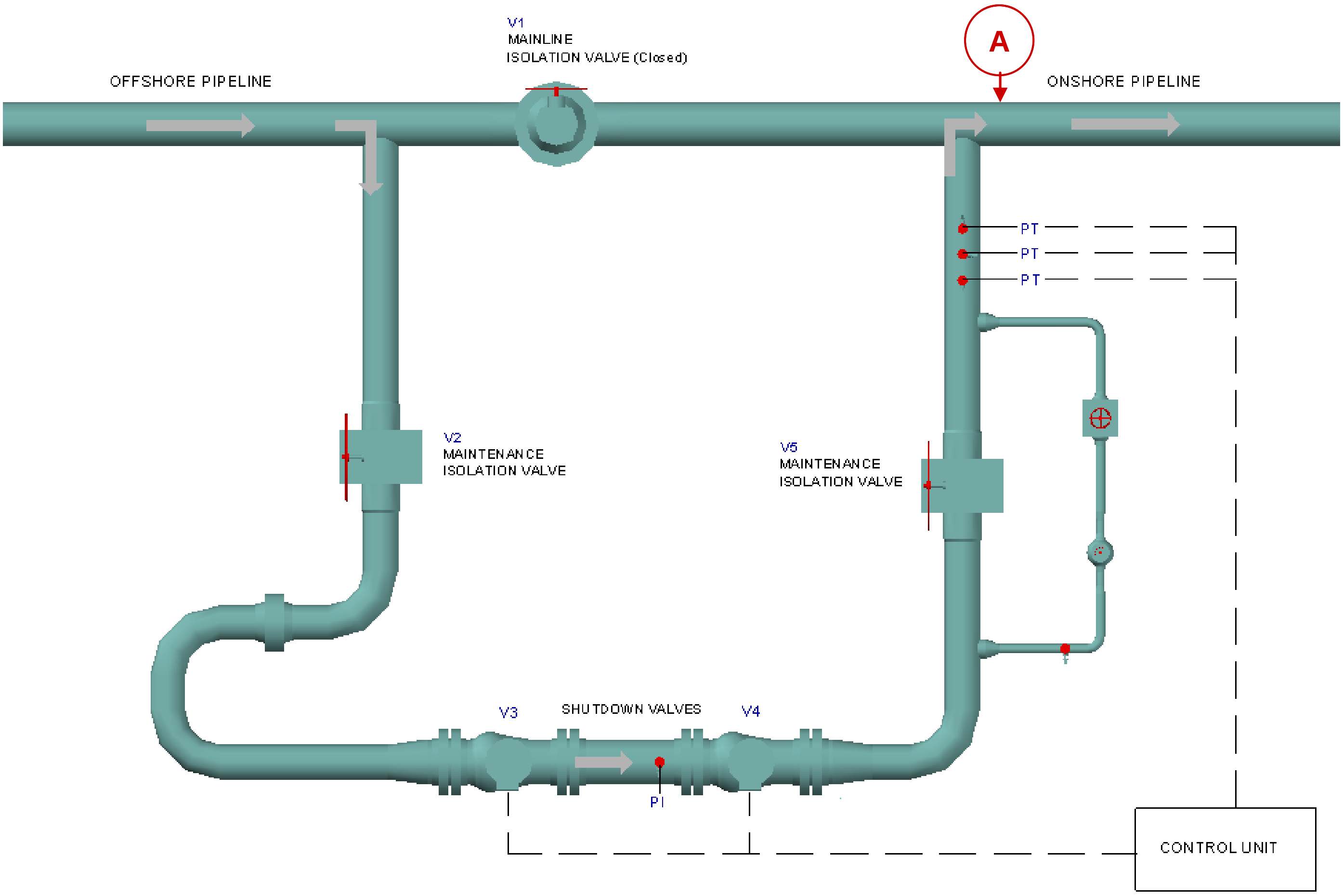
Appendix Q2.1 Figure 3.1

Slide 2



Appendix Q2.1 Figure 3.1 with Hydrostatic Test Pressures added

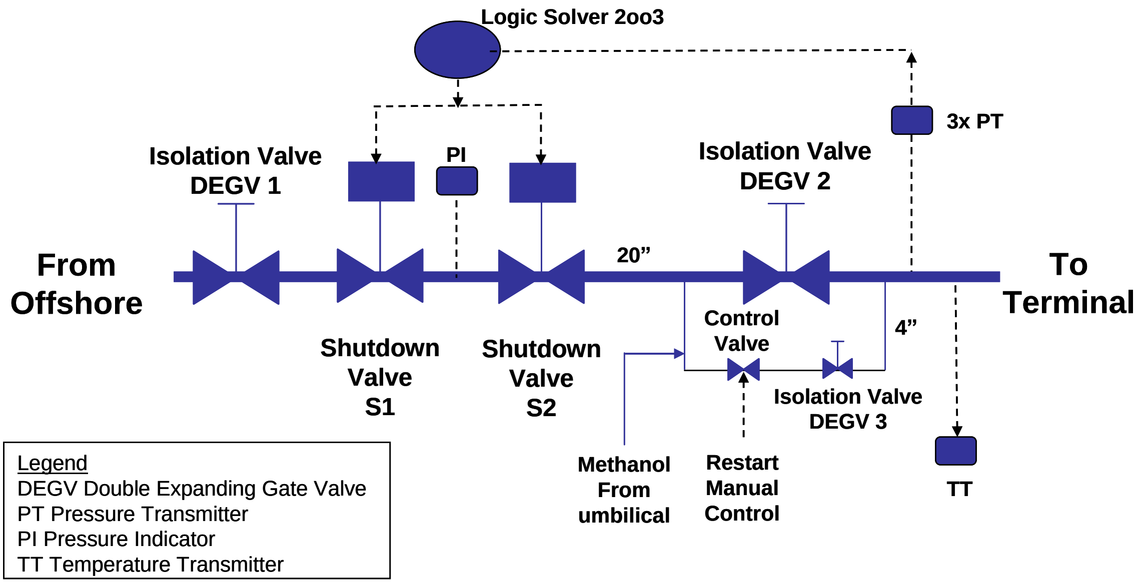
Slide 3



PT Pressure Sensors. measure the pressure in the pipeline.	V1 Mainline Isolation Valve. Closed during normal operation.	V2 & V5 Maintenance Isolation Valve. Open during normal operation, closed when maintenance of the shutdown valves is required.
CONTROL UNIT The control unit sends signals to shutdown valves to close them when pressure approaches 100 bar.	V3 & V4 Shutdown Valves. Will close automatically when pressure approaches 100 bar.	PI Pressure indicator

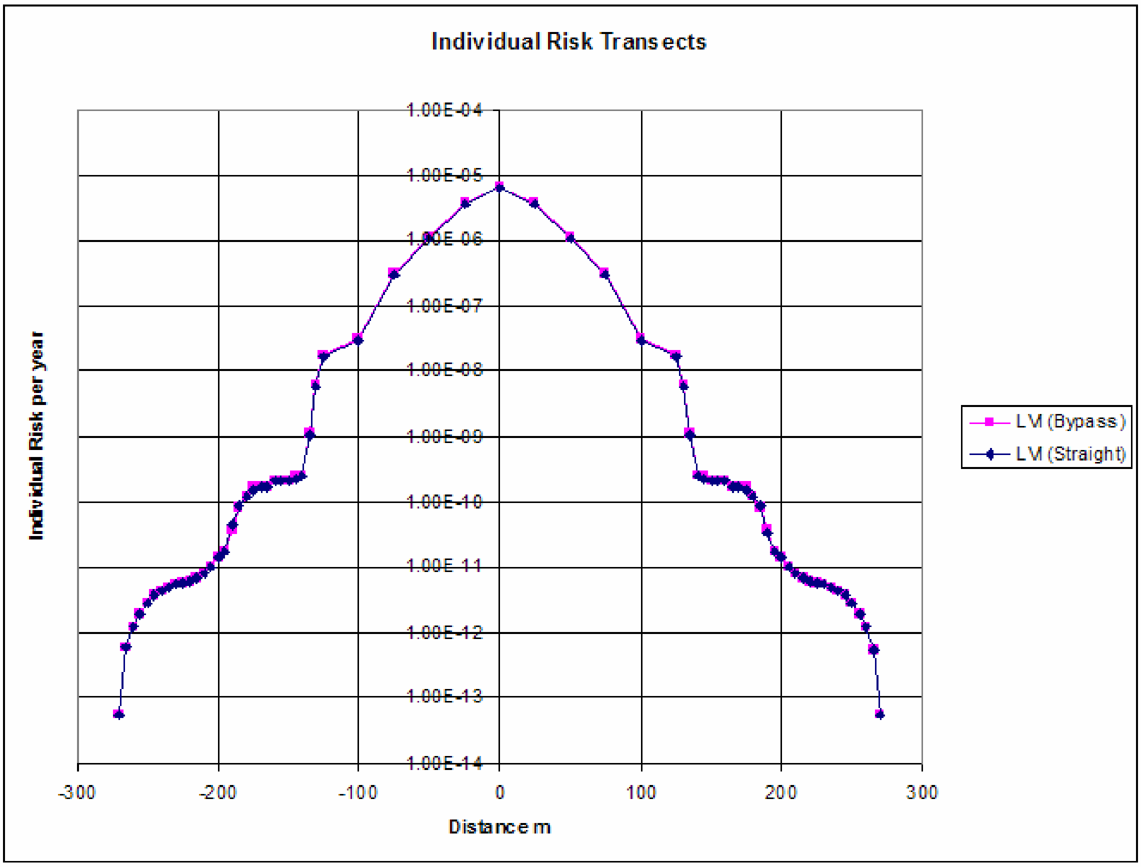
App Q4.3 Figure 5-1 LVI Configuration

Slide 4



App Q4.4 Figure 4-1 Straight pipe configuration

Slide 5



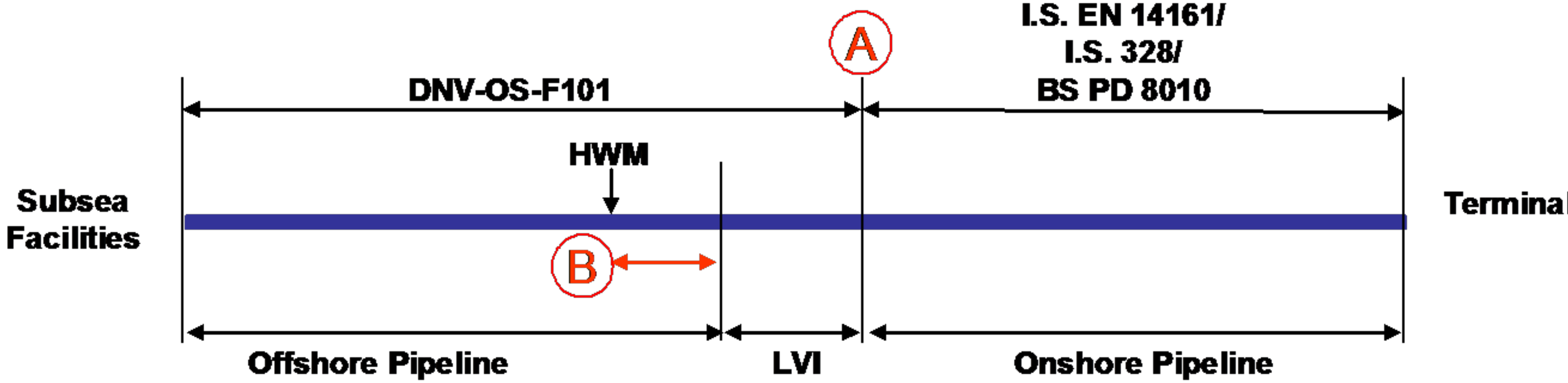
App Q4.4 Figure 6 -1 Comparison of Individual Risk per Year

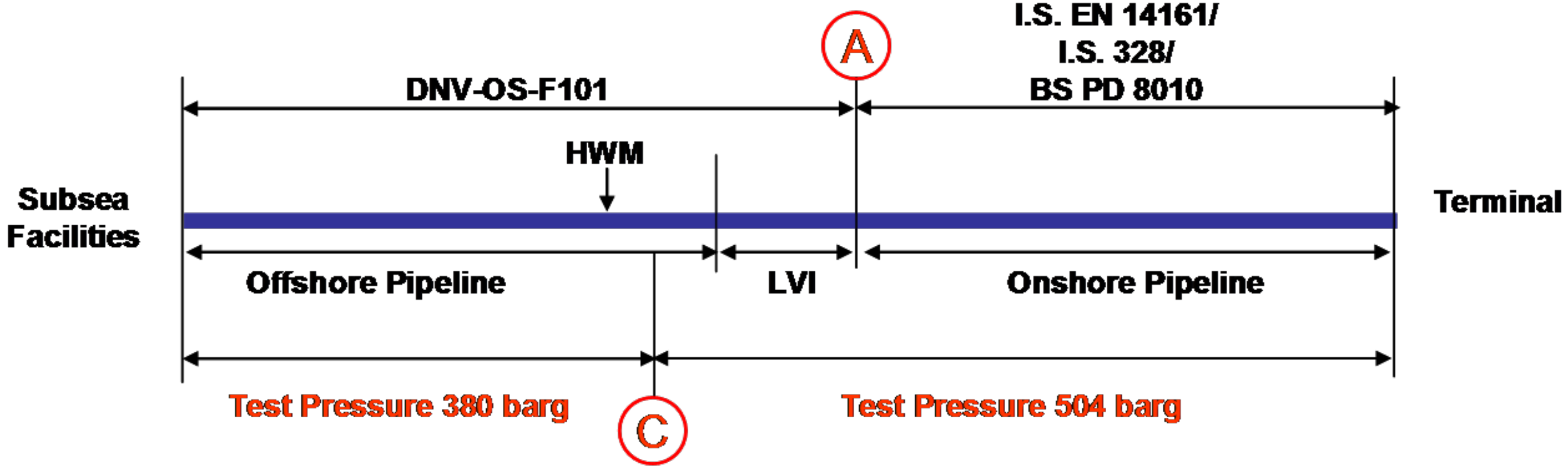
Corrib Onshore Pipeline –

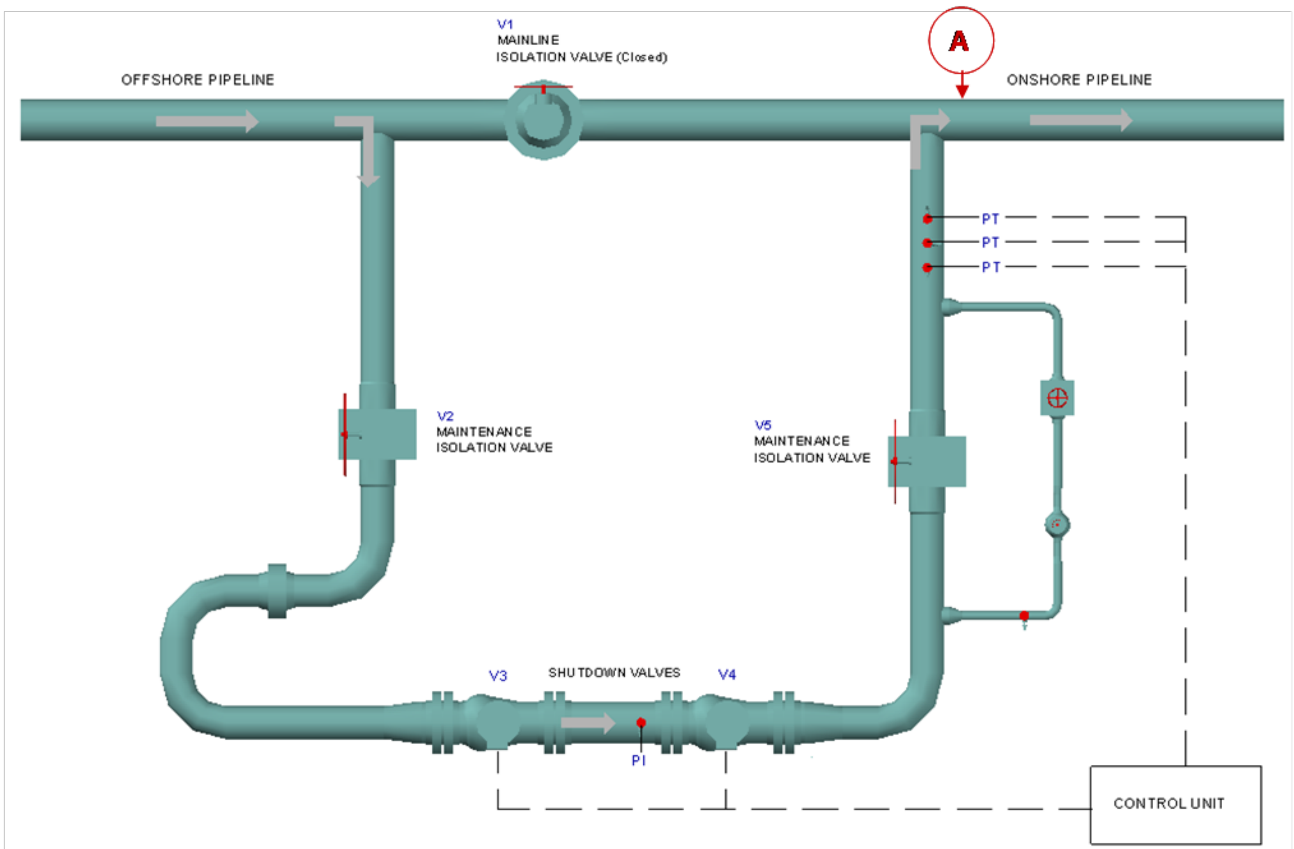
Onshore Pipeline and LVI Design

John Gurden

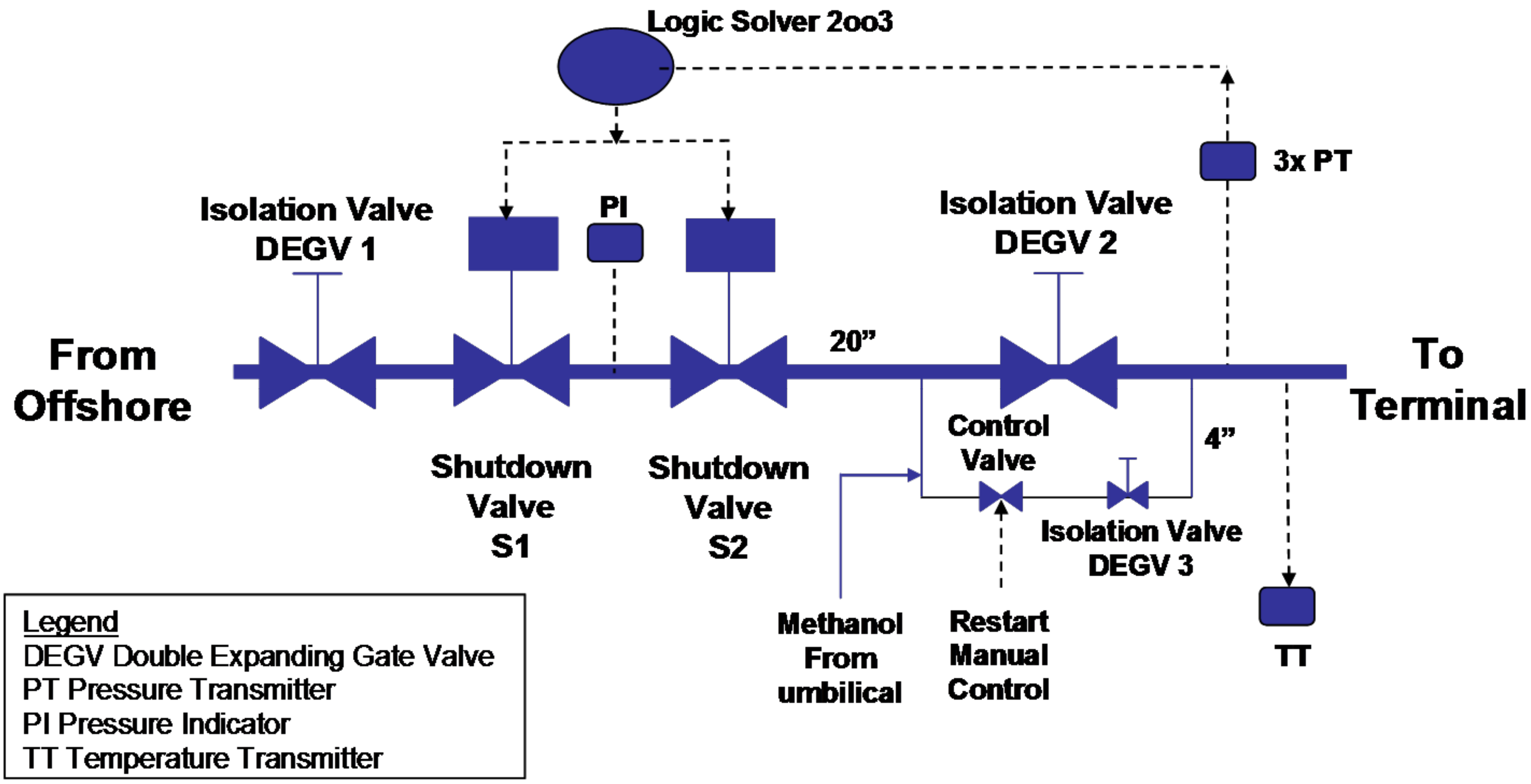
(An Bord Pleanála Application Reference No.: 16.GA0004)


I.S. EN 14161/
I.S. 328/
BS PD 8010
A
DNV-OS-F101
HWM
Subsea
Facilities
Terminal
B
Offshore Pipeline
LVI
Onshore Pipeline

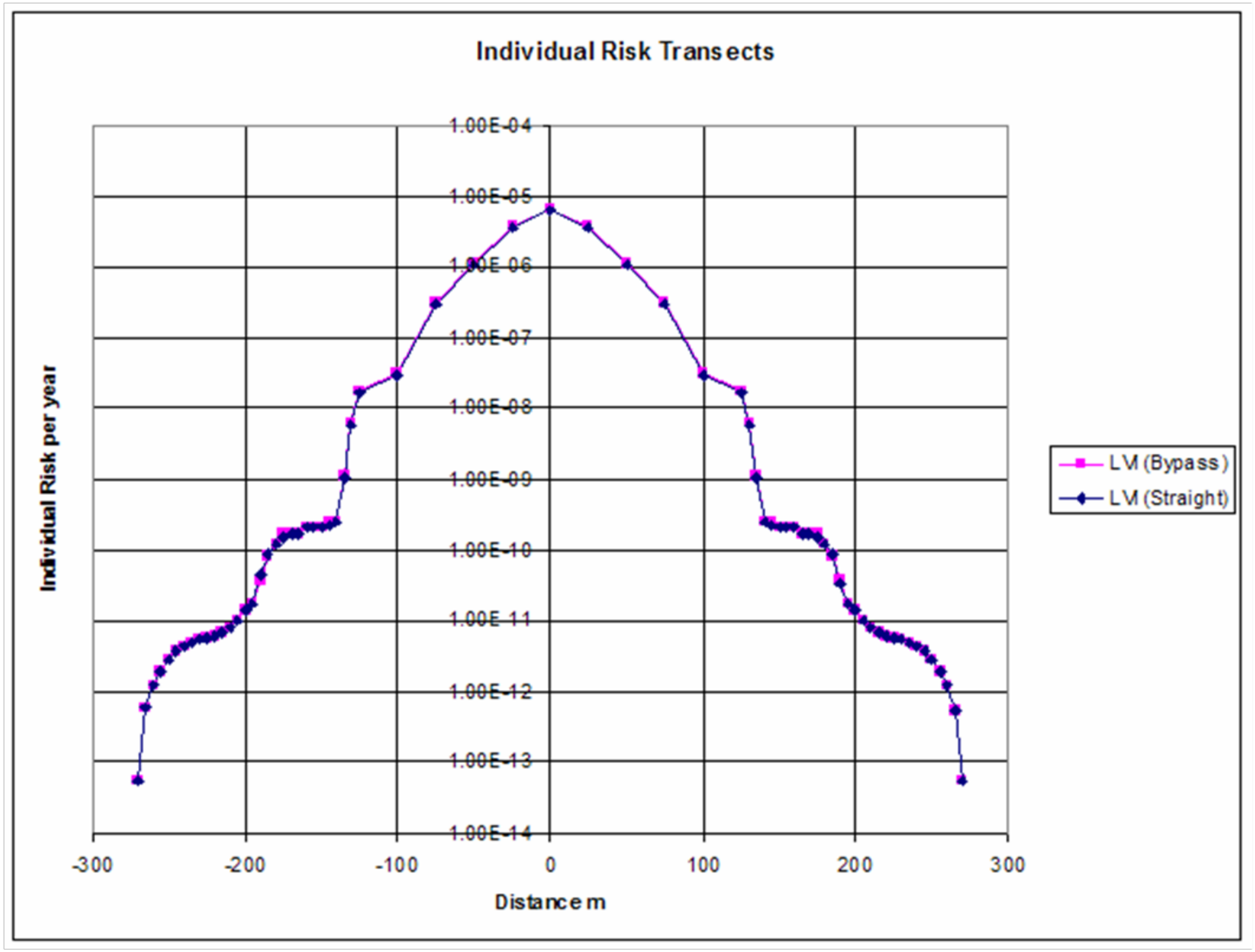

I.S. EN 14161/
I.S. 328/
BS PD 8010
A
DNV-OS-F101
HWM
Subsea
Facilities
Terminal
Offshore Pipeline
LVI
Onshore Pipeline
Test Pressure 380 barg
C
Test Pressure 504 barg



PT Pressure Sensors. measure the pressure in the pipeline.	V1 Mainline Isolation Valve. Closed during normal operation.	V2 & V5 Maintenance Isolation Valve. Open during normal operation, closed when maintenance of the shutdown valves is required.
CONTROL UNIT The control unit sends signals to shutdown valves to close them when pressure approaches 100 bar.	V3 & V4 Shutdown Valves. Will close automatically when pressure approaches 100 bar.	PI Pressure indicator



App Q4.4 Figure 4-1 Straight pipe configuration


Individual Risk Transects
Individual Risk per year
1.00E-04
1.00E-05
1.00E-06
1.00E-07
1.00E-08
1.00E-09
1.00E-10
1.00E-11
1.00E-12
1.00E-13
1.00E-14
-300
-200
-100
0
100
200
300
Distance m
LVI (Bypass)
LVI (Straight)

Corrib Onshore Pipeline –

Onshore Pipeline and LVI Design

John Gurden

(GA0004)