RGU ABERDEEN

Coursework Assignments

1. **ENM215 Oceans, Operability and Humans in the Ocean**
   Selecting a ROV for an Inspection Task

2. **ENM201 Wells**
   Olivia Field E10 Well Evaluation

3. **ENM202 Facilities**
   Black Dog Field – Field Development Plan

4. **ENM227 Subsea Systems**
   Asset Integrity Management Plan and Cost Projection

5. **ENM229 Subsea Pipeline and Riser Design**
   Subsea Pipeline Option Study and Design Analysis

6. **ENM239 Subsea Systems Risk and Reliability**
   Minimising Hydrocarbon Leakages in Subsea Systems through effective Data and Change Management

7. **ENM220 Control and Telemetry Systems**
   New Field Development Control and Telemetry Basis of Design

8. **ENM233 Materials and Corrosion Science**
   Zonko Sporran Delta Seawater Injection Failure Analysis Report

Robert Gordon University

ENM215 Oceans, Operability and Humans in the Ocean

Coursework Report

Selecting a ROV for an Inspection Task

Name: ADAM BEATON

Student No: 1418528

Date: 7/4/2015

Word Count: 1684

1.0 EXECUTIVE SUMMARY

Two ROVs with different operating limits were considered for inspection operations in the North Sea. Sea state data was provided for the region and time frame. “ROV-B” was significantly more expensive, and could only be justified if it could complete an 8-hour operation at least 15% more of the time than the less expensive “ROV-A”.

The sea state data was used to determine the probability of a successful operation for each ROV, and the results showed that ROV-B would be successful 15.2% more often than ROV-A. It is recommended to purchase ROV-B for the inspection operations.

CONTENTS

2.0 INTRODUCTION

Two different remotely operated vehicles (ROV-A and ROV-B) were considered for subsea inspection operations in the North Sea. ROV-A can operate in conditions up to a significant wave height (H_s) of 3 m, whereas ROV-B can continue to a H_s of 4 m. Statistical wave height data was provided for the region in the form of a Scatter Diagram (see Table 1) and a Transition Matrix (see Table 2).

The inspection operations will last for 8 hours, and the sea states must remain below the chosen ROV's limit for the operation to be successful. Sea state checks would occur at deployment, and every 3 hours thereafter. ROV-B is more expensive, such that it must be able to complete a successful operation at least 15% more often than ROV-A to justify its additional cost.

The statistical data was used, along with assumptions made in Section 3.0 in order to determine the most appropriate, cost-effective ROV to purchase for the operations.

Table 1 – Scatter Diagram

		Tz (s)											
		Tz < 1	1 < Tz < 2	2 < Tz < 3	3 < Tz < 4	4 < Tz < 5	5 < Tz < 6	6 < Tz < 7	7 < Tz < 8	8 < Tz < 9	9 < Tz < 10	10 < Tz < 11	11 < Tz < 12
Hs (m)	Hs > 6									3	6	3	2
	5 < Hs < 6								3	20	16	6	6
	4 < Hs < 5							2	22	40	28	14	3
	3 < Hs < 4						2	20	48	58	33	11	3
	2 < Hs < 3					1	12	60	93	75	28	5	2
	1 < Hs < 2					3	36	83	87	65	18	4	1
	Hs < 1	24				2	14	22	11	4	1		

Table 2 – Transition Matrix

		Hs Next Sea State						
		Hs < 1	1 < Hs < 2	2 < Hs < 3	3 < Hs < 4	4 < Hs< 5	5 < Hs < 6	Hs > 6
H s Current Sea State	Hs < 1	0.8	0.18	0.02				
	1 < Hs < 2	0.05	0.82	0.13				
	2 < Hs < 3		0.14	0.71	0.15			
	3 < Hs < 4			0.25	0.57	0.17	0.01	
	4 < Hs < 5			0.02	0.32	0.5	0.15	0.01
	5 < Hs < 6				0.04	0.4	0.43	0.13
	Hs > 6					0.26	0.51	0.23

3.0 ASSUMPTIONS

The following assumptions have been made in order to perform the calculations in this report;

1. The values in the supplied Scatter Diagram are in ‘parts per thousand’, given that the sum of the table is 1,000.
2. The Scatter Diagram has the standard validity of 3 hours, after which the Transition Matrix must be used to determine possible sea states for the following 3-hour time segments.
3. The sea states are stationary within each 3-hour time period, then “instantly” change to the next sea state according to the Transition Matrix.
4. A single instance of H_s exceeding the ROV limit will cause the failure of the operation. The operation would be re-started, rather than continued at the next opportunity.
5. The calculations consider the ROV’s probability of a successful operation based on attempting the operation “at any instant” during the year – Not just the probability of success from an acceptable sea state condition for that ROV. (i.e. The “total probability” calculation takes into account attempts which may fail instantly because of the initial sea state conditions). See Section 5.2 for an alternative interpretation of the problem.

4.0 CALCULATION METHOD

The overall probability of each ROV completing a successful operation was determined by first representing all of the possible sea state 'paths' in a Spider Diagram, based on the statistical data provided. The probability of each path occurring was calculated, and then the total probability of the operation having a successful path was determined.

In order to identify the possible paths, the 8 hour inspection operation was firstly divided into three time periods according to the 3-hour validity of the Scatter Diagram and the Transition Matrix as follows;

Table 3 - Outline of Sea State Transitions

Time Period	Hours	Sea State Check	Data Used
1	$0 < t \leq 3$	t = 0 hrs	Scatter Diagram
2	$3 < t \leq 6$	t = 3 hrs	Transition Matrix
3	$6 < t \leq 8$	t = 6 hrs	Transition Matrix

4.1 Initial Sea State

The Scatter Diagram was used to determine the probabilities of each possible Hs range at the start of the ROV operation (t = 0 hrs). The ROV operability depends only on the H_s, and not the mean zero up-crossing period (T_z). Thus, probabilities for each H_s range were summed across the rows of the Scatter Diagram to include all T_z states. The totals were divided by 1,000 to give the probabilities for each possible Hs range for 0 < t < 3 hrs (see Table 4).

Table 4 - Scatter Diagram with Hs Totals

		Tz (s)												TOTALS	Hs Probability
		Tz < 1	1 < Tz < 2	2 < Tz < 3	3 < Tz < 4	4 < Tz < 5	5 < Tz < 6	6 < Tz < 7	7 < Tz < 8	8 < Tz < 9	9 < Tz < 10	10 < Tz < 11	11 < Tz < 12		
Hs (m)	**Hs > 6**									3	6	3	2	14	**0.0140**
	5 < Hs < 6								3	20	16	6	6	51	**0.0510**
	4 < Hs < 5							2	22	40	28	14	3	109	**0.1090**
	3 < Hs < 4						2	20	48	58	33	11	3	175	**0.1750**
	2 < Hs < 3					1	12	60	93	75	28	5	2	276	**0.2760**
	1 < Hs < 2					3	36	83	87	65	18	4	1	297	**0.2970**
	Hs < 1	24				2	14	22	11	4	1			78	**0.0780**

4.2 Transitioning Sea States

Following the initial 3-hour time period, the next two time periods would experience sea states according to the probabilities give in the Transition Matrix. Two sea state transitions occur at t = 3 hrs and t = 6 hrs. Spider Diagrams are provided in Appendix A for both ROV-A and ROV-B, showing the possible sea state paths from each initial Hs. Note that for clarity, the Spider Diagram does not show paths that begin with H_s above the ROV limit, as the operation would be cancelled before an attempt is made. The actual full diagrams would show a total of 91 possible paths for each ROV.

The Transition Matrix models the behaviour of the sea state as a Markov chain, meaning that the process is random and memoryless (Brito 2011). At each transition (i.e. t = 3 hrs and t = 6 hrs), the sea state transitions are based only on the current condition and the data in the matrix (Grinstead 2010). The history before that does not affect the next sea state.

4.3 Probability of Each Path

Appendix B and C show tabulations of the spider diagram for each ROV, and the corresponding probabilities of each transition along each path. The probabilities are taken directly from the Transition Matrix. An example path is highlighted green on both the spider diagram and the table to illustrate the logic of the model. Again, in the table the instances of H_s exceedance are highlighted red to show a failed operation.

The last two columns on the right side of the table identify whether the path was successful, and then the path probability is multiplied across the three time periods, as follows;

$$P_{Total\ Path} = P_{Initial\ Hs} * P_{1st\ Transition} * P_{2nd\ Transition}$$

A path is only successful if it has experienced sea states below the operability limit at all three check times.

4.4 Total Probability of Completing an Operation

The sum of all the successful path probabilities is equal to the total probability of the ROV having a successful operation. The successful paths were summed, and the results are stated in Table 5.

Table 5 - Results of Calculations

ROV	Sum of Successful Paths
A	14.50%
B	29.66%
Difference	**15.16%**

The calculations revealed that at any given random point in time, ROV B would likely complete a successful 8-hour operation 15.16% of the time *more* than ROV A.

5.0 DISCUSSION

The results imply that if both ROV's were deployed at any given random instant, ROV-B would be close to twice as likely to successfully complete an 8-hour operation without being recovered due to sea state exceedance. ROV-B's probability of success is just above the 15 percentage points required for the additional cost to be justified. The cost justification is borderline, and could require further investigation to confirm the conclusion made by this report.

5.1 Limitations of the Calculation Method

Some limitations to the method of calculation have been identified below.

- The standard 3-hour validity period of the Transition Matrix is used. If the sea states were to change more frequently, it would lead to more divergent paths, and could likely exceed the ROV limits more frequently in reality.

- The ROV operability limit is based on H_s only for this problem. In reality, a large single wave (H_{max}) could probably also jeopardise the operation. If a limiting H_{max} were provided for the ROVs, then statistical analysis could be used to determine the probability of a specified H_{max} occurring during the 8-hour operation, given the T_z, H_s and time periods.

- The ROV operability could also be affected by the wave period (T_z), or the wave heading during deployment. These sea properties can determine the behaviour of the ROV umbilical, and thus the success of a deployment (Valen 2000).

5.2 Alternative Interpretation

As stated in Section 3.0, the total probability of success takes into account all possible starting conditions regardless of the ROV limit, because it is considering the probability from any instantaneous, *random* starting time. The scenario could alternatively be interpreted such that only 'acceptable' starting points are considered in the comparison (e.g. the paths for ROV-A would only start with H_s<1, 1<H_s<2 and 2<H_s<3, and the probability of those three sea states would be summed across the Scatter Diagram). Under this alternative assumption, the following results would be found:

Alternative Conclusion

ROV-A would be successful 88.2% of the time (once it is successfully deployed). ROV-B would be successful 93.1% of the time (once it is successfully deployed). The difference is only 4.9%, thus ROV-B is not successful 15% more often than ROV-A, and thus its cost is not justified.

6.0 CONCLUSIONS

The calculation results suggest that ROV-B would be able to successfully carry out the 8-hour inspection operation approximately 15.16% more often than ROV-A, at any point during the validity of the sea state data provided. The additional cost of ROV-B is justified, but only marginally.

Provided that the assumptions made during the calculations in this report are valid, and the financial clause for the justification of ROV-B is reliable, then it is recommended that ROV-B be purchased for the inspection operations in the North Sea.

7.0 REFERENCES

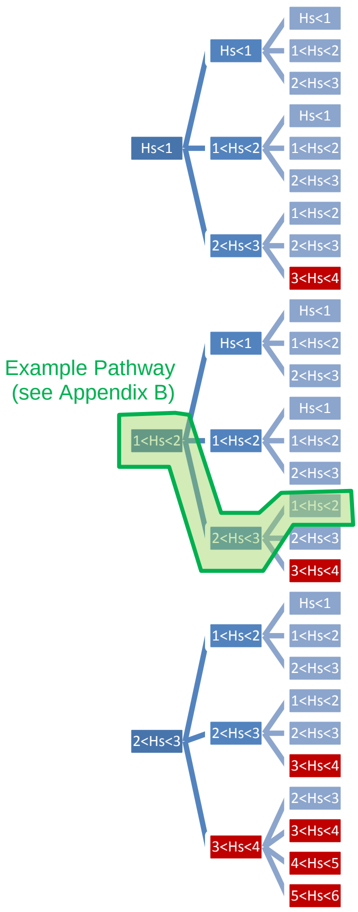
- BRITO, MARIO and GRIFFITHS, GWYN, 2011. *A Markov Chain state transition approach to Establishing Critical Phases for AUV Reliability.* IEEE Journal of Oceanic Engineering, 36 (1).
- GRINSTEAD, CHARLES, 2010. *Introduction to Probability*. 2nd ed. Dartmouth: AMS, pp 405-406.
- ROBERT GORDON UNIVERSITY, 2015. *ENM215: The Oceans, Operability and Humans in the Ocean [Lecture notes] Topic 2g – Operability*. Delivered February 2015.
- VALEN, MAGNUS, 2000. *Launch and recovery of ROV: Investigation of operational limit from DNV Recommended Practices and time domain simulations in SIMO.* Norwegian University of Science and Technology Department of Marine Technology.

APPENDIX A SPIDER DIAGRAMS

The two Spider Diagrams only show paths that begin with acceptable starting conditions. Starting conditions exceeding the ROV limits would be deemed an instant failure.

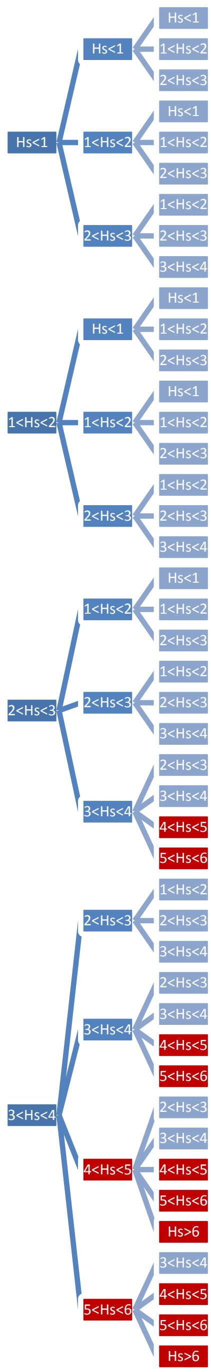
ROV-A

0 Hrs 3 Hrs 6 Hrs



ROV-B

0 Hrs 3 Hrs 6 Hrs



APPENDIX B ROV-A PATH PROBABILITY TABLE

0 < t < 3 Hrs		3 < t < 6 Hrs		6 < t < 8 Hrs		Successful Operation?	Path Probability
Sea State (m)	Probability	Sea State (m)	Probability	Sea State (m)	Probability		
Hs < 1	0.014	Hs < 1	0.8	Hs < 1	0.8	YES	0.00896
	0.014		0.8	1 < Hs < 2	0.18	YES	0.00202
	0.014		0.8	2 < Hs < 3	0.02	YES	0.00022
	0.014	1 < Hs < 2	0.18	Hs < 1	0.05	YES	0.00013
	0.014		0.18	1 < Hs < 2	0.82	YES	0.00207
	0.014		0.18	2 < Hs < 3	0.13	YES	0.00033
	0.014	2 < Hs < 3	0.02	1 < Hs < 2	0.14	YES	0.00004
	0.014		0.02	2 < Hs < 3	0.71	YES	0.00020
	0.014		0.02	3 < Hs < 4	0.15	NO	0.00004
1 < Hs < 2	0.051	Hs < 1	0.05	Hs < 1	0.8	YES	0.00204
	0.051		0.05	1 < Hs < 2	0.18	YES	0.00046
	0.051		0.05	2 < Hs < 3	0.02	YES	0.00005
	0.051	1 < Hs < 2	0.82	Hs < 1	0.05	YES	0.00209
	0.051		0.82	1 < Hs < 2	0.82	YES	0.03429
	0.051		0.82	2 < Hs < 3	0.13	YES	0.00544
	0.051	2 < Hs < 3	0.13	1 < Hs < 2	0.14	YES	0.00093
	0.051		0.13	2 < Hs < 3	0.71	YES	0.00471
	0.051		0.13	3 < Hs < 4	0.15	NO	0.00099
2 < Hs < 3	0.109	1 < Hs < 2	0.14	Hs < 1	0.05	YES	0.00076
	0.109		0.14	1 < Hs < 2	0.82	YES	0.01251
	0.109		0.14	2 < Hs < 3	0.13	YES	0.00198
	0.109	2 < Hs < 3	0.71	1 < Hs < 2	0.14	YES	0.01083
	0.109		0.71	2 < Hs < 3	0.71	YES	0.05495
	0.109		0.71	3 < Hs < 4	0.15	NO	0.01161
	0.109	3 < Hs < 4	0.15	2 < Hs < 3	0.25	NO	0.00409
	0.109		0.15	3 < Hs < 4	0.57	NO	0.00932
	0.109		0.15	4 < Hs < 5	0.17	NO	0.00278
	0.109		0.15	5 < Hs < 6	0.01	NO	0.00016
Hs > 3	0.175	2 < Hs < 3	0.25	1 < Hs < 2	0.14	NO	0.00613
	0.175		0.25	2 < Hs < 3	0.71	NO	0.03106
	0.175		0.25	3 < Hs < 4	0.15	NO	0.00656
	0.175	3 < Hs < 4	0.57	2 < Hs < 3	0.25	NO	0.02494
	0.175		0.57	3 < Hs < 4	0.57	NO	0.05686
	0.175		0.57	4 < Hs < 5	0.17	NO	0.01696
	0.175		0.57	5 < Hs < 6	0.01	NO	0.00100
	0.175	4 < Hs < 5	0.17	2 < Hs < 3	0.02	NO	0.00060
	0.175		0.17	3 < Hs < 4	0.32	NO	0.00952
	0.175		0.17	4 < Hs< 5	0.5	NO	0.01488
	0.175		0.17	5 < Hs < 6	0.15	NO	0.00446
	0.175		0.17	Hs > 6	0.01	NO	0.00030
	0.175	5 < Hs < 6	0.01	3 < Hs < 4	0.04	NO	0.00007
	0.175		0.01	4 < Hs< 5	0.4	NO	0.00070
	0.175		0.01	5 < Hs < 6	0.43	NO	0.00075
	0.175		0.01	Hs > 6	0.13	NO	0.00023
4 < Hs < 5	0.276	2 < Hs < 3	0.02	1 < Hs < 2	0.14	NO	0.00077
	0.276		0.02	2 < Hs < 3	0.71	NO	0.00392
	0.276		0.02	3 < Hs < 4	0.15	NO	0.00083
	0.276	3 < Hs < 4	0.32	2 < Hs < 3	0.25	NO	0.02208
	0.276		0.32	3 < Hs < 4	0.57	NO	0.05034
	0.276		0.32	4 < Hs < 5	0.17	NO	0.01501
	0.276		0.32	5 < Hs < 6	0.01	NO	0.00088
	0.276	4 < Hs< 5	0.5	2 < Hs < 3	0.02	NO	0.00276
	0.276		0.5	3 < Hs < 4	0.32	NO	0.04416
	0.276		0.5	4 < Hs< 5	0.5	NO	0.06900
	0.276		0.5	5 < Hs < 6	0.15	NO	0.02070
	0.276		0.5	Hs > 6	0.01	NO	0.00138
	0.276	5 < Hs < 6	0.15	3 < Hs < 4	0.04	NO	0.00166
	0.276		0.15	4 < Hs< 5	0.4	NO	0.01656
	0.276		0.15	5 < Hs < 6	0.43	NO	0.01780
	0.276		0.15	Hs > 6	0.13	NO	0.00538
	0.276	Hs > 6	0.01	4 < Hs< 5	0.26	NO	0.00072
	0.276		0.01	5 < Hs < 6	0.51	NO	0.00141
	0.276		0.01	Hs > 6	0.23	NO	0.00063
5 < Hs < 6	0.297	3 < Hs < 4	0.04	2 < Hs < 3	0.25	NO	0.00297
	0.297		0.04	3 < Hs < 4	0.57	NO	0.00677
	0.297		0.04	4 < Hs < 5	0.17	NO	0.00202
	0.297		0.04	5 < Hs < 6	0.01	NO	0.00012
	0.297	4 < Hs< 5	0.4	2 < Hs < 3	0.02	NO	0.00238
	0.297		0.4	3 < Hs < 4	0.32	NO	0.03802
	0.297		0.4	4 < Hs< 5	0.5	NO	0.05940
	0.297		0.4	5 < Hs < 6	0.15	NO	0.01782
	0.297		0.4	Hs > 6	0.01	NO	0.00119
	0.297	5 < Hs < 6	0.43	3 < Hs < 4	0.04	NO	0.00511
	0.297		0.43	4 < Hs< 5	0.4	NO	0.05108
	0.297		0.43	5 < Hs < 6	0.43	NO	0.05492
	0.297		0.43	Hs > 6	0.13	NO	0.01660
	0.297	Hs > 6	0.13	4 < Hs< 5	0.26	NO	0.01004
	0.297		0.13	5 < Hs < 6	0.51	NO	0.01969
	0.297		0.13	Hs > 6	0.23	NO	0.00888
Hs > 6	0.078	4 < Hs< 5	0.26	2 < Hs < 3	0.02	NO	0.00041
	0.078		0.26	3 < Hs < 4	0.32	NO	0.00649
	0.078		0.26	4 < Hs< 5	0.5	NO	0.01014
	0.078		0.26	5 < Hs < 6	0.15	NO	0.00304
	0.078		0.26	Hs > 6	0.01	NO	0.00020
	0.078	5 < Hs < 6	0.51	3 < Hs < 4	0.04	NO	0.00159
	0.078		0.51	4 < Hs< 5	0.4	NO	0.01591
	0.078		0.51	5 < Hs < 6	0.43	NO	0.01711
	0.078		0.51	Hs > 6	0.13	NO	0.00517
	0.078	Hs > 6	0.23	4 < Hs< 5	0.26	NO	0.00466
	0.078		0.23	5 < Hs < 6	0.51	NO	0.00915
	0.078		0.23	Hs > 6	0.23	NO	0.00413

= Sea state exceeds ROV limit. Unsuccessful operation.
= Example of a single path

Sum of Successful Operations	0.1450

APPENDIX C ROV-B PATH PROBABILITY TABLE

0 < t < 3 Hrs		3 < t < 6 Hrs		6 < t < 8 Hrs			
Sea State (m)	**Probability**	**Sea State (m)**	**Probability**	**Sea State (m)**	**Probability**	**Successful Operation?**	**Path Probability**
Hs < 1	0.014	Hs < 1	0.8	Hs < 1	0.8	YES	0.00896
	0.014		0.8	1 < Hs < 2	0.18	YES	0.00202
	0.014		0.8	2 < Hs < 3	0.02	YES	0.00022
	0.014	1 < Hs < 2	0.18	Hs < 1	0.05	YES	0.00013
	0.014		0.18	1 < Hs < 2	0.82	YES	0.00207
	0.014		0.18	2 < Hs < 3	0.13	YES	0.00033
	0.014	2 < Hs < 3	0.02	1 < Hs < 2	0.14	YES	0.00004
	0.014		0.02	2 < Hs < 3	0.71	YES	0.00020
	0.014		0.02	3 < Hs < 4	0.15	YES	0.00004
1 < Hs < 2	0.051	Hs < 1	0.05	Hs < 1	0.8	YES	0.00204
	0.051		0.05	1 < Hs < 2	0.18	YES	0.00046
	0.051		0.05	2 < Hs < 3	0.02	YES	0.00005
	0.051	1 < Hs < 2	0.82	Hs < 1	0.05	YES	0.00209
	0.051		0.82	1 < Hs < 2	0.82	YES	0.03429
	0.051		0.82	2 < Hs < 3	0.13	YES	0.00544
	0.051	2 < Hs < 3	0.13	1 < Hs < 2	0.14	YES	0.00093
	0.051		0.13	2 < Hs < 3	0.71	YES	0.00471
	0.051		0.13	3 < Hs < 4	0.15	YES	0.00099
2 < Hs < 3	0.109	1 < Hs < 2	0.14	Hs < 1	0.05	YES	0.00076
	0.109		0.14	1 < Hs < 2	0.82	YES	0.01251
	0.109		0.14	2 < Hs < 3	0.13	YES	0.00198
	0.109	2 < Hs < 3	0.71	1 < Hs < 2	0.14	YES	0.01083
	0.109		0.71	2 < Hs < 3	0.71	YES	0.05495
	0.109		0.71	3 < Hs < 4	0.15	YES	0.01161
	0.109	3 < Hs < 4	0.15	2 < Hs < 3	0.25	YES	0.00409
	0.109		0.15	3 < Hs < 4	0.57	YES	0.00932
	0.109		0.15	4 < Hs < 5	0.17	NO	0.00278
	0.109		0.15	5 < Hs < 6	0.01	NO	0.00016
3 < Hs < 4	0.175	2 < Hs < 3	0.25	1 < Hs < 2	0.14	YES	0.00613
	0.175		0.25	2 < Hs < 3	0.71	YES	0.03106
	0.175		0.25	3 < Hs < 4	0.15	YES	0.00656
	0.175	3 < Hs < 4	0.57	2 < Hs < 3	0.25	YES	0.02494
	0.175		0.57	3 < Hs < 4	0.57	YES	0.05686
	0.175		0.57	4 < Hs < 5	0.17	NO	0.01696
	0.175		0.57	5 < Hs < 6	0.01	NO	0.00100
	0.175	4 < Hs < 5	0.17	2 < Hs < 3	0.02	NO	0.00060
	0.175		0.17	3 < Hs < 4	0.32	NO	0.00952
	0.175		0.17	4 < Hs<5	0.5	NO	0.01488
	0.175		0.17	5 < Hs < 6	0.15	NO	0.00446
	0.175		0.17	Hs > 6	0.01	NO	0.00030
	0.175	5 < Hs < 6	0.01	3 < Hs < 4	0.04	NO	0.00007
	0.175		0.01	4 < Hs<5	0.4	NO	0.00070
	0.175		0.01	5 < Hs < 6	0.43	NO	0.00075
	0.175		0.01	Hs > 6	0.13	NO	0.00023
4 < Hs < 5	0.276	2 < Hs < 3	0.02	1 < Hs < 2	0.14	NO	0.00077
	0.276		0.02	2 < Hs < 3	0.71	NO	0.00392
	0.276		0.02	3 < Hs < 4	0.15	NO	0.00083
	0.276	3 < Hs < 4	0.32	2 < Hs < 3	0.25	NO	0.02208
	0.276		0.32	3 < Hs < 4	0.57	NO	0.05034
	0.276		0.32	4 < Hs < 5	0.17	NO	0.01501
	0.276		0.32	5 < Hs < 6	0.01	NO	0.00088
	0.276	4 < Hs<5	0.5	2 < Hs < 3	0.02	NO	0.00276
	0.276		0.5	3 < Hs < 4	0.32	NO	0.04416
	0.276		0.5	4 < Hs<5	0.5	NO	0.06900
	0.276		0.5	5 < Hs < 6	0.15	NO	0.02070
	0.276		0.5	Hs > 6	0.01	NO	0.00138
	0.276	5 < Hs < 6	0.15	3 < Hs < 4	0.04	NO	0.00166
	0.276		0.15	4 < Hs<5	0.4	NO	0.01656
	0.276		0.15	5 < Hs < 6	0.43	NO	0.01780
	0.276		0.15	Hs > 6	0.13	NO	0.00538
	0.276	Hs > 6	0.01	4 < Hs<5	0.26	NO	0.00072
	0.276		0.01	5 < Hs < 6	0.51	NO	0.00141
	0.276		0.01	Hs > 6	0.23	NO	0.00063
5 < Hs < 6	0.297	3 < Hs < 4	0.04	2 < Hs < 3	0.25	NO	0.00297
	0.297		0.04	3 < Hs < 4	0.57	NO	0.00677
	0.297		0.04	4 < Hs < 5	0.17	NO	0.00202
	0.297		0.04	5 < Hs < 6	0.01	NO	0.00012
	0.297	4 < Hs<5	0.4	2 < Hs < 3	0.02	NO	0.00238
	0.297		0.4	3 < Hs < 4	0.32	NO	0.03802
	0.297		0.4	4 < Hs<5	0.5	NO	0.05940
	0.297		0.4	5 < Hs < 6	0.15	NO	0.01782
	0.297		0.4	Hs > 6	0.01	NO	0.00119
	0.297	5 < Hs < 6	0.43	3 < Hs < 4	0.04	NO	0.00511
	0.297		0.43	4 < Hs<5	0.4	NO	0.05108
	0.297		0.43	5 < Hs < 6	0.43	NO	0.05492
	0.297		0.43	Hs > 6	0.13	NO	0.01660
	0.297	Hs > 6	0.13	4 < Hs<5	0.26	NO	0.01004
	0.297		0.13	5 < Hs < 6	0.51	NO	0.01969
	0.297		0.13	Hs > 6	0.23	NO	0.00888
Hs > 6	0.078	4 < Hs<5	0.26	2 < Hs < 3	0.02	NO	0.00041
	0.078		0.26	3 < Hs < 4	0.32	NO	0.00649
	0.078		0.26	4 < Hs<5	0.5	NO	0.01014
	0.078		0.26	5 < Hs < 6	0.15	NO	0.00304
	0.078		0.26	Hs > 6	0.01	NO	0.00020
	0.078	5 < Hs < 6	0.51	3 < Hs < 4	0.04	NO	0.00159
	0.078		0.51	4 < Hs<5	0.4	NO	0.01591
	0.078		0.51	5 < Hs < 6	0.43	NO	0.01711
	0.078		0.51	Hs > 6	0.13	NO	0.00517
	0.078	Hs > 6	0.23	4 < Hs<5	0.26	NO	0.00466
	0.078		0.23	5 < Hs < 6	0.51	NO	0.00915
	0.078		0.23	Hs > 6	0.23	NO	0.00413

= Sea state exceeds ROV limit. Unsuccessful operation.

Sum of Successful Operations	**0.2966**

Robert Gordon University

ENM201 Wells

RGU Petroleum - Olivia Field
E10 Well Evaluation

Name: ADAM BEATON

Student No: 1418528

Date: 19/7/2015

Word Count: 4238 *

(* *Excluding Executive Summary, Tables and Appendix*)

1.0 EXECUTIVE SUMMARY

This document outlines preliminary design considerations for the planned drilling of the RGU E10 well within the Olivia Field in the North Sea. Well E10 is an offshore well at 370 ft water depth, and is to be drilled vertically to a total depth (TD) of 10,000 ft.

The preliminary design covers the following areas;

- Rig types are outlined and a jackup rig has been identified as a suitable option;
- Drilling risks are identified and mitigation strategies are proposed;
- A casing design is proposed, including hole sizes, casing sizes and setting depths.
- Cementing components are discussed, and basic calculations have been performed for the intermediate casing;
- Critical material properties for drilling component selection are discussed;
- Considerations for lifting equipment design are outlined;
- The hook load and factor of safety are calculated for the final hole section;
- Lower completions methodologies are examined and a gravel pack is proposed.

CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDIX

2.0 INTRODUCTION

2.1 Background

RGU Petroleum Corporation plan to drill the vertical development well E10 within the Olivia Field in the North Sea. The water depth at Mean Sea Level (MSL) is 370 ft, and the target depth from the seabed is 10,000 ft. This document outlines preliminary designs, equipment and material selection for drilling and completing well E10.

Table 2-1 General Project Outline

Operator	RGU Petroleum Corporation
Field	Olivia Field
Well	E10
Location	North Sea
Depth RKB to MSL	80 ft
Water Depth	370 ft
TVD from Seabed	10,000 ft

(RGU 2015a)

2.2 Field Data

RGU have supplied some general field data and specifications, including the following:

- Basic geology prognosis;
- Anticipated Pore Pressure Gradients;
- Anticipated Fracture Gradients;
- Available casing sizes;
- Drilling equipment specifications.

2.3 Abbreviations

API	American Petroleum Institute
BF	Buoyancy Factor
BHA	Bottom Hole Assembly
BHCP	Bottom Hole Circulation Pressure
DC	Drill Collar
DF	Design Factor
DP	Drill Pipe
EMW	Equivalent Mud Weight
FOS	Factor Of Safety
HP	Horse power
HWDP	Heavy Weight Drill Pipe
I.D.	Inside Diameter
IWRC	Independent Wire Rope Core
LWD	Logging While Drilling
MODU	Mobile Offshore Drilling Unit
MOP	Margin Of Overpull
MSL	Mean Sea Level
MW	Mud Weight
MWD	Measurement While Drilling
O.D.	Outside Diameter
RGU	Robert Gordon University
RKB	Rotary Kelly Bushing
TD	Total Depth
TVD	True Vertical Depth
TVDSS	True Vertical Depth Subsurface
WOB	Weight On Bit

3.0 DRILLING PLAN

3.1 [Q1] Drilling Rig Selection

The selection of an offshore drilling rig is affected by many factors, including cost, water depth, sea conditions, seabed type, rig configuration and capacity. There are four general types of mobile offshore drilling units (MODU), as summarised in Table 3-1.

Table 3-1 Types of MODU

MODU Type	Typical Max. Water Depth	Description
Submersible	80 ft (Cleggs 2007)	Towed to location, then submerged to contact the seabed.
Jackup Rig	550 ft (Cleggs 2007)	Towed to location, then legs are extended to seabed and rig platform is jacked up above sea level.
Semi-Submersible	8,500 ft (Ensco 2015)	Towed to location and held on station with dynamic moorings. Depth is limited to moorings and riser.
Drillship	12,000 ft (Ensco 2015)	Self-propelled. Typically converted from existing vessels. Depth limited by riser only.

3.1.1 Cost

The dayrate of rigs vary from less than US100,000 up to US 1 million. The budget will depend on the anticipated drilling duration, mobilisation costs, and the purpose of the well. Jackup rigs are the most common and typically have a lower dayrate than the more sophisticated semi-submersibles or drillships.

3.1.2 Water Depth

As seen in Table 3-1, drilling at water depths of up to approximately 550 ft can utilise seabed-contacting structures such as submersibles or jackup rigs (Cleggs 2007). Beyond that, floating rigs such as semi-submersibles or drillships must be used. The depth range of these rigs are limited by moorings and/or riser technology only.

3.1.3 Sea Conditions

If a floating rig is required, then sea conditions must be considered in rig selection. Semi-submersibles have a deeper draft and wider base than drillships, which results in lower response amplitude for translational motion (heave, sway and surge), and angular motion (roll, pitch and yaw). (Cleggs 2007).

3.1.4 Seabed Conditions

Geotechnical properties of the seabed can determine if a submersible or jackup rig is appropriate, and also what type of moorings can be used for floating rigs.

3.1.5 Rig Capacity

A rig is selected based on capacities for storage of casings, drill pipe, mud pit, cement sacks and crew accommodation. These features will affect the maximum drilling depth, and the overall campaign efficiency. The drilling rig itself has many options such as the rotation system (e.g. Kelly or top drive), draw works lifting capacity and heave compensators (e.g. riser tensions or telescopic joints).

3.2 [Q2] Identified Risks

The lithology and formation pressure data presents several potential drilling challenges and hazards. The lithology shows water-bearing zones, unconsolidated sands, and is abnormally pressured (overpressured) from approximately 4,500 ft, where the pore pressure increases above 0.465 psi/ft (RGU 2015b p. 9).

Wells can be drilled in an overbalanced or underbalanced fashion. Water-bearing zones in the over-pressured region may present difficulties in controlling the well in an underbalanced state. Thus, it is assumed that the conventional overbalanced drilling method would be employed.

Drilling risks associated with lithology, and proposed mitigation strategies are outlined in Appendix A.

3.3 [Q3] Casing Configuration

The following casing design was performed using the provided pore and fracture gradients, and available casing sizes (see Table 3-2). Hole sizes were taken from the guidance chart in Appendix B. A pressure vs depth chart was created to aid in the design of casing setting depths (see Appendix C).

Table 3-2 Available Casing Sizes In-Store

Casing Diameter	Casing Grade/ Weight	Wall Thickness*	Nominal I.D. *	Nominal Bit Size *
24"	--	--	--	--
18-5/8"	--	0.435	17.755	17-1/2
13-3/8"	K55, 54.5 lb/ft	0.380	12.615	12-1/4
9-5/8"	N80, 40 lb/ft	0.395	8.835	8-5/8
7"	N80, 32 lb/ft	0.453	6.094	5-7/8

* (Cesmat 2015)

3.3.1 Pore Pressure

Pore pressure gradients were provided for the 10,000 ft depth. The gradient is a constant 0.458 psi/ft up to 4,260 ft, and then increases linearly from 0.458 psi/ft up to 0.614 psi/ft (overpressured) at 10,000 ft.

Pore pressure was calculated by assuming the gradients are referenced by distance from seabed, and already account for hydrostatic pressure caused by the 370 ft of seawater to Mean Sea Level (MSL).

The pore pressure (formation pressure) at each depth was calculated as follows:

$$P_f = Pore\ Pressure\ Gradient * TVDSS$$

It is more useful to represent the pressure as an equivalent mud weight (EMW). This is calculated as follows:

$$EMW = \frac{P_f}{0.052 * TVDSS}$$

The actual mud weight curve was constructed by adding a nominal 200 psi (RGU 2015b p. 6), or approximately 0.4 ppg EMW to the Pore Pressure as the overbalance, to account for swab and surge pressures (UPES 2015, p. 32).

3.3.2 Fracture Pressure

Fracture gradients were also provided, and calculated in a similar fashion to the pore pressure curve, with conversion to EMW. The fracture pressure was calculated as follows:

$$P_{Fracture} = Fracture\ Gradient * TVDSS$$

The Fracture Pressure was converted to EMW as follows:

$$EMW = \frac{P_{Fracture}}{0.052 * TVDSS}$$

A design curve was constructed by subtracting a nominal 0.3 ppg safety margin from the fracture pressure curve (RGU 2015c p. 23).

3.3.3 Casing Design

A bottom-to-top approach was used to determine casing shoe setting depths, by placing each casing between the pore pressure and fracture pressure limits, and also considering formation features. It is assumed that the wellhead has capacity for only three (3) casing hangers.

3.3.3.1 Production Liner

Casing design began with the production casing. The three casing hangers will be used for the structural casing, the surface casing and the intermediate casing. Thus, a liner configuration was selected for the production casing.

A mud weight of 12.4 ppg was chosen for this hole section to allow for significant safety margin from the mud weight curve, and to correlate with specifications outlined in later parts of this report.

From the TD, line A-B was drawn to determine the maximum allowable mud weight for this section, and the setting point for the intermediate casing (6,945 ft TVDSS). The production liner will start at 6,645 ft TVDSS to create an overlap with the intermediate casing by a nominal 300 ft. The cement seal must be gas tight due to the gas-bearing Upper Jurassic formation below.

The production liner is appropriately positioned through the entire primary and two secondary reservoirs. The production casing is a 7” N80 casing based on the in-store availability. The required hole size is 8-1/2”.

3.3.3.2 Intermediate Casing

The intermediate casing setting depth was selected by drawing line A-B on the pressure vs depth chart. Point B represents the maximum allowable mud weight for the hole section, and the intermediate casing shoe setting position of 6,945 ft TVDSS. The intermediate casing passes through the Paleocene sands, avoiding cementing issues by finishing beyond the upper water-bearing region. A 9-5/8” N80 casing is available for the intermediate casing. The required hole size is 12-1/4”.

3.3.3.3 Surface Casing

The surface casing was designed by drawing lines B-C and C-D on the pressure vs depth chart. Point C represents the minimum mud weight for this depth to avoid a kick. Point D represents the maximum allowable mud weight, and the casing shoe setting point for the surface casing, at a depth of 2,400 ft TVDSS.

The surface casing isolates the upper water-bearing region of the Paleocene middle shales, and is set greater than the recommended 300 ft below this hazard (RGU 2015d p. 14). The available 13-3/8” K55 casing was selected for the surface casing, which requires a 17-1/2” hole diameter.

3.3.3.4 Conductor Casing

An 18-5/8” conductor casing was selected based on the available material. It is set at a depth of 850 ft TVDSS, in order to be a nominal 200 ft past the unconsolidated clay formation and into the shale. It requires a 24” hole diameter.

3.3.3.5 Structural Casing

The structural casing provides support against bending moments caused by the riser (API 2007). The available 24” casing in store will not be used, as the hole size required for the 18-5/8” conductor casing is 24” (Clear 2015). Instead, a 30” structural casing will be required from an alternative supplier. The depth setting is a nominal 150 ft, to extend past the 105 ft silts and soft clays layer.

Table 3-3 and Figure 3-1 present the preliminary casing design.

Table 3-3 Preliminary Casing Design

Depth from Seabed (ft)	Type	Hole Diameter*	Casing Diameter	Grade / Weight
0 – 150	Structural	--	30″	--
0 – 850	Conductor	24″	18-5/8″	--
0 – 1,890	Surface	17-1/2″	13-3/8″	K55, 54.5 lb/ft
0 – 6,945	Intermediate	12-1/4″	9-5/8″	N80, 40 lb/ft
6,645 – 10,000	Production Liner	8-1/2″	7″	N80, 32 lb/ft

* (Cesmat 2015)

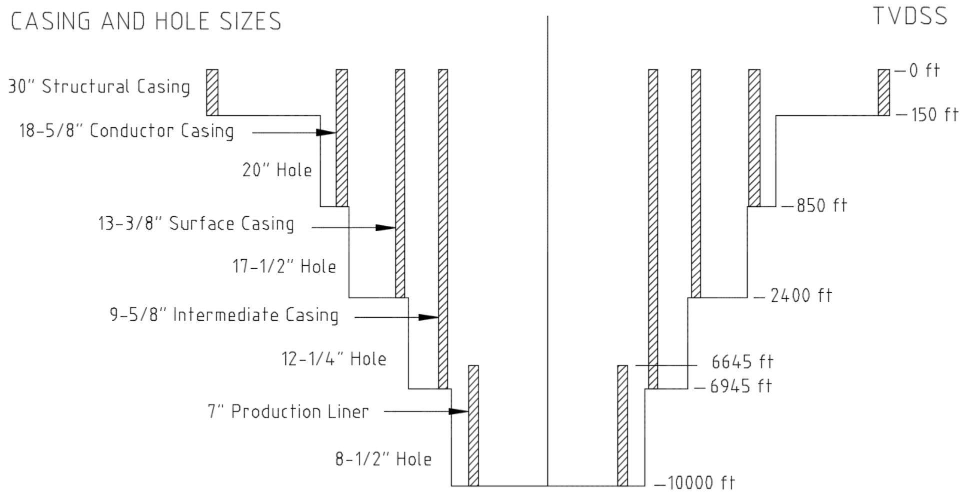


Figure 3-1 Casing Design Diagram

3.4 [Q4-a] Cementing Components

The following sections discuss several casing components necessary to aid in the cementing process.

3.4.1 Guide Shoe

The guide shoe is attached to the bottom of the casing and provides a tapered end to aid in directing the casing down the hole. The curved profile also helps to direct the cement upward, minimising pressure losses (Halliburton 2015).

3.4.2 Float Collar

The float collar acts as the stopper for the cement plugs, while allowing cement to pass through a check-valve. The check valve prevents backflow, but also causes the casing string to be buoyant if not filled during the run. It is typically placed several casing joints above the end (Halliburton 2015).

3.4.3 Cementing Head and Cement Plugs

The cementing head is the interface between the casing and discharge line, and enables the deployment of the cement plugs and cement volume.

Cementing is performed in the following sequence: A bottom plug is sent down followed by the prescribed volume of cement. The bottom plug begins as a sealing plug, and stops at the float collar. The cement is introduced between the bottom and top plugs. A displacement fluid (mud or water) is then pressurised down the hole which causes a disc on the bottom plug to rupture. The cement flows through the bottom plug, out the guide shoe and into the void between the casing and borehole. The top plug rests on the guide shoe.

3.4.4 Stage Collars

Stage collars are used when cementing is required at discrete depths (staged cementing). Typically a first stage is performed as described above, with a stage collar set in place at a secondary depth. Once the first stage is complete, an opening bomb is sent down which unlocks the outlet ports on the stage collar. Cementing can then be performed at the secondary location. Cement baskets are used as barriers on the outside of the casing to contain the cement at the required depth section. A closing bomb is then run down to close the ports.

3.4.5 Centralisers

Centralisers are radial attachments that keep the casing located centrally inside the borehole. They are placed at different intervals depending on the borehole geometry (typically around one every 3 joints), and are especially useful in angled or horizontal holes.

3.4.6 Scratchers

Scratchers (or wipers) are similarly attached to the casing and act to scrape off caked mud prior to cementing. There are a wide variety of designs to suit the conditions.

3.5 [Q4-b] Cement Mix

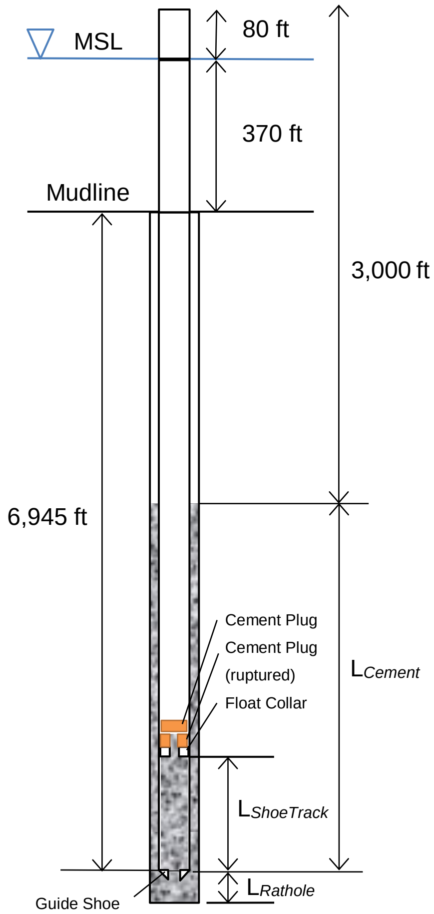
Table 3-4 shows the provided cement data for the final 9-5/8″ casing string.

Table 3-4 Cement Properties for 9-5/8" Casing String

Property	Value
Density	13.6 ppg
Mix Water Requirement	8.9 gal/sack
Slurry Yield	1.71 ft^3/sack
Top of Cement	3,000 ft (RKB)
Drilling Mud Weight	11 ppg
Shoe Track	80 ft
Cement Type	Class G
Bentonite	6%

(RGU 2015a)

3.5.1 Required Volume



The required volume for the 9-5/8" casing is calculated using the diagram to the left. An open hole excess of 20% is included. Full calculations are provided in Appendix D.

V_{Cement} = 245.2 bbl
$V_{ShoeTrack}$ = 6.1 bbl
$V_{Rathole}$ = 2.9 bbl

Total Volume = 306 bbl (inc. 20% excess)

Figure 3-2 Cement Volume for 9-5/8" Casing

3.5.2 Required Number of Cement Sacks

The number of cement sacks required to make up 306 bbls is calculated as follows:

V_{Cement} = 306 bbl * 5.614 bbl/ft^3
= 1657 ft^3

Slurry Yield = 1.71 ft^3/sack

No. Sacks = V_{Cement} / Slurry Yield
= 1657 ft^3 / 1.71 ft^3/sack
= **969 Sacks of Cement**

3.5.3 Mix Water Quantity

The cement is API Type G – General purpose cement for use up to 8,000 ft depth (API 2002). The API Specification 10A recommends 5.0 gal/sack for slurry mix. The project specifies 8.9 gal/sack which is used in the calculation below:

Water Cut = 8.9 gal/sack

No. Sacks = 969 Sacks

Water Volume = 8.9 gal/sack * 969 Sacks
= 8624 gal
= 8624 gal * 0.0238 bbl/gal
= **206 bbls** (rounded up)

3.5.4 Thickening Time

The thickening time is the duration that the cement slurry can still be pumped while it is curing. The thickening time is estimated by interpolating data from tables, such as those from in

Table 3-5.

Table 3-5 Thickening Times for API Type G Cement

Depth (ft)	Static Temp (F)	Circulating Temp (F)	High Pressure Thickening Time
6000	170	113	2:10
8000	200	125	1:44

(RGU 2015e, p. 7)

The temperature data for the project is not available, so it is assumed to be aligned with

Table 3-5. The depth of the 8-5/8" casing is 6,945 ft. Interpolation is required to determine the thickening time, as follows:

Calculate proportion of depth:

$$\frac{(6945\,ft - 6000\,ft)}{(8000\,ft - 6000\,ft)} = 0.48$$

Apply proportion to thickening time:

$$(130\,min - 104\,min) * 0.48 = 12.5\,min$$

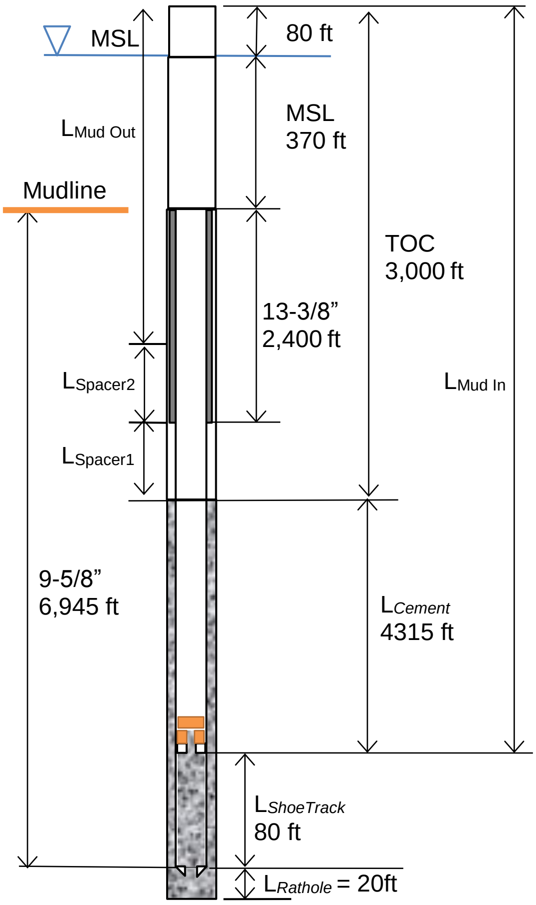
$$Thickening\ Time = 130\,\mathrm{min} - 12.5\,min$$

$$= 117.5\,min$$

$$= \mathbf{1{:}\,57}\ \boldsymbol{hrs}$$

This thickening time is less than the recommended 2 to 3 hours (RGU 2015e p. 8), and it does not include any safety margin for unanticipated delays.

3.5.5 Plug Bumping Pressure



The plug bumping pressure is the pressure experienced by the float collar at the instant immediately before the top cement plug is bumped against the bottom plug (WiperTrip 2015).

Figure 3-3 is used to determine the bumping pressure, using a U-tube analogy. The outside of the 9-5/8" casing is affected by the hydrostatic pressure from the cement column, the spacer column and the displaced drilling mud. The casing is supported on the inside by the drilling mud column used to push the cement plugs.

Figure 3-3 U-Tube Analogy for Cementing 9-5/8" casing

Some assumptions are made:

- A 50 bbl spacer is sent prior to the cement, with a weight of 9.0 ppg. Note: The spacer is situated partially across the 9-5/8" casing and the 13-3/8" casing (see diagram above).
- No overgauge in hole.
- Cement below float collar is ignored, as it is equally supported on the inside and outside.
- Cementing head is at 80 ft above MSL.
- Displaced drilling mud spans from the spacer fluid column all the way up to the Cementing Head (at RKB level).

The calculations suggest a bumping pressure differential (ΔP) of 499 psi acting upward against the float collar. Full calculations are provided in Appendix E.

3.6 [Q5] Material Selection

Material selection involves consideration of mechanical and chemical properties to ensure drilling components will remain fit for purpose. The following sections outline several major properties and their general application to load bearing drilling components.

3.6.1 Tensile Strength

Tensile strength is the ability for a component to be placed in tension without failure. Materials are measured for tensile strength using an extensometer, and strengths are typically specified as Ultimate Tensile Strength (UTS), or Yield Strength (the ability to handle tension without submitting to plastic deformation).

Tensile strength is a critical property for all drilling components, which typically experience extremely high tension loading while hung from the hook. Components are also subjected to compression, torsion and shear loading during drilling operations.

3.6.2 Elasticity

Elasticity is important for components under high tensile stress. Loads on a drill string may cause elastic elongation, as long as plastic deformation does not occur.

3.6.3 Hardness

Hardness is a measure of a material's resistance to surface damage. This is an important property for drilling components that are subjected to high impacts with other components. Hardness is of highest importance to drill bits. Hardness also affects the resistance to erosion from abrasive sands and other fluid components in casing and tubing.

3.6.4 Toughness

Toughness is a measure of the plastic deformation a material can be subjected to before fracturing. Toughness is important in drilling components to prevent complete failure from occasional impacts.

3.6.5 Corrosion Resistance

Corrosion is the chemical degradation of materials, typically due to reaction with oxygen, water and other acids. Corrosion in the oil and gas industry is commonly attributed to the presence of H_2S (sour conditions), or CO_2 (sweet conditions). Corrosion acts to reduce wall thicknesses in pipes, tanks and other components in a variety of methods including; galvanic corrosion, pitting, crevice corrosion, stress corrosion and erosion corrosion.

Mechanical performance of components is affected by corrosion in several ways. Most notably, the load bearing capacity is reduced once material is lost, for example a loss of pipe wall thickness will cause a reduction in hoop strength and thus the ability to contain pressure. A drill string tensile strength would be reduced in the same way.

Corrosion can also affect components by damaging the surface condition. A pipeline with heavy internal corrosion will induce a greater head loss due to the roughness of the surface. Similarly, corrosion damage can affect the performance of an impeller.

3.7 [Q6] Lifting System Selection

3.7.1 Lifting System Considerations

A number of basic design parameters are considered in the selection of a lifting system:

- The wire rope arrangement, which considers:
    - Number of sheaves on the crown block;
    - Number of sheaves on the travelling block;
    - Left or right handed string up;
    - Number of lines on the drawworks drum;
    - The reeving sequence.
- The draw works braking system (friction band or disk brake system).
- The draw works winch power, typically ranging from 550 HP for a 1,000 ft well, up to to 4000 HP for a 40,000 ft well (Oil and Gas Video 2015).
- Wire rope selection – material, nominal diameter, strand configuration (e.g. 6 x 19) and rope type (most commonly of type Independent Wire Rope Core – IWRC).

The design of the wire rope considers fast line tension, which is equal to the drill stem weight multiplied by a fast line factor. The fast line factor is dependent on the arrangement of the wire rope. A Design Factor (DF) of 3 is recommended for rotary drilling applications (API 2012).

3.7.2 Maintenance

Some maintenance considerations for the lifting system are listed below:

- Wire rope should be cleaned with brush and lubrication, not solvents (API 2012).
- Before cutting a rope, the ends must be seized to prevent the internal wires unwinding (API 2012).

- Sheaves should be maintained to minimise friction to avoid rapid heating and formation of martensite, which causes failure in the wire.
- Draw works brake systems should be checked regularly to ensure they are fit for service (Oil and Gas Video 2015).

3.8 [Q7] Drilling Components and Loads

3.8.1 Drill Stem Components

Table 3-6 outlines typical drill stem components and their functions, including the drill pipe and components of the bottom hole assembly (BHA).

Table 3-6 Drill Stem Components

Component	Function
Drill Pipe	The majority of the drill string comprises regular drill pipe lengths, which connect the BHA to the rotary table and is the conduit for drilling mud to travel from the surface to the drill bit. Drill pipe weights are typically designed and identified according to API RP7G.
Stabilizers	Stabilizers typically consist of spiralled blades which are positioned at several locations along the BHA in order to maintain positional rigidity, keep the drill string aligned and reduce vibration. They also reduce friction by spacing the drill collars away from the borehole (Schlumberger 2015a).
Reamers	Reamers are in-line cutting components which clean up the borehole by smoothing out under-gauged sections and avoiding stuck pipe.
MWD Tools	Measurement While Drilling (MWD) tools send directional data to the surface in order to monitor the trajectory of the borehole. They are typically used to monitor directional or horizontal drilling, but in this case, could be used to maintain verticality. (Schlumberger 2015b).
LWD Tools	Logging While Drilling (LWD) tools are similar to MWDs, but measure a variety of properties such as pressure, temperature, and geological properties such as porosity, density and resistivity (Schlumberger 2015b).
HWDP	Heavy Weight Drill Pipe (HWDP) is drill pipe with increased wall thickness, used between the drill collars and the regular drill pipe to add structural support against buckling and torsion failure.

Drill Collars (DC)	Drill collars are lengths of heavyweight drill pipe (HWDP) used in the BHA to increase the weight on bit (WOB) (Schlumberger 2015c). The heavier pipe also provides structural support against buckling under compression. Drill collars can be non-magnetic to avoid magnetic interference with MWD tools (JA Oilfield 2015).
Mud Motor	A mud motor can be used to provide additional rotation power to the drill bit. They are progressive cavity positive displacement (PCPD) motors, powered by the drilling mud pressure. A mud motor can also assist in deviating a hole for directional drilling purposes (Kalsi 2015).
Bit Sub	A bit sub is an interface between the drill bit and the drill pipe directly above.
Drill Bit	The drill bit is fitted to the bottom of the drill string. It cuts rock with teeth (often made of diamond) and is the outlet for drilling mud to circulate from the pipe and up the annulus.

3.8.2 Drill Stem Loads

Table 3-7 outlines the drill stem details for the final 8-1/2″ hole section, provided by the Company. The margin of over pull (MOP) has been specified as 100,000 lb, and the mud weight as 12.4 ppg.

Table 3-7 Drill Stem Details for Final Hole Section

Component	Specification
Drill Bit	8-1/2″
Drill Collars	6-1/2″ OD x 2-13/16″ ID x 390ft
HWDP	5″ OD x 50 lb/ft x 90 ft
Drill Pipe	Grade G 5″ x 19.5 lb/ft
Coupling	Grade G NC50(XH)
MOP	100,000 lb
MW	12.4 ppg

The Weight on Bit (WOB) is estimated using the guide in Table 3-8. The following assumptions are used:

- *Hard Insert Bit* chosen due to the shale and dolomites in the final hole section;
- *Diameter* refers to the drill bit diameter (8-1/2”);
- The median of the WOB range is used.

A WOB of 66,937 lb was calculated, which acts in an upward direction when calculating the load at the top of the drill string.

Table 3-8 Weight on Bit Guide

Formation Classification	lb per in of diameter	RPM
Soft	2270 – 6750	100 – 250
Medium	4500 – 9000	40 – 100
Hard Milled Tooth Insert	5600 – 11250	35 – 70
Hard Insert Bit	2250 – 9000	35 – 70
Hard Friction Bearing	4500 – 6750	35 – 60

(Bourgoyne 1986)

Using the above values, the hook load was determined to be 111,780 lb, and the factor of safety (FOS) is 1.89. Appendix F includes the full calculations for these values.

3.9 [Q8] Completion Method Selection

The following sections outline general options for lower completion methods for the well. Lower completions provide the pathway for production fluids to travel from the reservoir into the wellbore (RGU 2015f p. 1).

Lower completion design depends on many factors, some of which include:

- Operator objectives – required production rates, strategy for depleting the reservoir.
- Source of Formation Drive – Natural drive (e.g. solution gas, gas cap or water), or artificial drive (water, gas or chemical injection).
- Formation permeability – Hydraulic fracturing may be required if permeability is < 1md. Greater than 1 Darcy indicates low formation strength.
- Formation Grains – size, well sorted or heterogeneous.
- Production fluid properties – Temperature, pressure, bubble point.

3.9.1 Types of Completions

3.9.1.1 Barefoot

A well can be completed with a simple open hole (or barefoot) configuration. It is simple, but relies on stable formation and does not provide control over the production inflow.

3.9.1.2 Slotted Liner

Slotted liners or casings can be used where the formation requires support, and if discrete (and multiple) zones within the reservoir are to be accessed. The downfall is that a perforated casing causes a production resistance.

3.9.1.3 Sand Control Screens and Gravel Packs

The influx of sand must be controlled to prevent downstream equipment erosion damage, accumulation in the wellbore and formation collapse. Several options exist for sand control:

- Sand screens: Screens or slotted liners have holes which are sized to cause sand grain bridging, which prevents further passage into wellbore, but maximises porosity for fluid flow. Sand screens are used if formation is well-sorted, large-grain sand (RGU 2015g p.8). Expandable sand screens are newly developed technology.
- Gravel Pack: Specially sized gravel is placed outside sand screen to aid in holding back sand. Gravel can be placed in an open hole (the easiest option), or between a screen and a perforated casing. The cased-hole gravel pack provides more control over fluid inflow, but reduces the productivity.
- Chemical Consolidation: Used for high porosity (> 30%), homogenous sands.

3.9.1.4 Cased Hole Frac and Pack

Hydraulic fracturing can be used when the permeability is low, typically < 1 md (RGU 2015f). The formation is fractured and filled with gravel pack through the perforated casing or liner.

3.9.2 Perforation Methods

Many options are available for the perforation of casing or tubing. The main considerations include:

- Deployment method: Wireline, tubing, through-tubing. This affects the sequence of the completion activities and the size of the gun.
- Perforation Size: Big Hole or Deep Penetration, depending on the reservoir and packer. A gravel pack requires a big hole-type perforation.

- Type of gun: High Density, scallop, capsule or port plug. Depending on type of perforation and wellbore conditions.
- Gun size: Applicable to deployment method
- Charge Type: Depending on geology and completion objectives.

3.9.3 Lower Completion Selection for Well E10

The primary reservoir for well E10 lies in the Upper Jurassic shales and sandstones with high porosity, and secondary reservoirs of lower porosity lie below in the Triassic shales and Permian Zechsteins (dolomites). The primary reservoir would likely consist of unsorted grain sizes, which will require a carefully designed gravel pack between the 7" liner and the 8-1/2" wellbore.

4.0 CONCLUSIONS

The preliminary well evaluation has explored the main factors that will influence the final well and drilling design. The following conclusions and recommendations are made based on results of this study:

- A jackup rig is suitable for the water depth, and most economical.
- Gas-bearing regions pose a risk of uncontrolled kicks or blowouts. Sand and unconsolidated formations should be managed by controlling mud weight and continuous drilling to avoid stuck pipe.
- The casing design can make use of a 7” production liner to reduce material costs. A 30” structural casing will need to be sourced from alternative suppliers.
- Cementing the 9-5/8” intermediate casing will require approximately 306 bbl of cement (comprising 969 sacks of dry cement, and 206 bbl of water). The thickening time is approximately 2 hours, and the bumping pressure is approximately 500 psi upwards.
- The hook load during the final hole section will be approximately 112 kips, with a factor of safety of 1.89.
- Lower completions will likely require a gravel pack to minimise sand inflow, and isolate the primary from the secondary reservoirs.

5.0 REFERENCES

AMERICAN PETROLEUM INSTITUTE (API), 2002. *API Specification 10A, Specification for Cements and Materials for Well Cementing*, 23rd Ed. American Petroleum Institute. Washington, D.C. 2002.

AMERICAN PETROLEUM INSTITUTE (API), 2007. *API RP 59: 2006, Recommended Practice for Well Control Operations*. American Petroleum Institute.

AMERICAN PETROLEUM INSTITUTE (API), 2012. *API RP 9B Application, Care, and use of Wire Rope for Oil Field Service*, 13th Ed. American Petroleum Institute. Washington, D.C. April 2012.

BOURGOYNE, A.T. Et al, 1986. *Applied Drilling Engineering*. Society of Petroleum Engineers.

CESMAT SERVICE COMPANY INC, 2015. *API Casing Dimensions and Bit Clearance Data* [online]. Bakersfield, California. Available from: http://www.cesmatrockbits.com/charts/api.html [Accessed 19 June 2015].

CLEAR DIRECTIONAL DRILLING SOLUTIONS, 2015. *Hole Size vs Casing Size* [online]. Available from: http://www.cleardirectional.com/holesize.html [Accessed 2 July 2015].

CLEGG, J.D., ed., 2007. *Petroleum Engineering Handbook, Volume IV: Production Operations Engineering*. Society of Petroleum Engineers.

ENSCO PLC, 2015. *Rig Fleet Specification Sheets* [online]. Available from: http://www.enscoplc.com/Rig-Fleet/default.aspx [Accessed 15 June 2015].

GLENNIE, KW. 2009. *Petroleum Geology of the North Sea*. Wiley-Blackwell.

HALLIBURTON, 2015. *Casing Equipment – Floating Equipment* [online]. Available from: http://www.halliburton.com/en-US/ps/cementing/casing-equipment/floating-equipment/default.page?node-id=hfqela4z [Accessed 28 June 2015].

JA OILFIELD MANUFACTURING, INC, 2015. *Non-Magnetic Stainless Drill Collars* [online]. Available from: http://www.jaoilfield.com/NonMagCollars.html [Accessed 6 July 2015].

KALSI ENGINEERING, 2015. *Mud Motor Description* [online]. Available from: http://www.kalsi.com/seals/mud-motor-seals [Accessed 6 July 2015].

OIL AND GAS VIDEO, 2015. *Drawworks – Offshore Drilling*. [online video]. 30 March. Available from: https://www.youtube.com/watch?v=MFkxFjSkSYs [Accessed 4 July 2015].

ROBERT GORDON UNIVERSITY, 2015a. *ENM201: Wells Coursework*, Uploaded on June 9, 2015.

ROBERT GORDON UNIVERSITY, 2015b. *ENM201: Wells - Oilfield Pressures [Module Notes]*, Uploaded June 2015.

ROBERT GORDON UNIVERSITY and JENKINS, O.S., 2015c. *Casing and Tubing [ENM201 Module Slides].* Uploaded June 2015.

ROBERT GORDON UNIVERSITY, 2015d. *ENM201 – Wells – Tutorial I Introduction to Casing [Module Tutorial Slides]*. Uploaded Jun 2015.

ROBERT GORDON UNIVERSITY, 2015e. *ENM201: Wells – Cements and Cementing – An Introduction [Module Notes]*, Uploaded June 2015.

ROBERT GORDON UNIVERSITY, 2015f. *ENM201: Wells – Lower Completions [Module Notes]*, Uploaded June 2015.

ROBERT GORDON UNIVERSITY, 2015g. *ENM201 – Wells – Tutorial V Lower Completion [Module Tutorial Slides]*. Uploaded Jun 2015.

SCHLUMBERGER, 2015a. *Drilling Tools & Products – Reamers & Stabilizers* [online]. Available from: http://www.slb.com/services/drilling/tools_services/reamers_stabilizers.aspx [Accessed 6 July 2015].

SCHLUMBERGER, 2015b. *Oilfield Glossary – Measurements While Drilling* [online]. Available from: http://www.glossary.oilfield.slb.com/en/Terms/m/measurements_while_drilling.aspx [Accessed 6 July 2015]

SCHLUMBERGER, 2015c. *Oilfield Glossary – Drill Collar* [online]. Available from: http://www.glossary.oilfield.slb.com/en/Terms/d/drill_collar.aspx [Accessed 6 July 2015]

UPES - UNIVERSITY OF PETROLEUM AND ENERGY STUDIES, 2015. *Planning & Design of Casing* [online]. Available from: http://www.slideshare.net/narendrakumard/casing-design [Accessed 1 July 2015].

WIPER TRIP, 2015. *Example Calculation 9.5/8in Casing Cementation* [online] Available from: http://www.wipertrip.com/cementing/casing/299-example-calculation-958in-casing-cementation.html [Accessed 1 June 2015].

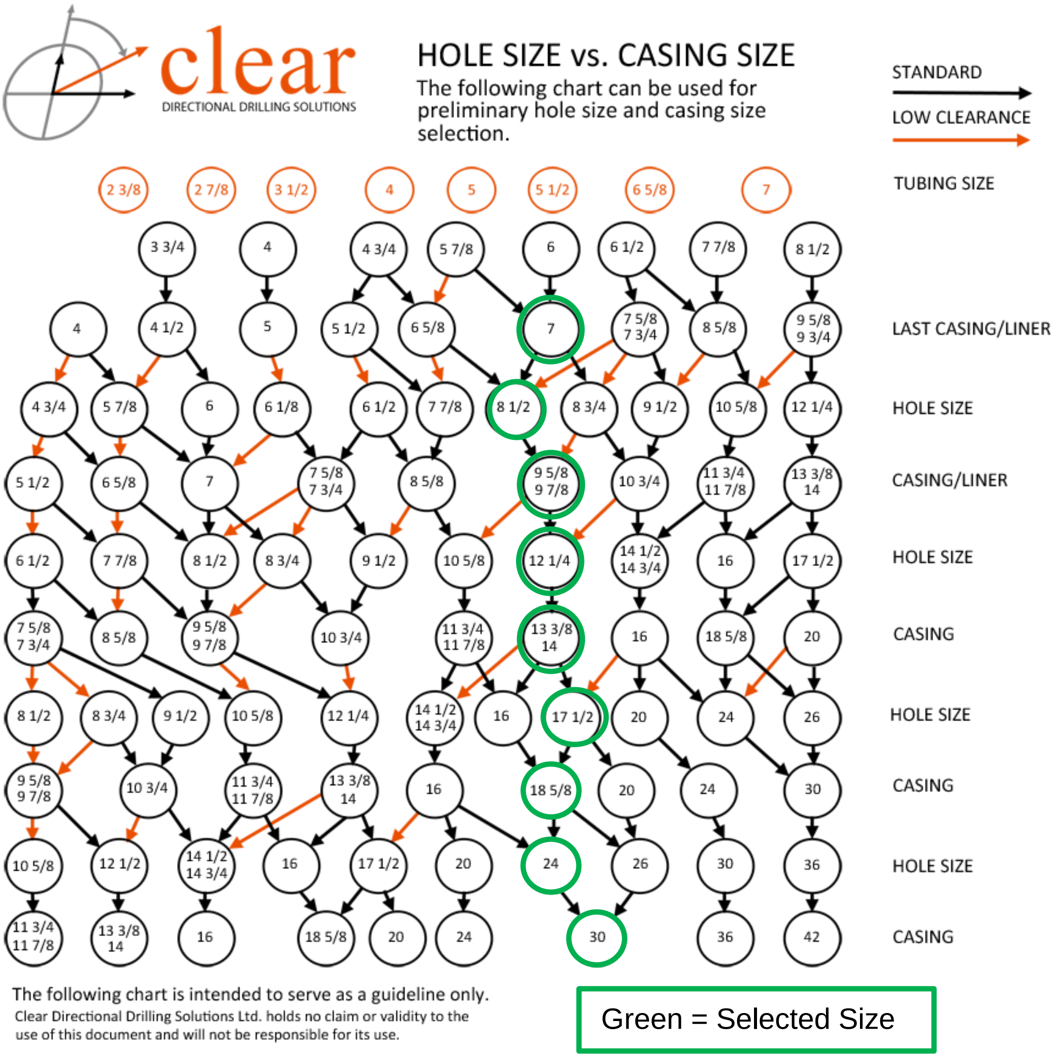
APPENDIX A DRILLING RISK MITIGATION STRATEGY

Depth from Seabed (ft)	Geology	Formation Water Migration	Porosity	Fracture Gradient	Pore Pressure Gradient	Anticipated Drilling Risks	Risk Mitigation Strategy
0 – 105	Silts and soft clays			0.551 psi/ft (constant)	0.458 psi/ft (constant)	Soft clays present geotechnical challenges with securing rig moorings and installation of structural casing.	Extensive geotechnical consideration prior to drilling campaign. Suitable selection of rig mooring anchor system.
105 – 650	Unconsolidated clays					Potential for lost circulation of drilling mud through unconsolidated, groundwater-bearing formation. Risk of stuck pipe.	Continuous drilling to prevent stuck pipe. Use suitable bit for soft material. Additives (or oil-based mud) to help consolidate formation.
650 – 4,260	Paleocene middle shales, clays and light sandstones	Yes		0.551 – 0.723 psi/ft		Potential for stuck pipe due to frequently changing formation.	Slow ROP, and careful monitoring of mud weight to ensure constant overbalance.

4,260 – 5,400	Paleocene lower sands	Yes		(from 1260 ft)		Sand, coupled with overpressured conditions (> 0.465 psi/ft at 4,500 ft). Potential for sand sloughing, creating over-gauged hole and lost drilling fluid. Sand can also enter drilling fluid and alter the density.	Limit lost circulation by lowering the overbalance (reduce mud weight). Use appropriate mud chemistry to create filter cake and prevent further lost circulation. Prepare equipment on topside to manage and separate sand.
5,400 – 5,910	Chalks, and fine/medium sandstones				0.458 – 0.614 psi/ft	Potential for chalk to enter well and contaminate drilling fluid.	Use calcium gypsum as dispersant to reduce contamination.
5,910 – 7,260	Upper and lower Cretaceous chalk/limestone					Risk of lost circulation though highly permeable limestone. Large mud losses through natural fractures could cause a kick from fluids below.	Limit mud weight to avoid fracturing formation. Prepare to circulate any kicks that may occur. Casing cement must be gas tight to protect annulus from gas-bearing region below.

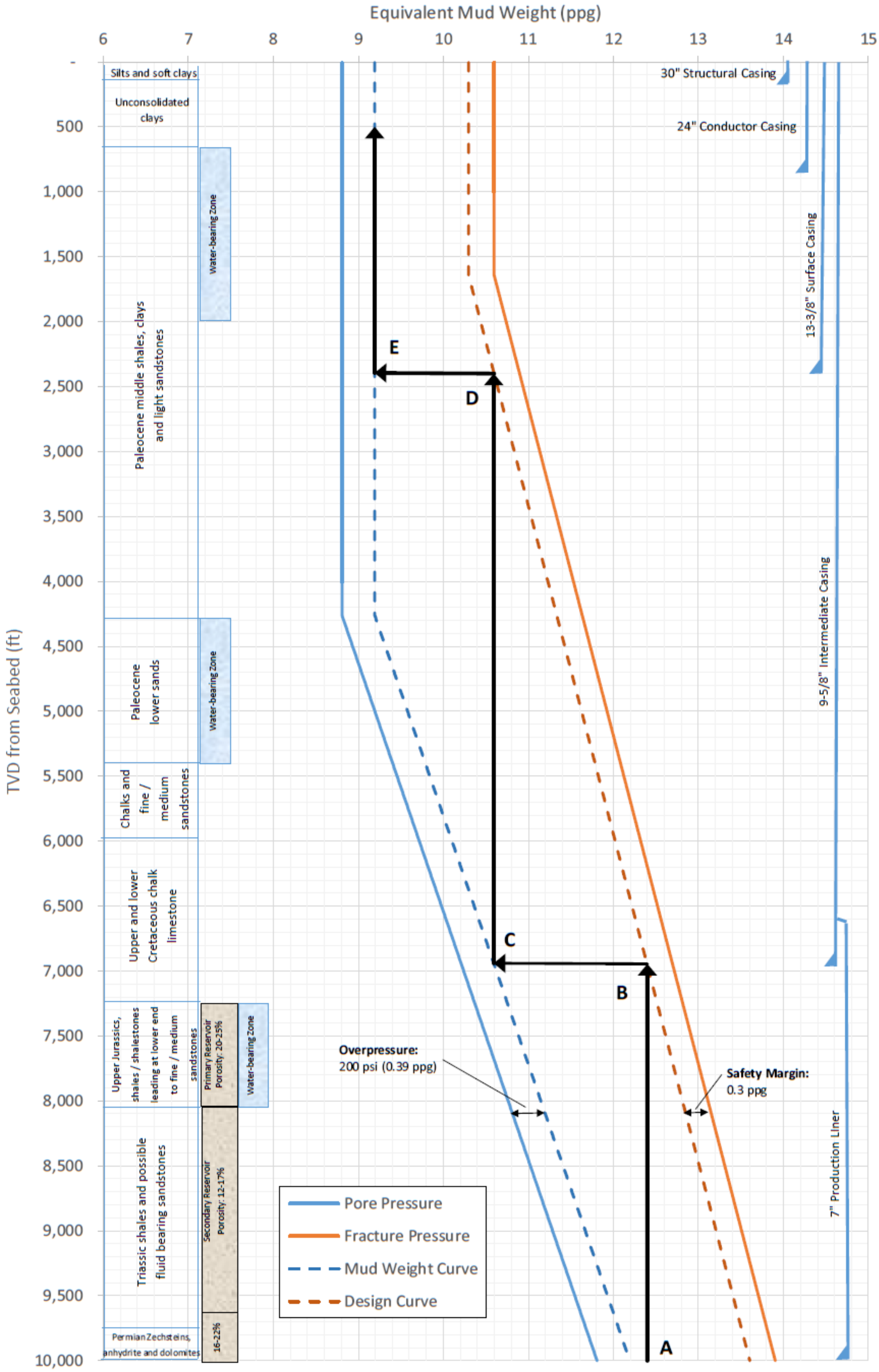
7,260 – 7,980	Upper Jurassics, shales/sandstones leading at lower end to fine/ medium sandstones	Yes	20-25%			Gas-bearing region, overpressured and highly porous. Risk of gas coming out of solution and casing a gas kick. Risk of blowout if not prepared for.	Drillers must be prepared for a gas kick, and use BOP to avoid a blowout. Ensure a significant overbalance in mud weight.
7,980 – 9,765	Triassic shales and possible fluid bearing sandstones		12-17%			Hydrocarbon fluids from secondary reservoir may enter well and reduce mud weight.	Monitor hydrocarbon content in returned fluids and adjust mud weight to remain overbalanced.
9,765 – 9,960	Permian Zechsteins, anhydrite and dolomites (gas bearing formation		16-22%			Secondary reservoir with gas-bearing, permeable formation. Risk of gas cut to mud, reducing density and causing a kick. Risk of hole enlargement and dissolved potash salts. Washout of clays (Glennie 2009 p. 204).	Use oil-based mud to prevent formation saturation. Adjust mud weight to account for gas cut, and prepare to divert gas at topside (Glennie 2009 p. 204).

APPENDIX B HOLE AND CASING SIZE CHART



Reference: (Clear 2015)

APPENDIX C PRESSURE VS DEPTH CHART



APPENDIX D CEMENT VOLUME CALCULATIONS

$I.D._{Hole} = 12.25"$

$O.D._{Casing} = 9.625"$

$I.D._{Casing} = 8.835"$

$L_{Cement} = 6945 + 370 + 80 - 3000$

$= 4395\ ft$

$L_{Shoe\ Track} = 80\ ft$

$L_{Rathole} = 20\ ft\ (assumption)$

Calculating volumes…

$$Volume = \frac{(I.D^2 - O.D^2) * Length}{1029.4}$$

$$V_{Cement} = \frac{\left(I.D_{Hole}^2 - O.D_{Casing}^2\right) * L_{Cement}}{1029.4} = \frac{(12.25^2 - 9.625^2) * 4395}{1029.4} = 245.2\ bbl$$

$$V_{ShoeTrack} = \frac{\left(I.D_{Casing}^2\right) * L_{ShoeTrack}}{1029.4} = \frac{(8.835^2) * 80}{1029.4} = 6.1\ bbl$$

$$V_{Rathole} = \frac{\left(I.D_{Hole}^2\right) * L_{Rathole}}{1029.4} = \frac{(12.25^2) * 20}{1029.4} = 2.9\ bbl$$

$$V_{Sum} = 245.2 + 6.1 + 2.9 = 254.2\ bbl$$

Adding a 20% open hole excess…

$V_{TOTAL} = 1.2 * V_{Sum}$

$= 1.2 * 254.2$

$= 305.04\ bbl$

$= \mathbf{306\ bbl}\ \ (rounded\ up)$

APPENDIX E PLUG BUMPING PRESSURE CALCULATIONS

Annulus Capacities:

9-5/8" / Open Hole = 0.056 bbl/ft

13-3/8" / 9-5/8" = 0.064 bbl/ft

Determining Lengths:

Length of spacer between TOC and 13-5/8" casing shoe:

$L_{Spacer1}$ = 3,000 ft – 2,400 ft – 370 ft – 80 ft = 150 ft

Volume of spacer between TOC and 13-3/8" casing shoe:

$V_{Spacer1}$ = 0.056 bbl/ft * $L_{Spacer1}$ = 0.056 bbl/ft * 150 ft = 8.4 bbl

Volume of spacer between 13-3/8" and 9-5/8" casings:

$V_{Spacer2}$ = 50 bbl – 8.4 bbl = 41.6 bbl

Length of spacer above 13-5/8" shoe:

$L_{Spacer2}$ = 41.6 bbl / 0.064 bb/ft = 650 ft

Total length of spacer:

L_{Spacer} = $L_{Spacer1}$ + $L_{Spacer2}$ = 150 ft + 650 ft = 800 ft

Length of mud above spacer:

$L_{Mud\ Out}$ = 3,000 ft – 800 ft = 2,200 ft

Length of mud column inside 9-5/8" casing:

$L_{Mud\ In}$ = 4,315 ft + 3,000 ft = 7,315 ft

Determining Fluid Gradients:

Slurry Gradient = 0.052 * ρ_{Cement} = 0.052 * 13.6 ppg = 0.707 psi/ft

Spacer Gradient = 0.052 * ρ_{Spacer} = 0.052 * 9.0 ppg = 0.468 psi/ft

Mud Gradient = 0.052 * MW = 0.052 * 11.0 ppg = 0.572 psi/ft

Calculating Pressures:

Pressure <u>Outside</u> Casing:

$P_{Outside}$ = (L_{Cement} * Slurry Gradient) + (L_{Spacer} * Spacer Gradient) + ($L_{Mud\ Out}$ * Mud Gradient)

= (4,315 ft * 0.707 psi/ft) + (800 ft * 0.468 psi/ft) + (2,200 ft * 0.572 psi/ft)

= **4,683 psi** (acting upwards on float collar)

Pressure <u>Inside</u> Casing:

P_{Inside} = $L_{Mud\ Out}$ * Mud Gradient

= 7,315 * 0.572 psi/ft

= **4,184 psi** (acting downward on float collar)

Pressure Differential:

ΔP = 4,683 psi – 4,184 psi = **<u>499 psi</u>** (upwards against the float collar)

APPENDIX F HOOK LOAD AND FACTOR OF SAFETY CALCULATIONS

Weight on Bit (WOB)

From Table 3-8…

WOB = (9000 – 2250)/2 * 8.5”

= 66,937 lb

Drill Pipe

L_{DP} = 10,000 ft – 390 ft – 90 ft = 9,250 ft

W_{DP} = 19.5 lb/ft

Drill Collars

L_{DC} = 390 ft

W_{DC}…

Volume per foot = π / 4 * (6.5^2 – 2.8125^2) * 12 = 323.6 in^3 = 1.40 gal

W_{DC} = 1.40 gal * 65.5 ppg = 91.7 lb/ft

(i.e. typical NC46 4” IF Spiral Drill Collar)

Heavy Weight Drill Pipe

L_{HWDP} = 90 ft

W_{HWDP} = 50 lb/ft

Hook Load

Assume steel weight ($W_{DrillStem}$) is 65.5 ppg

Buoyancy Factor (BF) = 1 – (MW / $W_{DrillStem}$)

= 1 – (12.4 ppg / 65.5 ppg)

= 0.81

T_{Hook}= [(L_{DP}*W_{DP} + L_{DC}*W_{DC} + L_{HWDP}*W_{HWDP}) * BF] - WOB

= [(9,250 * 19.5 + 390 * 91.7 + 90 * 50) * 0.81] – 66,937

=111,780 lb

Factor of Safety

MOP = $T_{Allowable}$ – T_{Hook}

100,000 lb = $T_{Allowable}$ – 111,780 lb

Thus, $T_{Allowable}$ = 211,780 lb

Factor of Safety (FOS) = $T_{Allowable}$ / T_{Hook}

= 211,780 lb / 111,780 lb

= 1.89

Robert Gordon University

ENM202 Facilities

RGU Petroleum Ltd
Black Dog Field – Field Development Plan

Name: ADAM BEATON

Student No: 1418528

Date: 29/11/2015

Word Count: 2006

1.0 EXECUTIVE SUMMARY

This document outlines preliminary design considerations for the development of the Black Dog Field in the North Sea. Production and export facilities are assessed, and process components outlined.

The recommended development option from an economical consideration only is the combination of a Fixed Steel Production Platform, and two export pipelines for oil and gas tie-in to the existing Forties Oil Pipeline and CATS Pipeline respectively. A total of 20 horizontally completed wells shall be drilled at a rate of 4 wells per year.

The Fixed Steel Platform option offers the highest net present value (NPV) and internal rate of return (IRR), however it poses significant risk by requiring a large initial CAPEX and decommissioning cost, and no option to transfer the facilities to future field developments. It is recommended to further investigate floating production facilities given the present volatility of the energy market, and potential for other fields to become more attractive in the future.

CONTENTS

2.0 INTRODUCTION

2.1 Background

RGU Petroleum Ltd are proposing to develop the Black Dog Field, located approximately 50 km north east of the Forties Field in the North Sea. The stock tank oil initially in place (STOIIP) is estimated at 750 MMbbl (60% recoverable), with a Gas to Oil Ratio (GOR) of 800 scf/bbl. The water depth is 160 m. First oil is planned for 2020.

2.2 Abbreviations

BOE	Barrels of Oil Equivalent
BS&W	Basic Sediments and Water
BTEX	Benzene, Toluene, Ethylbenzene, Xylene
CAPEX	Capital Expense
CATS	Central Area Transmission System
FLNG	Floating Liquid Natural Gas
FPS	Forties Pipeline System
FPSO	Floating Production Storage and Offloading
GC	Gas Chromatography
GOR	Gas-to-Oil Ratio
IRR	Internal Rate of Return
NORM	Normally Occuring Radioactive Materials
NPV	Net Present Value
OGA	Oil and Gas Authority (UK)
OPEX	Operational Expense
PAH	Phenol Aromatic Hydrocarbons
RGU	Robert Gordon University
STOIIP	Stock Tank Oil Initially in Place
TEG	Triethylene Glycol
UKCS	United Kingdom Continental Shelf

3.0 DEVELOPMENT OPTION SELECTION

3.1 Wells

Options for wells include vertically or horizontally completed wells, with differing production rates and CAPEX. They also differ in the *fraction of reservoir produced during plateau period*. This affects the production profile. A higher fraction means a faster, short-lived production life, with a more dramatic decline.

Table 3-1 Well Type Parameters

	Fraction of reserves produced in plateau period	Maximum number of wells that can be drilled per year	Initial well oil rate, stb/d	Cost per well ($mm)
Vertical well	0.3	5	3500	40
Horizontal well	0.4	4	5000	60

Analysis was performed by setting all other economic parameters constant, and toggling the two well options data.

The Horizontal Well was found to give the highest NPV and IRR. Note that the outputted results in Table 3-2 are indicative only, based on an arbitrary development setup for the purpose of selecting the well type.

Table 3-2 Well Type Analysis Results

Economic Results	Well Type		
	Vertical	Horizontal	
NPV	737	1215	US$mm
IRR	16.82%	20.53%	
Payback	7	7	years
Economic Reserves	387	407	mmboe
CAPEX	3631	3281	US$mm
CAPEX/boe	9	8	$/boe
Lifting Cost/boe	18	17	$/boe
Transportation Cost/boe	10.4	10.5	$/boe

Note: *Indicative figures used for selection of well types only.*

3.2 Production Plateau Rate

The economic success of the field development is dependent on the production profile. The well drilling program determines the production ramp-up to a desired plateau rate, until a nominal fraction of the recoverable STOIIP is recovered, then the production declines exponentially.

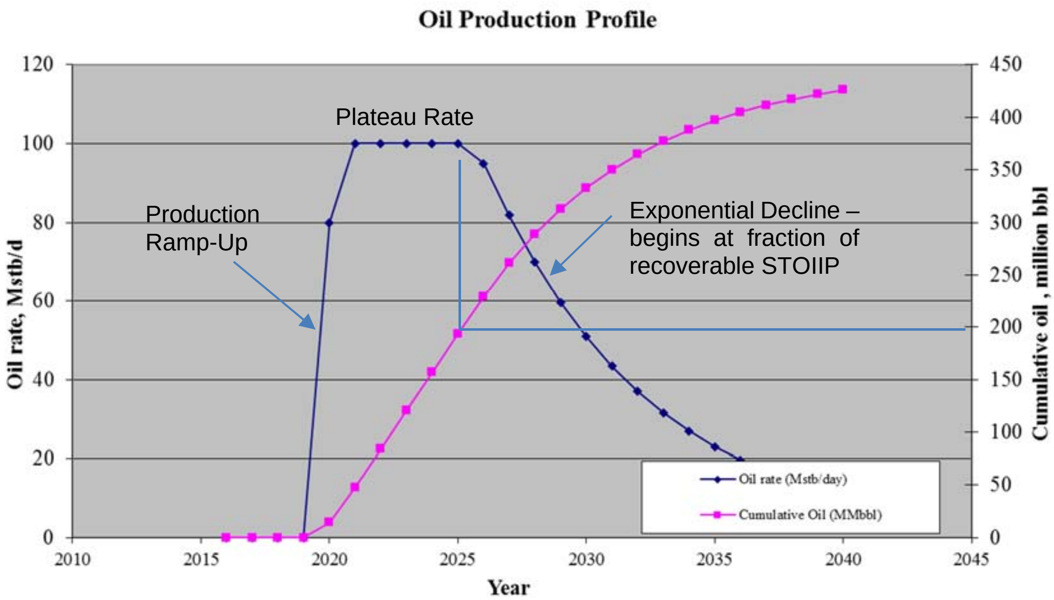


Figure 3-1 Example Production Profile

The plateau rate is commonly between 2 and 5% of the STOIIP per year (JAHN, 2008). The higher rate is chosen for the Black Dog Field.

Plateau Rate = 5% of STOIIP per year
= 5% * 750MMbbl / 365 days
= 102,740 bpd

This equates to a total of 20 horizontally completed wells producing at peak production.

3.3 Well Drilling Program

The well drilling program is a plan for the rate of bringing wells online, and determines the production profile, and hence the longevity of the project. Analysis was performed by setting all other parameters constant, and trialling different drilling programs. The results summarised in Table 3-3 show that drilling at the fastest rate allowable (4 wells per year for horizontal wells) gives the best economical results by all key indicators.

Table 3-3 Drilling Rate Analysis Results

Economic Results	Drilling Rate (wells per year)			
	2	3	4	
NPV	506	986	1215	US$mm
IRR	14.67%	18.69%	20.53%	
Payback	9	7	7	years
Economic Reserves	409	415	407	mmboe
Capex	3569	3372	3281	US$mm
Capex/boe	9	8	8	$/boe
Lifting Cost/boe	19	18	17	$/boe
Transportation Cost/boe	11.3	10.7	10.4	$/boe

Note: *In each case, wells were drilled each year until the target plateau rate of 100 mbpd was achieved.*

The resultant production profile is depicted in Figure 3-2.

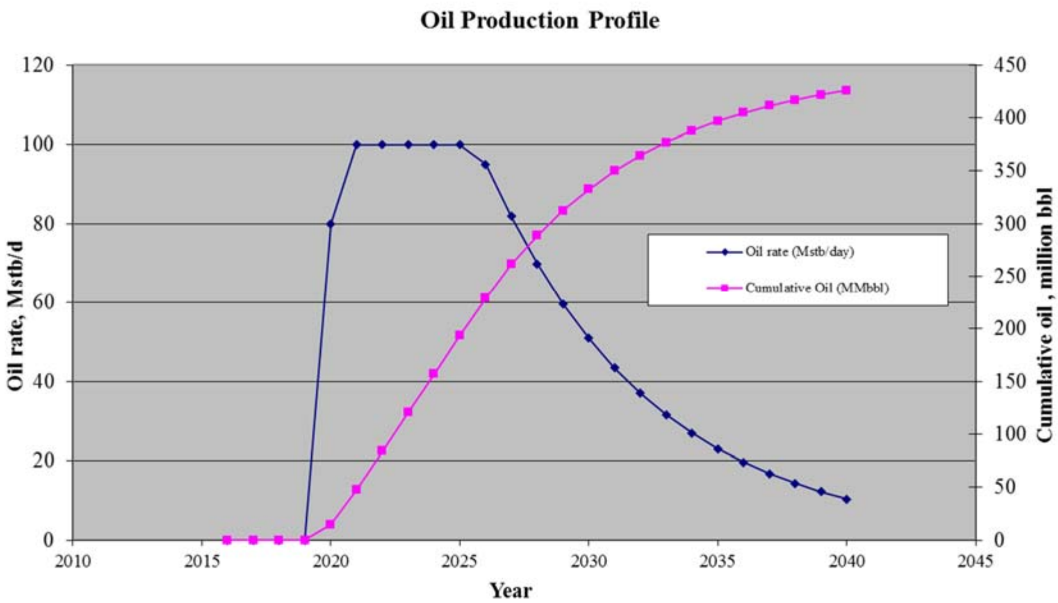


Figure 3-2 Production Profile – Drilling 4 Wells per year for 5 years

3.4 Production and Export Facilities

Production facilities and their respective export facility options were considered as shown in Table 3-4. All facility types are suitable for the 160 m water depth. This development plan has not considered using multiple production facilities.

Table 3-4 Production Facility Options

OPTION	Production Facility	Capacity	Export Facility Options	Comment
A	Fixed Steel Production Platform	500 mb/d 800 mmscf/d	Oil = Pipeline Gas = Pipeline	
B	Concrete Gravity Based Platform	500 mb/d 800 mmscf/d	Oil = Pipeline Gas = Pipeline	
C	Concrete Gravity Based Platform	500 mb/d 800 mmscf/d	Oil = Shuttle Gas = Pipeline	
D	Floating Production Platform 1	70 mb/d 70 mmscf/d	Oil = Shuttle Gas = Pipeline	Not viable Insufficient capacity.
E	Floating Production Platform 2	140 mb/d 120 mmscf/d	Oil = Tanker + Shuttle Gas = Pipeline	
F	FPSO 1	60 mb/d 60 mmscf/d	Oil = Shuttle Gas = Pipeline	Not viable Insufficient capacity.
G	FPSO 2	100 mb/d 100 mmscf/d	Oil = Shuttle Gas = Pipeline	

3.5 Development Option Analysis

Each of the viable development options in Table 3-4 were analysed by inputting the associated CAPEX, OPEX, decommissioning costs and other economic parameters into the calculation sheets. Detailed costs and outputs are provided in Appendix A. The key economic indicators are summarized in Table 3-5.

Table 3-5 Production and Export Facility Option Analysis Results

ECONOMIC INDICATORS	OPTIONS					
	A	B	C	E	G	
NPV	1329	952	1107	926	949	US$mm
IRR	20.99%	18.57%	20.21%	17.45%	17.77%	%
Payback	7	7	7	7	7	years
Economic Reserves	423	423	423	407	407	mmboe
CAPEX	3322	3732	3577	3674	3703	US$mm
CAPEX/boe	8	9	8	9	9	$/boe
Lifting Cost/boe	16	17	24	25	25	$/boe
Transportation Cost/boe	10.5	10.5	3.4	3.4	3.4	$/boe

The Fixed Steel Platform (Option A) returns the highest net present value (NPV) and internal rate of return (IRR), due to it requiring the lowest capital expenditure (CAPEX) and cost to produce each barrel (i.e. lifting cost). The Concrete Gravity Based Platform (Options B and C) suffers higher CAPEX and decommissioning costs, however the option to store oil in the base and only build one pipeline for gas (Option C) is a viable second option due to lower transportation costs than Option A.

4.0 PROCESS COMPONENTS

The following main process components shall be used to prepare fluids for entry into the export facilities. A flow scheme is provided in Appendix B.

4.1 Xmas Trees

Dry Xmas Trees shall be situated on the platform which provide individual choking capabilities to control production flow into a manifold and on to the processing facilities. Subsea Xmas Trees require higher CAPEX and operational / maintenance challenges.

4.2 Sand Removal

Formation sand, scales and organic solids will be separated from the production fluid with a hydrocyclone prior to entering the separator. A hydrocyclone uses centripetal force to extract heavy particular matter (RGU, 2015).

4.3 Multi-Phase Separator

A 3-stage separation system will be used to separate oil, water and gas in a staged pressure reducing sequence. The separators use gravity to separate the lower density hydrocarbons from water. Two stages of gas compression are required to prepare the gas for downstream facilities. A vertical (rather than horizontal) separator shall be used to reduce the footprint on the platform.

4.4 Produced Water Treatment

OSPAR Recommendation 2001/1 specifies a produced water hydrocarbon concentration of less than 30 mg/l, however this facility shall discharge with below the UKCS average of 19.78 mg/l (OilandGasUK, 2015). This shall be achieved using the following:

- **Enhanced Gravity Separation** – Multiple hydrocyclones in parallel
- **Gas Flotation** – Suspended emulsified oil attaches to gas bubbles and rise to surface

- **Coalescence** – Fluid passes through filter medium (granular material) which requires routine cleaning.

Critical contaminants to be removed include toxic, bio-accumulative or carcinogenic compounds such as phenol aromatic hydrocarbons (PAH), benzene/toluene/ethyl-benzene/xylenes (BTEX) and normally occurring radio-active materials (NORMs) (RGU, 2015).

4.5 Gas Treatment

Wet gas exits the separators, is compressed, then passes through a dehydrator system to prevent downstream corrosion and hydrate formation. Dehydration is achieved with a triethylene glycol (TEG) absorption process, which requires an absorber column (for bubbling the gas through the TEG) and a stripper column (for regenerating the TEG by boiling the water off) (Cameron, 2015).

4.6 Gas Export

Some of the dry gas is used by the gas turbine generator to power the platform, with the majority exported via a 50 km tie-in pipeline to the Central Area Transmission System (CATS) Pipeline. The CATS Pipeline has a capacity of 1700 MMscf/d, with an expected ullage of >25% by 2018, or 425 MMscf/d (adequate for the peak gas output of 80 MMscf/d). It transports gas 404 km from the Everest Field to the CATS terminal at Teesside, UK. (BP, 2015b). Gas conditioning shall meet the entry specifications for the CATS Pipeline. Some requirements paraphrased below:

- Free from lead, radioactive materials, waxes, gums, and gum forming constituents, foaming agents and excessive solids;
- Dew point -2 deg C for pressures greater than 10,340 KPa;
- Water content less than 15 Kg per million Cubic Metres;
- maximum H2S of 3.0 ppmv;
- Maximum delivery pressure 17,230 KPa;
- Maximum temperature of 51 deg C.

An onboard flare shall burn off excess gas in emergency situations only.

4.7 Oil Treatment

Oil is separated from water and gas via the 3-stage separation process. It will then be further treated to meet the Forties Pipeline System (FPS) Oil Pipeline entry specifications (selected requirements paraphrased below (PB, 2015c)):

- Maximum 0.2 %mol CO_2, 0.2 %mol N2, 0.1 ppm by weight H_2S
- Maximum 2% by volume basic sediment and water (BS&W).
- True Vapour Pressure 125 psig at 60°F.
- Entry Pressure 125 barg

Emulsified water is removed by flocculation or coalescence – which gather droplets together for removal with the help of agents added to the separators, and electrostatic heating.

4.8 Oil Export

A pipeline shall be constructed to transport the oil 50 km south west to tie into the Forties Field Oil Pipeline at the Forties Charlie Platform. The Forties Field Oil Pipeline is 36” diameter, with a maximum capacity of 675 mbpd, and an expected ullage of >25% in 2019, (or approximately 169 mbpd, adequate for the proposed peak production of 100 mbpd). Oil will then be transported 169 km to landfall at Cruden Bay, and then 209 km onshore to the Kinneil Terminal for refining (BP, 2015).

5.0 FISCALISATION EQUIPMENT

Fiscalisation equipment is used to measure and delivered product quantities to the custody point. Redundancies and prover equipment are required in order to verify accuracy between the supplier and receiver, in accordance with the Oil & Gas Authority (formerly DECC) guidelines. A map of the export plan is provided in Appendix C.

5.1 Gas Measurement

Gas volume flowrate is measured using an orifice plate, in conjunction with temperature and pressure measurements. An orifice plate measures the differential pressure across an in-line orifice, and relates it to volumetric flowrate. Gas chromatography (GC) is typically used to determine chemical composition. Calibration is achieved by passing a known volume and composition of gas through the system.

Measurements shall be taken prior to entry into the CATS Gas Pipeline, as the point of custody transfer.

5.2 Oil Measurement

Two redundant turbine meters shall measure the oil flowrate at the platform, prior to entry into the Forties Field Oil Pipeline. They shall be calibrated to determine the K-value using a bi-directional prover meter (OGA, 2015). The prover meter consists of a loop by which a known volume of fluid is passed (in either direction) through the turbine meters to verify the calibration accuracy. Flow straighteners are placed upstream of the meters.

Oil composition is determined by grab sampling and laboratory inspection. Results are presented in terms of standard conditions (i.e. 60 F, atmospheric pressure).

6.0 CRITICAL OPTION ASSESSMENT

The following criteria have been assessed in consideration of the development options.

6.1 Technical Viability

The Fixed Steel Platform option is an established, common development in the North Sea, and should not pose any significant technical challenges. Other options such as floating platforms and FPSOs require more advanced technologies such as subsea xmas trees, remote field control, mooring systems and flexible risers. The large size of the jacket may require consideration of construction yard availability, and vessels for float-over of the topsides.

6.2 Financial Sensitivity

Each of the development options were tested by incrementally reducing the oil price until the option was economically not feasible (i.e. NPV of zero). The Fixed Steel Platform can sustain the lowest at US45.00 per barrel as shown in Table 6-1.

Table 6-1 Oil Price Sensitivity

	OPTIONS				
	A	B	C	E	G
NPV (at US 58/bbl)	1329	952	1107	926	949
IRR (at US 58/bbl)	20.99%	18.57%	20.21%	17.45%	17.77%
Lowest Oil Price (for NPV = 0)	$45.00	$48.60	$47.20	$48.80	$48.70

6.3 Health, Safety and Environmental (HS&E) Risks

The Fixed Steel Platform option avoids using storage and shuttle tankers which eliminates risk of vessel spills. Pipeline leaks are less common. The fixed platform is also not subject to environmental conditions, and can export product under any sea conditions, unlike a storage and shuttle tanker arrangement.

6.4 Flow Assurance

Flow assurance for the pipeline export option will pose a more significant challenge and expense than using tankers.

6.5 Decommissioning

The Fixed Steel Platform has the highest decommissioning cost of all options, at $877m. This is considered a significant financial risk to the project, given the current oil price volatility, and increasing regulatory pressure regarding decommissioning requirements. Removal of jackets and concrete bases are inherently more expensive and technically challenging than floating facilities. Decommissioning pipelines are similarly expensive, and a source of environmental controversy (e.g. removal may disturb established marine habitats).

6.6 Field Development Value

The Fixed Steel Platform has a relatively high initial CAPEX for production and export facilities, both of which are not transferable to other field developments. A floating production facility or FPSO may well benefit from the ability to produce from a future field in changing economic climates. Export via tankers also allows for product sales outside of the UK-based delivery points which the pipeline option is committed to. This could be a disadvantage under changing global currency markets.

7.0 CONCLUSIONS

While the Fixed Steel Platform has been shown to offer the greatest economic returns, it is not the recommended investment from a financial risk perspective. The concern for flexibility in the development plan is supported by the recent industry shift toward floating production facilities, FPSOs, and more recently, FLNG. It is recommended to investigate the floating facilities further, with consideration for future field developments and economic sensitivity analysis.

8.0 REFERENCES

- BP, 2015. Forties Pipeline System (FPS) – System Ullage. Available at: http://www.bp.com/en/global/forties-pipeline/about_fps/Technical/system_ullage.html [Accessed 31/10/2015].
- BP, 2015b. CATS – System Ullage. Available at: http://www.bp.com/content/dam/bp-north-sea-infrastructure/en/pdf/Ullage.pdf [Accessed 31/10/2015].
- B, 2015c. FPS Entry Specifications. Available at: http://www.bp.com/content/dam/bp-north-sea-infrastructure/en/pdf/nsi_fps_entry_specification.pdf [Accessed 20/11/2015]
- CAMERON, 2015. *Glycol Dehydration Systems*. Available at: https://www.c-a-m.com/products-and-services/separation-processing-and-treatment/gas-processing-and-treatment/glycol-dehydration-systems [Accessed 20/11/2015].
- ROBERT GORDON UNIVERSITY, 2015. *ENM202: Facilities [Lecture notes]* Delivered August 2015.
- JAHN, FRANK. Et al, 2008. *Hydrocarbon Exploration and Production 2nd Ed*. Elsevier(p. 205)
- http://oilandgasuk.co.uk/knowledgecentre/producedwater.cfm
- OGA, 2015. *Guidance Notes for Petroleum Measurement* – Issue 9.2. Oil & Gas Authority.

APPENDIX A DEVELOPMENT OPTIONS DATA

OPTION A
Fixed Steel Platform – Exporting Oil and Gas via Two Pipelines

PRODUCTION FACILITY

FIXED STEEL PLATFORM			
Capacity	Value	Units	Notes
Max. Liquids Throughput	500000	bpd	
Max. Gas Throughput	800	mmscf/d	
POB	40	pax	
Actual Oil Throughput	102740	mb/d	*Plateau Rate*
Actual Gas Throughput	82.19	mmscf/d	*GOR of 800 scf/bbl*
Topsides Weight			
Accomodation	1600	t	*40 t * POB*
Utilities	1500	t	*1500 t*
Oil Processing	1541	t	*15 t per mb/d (Chart)*
Gas Processing	1233	t	*15 t per mmscf/d (Chart)*
Total Topsides Weight	5874	t	
Total Jacket Weight	7636.174	t	*1.3 * Topsides Weight*
Cost			
Topsides Cost	$ 881,097,000		*$150k per Tonne*
Jacket Cost	$ 763,617,400		*$100k per Tonne*
Total CAPEX	**$ 1,644,714,400**		
Construction Time	3	years	
CAPEX Per Year	$ 548,238,133		
Decommissioning			
Topsides	$ 117,479,600		*$20k per Tonne*
Jacket	$ 152,723,480		*$20k per Tonne*
Total	**$ 270,203,080**		

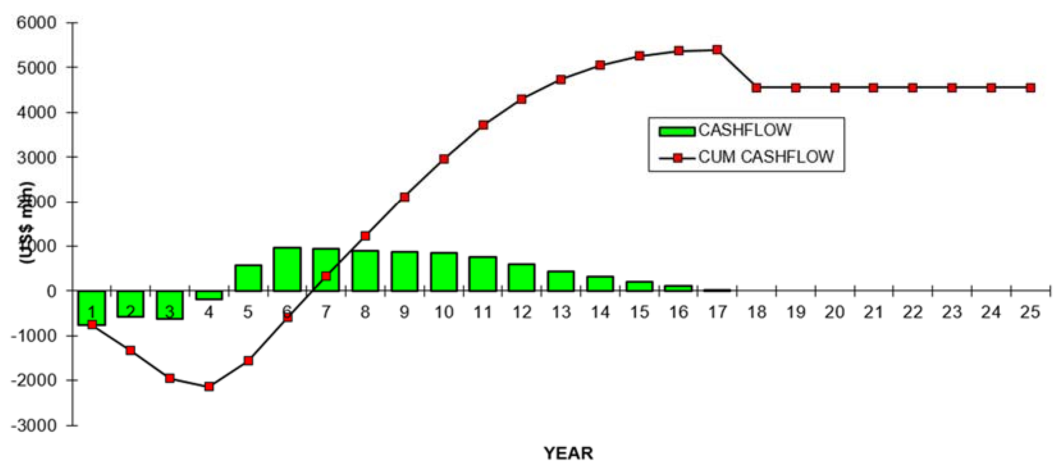
EXPORT FACILITY

PIPELINE				
Oil Pipeline Length		50	km	*Black Dog to Forties Charlie Tie-In*
Gas Pipeline Length		50	km	*Black Dog to CAPS Tie-In*
Total Length		100	km	
Unit Cost	$	3,000,000	$/per km	*for 0-100 mb/d*
Total CAPEX	**$**	**300,000,000**		
Construction Time		0.55	Years	*2 days per km*
Decommissioing Cost	$	50,000,000		*$500k per m*

DECOMMISSIONING

Production Facility	$	270,203,000	*See Production Facility Table*
Wells	$	200,000,000	*$10m per Well*
Pipelines	$	50,000,000	*See Export facility Table*
Storage Tanker	$	-	*No storage tanker*
TOTAL	**$**	**520,203,000**	

CASHFLOW, CUMULATIVE CASHFLOW



OUTPUT from Economics Calulator sheet

NPV	(10)	1329	US$mm
IRR		20.99%	
Payback		7	years
Economic Reserves		423	mmboe
Capex		3322	US$mm
Capex/boe		8	$/boe
Lifting Cost/boe		16	$/boe
Transportation Cost/boe		10.5	$/boe

OPTION A - ECONOMICS CALCULATIONS

CASH FLOW																		
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CAPEX ($mm)	1048	748	748	200	200	0	0	0	0	0	0	0	0	0	0	0	0	0
DECOMMISSIONING ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	520
Production wells drilled	4	4	4	4	4						0	0	0	0	0	0	0	0
Production wells	0	0	0	0	16	20	20	20	20	20	20	20	20	20	20	20	20	20

CAPEX					
Well cost ($mm)	200	200	200	200	200
FPSO cost ($mm)	548	548	548		
Pipeline gas ($mm)	300				

ECONOMICS INPUT	
Fixed opex (% cum. capex)	6
Variable opex ($/bbl)	5
Gas transportation tariff ($/Mscf)	3
Oil transportation tariff ($/bbl)	5

ECONOMICS DATA													
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Sales gas rate (MMscf/d)	0	0	0	0	64	80	80	80	80	80	76	65	56
Oil rate (Mstb/d)	0	0	0	0	80	100	100	100	100	100	95	82	70
RT Gas revenues ($mm)	0	0	0	0	66	83	83	83	83	83	79	68	58
RT Oil revenues ($mm)	0	0	0	0	1694	2117	2117	2117	2117	2117	2012	1732	1479
MOD Gross rev ($mm)	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537
Units all $mm													
Capex ($mm)	1048	748	748	200	200	0	0	0	0	0	0	0	0
Decommissioning ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0
REAL Fixed opex ($mm)	0	0	0	0	177	177	177	177	177	177	177	177	177
REAL Variable opex ($mm)	0	0	0	0	146	183	183	183	183	183	173	149	128
REAL Gas transportation tariff ($mm)	0	0	0	0	70	88	88	88	88	88	83	72	61
REAL Oil transportation tariff ($mm)	0	0	0	0	146	183	183	183	183	183	173	149	128
REAL Total opex ($mm)	0	0	0	0	539	629	629	629	629	629	607	547	493
MOD Capex	1084	828	886	253	271	0	0	0	0	0	0	0	0
MOD Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0
MOD Fixed + variable opex	0	0	0	0	402	470	493	518	544	571	584	571	560
MOD Oil + Gas transp Tariff	0	0	0	0	269	353	371	389	409	429	428	387	347
MOD Total opex	0	0	0	0	671	823	864	907	953	1000	1013	959	907
Gross Revenue	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537
Total costs	1084	828	886	253	942	823	864	907	953	1000	1013	959	907
Pre tax Cash Flow	-1084	-828	-886	-253	818	1377	1336	1293	1247	1200	1078	842	630
Corporation tax	-325	-248	-266	-76	245	413	401	388	374	360	323	252	189
MOD Net Cashflow	-759	-580	-620	-177	572	964	935	905	873	840	754	589	441
Project still profitable?				STOP	OK	OK	OK	OK	OK	OK	OK	OK	OK
Economic production (mboed)				0	91	114	114	114	114	114	108	93	80
MOD Economic Lifting costs	0	0	0	0	402	470	493	518	544	571	584	571	560
MOD Economic Transptn costs	0	0	0	0	269	353	371	389	409	429	428	387	347
MOD Economic Cashflow	-759	-580	-620	-177	572	964	935	905	873	840	754	589	441
MOD Cashflow with Decom	-759	-580	-620	-177	572	964	935	905	873	840	754	589	441
MOD Cum. Cashflow	-759	-1338	-1958	-2136	-1563	-600	336	1240	2114	2953	3708	4297	4738
RT Economic cashflow	-741	-539	-549	-150	460	737	681	628	577	528	452	336	240
RT Cum. Cashflow	-741	-1279	-1828	-1978	-1518	-781	-100	528	1104	1633	2085	2421	2660
Payback calculation	0	0	0	0	0	6.6411336	0	0	0	0	0	0	0

ECONOMICS DATA													
Project Year	14	15	16	17	18	19	20	21	22	23	24	25	S
Calendar Year	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
Sales gas rate (MMscf/d)	48	41	35	30	25	22	18	16	13	11	10	8	321
Oil rate (Mstb/d)	60	51	43	37	32	27	23	20	17	14	12	10	401
RT Gas revenues ($mm)	49	42	36	31	26	22	19	16	14	12	10	9	333
RT Oil revenues ($mm)	1262	1077	919	784	669	571	487	415	354	302	258	220	8494
MOD Gross rev ($mm)	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Units all $mm													
Capex ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	2944
Decommissioning ($mm)	0	0	0	0	520	0	0	0	0	0	0	0	
REAL Fixed opex ($mm)	177	177	177	177	177	177	177	177	177	177	177	177	2826
REAL Variable opex ($mm)	109	93	79	68	58	49	42	36	31	26	22	19	2006
REAL Gas transportation tariff ($mm)	52	45	38	32	28	24	20	17	15	13	11	9	
REAL Oil transportation tariff ($mm)	109	93	79	68	58	49	42	36	31	26	22	19	
REAL Total opex ($mm)	447	407	373	344	320	299	281	265	252	241	232	224	7801
MOD Capex	0	0	0	0	0	0	0	0	0	0	0	0	3322
MOD Decommissioning	0	0	0	0	1699	0	0	0	0	0	0	0	
MOD Fixed + variable opex	552	547	545	546	550	557	566	578	591	608	626	646	8575
MOD Oil + Gas transp Tariff	311	279	250	224	200	180	161	144	129	116	104	93	4988
MOD Total opex	863	826	795	770	751	736	727	722	721	723	730	739	13564
Gross Revenue	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Total costs	863	826	795	770	751	736	727	722	721	723	730	739	16886
Pre tax Cash Flow	449	294	160	45	-56	-143	-221	-290	-352	-409	-461	-511	7296
Corporation tax	135	88	48	13	-17	-43	-66	-87	-106	-123	-138	-153	2189
MOD Net Cashflow	314	206	112	31	-39	-100	-155	-203	-247	-286	-323	-357	5107
Project still profitable?	OK	OK	OK	OK	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	
Economic production (mboed)	68	58	49	42	0	0	0	0	0	0	0	0	423
MOD Economic Lifting costs	552	547	545	546	0	0	0	0	0	0	0	0	6902
MOD Economic Transptn costs	311	279	250	224	0	0	0	0	0	0	0	0	4448
MOD Economic Cashflow	314	206	112	31	0	0	0	0	0	0	0	0	5401
MOD Cashflow with Decom	314	206	112	31	-850	0	0	0	0	0	0	0	
MOD Cum. Cashflow	5052	5258	5370	5401	4552	4552	4552	4552	4552	4552	4552	4552	45767
RT Economic cashflow	163	101	53	14	-362	0	0	0	0	0	0	0	2629
RT Cum. Cashflow	2823	2924	2977	2991	2629	2629	2629	2629	2629	2629	2629	2629	
Payback calculation	0	0	0	0	0	0	0	0	0	0	0	0	

OPTION B
Concrete Gravity Base Platform – Exporting Oil and Gas via Two Pipelines

PRODUCTION FACILITY

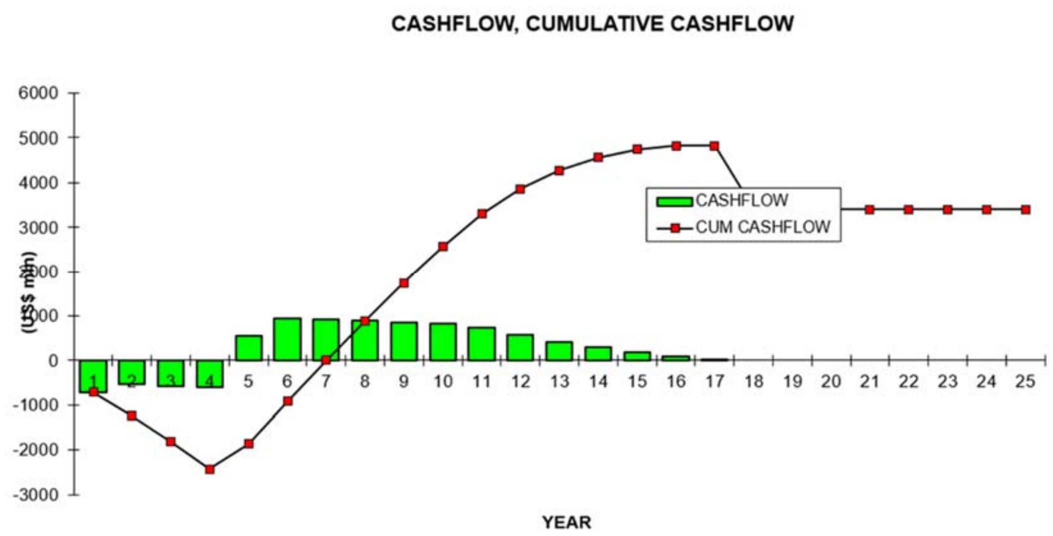
CONCRETE GRAVITY BASED PLATFORM			
Capacity	Value	Units	Notes
Max. Liquids Throughput	500000	bpd	
Max. Gas Throughput	800	mmscf/d	
POB	50	pax	
Actual Oil Throughput	102740	mb/d	*Plateau Rate*
Actual Gas Throughput	82.19	mmscf/d	*GOR of 800 scf/bbl*
Topsides Weight			
Accomodation	2000	t	*40 t * POB*
Utilities	1500	t	*1500 t*
Oil Processing	1541	t	*15 t per mb/d (Chart)*
Gas Processing	1233	t	*15 t per mmscf/d (Chart)*
Total Topsides Weight	6274	t	
Total Concrete Weight	12548	t	*2 * Topsides Weight*
Cost			
Topsides Cost	$ 941,097,000		*$150k per Tonne*
Concrete Cost	$ 1,003,836,800		*$80k per Tonne*
TOTAL CAPEX	**$ 1,944,933,800**		
Construction Time	4	years	
CAPEX Per Year	$ 486,233,450		
Decommissioning			
Topsides	$ 125,479,600		*$20k per Tonne*
Concrete	$ 501,918,400		*$40k per Tonne*
Total	**$ 627,398,000**		

EXPORT FACILITY

PIPELINE			
Oil Pipeline Length	50	km	*Black Dog to Forties Charlie Tie-In*
Gas Pipeline Length	50	km	*Black Dog to CAPS Tie-In*
Total Length	100	km	
Unit Cost	$ 3,000,000	$/per km	*for 0-100 mb/d*
Total CAPEX	**$ 300,000,000**		
Construction Time	0.55	Years	*2 days per km*
Decommissioing Cost	$ 50,000,000		*$500k per m*

DECOMMISSIONING

Production Facility	$ 627,398,000	*See Production Facility Table*
Wells	$ 200,000,000	*$10m per Well*
Pipelines	$ 50,000,000	*See Export facility Table*
Storage Tanker	$ -	*No storage tanker*
TOTAL	**$ 877,398,000**	



OUTPUT from Economics Calulator sheet

NPV	(10)	952	US$mm
IRR		18.57%	
Payback		7	years
Economic Reserves		423	mmboe
Capex		3732	US$mm
Capex/boe		9	$/boe
Lifting Cost/boe		17	$/boe
Transportation Cost/boe		10.5	$/boe

OPTION B – ECONOMICS CALCULATIONS

CASH FLOW																		
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CAPEX ($mm)	986	686	686	686	200	0	0	0	0	0	0	0	0	0	0	0	0	0
DECOMMISSIONING ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	877
Production wells drilled	4	4	4	4	4						0	0	0	0	0	0	0	0
Production wells	0	0	0	0	16	20	20	20	20	20	20	20	20	20	20	20	20	20

CAPEX					
Well cost ($mm)	200	200	200	200	200
FPSO cost ($mm)	486	486	486	486	
Pipeline gas ($mm)	300				

ECONOMICS INPUT	
Fixed opex (% cum. capex)	6
Variable opex ($/bbl)	5
Gas transportation tariff ($/Mscf)	3
Oil transportation tariff ($/bbl)	5

ECONOMICS DATA																										
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	S
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
Sales gas rate (MMscf/d)	0	0	0	0	64	80	80	80	80	80	76	65	56	48	41	35	30	25	22	18	16	13	11	10	8	321
Oil rate (Mstb/d)	0	0	0	0	80	100	100	100	100	100	95	82	70	60	51	43	37	32	27	23	20	17	14	12	10	401
RT Gas revenues ($mm)	0	0	0	0	66	83	83	83	83	83	79	68	58	49	42	36	31	26	22	19	16	14	12	10	9	333
RT Oil revenues ($mm)	0	0	0	0	1694	2117	2117	2117	2117	2117	2012	1732	1479	1262	1077	919	784	669	571	487	415	354	302	258	220	8494
MOD Gross rev ($mm)	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Units all $mm																										
Capex ($mm)	986	686	686	686	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3244
Decommissioning ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	877	0	0	0	0	0	0	0	
REAL Fixed opex ($mm)	0	0	0	0	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	3114
REAL Variable opex ($mm)	0	0	0	0	146	183	183	183	183	183	173	149	128	109	93	79	68	58	49	42	36	31	26	22	19	2006
REAL Gas transportation tariff ($mm)	0	0	0	0	70	88	88	88	88	88	83	72	61	52	45	38	32	28	24	20	17	15	13	11	9	
REAL Oil transportation tariff ($mm)	0	0	0	0	146	183	183	183	183	183	173	149	128	109	93	79	68	58	49	42	36	31	26	22	19	
REAL Total opex ($mm)	0	0	0	0	557	647	647	647	647	647	625	565	511	465	425	391	362	338	317	299	283	270	259	250	242	8089
MOD Capex	1020	759	812	869	271	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3732
MOD Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2866	0	0	0	0	0	0	0	
MOD Fixed + variable opex	0	0	0	0	424	493	518	544	571	600	614	603	593	586	583	583	587	593	601	613	627	643	662	683	706	9106
MOD Oil + Gas transp Tariff	0	0	0	0	269	353	371	389	409	429	428	387	347	311	279	250	224	200	180	161	144	129	116	104	93	4988
MOD Total opex	0	0	0	0	693	846	889	933	980	1029	1043	990	940	898	862	833	810	793	781	774	771	772	777	786	799	14094
Gross Revenue	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Total costs	1020	759	812	869	965	846	889	933	980	1029	1043	990	940	898	862	833	810	793	781	774	771	772	777	786	799	17826
Pre tax Cash Flow	-1020	-759	-812	-869	795	1353	1311	1267	1220	1171	1048	810	597	414	257	122	4	-98	-188	-268	-339	-404	-463	-518	-570	6356
Corporation tax	-306	-228	-244	-261	239	406	393	380	366	351	314	243	179	124	77	37	1	-29	-56	-80	-102	-121	-139	-155	-171	1907
MOD Net Cashflow	-714	-531	-569	-609	557	947	918	887	854	820	733	567	418	290	180	85	3	-69	-131	-187	-237	-283	-324	-363	-399	4449
Project still profitable?				STOP	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	
Economic production (mboed)				0	91.03448	113.7931	113.7931	113.7931	113.7931	113.7931	108.1245	93.12453	79.52159	67.85199	57.89063	49.39136	42.13989	0	0	0	0	0	0	0	0	422.68624
MOD Economic Lifting costs	0	0	0	0	424.275	493.2235	517.8847	543.7789	570.9678	599.5162	614.3177	602.8722	592.8695	586.3505	583.2556	583.3807	586.5364	0	0	0	0	0	0	0	0	7299.2287
MOD Economic Transptn costs	0	0	0	0	269.1327	353.2366	370.8985	389.4434	408.9156	429.3613	428.3714	387.3911	347.3441	311.1908	278.7801	249.7432	223.7306	0	0	0	0	0	0	0	0	4447.5394
MOD Economic Cashflow	-713.9484	-531.4933	-568.6979	-608.5067	556.7486	947.4275	917.8014	886.694	854.0312	819.7353	733.3549	567.0597	418.0074	289.9546	180.0025	85.22108	3.087599	0	0	0	0	0	0	0	0	4836.4796
MOD Cashflow with Decom	-713.9484	-531.4933	-568.6979	-608.5067	556.7486	947.4275	917.8014	886.694	854.0312	819.7353	733.3549	567.0597	418.0074	289.9546	180.0025	85.22108	3.087599	-1432.8	0	0	0	0	0	0	0	
MOD Cum. Cashflow	-713.9484	-1245.442	-1814.14	-2422.646	-1865.898	-918.4703	-0.668835	886.0252	1740.056	2559.792	3293.147	3860.206	4278.214	4568.168	4748.171	4833.392	4836.48	3403.679	3403.679	3403.679	3403.679	3403.679	3403.679	3403.679	3403.679	36833.476
RT Economic cashflow	-696.7423	-493.9851	-503.3944	-512.9828	446.9997	724.4441	668.3721	614.9701	564.1112	515.6741	439.3661	323.5578	227.1526	150.0633	88.72249	40.00487	1.380376	-610.0606	0	0	0	0	0	0	0	1987.6536
RT Cum. Cashflow	-696.7423	-1190.727	-1694.122	-2207.105	-1760.105	-1035.661	-367.2888	247.6813	811.7925	1327.467	1766.833	2090.391	2317.543	2467.606	2556.329	2596.334	2597.714	1987.654	1987.654	1987.654	1987.654	1987.654	1987.654	1987.654	1987.654	
Payback calculation	0	0	0	0	0	0	7.000754	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
LC/boe				#DIV/0!	12.76876	11.87504	12.46879	13.09223	13.74684	14.43418	15.56596	17.73652	20.4259	23.67565												

OPTION C
Concrete Gravity Base Platform – Exporting Oil via Shuttle, Gas via Pipeline

PRODUCTION FACILITY

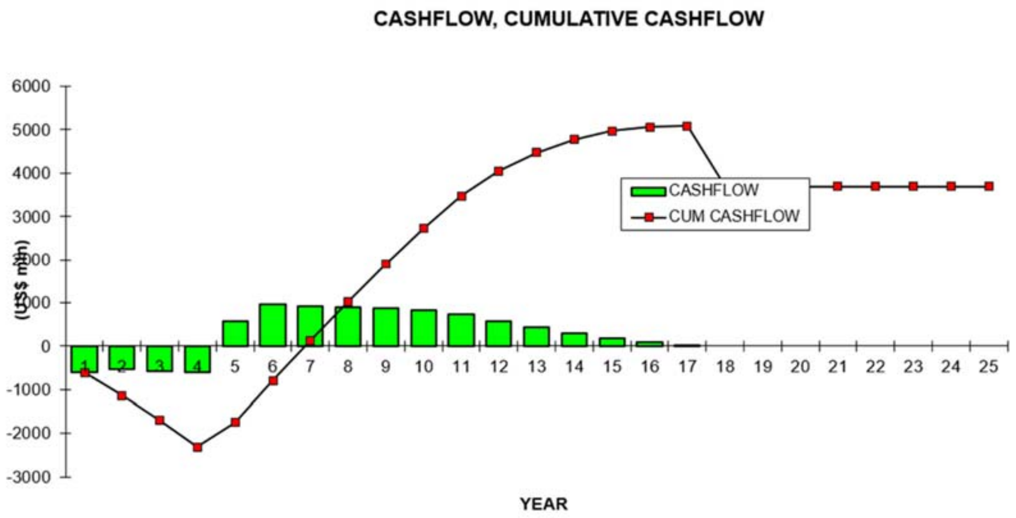
CONCRETE GRAVITY BASED PLATFORM			
Capacity	Value	Units	Notes
Max. Liquids Throughput	500000	bpd	
Max. Gas Throughput	800	mmscf/d	
POB	50	pax	
Actual Oil Throughput	102740	mb/d	*Plateau Rate*
Actual Gas Throughput	82.19	mmscf/d	*GOR of 800 scf/bbl*
Topsides Weight			
Accomodation	2000	t	*40 t * POB*
Utilities	1500	t	*1500 t*
Oil Processing	1541	t	*15 t per mb/d (Chart)*
Gas Processing	1233	t	*15 t per mmscf/d (Chart)*
Total Topsides Weight	6274	t	
Total Concrete Weight	12548	t	*2 * Topsides Weight*
Cost			
Topsides Cost	$ 941,097,000		*$150k per Tonne*
Concrete Cost	$ 1,003,836,800		*$80k per Tonne*
TOTAL CAPEX	**$ 1,944,933,800**		
Construction Time	4	years	
CAPEX Per Year	$ 486,233,450		
Decommissioning			
Topsides	$ 125,479,600		*$20k per Tonne*
Concrete	$ 501,918,400		*$40k per Tonne*
Total	**$ 627,398,000**		

EXPORT FACILITY

PIPELINE			
Oil Pipeline Length	0	km	*Export via Shuttle*
Gas Pipeline Length	50	km	*Black Dog to CAPS Tie-In*
Total Length	50	km	
Unit Cost	$ 3,000,000	$/per km	*for 0-100 mb/d*
Total CAPEX	**$ 150,000,000**		
Construction Time	0.27	Years	*2 days per km*
Decommissioning Cost	$ 25,000,000		*$500k per m*

DECOMMISSIONING

Production Facility	$ 627,398,000	*See Production Facility Table*
Wells	$ 200,000,000	*$10m per Well*
Pipelines	$ 25,000,000	*See Export facility Table*
Storage Tanker	$ -	*No storage tanker*
TOTAL	**$ 852,398,000**	



OUTPUT from Economics Calulator sheet

NPV	(10)	1107	US$mm
IRR		20.21%	
Payback		7	years
Economic Reserves		423	mmboe
Capex		3577	US$mm
Capex/boe		8	$/boe
Lifting Cost/boe		24	$/boe
Transportation Cost/boe		3.4	$/boe

OPTION C – ECONOMICS DATA

CASH FOW																		
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CAPEX ($mm)	836	686	686	686	200	0	0	0	0	0	0	0	0	0	0	0	0	0
DECOMMISSIONING ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	852
Production wells drilled	4	4	4	4	4						0	0	0	0	0	0	0	0
Production wells	0	0	0	0	16	20	20	20	20	20	20	20	20	20	20	20	20	20
CAPEX																		
Well cost ($mm)	200	200	200	200	200													
FPSO cost ($mm)	486	486	486	486														
Pipeline gas ($mm)	150																	
ECONOMICS INPUT																		
Fixed opex (% cum. capex)	6																	
Variable opex ($/bbl)	10	*$5/bll for Variable OPEX + $5/bbl for Shuttle*																
Gas transportation tariff ($/Mscf)	3																	
Oil transportation tariff ($/bbl)	0																	

ECONOMICS CALCULATIONS																									
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	S
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
Sales gas rate (MMscf/d)	0	0	0	0	64	80	80	80	80	80	76	65	56	48	41	35	30	25	22	18	16	13	11	10	8	321
Oil rate (Mstb/d)	0	0	0	0	80	100	100	100	100	100	95	82	70	60	51	43	37	32	27	23	20	17	14	12	10	401
RT Gas revenues ($mm)	0	0	0	0	66	83	83	83	83	83	79	68	58	49	42	36	31	26	22	19	16	14	12	10	9	333
RT Oil revenues ($mm)	0	0	0	0	1694	2117	2117	2117	2117	2117	2012	1732	1479	1262	1077	919	784	669	571	487	415	354	302	258	220	8494
MOD Gross rev ($mm)	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Units all $mm																										
Capex ($mm)	836	686	686	686	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3094
Decommissioning ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	852	0	0	0	0	0	0	0	
REAL Fixed opex ($mm)	0	0	0	0	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	2970
REAL Variable opex ($mm)	0	0	0	0	292	365	365	365	365	365	347	299	255	218	186	158	135	115	98	84	72	61	52	44	38	4012
REAL Gas transportation tariff ($mm)	0	0	0	0	70	88	88	88	88	88	83	72	61	52	45	38	32	28	24	20	17	15	13	11	9	
REAL Oil transportation tariff ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
REAL Total opex ($mm)	0	0	0	0	548	638	638	638	638	638	616	556	502	456	416	382	353	329	308	290	274	261	250	241	233	7945
MOD Capex	865	759	812	869	271	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3577
MOD Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2784	0	0	0	0	0	0	0	
MOD Fixed + variable opex	0	0	0	0	595	720	756	794	834	875	889	849	811	779	753	733	718	707	700	698	699	704	713	724	739	12211
MOD Oil + Gas transp Tariff	0	0	0	0	87	115	120	126	133	139	139	126	113	101	90	81	73	65	58	52	47	42	38	34	30	1618
MOD Total opex	0	0	0	0	682	835	876	920	966	1015	1028	974	924	880	844	814	790	772	759	750	746	746	750	758	769	13829
Gross Revenue	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Total costs	865	759	812	869	953	835	876	920	966	1015	1028	974	924	880	844	814	790	772	759	750	746	746	750	758	769	17406
Pre tax Cash Flow	-865	-759	-812	-869	807	1365	1324	1280	1234	1185	1063	826	614	432	275	141	25	-77	-166	-244	-315	-378	-436	-490	-540	6776
Corporation tax	-259	-228	-244	-261	242	410	397	384	370	356	319	248	184	129	83	42	7	-23	-50	-73	-94	-113	-131	-147	-162	2033
MOD Net Cashflow	-605	-531	-569	-609	565	956	926	896	864	830	744	578	430	302	193	99	17	-54	-116	-171	-220	-265	-305	-343	-378	4743
Project still profitable?				STOP	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	
Economic production (mboed)				0	91	114	114	114	114	114	108	93	80	68	58	49	42	0	0	0	0	0	0	0	0	423
MOD Economic Lifting costs	0	0	0	0	595	720	756	794	834	875	889	849	811	779	753	733	718	0	0	0	0	0	0	0	0	10106
MOD Economic Transptn costs	0	0	0	0	87	115	120	126	133	139	139	126	113	101	90	81	73	0	0	0	0	0	0	0	0	1442
MOD Economic Cashflow	-605	-531	-569	-609	565	956	926	896	864	830	744	578	430	302	193	99	17	0	0	0	0	0	0	0	0	5084
MOD Cashflow with Decom	-605	-531	-569	-609	565	956	926	896	864	830	744	578	430	302	193	99	17	-1392	0	0	0	0	0	0	0	
MOD Cum. Cashflow	-605	-1137	-1706	-2314	-1749	-794	133	1028	1892	2722	3466	4044	4473	4775	4968	5067	5084	3692	3692	3692	3692	3692	3692	3692	3692	40424
RT Economic cashflow	-591	-494	-503	-513	453	731	675	621	570	522	446	330	233	156	95	46	8	-593	0	0	0	0	0	0	0	2193
RT Cum. Cashflow	-591	-1085	-1588	-2101	-1648	-917	-242	379	949	1471	1917	2247	2480	2637	2732	2778	2786	2193	2193	2193	2193	2193	2193	2193	2193	
Payback calculation	0	0	0	0	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
LC/boe				#DIV/0!	18	17	18	19	20	21	23	25	28	31												

OPTION E
Floating Production Platform – Exporting Oil via Storage Tanker + Shuttle, and Gas via Pipeline

PRODUCTION FACILITY

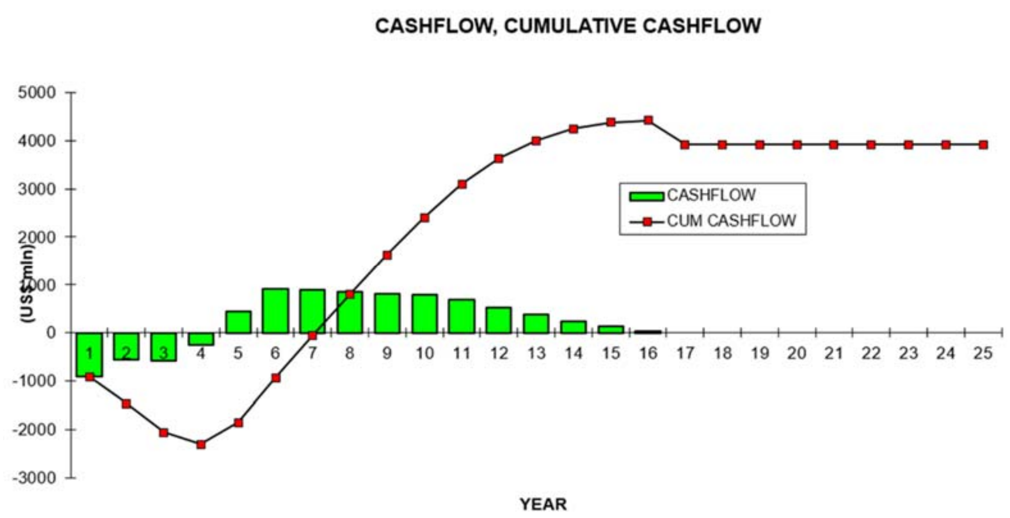
FLOATING PRODUCTION PLATFORM 2			
Capacity	Value	Units	Notes
Max. Liquids Throughput	140000	bpd	
Max. Gas Throughput	120	mmscf/d	
Actual Oil Throughput	102740	mb/d	*Plateau Rate*
Actual Gas Throughput	82.19	mmscf/d	*GOR of 800 scf/bbl*
Cost			
Platform Cost	$ 1,300,000,000		
TOTAL CAPEX	**$ 1,300,000,000**		
Construction Time	3	years	
CAPEX Per Year	$ 433,333,333		
Decommissioning			
Total	**$ 50,000,000**		

EXPORT FACILITY

PIPELINE				
Oil Pipeline Length		0	km	*Export via Storage Tanker + Shuttle*
Gas Pipeline Length		50	km	*Black Dog to CAPS Tie-In*
Total Length		50	km	
Unit Cost	$	3,000,000	$/per km	*for 0-100 mb/d*
Total CAPEX	**$**	**150,000,000**		
Construction Time		0.27	Years	*2 days per km*
Decommissioning Cost	$	25,000,000		*$500k per m*
STORAGE TANKER				
CAPEX	**$**	**400,000,000**		
Decommissioning Cost	$	50,000,000		

DECOMMISSIONING

Production Facility	$	50,000,000	*See Production Facility Table*
Wells	$	200,000,000	*$10m per Well*
Pipelines	$	25,000,000	*See Export facility Table*
Storage Tanker	$	50,000,000	*See Export facility Table*
TOTAL	**$**	**325,000,000**	



OUTPUT from Economics Calulator sheet

NPV	(10)	926	US$mm
IRR		17.45%	
Payback		7	years
Economic Reserves		407	mmboe
Capex		3674	US$mm
Capex/boe		9	$/boe
Lifting Cost/boe		25	$/boe
Transportation Cost/boe		3.4	$/boe

OPTION E – ECONOMIC DATA

CASH FLOW																	
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CAPEX ($mm)	1263	713	713	280	280	0	0	0	0	0	0	0	0	0	0	0	0
DECOMMISSIONING ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325
Production wells drilled	4	4	4	4	4						0	0	0	0	0	0	0
Production wells	0	0	0	0	16	20	20	20	20	20	20	20	20	20	20	20	20
CAPEX																	
Well cost ($mm)	280	280	280	280	280												
FPSO cost ($mm)	433	433	433														
Pipeline gas ($mm)	550																

ECONOMIC INPUTS						
Fixed opex (% cum. capex)	7					
Variable opex ($/bbl)	10	*$5/bbl for Variable OPEX + $%/bbl for Shuttle*				
Gas transportation tariff ($/Mscf)	3					
Oil transportation tariff ($/bbl)	0					

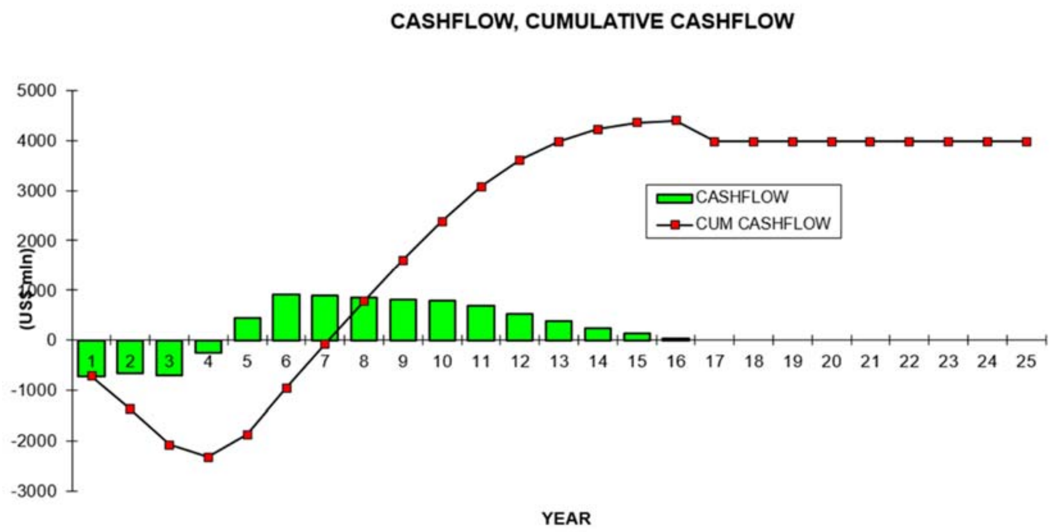
ECONOMIC CALCULATIONS																										
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	S
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
Sales gas rate (MMscf/d)	0	0	0	0	64	80	80	80	80	80	76	65	56	48	41	35	30	25	22	18	16	13	11	10	8	321
Oil rate (Mstb/d)	0	0	0	0	80	100	100	100	100	100	95	82	70	60	51	43	37	32	27	23	20	17	14	12	10	401
RT Gas revenues ($mm)	0	0	0	0	66	83	83	83	83	83	79	68	58	49	42	36	31	26	22	19	16	14	12	10	9	333
RT Oil revenues ($mm)	0	0	0	0	1694	2117	2117	2117	2117	2117	2012	1732	1479	1262	1077	919	784	669	571	487	415	354	302	258	220	8494
MOD Gross rev ($mm)	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Units all $mm																										
Capex ($mm)	1263	713	713	280	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3249
Decommissioning ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	0	0	0	0	0	0	0	0	
REAL Fixed opex ($mm)	0	0	0	0	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	3639
REAL Variable opex ($mm)	0	0	0	0	292	365	365	365	365	365	347	299	255	218	186	158	135	115	98	84	72	61	52	44	38	4012
REAL Gas transportation tariff ($mm)	0	0	0	0	70	88	88	88	88	88	83	72	61	52	45	38	32	28	24	20	17	15	13	11	9	
REAL Oil transportation tariff ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
REAL Total opex ($mm)	0	0	0	0	590	680	680	680	680	680	657	598	544	497	458	424	395	370	349	332	316	303	292	283	274	8614
MOD Capex	1306	789	844	355	380	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3674
MOD Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	992	0	0	0	0	0	0	0	0	
MOD Fixed + variable opex	0	0	0	0	647	775	814	854	897	942	958	922	888	860	838	822	811	805	803	806	813	824	838	856	877	13442
MOD Oil + Gas transp Tariff	0	0	0	0	87	115	120	126	133	139	139	126	113	101	90	81	73	65	58	52	47	42	38	34	30	1618
MOD Total opex	0	0	0	0	734	889	934	981	1030	1081	1097	1048	1001	961	929	903	884	870	862	858	860	866	876	889	907	15060
Gross Revenue	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Total costs	1306	789	844	355	1114	889	934	981	1030	1081	1097	1048	1001	961	929	903	884	870	862	858	860	866	876	889	907	18735
Pre tax Cash Flow	-1306	-789	-844	-355	646	1311	1266	1219	1170	1119	993	753	537	351	191	52	-69	-175	-269	-352	-428	-497	-561	-621	-678	5447
Corporation tax	-392	-237	-253	-106	194	393	380	366	351	336	298	226	161	105	57	16	-21	-52	-81	-106	-128	-149	-168	-186	-204	1634
MOD Net Cashflow	-915	-552	-591	-248	452	917	886	854	819	783	695	527	376	246	133	36	-48	-122	-188	-247	-300	-348	-393	-435	-475	3813
Project still profitable?				STOP	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	
Economic production (mboed)				0	91	114	114	114	114	114	108	93	80	68	58	49	0	0	0	0	0	0	0	0	0	407
MOD Economic Lifting costs	0	0	0	0	647	775	814	854	897	942	958	922	888	860	838	822	0	0	0	0	0	0	0	0	0	10217
MOD Economic Transptn costs	0	0	0	0	87	115	120	126	133	139	139	126	113	101	90	81	0	0	0	0	0	0	0	0	0	1370
MOD Economic Cashflow	-915	-552	-591	-248	452	917	886	854	819	783	695	527	376	246	133	36	0	0	0	0	0	0	0	0	0	4419
MOD Cashflow with Decom	-915	-552	-591	-248	452	917	886	854	819	783	695	527	376	246	133	36	-496	0	0	0	0	0	0	0	0	
MOD Cum. Cashflow	-915	-1467	-2058	-2306	-1854	-937	-50	803	1622	2406	3101	3628	4003	4249	4382	4419	3922	3922	3922	3922	3922	3922	3922	3922	3922	34715
RT Economic cashflow	-892	-513	-523	-209	363	701	645	592	541	493	416	301	204	127	66	17	-222	0	0	0	0	0	0	0	0	2107
RT Cum. Cashflow	-892	-1406	-1929	-2138	-1775	-1074	-429	164	705	1197	1614	1914	2119	2246	2311	2329	2107	2107	2107	2107	2107	2107	2107	2107	2107	
Payback calculation	0	0	0	0	0	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
LC/boe				#DIV/0!	19	19	20	21	22	23	24	27	31	35												

OPTION G
FPSO 2 – Exporting Oil via Shuttle, and Gas via Pipeline

PRODUCTION FACILITY			
FPSO - 2			
Capacity	Value	Units	Notes
Max. Liquids Throughput	100000	bpd	
Max. Gas Throughput	100	mmscf/d	
Actual Oil Throughput	102740	mb/d	*Plateau Rate*
Actual Gas Throughput	82.19	mmscf/d	*GOR of 800 scf/bbl*
Cost			
Platform Cost	$ 1,700,000,000		
TOTAL CAPEX	**$ 1,700,000,000**		
Construction Time	3	years	
CAPEX Per Year	$ 566,666,667		
Decommissioning			
Total	**$ 50,000,000**		

EXPORT FACILITY			
PIPELINE			
Oil Pipeline Length	0	km	*Export via Storage Tanker + Shuttle*
Gas Pipeline Length	50	km	*Black Dog to CAPS Tie-In*
Total Length	50	km	
Unit Cost	$ 3,000,000	$/per km	*for 0-100 mb/d*
Total CAPEX	**$ 150,000,000**		
Construction Time	0.27	Years	*2 days per km*
Decommissioning Cost	$ 25,000,000		*$500k per m*

DECOMMISSIONING		
Production Facility	$ 50,000,000	*See Production Facility Table*
Wells	$ 200,000,000	*$10m per Well*
Pipelines	$ 25,000,000	*See Export facility Table*
Storage Tanker	$ -	*Shuttle only*
TOTAL	**$ 275,000,000**	



OUTPUT from Economics Calulator sheet			
NPV	(10)	949	US$mm
IRR		17.77%	
Payback		7	years
Economic Reserves		407	mmboe
Capex		3703	US$mm
Capex/boe		9	$/boe
Lifting Cost/boe		25	$/boe
Transportation Cost/boe		3.4	$/boe

OPTION G – ECONOMICS DATA

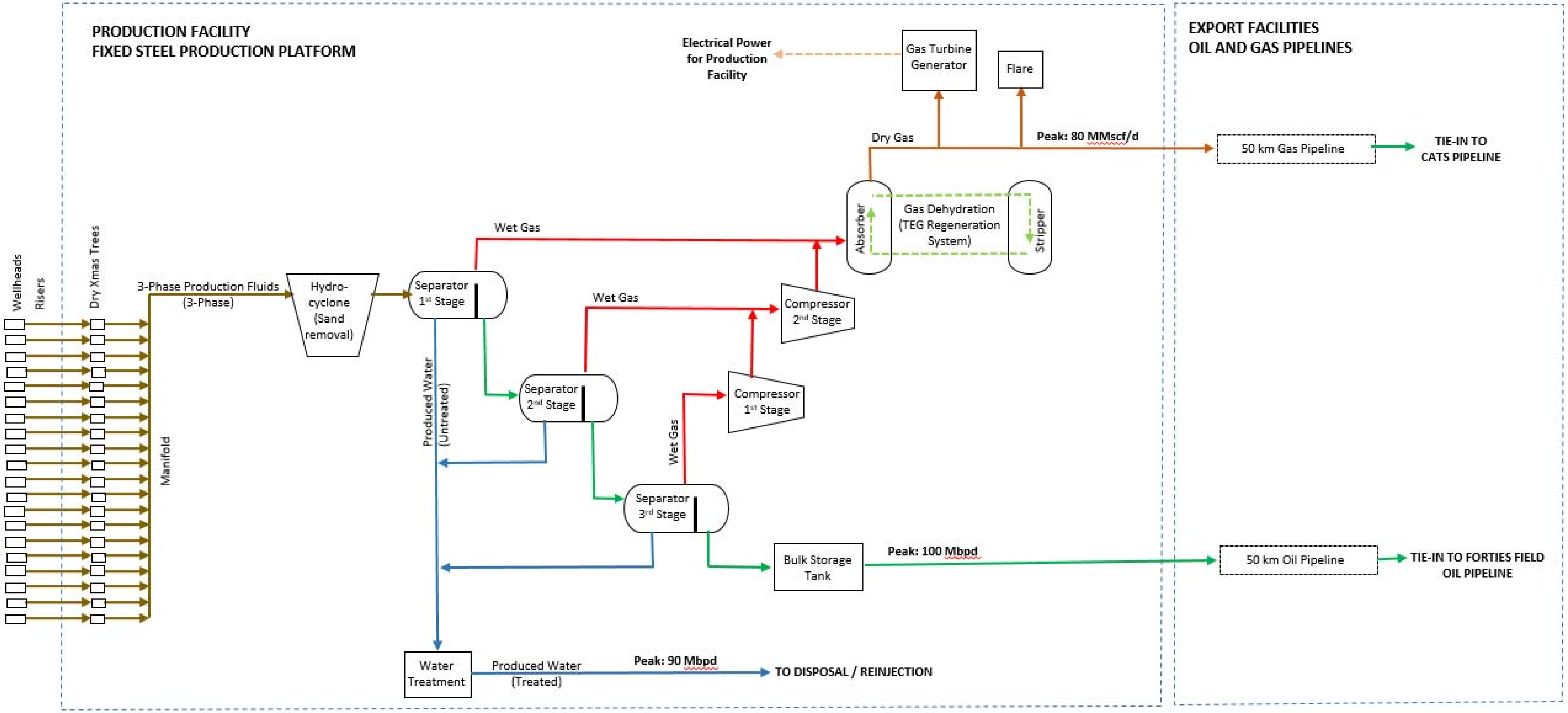
CASH FLOW																	
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CAPEX ($mm)	996	846	846	280	280	0	0	0	0	0	0	0	0	0	0	0	0
DECOMMISSIONING ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	275
Production wells drilled	4	4	4	4	4						0	0	0	0	0	0	0
Production wells	0	0	0	0	16	20	20	20	20	20	20	20	20	20	20	20	20

CAPEX					
Well cost ($mm)	280	280	280	280	280
FPSO cost ($mm)	566	566	566		
Pipeline gas ($mm)	150				

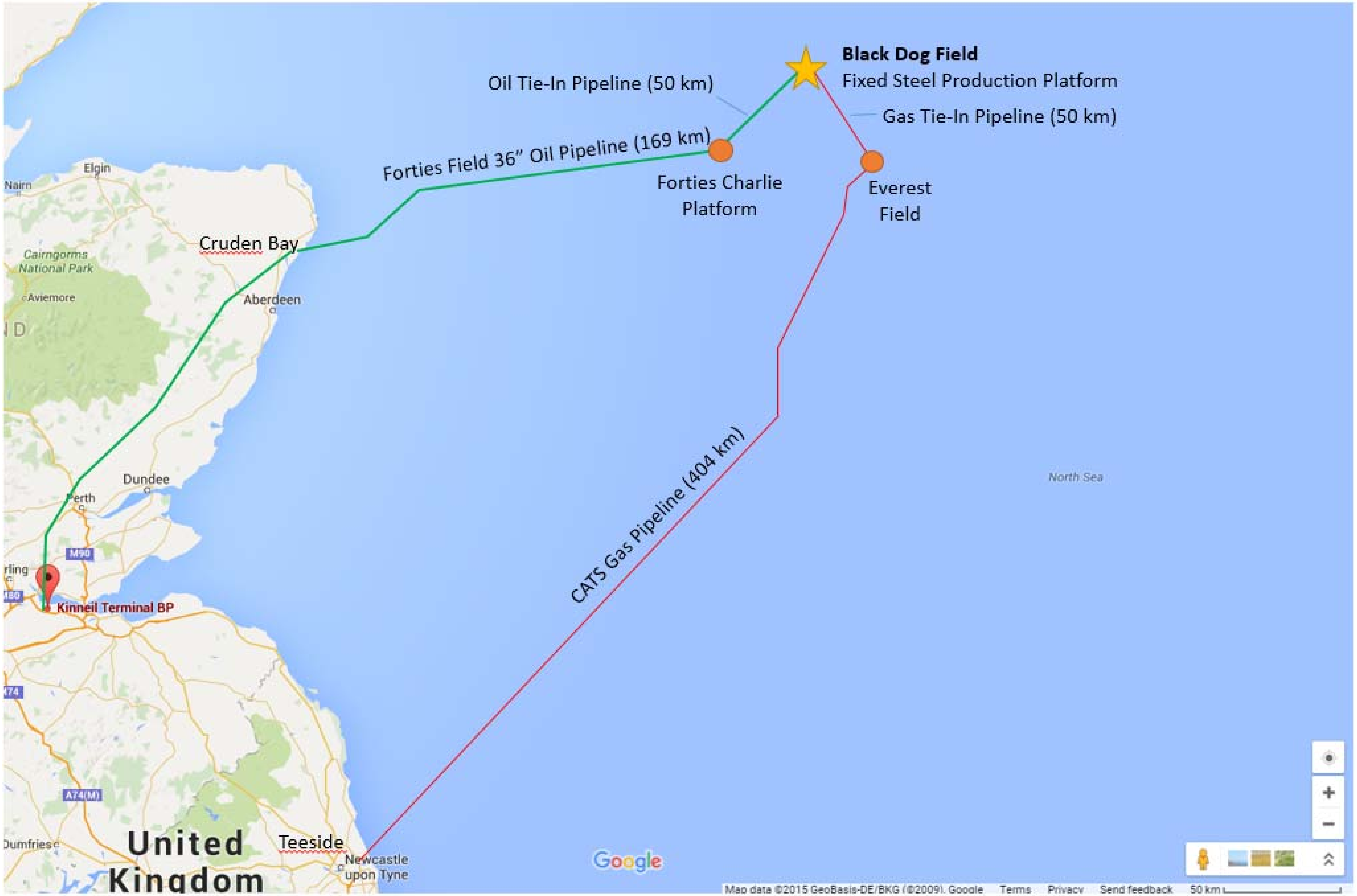
ECONOMIC INPUT						
Fixed opex (% cum. capex)	7					
Variable opex ($/bbl)	10	*$5/bbl for Variable OPEX + $%/bbl for Shuttle*				
Gas transportation tariff ($/Mscf)	3					
Oil transportation tariff ($/bbl)	0					

ECONOMICS CALCULATIONS																										
Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	S
Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
Sales gas rate (MMscf/d)	0	0	0	0	64	80	80	80	80	80	76	65	56	48	41	35	30	25	22	18	16	13	11	10	8	321
Oil rate (Mstb/d)	0	0	0	0	80	100	100	100	100	100	95	82	70	60	51	43	37	32	27	23	20	17	14	12	10	401
RT Gas revenues ($mm)	0	0	0	0	66	83	83	83	83	83	79	68	58	49	42	36	31	26	22	19	16	14	12	10	9	333
RT Oil revenues ($mm)	0	0	0	0	1694	2117	2117	2117	2117	2117	2012	1732	1479	1262	1077	919	784	669	571	487	415	354	302	258	220	8494
MOD Gross rev ($mm)	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Units all $mm																										
Capex ($mm)	996	846	846	280	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3248
Decommissioning ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	275	0	0	0	0	0	0	0	0	
REAL Fixed opex ($mm)	0	0	0	0	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	3638
REAL Variable opex ($mm)	0	0	0	0	292	365	365	365	365	365	347	299	255	218	186	158	135	115	98	84	72	61	52	44	38	4012
REAL Gas transportation tariff ($mm)	0	0	0	0	70	88	88	88	88	88	83	72	61	52	45	38	32	28	24	20	17	15	13	11	9	
REAL Oil transportation tariff ($mm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
REAL Total opex ($mm)	0	0	0	0	589	680	680	680	680	680	657	598	544	497	458	424	395	370	349	331	316	303	292	283	274	8613
MOD Capex	1030	936	1002	355	380	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3703
MOD Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	840	0	0	0	0	0	0	0	0	
MOD Fixed + variable opex	0	0	0	0	647	775	813	854	897	942	958	922	888	860	838	822	811	805	803	806	813	824	838	856	877	13440
MOD Oil + Gas transp Tariff	0	0	0	0	87	115	120	126	133	139	139	126	113	101	90	81	73	65	58	52	47	42	38	34	30	1618
MOD Total opex	0	0	0	0	734	889	934	980	1029	1081	1097	1048	1000	961	928	903	883	870	862	858	860	865	875	889	907	15058
Gross Revenue	0	0	0	0	1760	2200	2200	2200	2200	2200	2090	1800	1537	1312	1119	955	815	695	593	506	432	368	314	268	229	24182
Total costs	1030	936	1002	355	1114	889	934	980	1029	1081	1097	1048	1000	961	928	903	883	870	862	858	860	865	875	889	907	18761
Pre tax Cash Flow	-1030	-936	-1002	-355	646	1311	1266	1220	1171	1119	993	753	537	351	191	52	-69	-175	-269	-352	-428	-497	-561	-621	-678	5421
Corporation tax	-309	-281	-301	-106	194	393	380	366	351	336	298	226	161	105	57	16	-21	-52	-81	-106	-128	-149	-168	-186	-203	1626
MOD Net Cashflow	-721	-655	-701	-248	452	917	886	854	819	783	695	527	376	246	134	36	-48	-122	-188	-247	-300	-348	-393	-435	-475	3795
Project still profitable?				STOP	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	
Economic production (mboed)				0	91	114	114	114	114	114	108	93	80	68	58	49	0	0	0	0	0	0	0	0	0	407
MOD Economic Lifting costs	0	0	0	0	647	775	813	854	897	942	958	922	888	860	838	822	0	0	0	0	0	0	0	0	0	10215
MOD Economic Transptn costs	0	0	0	0	87	115	120	126	133	139	139	126	113	101	90	81	0	0	0	0	0	0	0	0	0	1370
MOD Economic Cashflow	-721	-655	-701	-248	452	917	886	854	819	783	695	527	376	246	134	36	0	0	0	0	0	0	0	0	0	4400
MOD Cashflow with Decom	-721	-655	-701	-248	452	917	886	854	819	783	695	527	376	246	134	36	-420	0	0	0	0	0	0	0	0	
MOD Cum. Cashflow	-721	-1377	-2078	-2326	-1874	-957	-70	783	1603	2386	3081	3608	3984	4230	4363	4400	3980	3980	3980	3980	3980	3980	3980	3980	3980	34954
RT Economic cashflow	-704	-609	-621	-209	363	702	645	592	541	493	416	301	204	127	66	17	-188	0	0	0	0	0	0	0	0	2137
RT Cum. Cashflow	-704	-1313	-1934	-2143	-1780	-1079	-433	159	700	1193	1609	1910	2114	2242	2307	2324	2137	2137	2137	2137	2137	2137	2137	2137	2137	
Payback calculation	0	0	0	0	0	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
LC/boe				#DIV/0!	19	19	20	21	22	23	24	27	31	35												

APPENDIX B FLOW SCHEME OF MAIN PROCESS COMPONENTS



APPENDIX C PRODUCT EXPORT PLAN



Robert Gordon University

ENM227 Subsea Systems

RGU Petroleum Ltd
Asset Integrity Management Plan and Cost Projection

Name: ADAM BEATON

Student No: 1418528

Date: 22/04/2016

Word Count: 6473

1.0 EXECUTIVE SUMMARY

RGU Petroleum Ltd plan to develop a marginal subsea field by drilling two production wells and a water injection well, and tying these back to an existing FPSO. This document outlines a proposed subsea field architecture, an asset integrity management (AIM) plan for the major components, and a Class 5 OPEX cost projection for the life of field.

This document proposes the following basic field architecture (see Figure 1):

- Horizontal wells, with horizontal Xmas trees (HXTs)
- Cluster arrangement centred around a single manifold, with SDU, SEM and SCM built into the manifold.
- One production flowline and one water injection line
- Steel catenary risers up to the FPSO
- A single umbilical for electro-hydraulic control, chemical injection and power/communications to the field.

The AIM Plan outlines the highest risks to each subsea component, and proposes mitigation strategies and key performance indicators (KPIs). The Class 5 OPEX cost estimate is projected at approximately USD 1.4 billion (with an accuracy of -4/+20%).

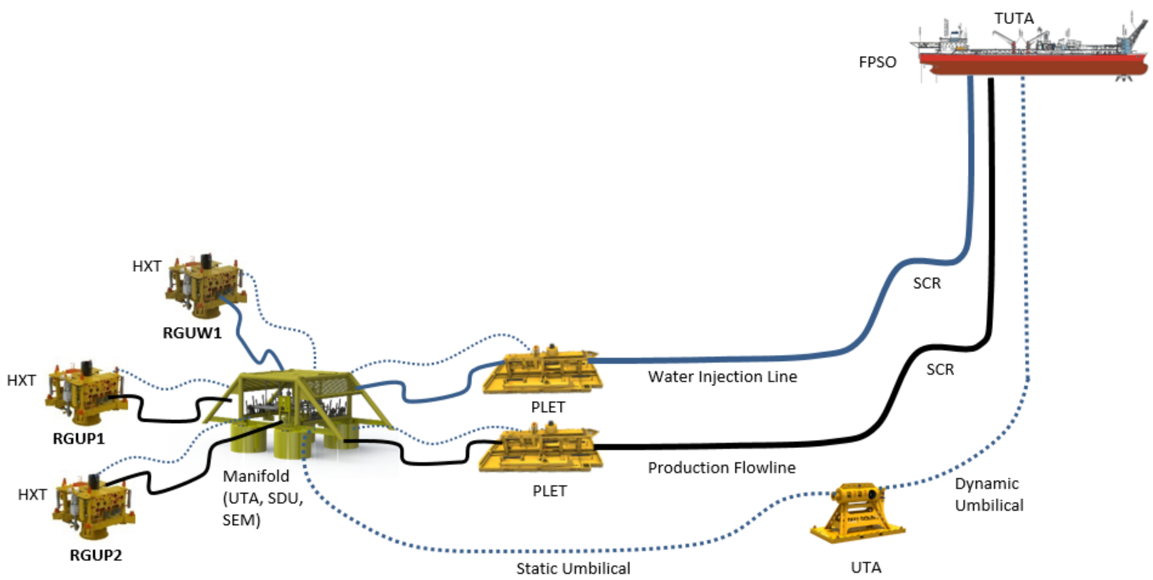


Figure 1 – Proposed Subsea Field Architecture

CONTENTS

2.0 INTRODUCTION

2.1 Background

RGU Petroleum Ltd plan to develop a marginal subsea field and tie back to an existing FPSO. Table 1 outlines the field data used for the architecture design.

Table 1 - General Field Data

Production Facility	Existing FPSO
Water Depth	1,200 m
No. of Producing Wells	2 (RGUP1, RGUP2)
No. of Water Injection Wells	1 (RGUW1)
TVD – Production Wells	9,500 ft
TVD – Injection Wells	10,000 ft
Production Rate	25,000 bbl/day
Gas-to-Oil Rate (GOR)	150 scf/bbl
SIWHP	10,500 Psi
FWHP	4,500 Psi
Life of Field (LOF)	12 years

2.2 Abbreviations

AIM	Asset Integrity Management
AMV	Annulus Main Valve
API	American Petroleum Institute
AWV	Annulus Wing Valve
CAPEX	Capital Expense
CoF	Consequence of Failure
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CV	Construction Vessel
CVI	Close Visual Inspection
DCV	Directional Control Valve

DNV	Det Norske Veritas
EPU	Electrical Power Unit
FPSO	Floating Production, Storage and Offloading
FWHP	Flowing Wellhead Pressure
GOR	Gas to Oil Ratio
GVI	General Visual Inspection
HIPPS	High Integrity Pressure Protection System
HP	High Pressure
HPHT	High Pressure High Temperature
HPU	Hydraulic Power Unit
HXT	Horizontal Xmas Tree
IR	Insulation Resistance
KPI	Key Performance Indicator
LOF	Life of Field
MAOP	Maximum Allowable Operating Pressure
MCS	Master Control Station
MEG	Monoethylene Glycol
MODU	Mobile Offshore Drilling Unit
MTBF	Mean Time Before Failure
OPEX	Operating Expense
PINC	Potential Incident of Non-Compliance
PLET	Pipeline End Termination
PMV	Production Main Valve
PoF	Probability of Failure
Psi	Pounds per Square Inch
PV	Present Value
PWV	Production Wing Valve
RGU	Robert Gordon University
RLWI	Riserless Light Well Intervention
ROV	Remotely Operated Vehicle
ROVSV	ROV Support Vessel
SCM	Subsea Control Module

SCR	Steel Catenary Riser
SCSSV	Surface Controlled Subsurface Safety Valve
SDU	Subsea Distribution Unit
SEM	Subsea Electronics Module
SIWHP	Shut-In Wellhead Pressure
SSPL/R	Subsea Pig Launcher / Receiver
TUTA	Topside Umbilical Termination Assembly
TVD	Total Vertical Depth
UPS	Uninterrupted Power Supply
UT	Ultrasonic Testing
UTA	Umbilical Termination Assembly
VXT	Vertical Xmas Tree
WT	Wall Thickness
XT	Xmas Tree

3.0 FIELD ARCHITECTURE DESIGN

The following design options were considered in determining the proposed subsea field architecture. The proposed field layout is provided in Appendix B.

3.1 Drilling Options

The wells could be drilled as vertical or directional. Several major design considerations are compared below, which affect the installation CAPEX, and the entire subsea field architecture.

Table 2 – Drilling Options

Considerations	Vertical	Directional
MODU Repositions (after initial mob)	2 (i.e. additional 28 days)	0
Total Measured Depth (see Appendix A1)	30,000 ft	48,300 ft
Tieback Options	• 3 x 2,000m Flowlines to Manifold, or; • Inline configuration (daisy-chain or 'looped')	• Template (no flowlines) or; • Cluster (jumpers to manifold)

It is assumed that the additional time for rig repositioning would be similar to the additional drilling time for directional wells. Also, the field layout is already complicated by the existing FPSO mooring lines. Therefore, directional wells are proposed based on the tieback options available for this drilling strategy.

3.2 Well Tieback Configuration Options

The wells will be spudded, and wellheads installed in close proximity from a single drilling location. This offers two configurations – Use of a subsea template, or a cluster configuration consisting of jumpers between the XTs and a central manifold. Considerations for these options are outlined below.

Table 3 – Well Tieback Options

Considerations	Template	Cluster
Drill Timing	Drilling starts after fabrication and installation of template.	Drilling can start prior to fabrication / installation of subsea structures.
Installation Requirements	Significant heavy-lift requirements. Limited to vessel availabilities	No heavy-lift required. More complex installation of jumpers.
Flow Assurance	No exposed flowlines.	Jumpers exposed to heat loss, hydrate issues etc.
Asset Protection	Structure is protected from dropped objects, snagging etc.	Jumpers exposed to snagging
Abandonment	Difficult to remove (heavy-lift required)	Easy to remove

The production life of the field development is short. For this reason, it would be prudent to expedite the field development, and also consider the decommissioning costs. Pressure and temperature losses should not be problematic, considering the reservoir is high pressure, high temperature (HPHT). Therefore, a cluster configuration is proposed so that drilling and development of subsea structures can commence simultaneously.

3.3 Jumper Options

Jumpers can be either rigid or flexible, and both options may have vertical or horizontal connectors. Flexibles are more expensive, and are typically used to cover longer spans, reduce heat loss, and simplify installation. It is assumed that spans from the manifold to XTs are short enough for traditional rigid jumpers, and that high temperature production shall not warrant additional insulation. Horizontal connectors are proposed to reduce the risk of snagging, and prevent issues with trapped water. Jumper material shall be corrosion resistant allow (CRA), since the jumpers will not be inspected internally by pigging.

3.4 Flowline Options

The short distance of 4500 m to the FPSO could allow for flexible technologies, however given the high shut in wellhead pressure (SIWHP), it is preferable to use conventional carbon steel pipe materials. One flowline and one water injection line are proposed to run from the riser base to two pipeline end terminations (PLET). The PLETs shall include facilities to mate a subsea pig launchers (SSPL) to allow inspection pigging to the FPSO, or a pigging loop with sweeping wyes to allow pigging from surface to surface.

3.5 HIPPS

The high integrity pressure protection system (HIPPS) shall be based on EIC 61511, as per API 17O *Subsea High Integrity Pressure Protection Systems (Hipps)* (API, 2015). Three independent pressure transmitters feed into a ‘2 out of 3’ (2oo3) voting logic solver, which controls two valves located on the Production Line PLET. The HIPPS system shall limit the pressure in the Production Flowline to 5,000 Psi. The HXT and Jumpers shall be rated for 15,000 Psi, due to the high SIWHP of 10,500 Psi.

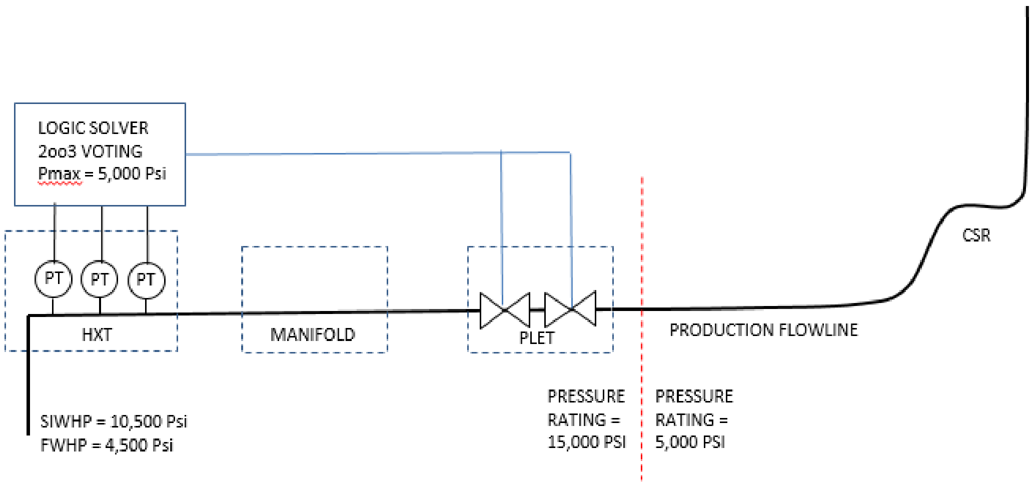


Figure 2 – HIPPS Schematic

3.6 Riser

Many options exist for riser configurations. This proposal has compared two preferable options: A hybrid bundled riser and a steel catenary riser.

Table 4 – Riser Options

Considerations	Hybrid Bundled (Flexible) Riser	Steel Catenary Riser (SCR)
Cost	High (advanced elastomers and sheathing etc)	Low (standard pipeline materials)
Flow Assurance	Better thermal insulation Rougher bore, higher pressure losses	Larger heat losses
Fabrication	Limited suppliers in select regions	Standard pipeline materials. Extension of flowline fabrication
Installation	Complex. Requires heavy lift vessels. Can be installed prior to arrival of FPSO.	Time consuming, costly. Must occur at same time as flowline lay. FPSO must arrive first.
Fatigue	Good. Decoupled from vessel, with short flexible jumper (which could be replaced).	Sensitive to vessel motions, position of connection. Requires Flexjoint. Careful consideration of seabed conditions.
Pressure	Limited to ~ 8000 Psi for 8” line.	Same capacity as flowline.

The hybrid riser is beneficial only if the FPSO is to arrive later. In this case the FPSO is already on site, so SCRs are proposed due to the simplicity for installation and lower capital expense. A lazy wave arrangement should be used to reduce problems with riser compression in such a deep application (Ghosh, 2012).

3.7 Xmas Tree Options

Xmas Trees are categorised into two types; vertical (VXT) and horizontal (HXT). The main difference is that a HXT incudes the tubing hanger inside the tree, rather than attached to the wellhead (Krenek 1995), which allows tubing retrieval while the HXT remains in-situ. HXTs are easier for major workover, whereas VXTs are easier for minor workover.

Table 5 – Xmas Tree Options

Considerations	Vertical (VXT)	Horizontal (HXT)
Cost	\$1.5 - \$3.5 million (BAI, 2012 p.174)	\$1.5 - \$3.5 million (BAI, 2012 p.174)
Location of Tubing Hanger	On Wellhead	Inside XT
Workover	Must recover entire XT to remove tubing. Requires dedicated completion riser system (Cluster, 2000)	Tubing can be removed by recovering the BOP only. Use standard drilling BOPs
XT Recovery	Can remove without removing tubing	Must remove tubing to remove XT.

Water cut is expected to increase by 10% each year. The wells will need remediating at 50% water cut (year 6), which means it is certain that a major workover will be required. Thus, HXTs are proposed.

HXTs are typically designed for 5, 10 or 15 Ksi as per API 17D (Bai, 2012. p. 173). Trees similar to the Vetco Gray Deepwater DHXT 15 Ksi series are proposed due to the high SIWHP of 10,500 Psi.

3.8 Control and Instrumentation

The two main control options are compared below.

Table 6 – Control Options

Considerations	All Hydraulic	Multiplexed Electro-Hydraulic
Cost	Low	High – Approx 10 x Hydraulic cost (Bai, 2012. p 196)
Umbilical Size	Requires one dedicated hose per valve actuator	One hydraulic hose in umbilical
Reliability / Ease of Maintenance	High – Main components are in surface (Bai, 2012. p 197)	Lower – Active components subsea.
Response Time	Long	Short

Electrohydraulic control is proposed to reduce the umbilical size due to the fewer hydraulic hoses required. The additional cost of the system is considered a worthwhile investment given the increased level of monitoring and control capability.

A single umbilical shall transmit hydraulic power, electrical power, instrument communications and chemical injection. This should be achievable in a single line given the water depth, short distance of 4500 m, and only 3 XTs. An umbilical termination assembly (UTA) shall receive the subsea end of the dynamic section to remove dynamic loading from the seabed-laid static section.

Methanol is proposed as the thermodynamic inhibitor for preventing hydrate formation due to the lower cost and larger shift in hydrate-formation temperature than monoethylene glycol (MEG). (Bai, 2012. p. 465). The lower recovery potential is not considered, as the flowlines are short.

4.0 SUBSEA EQUIPMENT LIST

The following major subsea components are proposed based on the analysis outlined in Section 3.0. See schematics of the flowline system and control system in Appendix C and D respectively.

Table 7 – Subsea Equipment List

Component	Qty	Description / Justification
Horizontal Xmas Tree (HXT)	3	• Horizontal configuration, with tubing hanger inside tree to make workovers simple (see Section 3.7). • 15ksi Tree due to the SIWHP of 10,500 Psi – Example: Vetco Gray Deepwater DHXT 15 Ksi series (GE Oil & Gas, 2016).
Manifold (including SDU, SEM)	1	Large module with the following functions: • Route production from XTs to Production PLET • Route water injection from Water Injection PLET to XT • Flow control valves • Umbilical Termination Assembly (UTA) – Connection and distribution of hydraulics, chemical injection and electrical communications • Subsea Distribution Unit (SDU) for distributing chemicals • Subsea Electronics Module (SEM) • Flying lead stab plates
Pipeline End Termination (PLET)	2	• 1 x Production Flowline PLET • 1 x Water Injection Line PLET • Both with facilities to mate a subsea pig launcher / receiver (SSPL/R) • Both with yoke to allow installation inline during pipe lay. • Production Flowline PLET includes dual valves controlled by the HIPPS system.
Production Flowline	1	• Conventional API 5L carbon steel materials, given the short production field life. • Wall thickness (WT) design based on HIPPS limit of 5000 Psi (see Section 3.5).

		• Collar type anodes for cathodic protection
Water Injection Line	1	• Conventional API 5L low alloy carbon steel material (assuming water treatment to < 10 ppb oxygen equivalent) (NORSOK, 1994). • WT to include corrosion allowance of 3 mm (NORSOK, 1994). • Collar type anodes for cathodic protection
Umbilical	1	Single line from FPSO to Manifold, with the following cores: • 2 x Hydraulic fluid hoses (1 HP, 1 return line) • Electrical power cable • Fibre Optic Cable – Fibres for each instrument / control device • 2 x Chemical injection fluid hoses (Methanol, and scale / corrosion inhibitor)
Umbilical Termination Assembly (UTA)	1	• Located at contact point of umbilical to separate the dynamic load from the 'static' length of umbilical running to the manifold.
Jumpers	5	Rigid CRA jumpers with horizontal connectors, designed for pressure up to SIWHP of 10,500 Psi (due to location upstream of HIPPS). • RGUP1 to Manifold • RGUP2 to Manifold • Manifold to RGUW1 • Manifold to Production PLET • Manifold to Water Injection Line PLET
Flying Leads	5	ROV-operable flying leads from the manifold to each HXT, plus the 2 x PLETS.
Risers	2	Steel catenary risers (SCR) in lazy-wave configuration to reduce compression (Ghosh, 2012). Same grade, diameter and WT as flowline. Motion loggers to monitor fatigue. No riser base or PLET required.
Topside Umbilical Termination Unit (TUTA)	1	Topside junction box, routing the following to the umbilical: • Hydraulic fluid from the Hydraulic Power Unit (HPU) • Power from the Electrical Power Unit (EPU)

		• Communications from the Master Control Station (MCS) • Methanol and Scale / Corrosion Inhibitor from the Topside Chemical Skid

5.0 ASSET INTEGRITY PLAN

The following table outlines a high level Asset Integrity Management (AIM) Plan for the subsea development. For each major subsea component, several risks are identified and ranked. Inspection activities are proposed, and mitigations are planned, generally in increasing order of severity.

The Risk Rankings have been determined using DNV-RP-F116 *Integrity Management of Submarine Pipeline Systems.* The Probability of Failure (PoF) for each risk was calculated using the following formula (RGU, 2016a):

$$R_t = e^{-\frac{LOF}{MTBF}}$$

$$PoF = 1 - R_t$$

Where:

R_t	Probability of Survival
LOF	Life of Field (12 years)
MTBF	Mean Time Before Failure (years).

MTBF values were generally taken from RGU course notes (RGU, 2016a).

PoF values were then converted to Probability Rankings according to Table 4-1 of DNV-RP-F116 (see below, Figure 3). The Consequence of Failure (CoF) rankings were then assigned, and the table was used to determine the Risk Ranking. All rankings above “H = High” are unacceptable and must be mitigated with inspections. A Risk Ranking table is provided in Appendix E.

Increasing consequences →	Consequence Categories				Increasing probability				
	Severity	Safety	Environment	Cost (million Euro)	1 Failure is not expected $< 10^{-5}$	2 Never heard of in the industry $10^{-5} - 10^{-4}$	3 An accident has occurred in the industry $10^{-4} - 10^{-3}$	4 Has been experienced by most operators $10^{-3} - 10^{-2}$	5 Occurs several times per year $10^{-2} - 10^{-1}$
	E	Multiple fatalities	Massive effect Large damage area, > 100 BBL	> 10	M	H	VH	VH	VH
	D	Single fatality or permanent disability	Major effect Significant spill response, < 100 BBL	1 - 10	L	M	H	VH	VH
	C	Major injury, long term absence	Localized effect Spill response < 50 BBL	0.1 - 1	VL	L	M	H	VH
	B	Slightly injury, a few lost work days	Minor effect Non-compliance, < 5 BBL	0.01- 0.1	VL	VL	L	M	H
	A	No or superficial injuries	Slightly effect on the environment, < 1BBL	< 0.01	VL	VL	VL	L	M

Risk	Description
VH	Unacceptable risk – immediate action to be taken
H	Unacceptable risk– action to be taken
M	Acceptable risk – action to reduce the risk may be evaluated
L	Acceptable risk - Low
VL	Acceptable risk - Insignificant

Figure 3 – Risk Matrix – DNV-RP-F116 Table 4-1

Table 8 – Asset Integrity Management Plan

Item	Risk	Risk Ranking	Inspections / Checks	Mitigation Plan
Well / Borehole	Production flowrate drop – Fouling of sand screens	VH	• Borehole camera inspection of sand screens, tubing and casing (RGU, 2016a)	• Workover - Major (removable of tubing) or minor (downhole tools lowered through tubing) – Requires temporary installation of drilling BOP and riser (due to use of HXT). (RGU, 2016a).
	SCSSV failure to open	VH	• Periodic function test	• Major workover – remove tubing and SCSSV.
Horizontal Xmas Tree (HXT)	Blockage – valve malfunction	VH	• Periodic valve actuation (function test)	• Recover tubing & completions, then recover HXT to surface for workover.
Manifold (including SDU, SEM)	Loss of containment – Piping leak	VH	• ROV close visual inspection (CVI) • ROV UT probe inspections on piping to check wall thickness. • Hot stab dye injection – Leak detection in accordance with DNV-RP-F302 (DNV, 2016).	• Disconnect and recover unit to surface for repair.
	Blockage – valve malfunction	VH	• Period valve actuation (function test)	• Recover tubing & completions, then recover HXT to surface for workover.

Item	**Risk**	**Risk Ranking**	**Inspections / Checks**	**Mitigation Plan**
	Failure of SCM / SEM / SDU equipment	VH	• ROV visual inspection of connections. • Leak test of hydraulic and chemical lines using fluorescent dye injection with ROV hot stab.	• Retrieval and replacement of unit.
Pipeline End Termination (PLET)	Blockage – valve malfunction	VH	• Periodic valve actuation (function test)	• Disconnect and recover PLET to surface for workover.
Production Flowline	Loss of containment - Overpressure	VH	• Routine check of HIPPS – Use ROV to manually override valve actuators. check sensors.	• Replace logic solver unit • Replace valve actuator.

Item	Risk	Risk Ranking	Inspections / Checks	Mitigation Plan
	Loss of containment - Internal Corrosion	VH	• Intelligent pigging from FPSO to PLET (SSPL/R) – Ultrasonic wall thickness inspection. (MACDONALD, 2015) • Chemical Injection – Corrosion Inhibitor. Adjust dosage	• Adjust dosage of corrosion inhibitor • De-rate flowline MAOP based on remaining WT. • Install ROV-operable subsea pipeline repair clamps. Designed in accordance with DNV-OS-F101 Submarine Pipeline Systems, and DNV-RP-F113 Subsea Pipeline Repair (SUBSEA INNOVATION, 2016) • Install ‘Hot Tap & Plug’ assemblies and bypass the anomaly (T.D. WILLIAMSON, 2016).

Item	**Risk**	**Risk Ranking**	**Inspections / Checks**	**Mitigation Plan**
	Loss of containment – External corrosion	VH	• Cathodic protection (CP) potential checks with ROV CP Probe. • ROV Close Visual Inspection (CVI) • UT inspection – Either a ROV probe for discrete checks, or an automated C-scan type for large areas.	• Replace anodes. • De-rate flowline MAOP based on remaining WT. • Install ROV-operable subsea pipeline repair clamps. Designed in accordance with DNV-OS-F101 Submarine Pipeline Systems, and DNV-RP-F113 Subsea Pipeline Repair (SUBSEA INNOVATION, 2016) • Install 'Hot Tap & Plug' assemblies and bypass the anomaly (T.D. WILLIAMSON, 2016).
	Loss of containment – Overbending	VH	• Close visual inspection (CVI) to check span lengths. •	• Remediate with rock dump or concrete mattress.
	Loss of containment – Internal sand scour	VH	• Intelligent pigging from FPSO to PLET (SSPL/R) – Ultrasonic wall thickness and CVI (camera).	• Adjust production rate to reduce sand inflow • Minor workover – remove tubing and completions from hole
	Blockage – Scale or wax / asphaltene	VH	• Monitor mass balance from upstream and downstream gauges.	• Adjust dosage of scale inhibitor • Pig line with chemical surfactant (Wylde, 2011).

Item	Risk	Risk Ranking	Inspections / Checks	Mitigation Plan
	Blockage - Hydrates	VH	• Monitor temperature and pressure to maintain below hydrate-forming envelope (BAI, 2012. p. 464). • Monitor Methanol injection and recovery condition.	• Adjust Methanol injection dosage. • Dose with Low dosage hydrate inhibitor (LDHI) • Flood line with Methanol during shut-in.
Water Injection Line	Loss of containment - Internal Corrosion	VH	• Intelligent pigging from FPSO to PLET (SSPL/R) – Ultrasonic wall thickness inspection. (MACDONALD, 2015) • Chemical Injection – Corrosion Inhibitor. Adjust dosage	• Adjust dosage of corrosion inhibitor • De-rate flowline MAOP based on remaining WT. • Install ROV-operable subsea pipeline repair clamps. Designed in accordance with DNV-OS-F101 Submarine Pipeline Systems, and DNV-RP-F113 Subsea Pipeline Repair (SUBSEA INNOVATION, 2016) • Install 'Hot Tap & Plug' assemblies and bypass the anomaly (T.D. WILLIAMSON, 2016).

Item	**Risk**	**Risk Ranking**	**Inspections / Checks**	**Mitigation Plan**
	Loss of containment – External corrosion	VH	• Cathodic protection (CP) potential checks with ROV CP Probe. • ROV Close Visual Inspection (CVI) • UT inspection – Either a ROV probe for discrete checks, or an automated C-scan type for large areas.	• Replace anodes. • De-rate flowline MAOP based on remaining WT. • Install ROV-operable subsea pipeline repair clamps. Designed in accordance with DNV-OS-F101 Submarine Pipeline Systems, and DNV-RP-F113 Subsea Pipeline Repair (SUBSEA INNOVATION, 2016) • Install 'Hot Tap & Plug' assemblies and bypass the anomaly (T.D. WILLIAMSON, 2016).
	Loss of containment – Overbending	VH	• Close visual inspection (CVI) to check span lengths. •	• Remediate with rock dump or concrete mattress.
Umbilical	Loss of containment – Damage to sheath / armouring	VH	• ROV visual inspection. • Continual monitoring of upstream / downstream flowmeters and pressure gauges to check mass balance.	• Replace umbilical (Recovery to surface for repair not possible due to water depth).
Jumpers	Damage due to snagging	VH	• ROV visual inspection	• Replace jumper

Item	Risk	Risk Ranking	Inspections / Checks	Mitigation Plan
Flying Leads	Loss of containment – Damage to sheath or J-plate connector	H	• ROV visual inspection • Function test of associated valves, injection points etc.	• Replace jumper using ROV to make connections. (RGU, 2016a)
	Electrical short circuit	H	• Insulation resistance (IR) testing.	• Replace jumper using ROV to make connections. (RGU, 2016a)
Risers	Loss of containment - Fatigue	VH	• Monitor the motion loggers to determine accumulated fatigue loading (MACDONALD, 2014). •	• Adjust lazy wave configuration with addition of floaters. • Reposition FPSO
	Loss of containment - Overpressure	VH	• Routine check of HIPPS – Use ROV to manually override valve actuators. check sensors.	• Replace logic solver unit • Replace valve actuator.
	Loss of containment - Internal Corrosion	VH	• Intelligent pigging from FPSO to PLET (SSPL/R) – Ultrasonic wall thickness inspection. (MACDONALD, 2015) • Chemical Injection – Corrosion Inhibitor. Adjust dosage	• Adjust dosage of corrosion inhibitor • Install ROV-operable subsea pipeline repair clamps. Designed in accordance with DNV-OS-F101 Submarine Pipeline Systems, and DNV-RP-F113 Subsea Pipeline Repair (SUBSEA INNOVATION, 2016)

Item	Risk	Risk Ranking	Inspections / Checks	Mitigation Plan
	Loss of containment – External corrosion	VH	• Cathodic protection (CP) potential checks with ROV CP Probe. • ROV Close Visual Inspection (CVI) • UT inspection – Either a ROV probe for discrete checks, or an automated C-scan type for large areas.	• Replace anodes. • Install ROV-operable repair clamps.
	Loss of containment – Overbending	VH	• Close visual inspection (CVI) to check touchdown zone.	• Remediate with rock dump or concrete mattress.
	Loss of containment – Internal sand scour	VH	• Intelligent pigging from FPSO to PLET (SSPL/R) – Ultrasonic wall thickness and CVI (camera).	• Adjust production rate to reduce sand inflow • Minor workover – remove tubing and completions from hole
	Blockage – Scale or wax / asphaltene	VH	• Monitor mass balance from upstream and downstream gauges.	• Adjust dosage of scale inhibitor • Pig line with chemical surfactant (Wylde, 2011).

Item	**Risk**	**Risk Ranking**	**Inspections / Checks**	**Mitigation Plan**
	Blockage - Hydrates	VH	• Monitor temperature and pressure to maintain below hydrate-forming envelope (BAI, 2012. p. 464). • Monitor Methanol injection and recovery condition.	• Adjust Methanol injection dosage. • Dose with Low dosage hydrate inhibitor (LDHI) • Flood line with Methanol during shut-in.

6.0 KEY PERFORMANCE INDICATORS

The following table outlines key performance indicators (KPIs) for the AIM plan. The list includes leading and lagging KPIs. Leading KPIs are preventative, proactive measures whereas lagging KPIs simply indicate a failure has already occurred (RGU, 2016a).
The BSEE Potential Incidents of Non-Compliance checklists were reviewed for relevant KPIs related to a BSEE audit of the facility.

Table 9 – Key Performance Indicators

Key Performance Indicator (KPI)	Target	Alert	Remedial Action
Well / Borehole Sand Production	< 5 lb / bbl	10 lb/bbl	Choke back production (RGU, 2016a)
Well / Borehole Successful function test of SCSSV	Within 30 days of scheduled test	30 days past scheduled test	Mobilise rig and complete test
Well / Borehole Successful SCSSV close test	SCSSV shuts within 2 minutes during test shut-in. (as per BSEE PINC P-241)	SCSSV time to close > 2 mins	Facility shut-in as per BSEE PINC notice. (BSEE, 2016a).
Xmas Tree Successful function test of tree valves	Within 30 days of scheduled test	30 days past scheduled test	Complete test from FPSO topside.

Manifold Visual inspection	Within 30 days of scheduled test	30 days past scheduled test	Mobilise ROVSV and complete inspection
Manifold Successful function test of Manifold valves	Within 30 days of scheduled test	30 days past scheduled test	Complete test from FPSO topside.
Control System Hydraulic mass balance	Deviation plus 10%	Deviation plus 20%	Check all flowmeters to locate leak. (RGU, 2016a) Mobilise ROV for inspection.
PLET Visual inspection	Within 30 days of scheduled test	30 days past scheduled test	Mobilise ROVSV and complete inspection
Flowlines Visual Inspection (inc. span survey)	Within 30 days of scheduled test	30 days past scheduled test	Mobilise ROVSV and complete inspection
Flowlines Inspection Pigging (UT)	Within 30 days of scheduled test	30 days past scheduled test	Perform inspection pigging from FPSO. Receive IP from SSPL/R with ROV.

Flowlines WT within allowable corrosion loss limit	WT within limit as per DNV-OS-F101. Projected WT within limit beyond next scheduled pigging campaign. (DNV, 2012)	Critical WT anomalies identified.	Depressurise line. Mobilise ROV-operable C-Scan to verify anomaly geometry. Install ROV repair clamp if required De-rate pipeline if required
Flowlines Anode Potential Survey	Within 30 days of scheduled test	30 days past scheduled test	Mobilise ROV with CP Probe and perform survey
Flowlines All anodes present and active	Anode potential of -1.05 V (assume Aluminium anodes) (Bai, 2012 p.527)	Anode potential of -0.8 V (Bai, 2012 p.528)	Mobilise ROV to replace depleted anodes.
Flowlines Successfully complete scale removal pigging	Within 30 days of scheduled test	30 days past scheduled test	Mobilise ROVSV. Deploy scale removal / chemical gel plug pigs from FPSO. Retrieve pigs from SSPL/R with ROV.

Flowlines Successfully complete hydrostatic test of flowlines	Within 30 days of scheduled test	30 days past scheduled test	Mobilise hydrotest spread and complete test, as per regulatory requirement (typically to DNV-OS-F101 Sec 5 E100).
Umbilical Visual Inspection	Within 30 days of scheduled test	30 days past scheduled test	Mobilise ROVSV and complete inspection
Jumpers Visual Inspection	Within 30 days of scheduled test	30 days past scheduled test	Mobilise ROVSV and complete inspection
Jumpers No electrical losses / short circuits	Insulation Resistance (IR) test result within manufacturer tolerance	IR test result outside manufacturer tolerance	Mobilise ROV for visual inspection Replace jumper

7.0 OPEX ESTIMATE

A high level operating expense (OPEX) projection has been developed in line with AACE *Recommended Practice 17R-97 Cost Estimate Classification System*. This cost projection is Class 5, given the level of project definition and preparation effort. Class 5 has an expected accuracy range of - 4 / + 20 % (AACE, 2011).

Costs have been estimated in two categories; Planned inspection and maintenance costs (see Table 11) and costs of potential failures and subsequence remediation activities (see
Table 12).

7.1 Planned OPEX Costs

Planned OPEX costs are based on the inspection and maintenance activities listed as KPIs in Section 6.0. The schedule of these activities are laid across the life of field, and the present value (PV) calculation is applied according to the year each activity occurs.

A major workover of both production wells is planned for year 6, when it is anticipated that the water cut will reach 50%. Methanol costs appear to be a significant cost, and should be investigated further and compared with costs for providing a MEG regeneration system.

Appendix A2 provides some calculation formulas used in the OPEX cost spreadsheets.

7.2 Remedial OPEX Costs

Remedial OPEX costs are based on the activities listed in the AIM Plan. For each potential failure, the cost of repair/intervention is estimated, and multiplied by the probability that the cost will be incurred (i.e. the PoF values in Appendix E). Cost estimate details are provided in
Table 12.

7.3 OPEX Cost Summary

The following table summarises the OPEX cost projection detailed in Table 11 and Table 12..

Table 10 – OPEX Cost Projection Summary

Planned Activity Costs			
Activities	**Occurances / Qty**	**PV Cost (USD)**	
Major Workover (Reduce Water Cut)	1	$	24,684,910
ROV Field Survey	24	$	36,063,118
Flowline Pigging Inspection	12	$	7,334,265
ROV CP Survey on Flowlines	6	$	3,154,244
Methanol Usage	805MM gal	$	1,294,192,627
	Sub-Total	**$**	**1,365,429,164**
Remedial Activity Costs			
Remedial Activity	**PoF**	**Probability-Adjusted Cost (USD)**	
Wellbore - Fouled Sand screens - Minor Workover	0.64	$	3,450,000
SCSSV Replacement	0.13	$	559,000
HXT Valve Failure - Recover HXT	0.55	$	3,080,000
Manifold - Leak - Recover Manifold	0.05	$	330,000
Manifold - Failure of SCM / SEM / SDU - Recover unit	0.99	$	4,158,000
Manifold - Valve Failure - recover Manifold	0.18	$	1,188,000
PLET - Valve Failure - Recover PLET	0.18	$	1,188,000
Production Flowline - Burst - Install Repair Clamp	0.62	$	4,278,000
Production Flowline - Internal Corrosion - Install Clamp	0.05	$	345,000
Production Flowline - External Corrosion - Install Clamp	0.62	$	4,278,000
Production Flowline - Overbending - Hot Tap and Bypass	0.62	$	4,712,000
Injection Line - Internal Corrosion - Install Clamp	0.05	$	345,000
Injection Line - External Corrosion - Install Clamp	0.62	$	4,278,000
Injection Line - Overbending - Hot Tap and Bypass	0.62	$	4,712,000
Umbilical - Damaged - Repalce Umbilical	0.36	$	3,384,000
Flying Lead - Damage - Replace Flying Lead	0.99	$	768,000
Flying Lead - Short Circuit - Replace Flying Lead	0.99	$	768,000
	Sub-Total	**$**	**41,821,000**
	TOTAL	**$**	**1,407,250,164**

Table 11 – Cost Details – Planned Activities

Inspection / Intervention	Frequency	Cost	Cost Details and Justification
Major Workover - Remediate Completions to reduce Water Cut	At 50% Water Cut (occurs once only)	$17,600,000	• Assume MODU on site for 4 days per Production Well (8 days total). • MODU dayrate includes crew and workover / completions equipment • Relocation takes 14 days between Wells. • Total charter days = 8 + 14 = 22. Cost = 22 days * $800k = $17.6 m
ROV Visual Inspection of Field	Every 6 months	$1,008,000	• Two surveys per year to cover entire subsea field (HXT, Manifold, Flowlines, Umbilical, Risers) • Assume ROVSV on site for 14 days per survey • ROVSV bare charter dayrate is $42k /day (Sparebank 1, 2014) • Crew = 20 pax * $1000 / day (est) • ROV = $10k / day (est) • Total dayrate for ROVSV = $72k / day Cost = 14 days * $72k = $1 m
Flowline Pigging Inspection	Annual	$410,000	• Pig from FPSO to Manifold. Recover pig with ROV

			• Assume ROVSV on site for 5 days • ROVSV bare charter dayrate is $42k /day (Sparebank 1, 2014) • Crew = 20 pax * $1000 / day (est) • ROV = $10k / day (est) • Total dayrate for ROVSV = $72k / day • Inspection Pig = $10 k / day (est) • Assume SSPL/R is available and part of CAPEX Cost = 5 days * $82k = $410k
ROV CP Survey on Flowlines	Bi-Annual	$365,000	• Assume ROVSV on site for 5 days per survey • ROVSV bare charter dayrate is $42k /day (Sparebank 1, 2014) • Crew = 20 pax * $1000 / day (est) • ROV = $10k / day (est) • CP Tooling = $1000 (est) • Total dayrate for ROVSV = $73k / day Cost = 5 days * $73k = $365k

Table 12 – Cost Details – Remedial Activities

Component	Failure	Cost Details and Justification
Well / Borehole	Production flowrate drop – Fouling of sand screens	• Minor Workover using CV to perform RLWI (FMC, 2016). • Assume a workover required on both Production Wells • Estimated duration of 4 days on site per well, total 8 days (Muller, 2015). • Mob/De-Mob/Relocation = 10 days total • CV Dayrate = $300,000 (inc. equipment and crew) • **PoF = 0.64** (see Appendix E) Adjusted Cost = [$300,000 * 18] * 0.64 = **$3,450,000**
	SCSSV failure to open	• Minor Workover using CV to recover SCSSV • Estimated duration of 4 days on site • Mob/De-Mob/Relocation = 10 days total • CV Dayrate = $300,000 (inc. equipment and crew) • New SCSSV = $100,000 (est) • **PoF = 0.13** (see Appendix E) Adjusted Cost = [($300k * 14) + $100k] * 0.13 = **$559,000**

Horizontal Xmas Tree (HXT)	Blockage – valve malfunction	• Major Workover - Recover XT using MODU and repair • Estimated duration on site 7 days • Repair or use spare XT (part of CAPEX) • MODU Dayrate = $800,000 (in. equipment and crew for repair) • **PoF = 0.55** Adjusted Cost = $800k * 7 * 0.55 = **$3,080,000**
Manifold (including SDU, SEM)	Loss of containment – Piping leak	• Use CV to recover Manifold for Repair • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 10 days total • CV Dayrate = $300,000 (inc. equipment and crew, ROV) • **PoF = 0.05** (see Appendix E) Adjusted Cost = [$300k * 22] * 0.05 = **$330,000**
	Failure of SCM / SEM / SDU equipment	• Use CV to recover individual module for repair/replacement • Estimated duration of 4 days on site • Mob/De-Mob/Relocation = 10 days total • CV Dayrate = $300,000 (inc. equipment and crew, ROV) • **PoF = 0.99** (see Appendix E) Adjusted Cost = [$300k * 14] * 0.99 = **$4,158,000**

	Blockage – valve malfunction	• Use CV to recover Manifold for Repair • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 10 days total • CV Dayrate = $300,000 (inc. equipment and crew, ROV) • **PoF = 0.18** (see Appendix E) Adjusted Cost = [$300k * 22] * 0.18 = **$1,188,000**
Pipeline End Termination (PLET)	Blockage – valve malfunction	• Use CV to recover PLET for Repair • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 10 days total • CV Dayrate = $300,000 (inc. equipment and crew, ROV) • **PoF = 0.18** (see Appendix E) Adjusted Cost = [$300k * 22] * 0.18 = **$1,188,000**
Production Flowline	Loss of containment - Overpressure	• Use ROVSV to Install ROV Pipe Repair Clamp • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Repair Clamp = $300,000 (est) • **PoF = 0.62** (see Appendix E) Adjusted Cost = [($300k * 22) + $300k] * 0.62 = **$4,278,000**

	Loss of containment - Internal Corrosion	• Use ROVSV to Install ROV Pipe Repair Clamp • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Repair Clamp = $300,000 (est) • **PoF = 0.05** (see Appendix E) Adjusted Cost = [($300k * 22) + $300k] * 0.05 = **$345,000**
	Loss of containment – External corrosion	• Use ROVSV to Install ROV Pipe Repair Clamp • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Repair Clamp = $300,000 (est) • **PoF = 0.62** (see Appendix E) Adjusted Cost = [($300k * 22) + $300k] * 0.62 = **$4,278,000**
	Loss of containment – Overbending	• Use ROVSV to Install Hot Tap Assembly • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Hot Tap Assembly = $1,000,000 (est) • **PoF = 0.62** (see Appendix E) Adjusted Cost = [($300k * 22) + $1,000,000] * 0.62 = **$4,712,000**

Water Injection Line	Loss of containment - Internal Corrosion	• Use ROVSV to Install ROV Pipe Repair Clamp • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Repair Clamp = $300,000 (est) • **PoF = 0.05** (see Appendix E) Adjusted Cost = [($300k * 22) + $300k] * 0.05 = **$345,000**
	Loss of containment – External corrosion	• Use ROVSV to Install ROV Pipe Repair Clamp • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Repair Clamp = $300,000 (est) • **PoF = 0.62** (see Appendix E) Adjusted Cost = [($300k * 22) + $300k] * 0.62 = **$4,278,000**
	Loss of containment – Overbending	• Use ROVSV to Install Hot Tap Assembly • Estimated duration of 12 days on site • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Hot Tap Assembly = $1,000,000 (est) • **PoF = 0.62** (see Appendix E) Adjusted Cost = [($300k * 22) + $1,000,000] * 0.62 = **$4,712,000**

Umbilical	Loss of containment – Damage to sheath / armouring	• Use CV to Replace Umbilical • Estimated duration of 8 days on site (based on Bai, 2012 p. 181) • Mob/De-Mob/Relocation = 10 days total • CV Dayrate = $300,000 (inc. equipment and crew, ROV) • Cost of Replacement Umbilical = $4,000,000 (est) • **PoF = 0.36** (see Appendix E) Adjusted Cost = [($300k * 18) + $4,000,000] * 0.36 = **$3,384,000**
Flying Leads	Loss of containment – Damage to sheath or J-plate connector	• Use ROVSV to Replace Flying Lead • Estimated duration of 8 days on site (based on Bai, 2012 p. 181) • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Flying Lead = $200,000 (est) • **PoF = 0.99** (see Appendix E) Adjusted Cost = [($72,000k * 8) + $200,000] * 0.99 = **$768,000**
	Electrical short circuit	• Use ROVSV to Replace Flying Lead • Estimated duration of 8 days on site (based on Bai, 2012 p. 181) • Mob/De-Mob/Relocation = 0 • ROVSV Dayrate = $72,000 (inc. equipment and crew, ROV) • Flying Lead = $200,000 (est) • **PoF = 0.99** (see Appendix E) Adjusted Cost = [($72,000k * 8) + $200,000] * 0.99 = **$768,000**

8.0 REFERENCES

- AACE, 2011. *Recommended Practice No. 17R-97 Cost Estimate Classification System*. AACE International. November, 2011.
- API, 2014. *API 17O Subsea High Integrity Pressure Protection Systems (Hipps).Ed. 2, 2014.* American Petroleum Institute.
- BAI, Y. & BAI, Q., 2012. *Subsea Engineering Handbook.* Elsevier
- BSEE, 2016a. *Potential Incident of Non-Compliance – Production Operations.* Bureau of Safety and Environmental Enforcement. 2016.
- BSEE, 2016b. *Potential Incident of Non-Compliance – Pipelines.* Bureau of Safety and Environmental Enforcement. 2016.
- BSEE, 2016c. *Potential Incident of Non-Compliance – Appendices.* Bureau of Safety and Environmental Enforcement. 2016.
- CUTLER, J.G., 2000. *Deepwater Reference Book*. TOTALFINAELF (p. 34).
- DET NORSKE VERITAS, 2009. DNV-RP-F116 *Integrity Management of Submarine Pipeline Systems*. Det Norske Veritas. Norway, October 2009.
- DET NORSKE VERITAS, 2012. *DNV-OS-F101 Submarine Pipeline Systems.* Det Norske Veritas. Norway, August 2012.
- DET NORSKE VERITAS, 2016. *DNV-RP-F302 Offshore Leak Detection.* Det Norske Veritas. Norway, April 2016.
- FMC TECHNOLOGIES, 2016. *Riserless Light Well Intervention Using FMC's RLWI Stack [Marketing Material].* Norway, 2016.

- GE OIL & GAS, 2016. *Subsea trees - Proven systems for easy installation and reliable operation in all water depths and operating conditions.* Available at: https://www.geoilandgas.com/sites/geog.dev.local/files/345_GE_SS_Subsea_Trees_Pages_280113.pdf [Accessed 15/4/2016].
- GHOSH, P. Et al, 2012. *Design Considerations for HT/HP Steel Catenary Risers*. Offshore Magazine. Available at http://www.offshore-mag.com/articles/print/volume-72/issue-5/productions-operations/design-considerations-for-hp-ht-steel-catenary-risers.html [Accessed 10/4/2016].
- KRENEK. M. Et al, 1995. *Horizontal Trees Allow Frequent Deepwater Workovers.* Oil & Gas Journal. Available at http://www.ogj.com/articles/print/volume-93/issue-18/in-this-issue/general-interest/horizontal-subsea-trees-allow-frequent-deepwater-workovers.html [Accessed 9/4/2016].
- MACDONALD, J. & TRAN, L., 2014. *Extending the Life of Steel Catenary Risers.* Offshore Engineer. Available at: http://www.oedigital.com/engineering/design/item/7381-extending-the-life-of-steel-catenary-risers [Accessed 17/4/2016].
- MULLER, G. 2015. *Subsea Modelling Example Rev 0.5.* Gaudisite.nl. Available at: http://www.gaudisite.nl/SubSeaModelingExampleSlides.pdf [Accessed 20/4/2016]
- NORSOK, 1994. *M-DP-001 Design Principles – Material Selection*. Rev 1, December 1994. NORSOK Standards.

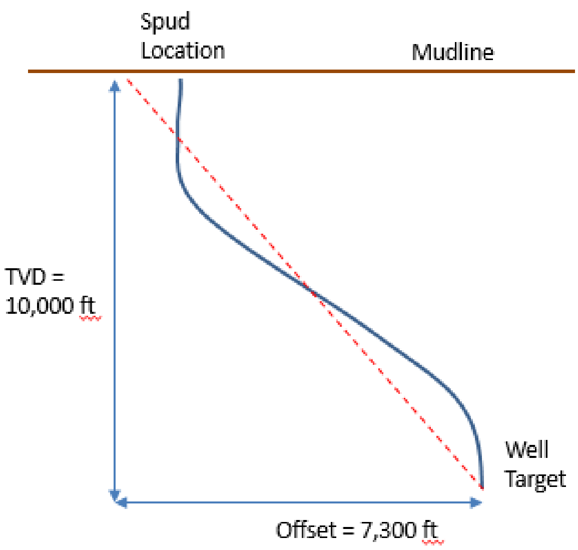
- ROBERT GORDON UNIVERSITY, 2016a. *ENM227: Subsea Systems [Lecture Notes – Topic 9]* Delivered March 2016.
- ROBERT GORDON UNIVERSITY, 2016b. *ENM227: Subsea Systems [Lecture Notes – Topic 1]* Delivered March 2016.
- ROBERT GORDON UNIVERSITY, 2016b. *ENM227: Subsea Systems [Lecture Notes – Topic 3]* Delivered March 2016.
- SPAREBANK 1, 2014. *Offshore Report Weekly 50/2014.* Sparebank 1 Guppen A.S. Norway, December 2014. Available at: http://www.sb1markets.com/showfile.ashx?fileinstanceid=18cab33b-7d2c-4c1d-8ee1-9f48c0232d59 [Accessed 20/4/2016]
- SUBSEA INNOVATION, 2016. *SIClamp ROV Installed Clamps.* UK. Available at: http://www.subsea.co.uk/pipeline-repair-systems/rov-installed-clamps [Accessed 17/4/2016].
- T.D. WILLIAMSON, 2016. *Subsea 1200RC Tapping Machine.* T.D. Williamson. Available at: http://www.tdwilliamson.com/content/Bulletins/Subsea%201200RC%20Tapping%20Machine%20Brochure.pdf [Accessed 17/4/2016]
- WYLDE, J. 2011. *Chemically Assisted Pipeline Cleaning for Pigging Operations.* Pipeline & Gas Journal – Volume 238 No. 8.

APPENDIX A CALCULATIONS

A1: Total Measured Depths

(b) Vertical Drilled Wells

Total = 3 * TVD
= 3 * 10,000 ft
= 30,000 ft



(a) Directional Drilled Wells
Measured Depth
= sqrt (TVD^2 + $Offset^2$) * "S Factor"

S Factor = ~ 1.3 (RGU, 2016c)

= sqrt ($10{,}000^2$ + 7300^2) * 1.3

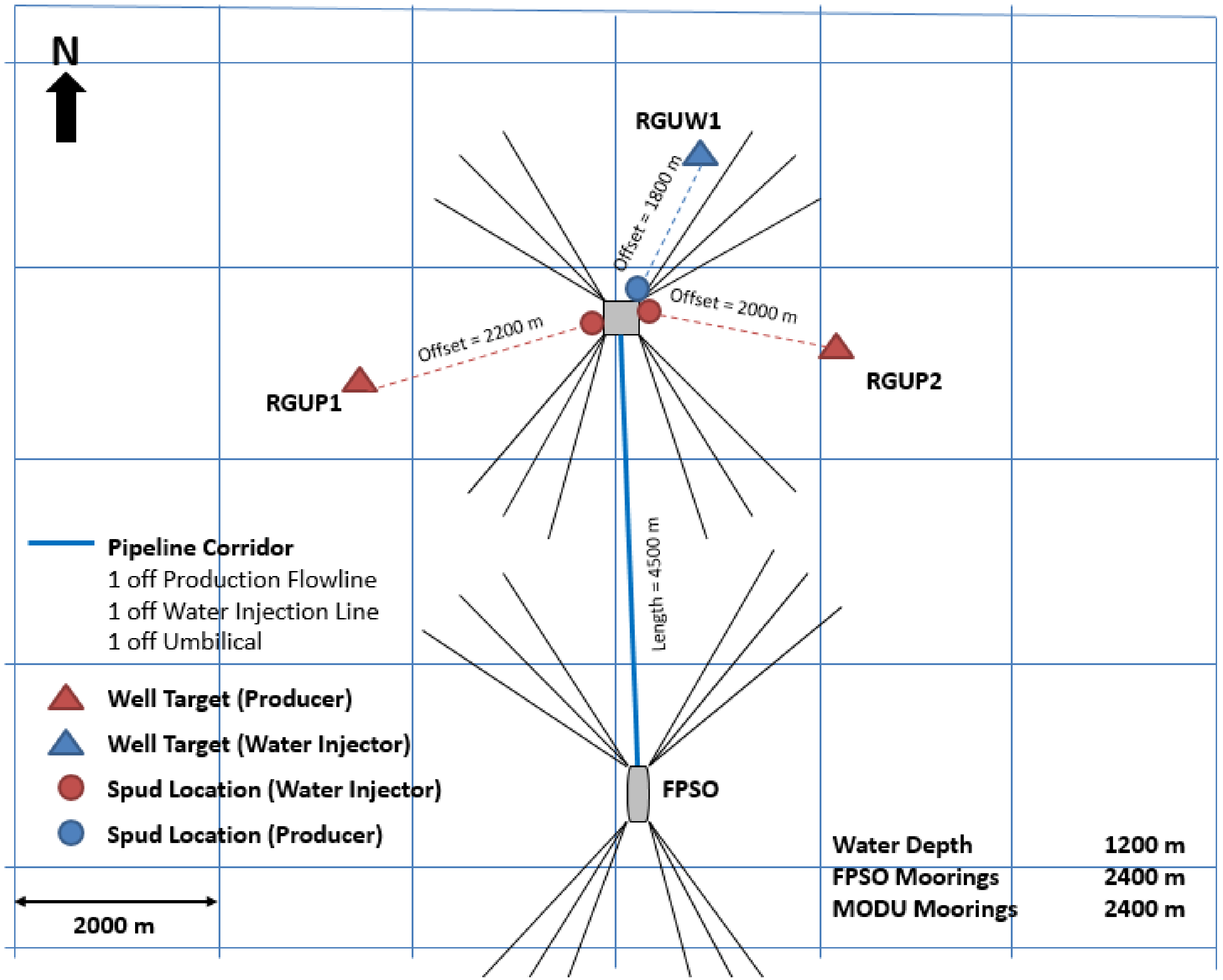
= 16,100 ft

Total = 3 * 16,100 ft
= 48,300 ft

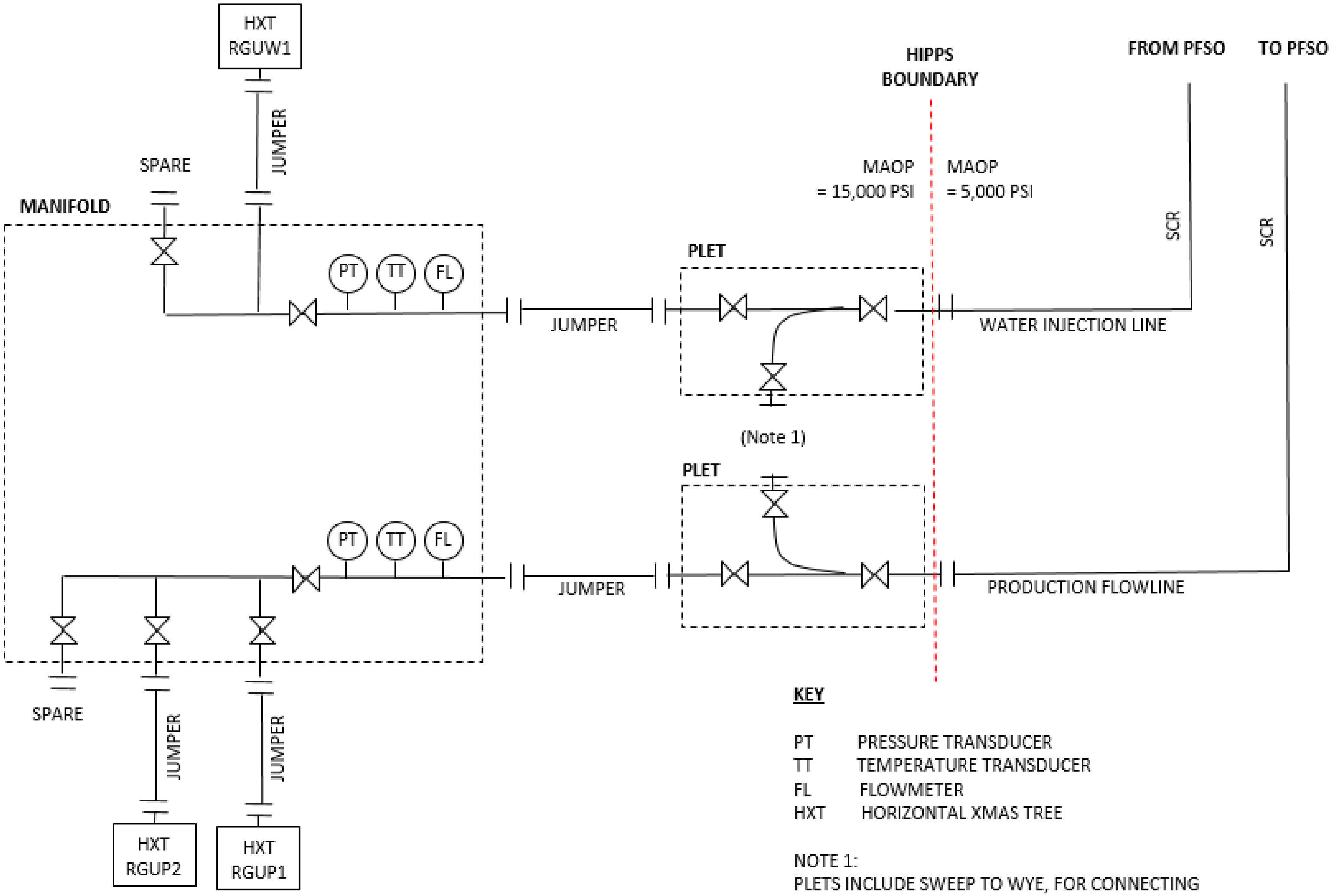
A2: OPEX Cost Estimate Calculations

Item	Calculation
Present Value (PV) Factor	= 1 * (1 + i)^(t-1) (RGU, 2016b)
Production Rate (bbl/d)	= 25,000 bbl
Oil Production (bbl/d)	= Production * (1 - Water Cut)
Produced Water Rate (bbl/d)	= Production - Oil Rate
Major Workover	= $17,600,000 * PV Factor (see Table 10)
ROV Field Survey	= $1,008,000 * PV Factor (see Table 10)
Flowline Pigging Inspection	= $410,000 * PV Factor (see Table 10)
ROV CP Survey on Flowlines	= $365,000 * PV Factor (see Table 10)
Methanol Cost	= $1 / gal (RGU, 2016c)
Methanol Rate	= 0.7 bbl / bbl of water (RGU, 2016c)
Methanol Volume (gal)	= Water * 0.7 * 42 gal/bbl * 365 days/yr
Methanol Cost per Year	= MeOH Cost * MeOH Volume * PV Factor

APPENDIX B FIELD LAYOUT



APPENDIX C SUBSEA FLOWLINE SYSTEM SCHEMATIC

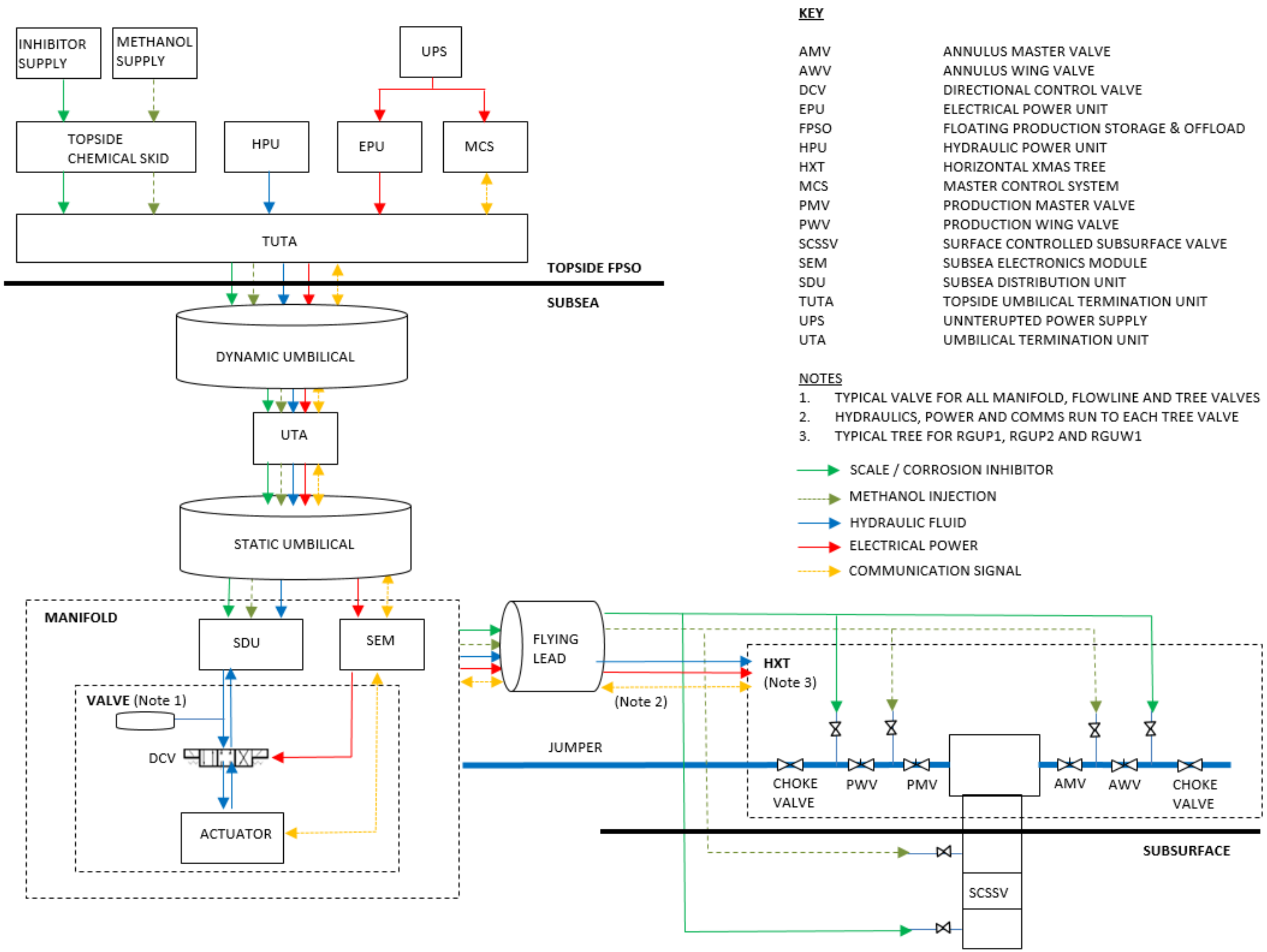


KEY

PT	PRESSURE TRANSDUCER
TT	TEMPERATURE TRANSDUCER
FL	FLOWMETER
HXT	HORIZONTAL XMAS TREE

NOTE 1:
PLETS INCLUDE SWEEP TO WYE, FOR CONNECTING PIGGING LOOP SPOOL BETWEEN PLETS. SSPL/R CAN ALSO MATE TO EACH PLET.

APPENDIX D SUBSEA CONTROL SYSTEM SCHEMATIC



APPENDIX E RISK RANKING TABLE

Component	Risk	MTBF (yrs)[1]	Notes	R(t) [= exp(- 12 / MTBF)]	PoF [=1 - R(t)]	Probability Rank	CoF Safety	CoF Enviro	CoF Cost	Risk Ranking
Well / Borehole	Production flowrate drop – Fouling of sand screens	12	(6)	0.37	0.63	5	--	--	E	**VH**
	SCSSV failure to open	89.4		0.87	0.13	5	--	--	E	**VH**
Horizontal Xmas Tree (HXT)	Blockage – valve malfunction	15.1		0.45	0.55	5	--	--	E	**VH**
	Failure of SCM / SEM / SDU equipment	2.3	(2)	0.01	0.99	4	--	--	D	**VH**
Manifold (including SDU, SEM)	Loss of containment – Piping leak	259.3		0.95	0.05	4	--	E	E	**VH**
	Blockage – valve malfunction	60		0.82	0.18	5	--	--	E	**VH**
Pipeline End Termination (PLET)	Blockage – valve malfunction	60		0.82	0.18	5	--	--	E	**VH**
Production Flowline	Loss of containment - Overpressure	12.4	(3)	0.38	0.62	5	--	E	E	**VH**
	Loss of containment - Internal Corrosion	259.4		0.95	0.05	4	--	E	E	**VH**
	Loss of containment – External corrosion	15.4	(4)	0.46	0.54	5	--	E	E	**VH**
	Loss of containment – Overbending	12	(6)	0.37	0.63	5	--	E	E	**VH**
	Loss of containment – Internal sand scour	12	(6)	0.37	0.63	5	--	E	E	**VH**
	Blockage – Scale or wax / asphaltene	12	(6)	0.37	0.63	5	--	--	D	**VH**
	Blockage - Hydrates	12	(6)	0.37	0.63	5	--	--	E	**VH**
Water Injection Line	Loss of containment - Internal Corrosion	259.3		0.95	0.05	4	--	--	D	**VH**
	Loss of containment – External corrosion	15.4	(4)	0.46	0.54	5	--	--	D	**VH**
	Loss of containment – Overbending	12	(6)	0.37	0.63	5	--	E	E	**VH**
Umbilical	Loss of containment – Damage to sheath / armouring	26.8		0.64	0.36	5	--	C	D	**VH**
Jumpers	Damage due to snagging	24	(6)	0.61	0.39	5	--	E	E	**VH**
Flying Leads	Loss of containment – Damage to sheath or J-plate connector	2.7		0.01	0.99	4	--	B	C	**H**
	Electrical short circuit	2.7		0.01	0.99	4	--	--	C	**H**
Risers	Loss of containment - Fatigue	13.7		0.42	0.58	5	--	E	E	**VH**
	Loss of containment - Overpressure	12.4	(3)	0.38	0.62	5	--	E	E	**VH**
	Loss of containment - Internal Corrosion	13.7		0.42	0.58	5	--	E	E	**VH**
	Loss of containment – External corrosion	13.7		0.42	0.58	5	--	E	E	**VH**
	Loss of containment – Overbending	13.7		0.42	0.58	5	--	E	E	**VH**
	Loss of containment – Internal sand scour	12		0.37	0.63	5	--	E	E	**VH**
	Blockage – Scale or wax / asphaltene	12		0.37	0.63	5	--	--	D	**VH**
	Blockage - Hydrates	12		0.37	0.63	5	--	--	E	**VH**

Notes:
1. All MTBF values taken from RGU Notes - ENM227 Subsea Systems - Topic 9 - Inspection, Monitoring and Intervention
2. MTBF value for SCM used, as the lowest for all manifold compoent failure values.
3. MTBF value for 'Sensor Failure' used as most likely failure point on HIPPS system
4. MTBF value for anode failure used
5. Probability and Risk Ranking taken from DNV-RP-F116 Table 4-1
6. MTBF estimated at 12 years,based on the assumption that it may occur once during LOF.

APPENDIX F COST ESTIMATE SPREADSHEET – PLANNED OPEX

Year	**1**	**2**	**3**	**4**	**5**	**6**
PV Factor	1.00	1.07	1.14	1.23	1.31	1.40
Production Rate (bbl/d)	25,000	25,000	25,000	25,000	25,000	25,000
Water Cut (%)	0%	10%	20%	30%	40%	50%
Oil Production (bbl/d)	25,000	22,500	20,000	17,500	15,000	12,500
Produced Water Rate (bbl/d)	0	2,500	5,000	7,500	10,000	12,500

Planned Activities							
Major Workover (Reduce Water Cut)	Occurances	--	--	--	--	--	1
	Cost (USD)	--	--	--	--	--	$24,684,910
ROV Field Survey	Occurances	2	2	2	2	2	2
	Cost (USD)	$2,016,000	$2,157,120	$2,308,118	$2,469,687	$2,642,565	$2,827,544
Flowline Pigging Inspection	Occurances	1	1	1	1	1	1
	Cost (USD)	$410,000	$438,700	$469,409	$502,268	$537,426	$575,046
ROV CP Survey on Flowlines	Occurances	1	--	1	--	1	--
	Cost (USD)	$365,000	--	$417,889	--	$478,441	--
Methanol Usage							
MeOH Volume (gal)	Volume (Gal)	0	26,827,500	53,655,000	80,482,500	107,310,000	134,137,500
MeOH Cost	Cost (USD)	--	$28,705,425	$61,429,610	$98,594,523	$140,661,520	$188,134,783

Year	**7**	**8**	**9**	**10**	**11**	**12**
PV Factor	1.50	1.61	1.72	1.84	1.97	2.10
Production Rate (bbl/d)	25,000	25,000	25,000	25,000	25,000	25,000
Water Cut (%)	0%	10%	20%	30%	40%	50%
Oil Production (bbl/d)	25,000	22,500	20,000	17,500	15,000	12,500
Produced Water Rate (bbl/d)	0	2,500	5,000	7,500	10,000	12,500

Planned Activities								**Sub-Total**
Major Workover (Reduce Water Cut)	Occurances	--	--	--	--	--	--	
	Cost (USD)	--	--	--	--	--	--	$24,684,910
ROV Field Survey	Occurances	2	2	2	2	2	2	
	Cost (USD)	$3,025,472	$3,237,255	$3,463,863	$3,706,334	$3,965,777	$4,243,382	$36,063,118
Flowline Pigging Inspection	Occurances	1	1	1	1	1	1	
	Cost (USD)	$615,299	$658,370	$704,456	$753,768	$806,532	$862,989	$7,334,265
ROV CP Survey on Flowlines	Occurances	1	--	1	--	1	--	
	Cost (USD)	$547,767	--	$627,138	--	$718,010	--	$3,154,244
Methanol Usage								
MeOH Volume (gal)	Volume (Gal)	0	26,827,500	53,655,000	80,482,500	107,310,000	134,137,500	
MeOH Cost	Cost (USD)	--	$43,079,103	$92,189,279	$147,963,794	$211,095,012	$282,339,579	$1,294,192,627
							TOTAL	**$1,365,429,164**

Robert Gordon University

ENM229 Subsea Pipeline and Riser Design

RGU Petroleum Ltd
Subsea Pipeline Option Study
and Design Analysis

Name: ADAM BEATON

Student No: 1418528

Date: 11/08/2016

Word Count: 4087

1.0 EXECUTIVE SUMMARY

This document provides a comparison and design analysis of pipeline system options for the future in-field pipeline associated with the new subsea well P6. Several candidates were compared qualitatively, and the following three candidates underwent further design analysis;

- Carbon Steel Pipe
- Carbon Steel Pipe with Concrete Weight Coating
- Carbon Steel Pipe with Thermal Insulation

The results of the analysis showed that the plain carbon steel pipe could not meet the bottom stability or the thermal performance requirements. Addition of an 80 mm concrete weight coat provided stability and supported steady state temperature, but could not contain heat during shut down. A 50 mm thermal insulation met the thermal performance requirement, but increased the buoyancy and caused vertical instability.

It is recommended that further studies consider combinations of weigh coat and insulation to meet all of the pipeline requirements.

CONTENTS

2.0 INTRODUCTION

2.1 Background

RGU Petroleum Ltd currently operates a subsea oil field comprising a cluster well arrangement, subsea manifold, riser base and a spar buoy facility (see Figure 1). A new satellite well P6 is planned for installation, and an additional pipeline is required between the subsea manifold and the riser base to accommodate the increased oil flowrate. The basis of design is detailed in Section 3.0, which provides known fluid properties and environmental data.

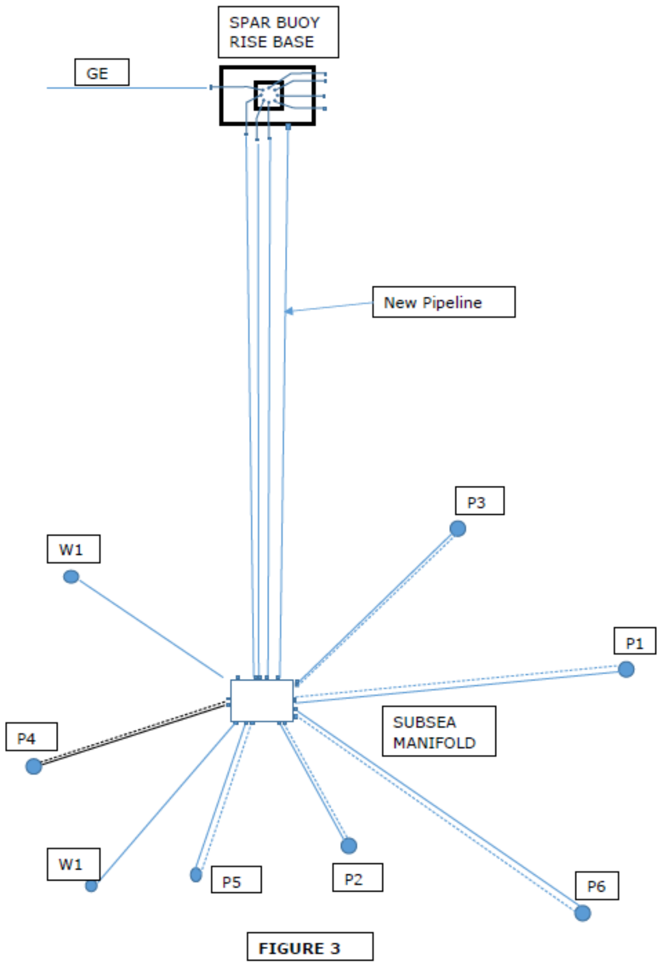


Figure 1 – General Field Architecture

2.2 Abbreviations

API	American Petroleum Institute
BOD	Basis of Design
CWC	Concrete Weight Coat
DN	Nominal Diameter
DNV	Det Norske Veritas
GOR	Gas to Oil Ratio
ID	Internal Diameter
NPS	Nominal Pipe Size
OD	Outside Diameter
OHTC	Overall Heat Transfer Coefficient
PIP	Pipe-in-Pipe
RGU	Robert Gordon University
ROV	Remotely Operated Vehicle
SIWHP	Shut-In Well Head Pressure
SMYS	Specified Minimum Yield Stress
WT	Wall Thickness

3.0 BASIS OF DESIGN

The following data represents the basis of design for the new pipeline.

Production Fluid Data		
Max. Flow Rate	Q_{Oil}	9,545 stb/day
Gas-to-Oil Ratio	GOR	0 mmscf/bbl
Specific Gravity	S_g	28° API
Flowing Pressure at Manifold	P_{in}	64 barg
Flowing Pressure at Riser Base	P_{out}	31 barg
Specific Heat Capacity	c_p	4,005 J/kg°C
Well Temp.	T_{well}	140 °C
Corrosive?	--	YES
Pipeline and Facilities Data		
Length of Pipeline (direct)	L	9.7 km
Manifold Design Pressure (shut-in)	SIWHP	143 barg
Manifold Inlet Design Temp.	$T_{in,\ max}$	120 °C
Pipeline Inlet Design Temp (Min.)	$T_{in,\ min}$	-42 °C
Pipeline Outlet Temp. (Min.)	$T_{out,\ min}$	27 °C
Pipeline Outlet Temp. (Max.)	$T_{out,\ max}$	67 °C
Max. Cooldown Time Until Restart (lump cap.)	t_{cool}	32 hours
Overall Heat Transfer Coefficient (OHTC)	U	1.5 W/m^{2}K
Coefficient of Drag	C_D	0.7
Coefficient of Inertia	C_M	3.29
Coefficient of Lift	C_L	0.9
Environmental Data		
Water Depth (constant)	d	350 m
Seawater Temp. at Seabed (Min.)	$T_{e,\ max}$	4 °C
Seawater Temp. at Seabed (Max)	$T_{e,\ max}$	7.7 °C
Sig. Wave Height (Omni-directional, 100 yr)	H_s	13.7 m
Wave Period	T	15 sec
Friction Factor – seabed / pipe	μ	0.74

4.0 PIPELINE SYSTEM OPTIONS

The fundamental requirements of the pipeline system are to contain the product at the design pressure, and resist structural loads throughout the design life. The basis of design specifies several other main requirements. Some typical solutions to these challenges are listed in Table 1, with reference to (BAI, 2005).

Table 1 - Typical Pipeline System Features

Requirement	Typical Solutions
Resist Internal Corrosion	• Carbon Steel, with allowance in W.T. • Carbon Steel with Duplex cladding • Duplex Steel
Thermally Insulated (OHTC ≤ 1.5 W/mK)	• External Insulation Coating • Pipe-in-Pipe (PIP) • Electrical Heating • Buried pipe (*Not possible for this field*)
Stability on Seabed	• Concrete Weight Coat (CWC) • Buried pipe (*Not possible for this field*)

Some of the features listed in Table 1 are mutually exclusive. For example, if a PIP arrangement is used, then it is typically heavy enough to not require a CWC. Burying the pipe would aid in thermal performance and seabed stability, but is not possible for this field. Exotic materials, including composites have not been explored in this study.
A selection of the solutions above have been chosen to form a list of candidate pipeline systems. A qualitative comparison of the pipeline system candidates is presented in Appendix A.

Table 2 – Pipeline System Candidates

Pipeline System Candidates	**Description**
Candidate A Carbon Steel Pipe	Plain carbon steel pipe is considered as a base case in order to identify the limitations. A typical API 5L X65 linepipe is used as a common, inexpensive material. It is expected that high wall thickness would be required to account for corrosion and to increase stability. Heat loss would be high, given the high conductivity of steel. Typically an external polypropylene coating is applied to protect against corrosion. **(*Chosen for further analysis*)**
Candidate B Carbon Steel with Concrete Weight Coat	A concrete coating is applied onshore, which increases the submerged weight to aid in stability. The CWC also protects from corrosion, and provides limited thermal insulation. **(*Chosen for further analysis*)**
Candidate C Carbon Steel Pipe with Thermal Insulation	A specially engineered thermal insulation such as Bredero Shaw's Thermotite ULTRA is applied onshore, and joints are completed during offshore welding. The insulation materials can be positively or negatively buoyant, which affects the bottom stability and installation scenario. **(*Chosen for further analysis*)**
Candidate D Duplex Steel Pipe	Duplex steels such as the commonly used Grade 2205 can eliminate problems with internal corrosion, and reduce the operation and maintenance costs. Duplex steel is more expensive than carbon steel.
Candidate E Pipe-In-Pipe	This option comprises two carbon steel pipes, with hot liquid passed through the annulus to minimize heat loss. The larger diameter pipe is typically the governing factor for bending and buckling.

5.0 INSTALLATION METHODS

The following aspects of the project are considered when assessing installation methods:

- Water Depth is 350 m, which prevents diving, and hence underwater welding of joints;
- The pipeline corridor is a straight 9.7 km;
- The seabed terrain is completely flat;
- The subsea field is already busy with existing pipelines and mooring lines;
- The seabed soil is densely compacted sand;
- Trenching is not an option;
- All current installation vessel technologies are available and equally economical to mobilise to the field.

Table 3 – Installation Methods

Installation Method	Description
J-Lay	Linepipe is positioned and welded in a vertical firing line, and deployed vertically from the vessel, causing a single bend toward the seabed in a 'J' shaped catenary. Advantages • Can lay in up to 2,000 m water depth • Shorter touchdown length provides better vessel maneuverability. • Can lay continuously with supply vessels delivering linepipe Disadvantages • Slower lay rate than S-Lay

S-Lay	Horizontal firing line toward an arched stinger with a variable deployment angle. The pipeline is laid in an 'S' catenary. <u>Advantages</u> • All pipe sizes are possible • Can lay continuously with supply vessels delivering linepipe <u>Disadvantages</u> • Limited water depth up to ~ 600 m due to increasing overbend loads at stinger
Reel Lay	Long pipeline lengths are welded and spooled onshore, then laid in either 'J' or 'S' style deployment. <u>Advantages</u> • Fast lay speed offshore • Onshore welding is less expensive <u>Disadvantages</u> • Limited to typically ~ 16" Pipe O.D. • Higher bending stress when spooled – not possible for CWC. • Vessel must return to shore for re-supply
Towed	Lengths of up to 3 – 4 km are pre-welded onshore, then towed to the field at either; Bottom tow, off-bottom tow, controlled-depth tow or surface tow. <u>Advantages</u> • Fast installation • Onshore welding is less expensive • Can prepare any type of complex pipe arrangement (PIP, bundled/piggybacked) <u>Disadvantages</u> • Inherent risks in towing activity – weather, vessel motions, current drag. • Complex deepwater tie-in

Tie-in methods should also be considered for the pipeline, whether it be a layaway or pull-in method. Both shall require remotely operated vehicle (ROV) to operate tie-in equipment.

5.1 Candidate A – Carbon Steel Pipe only

All installation methods are possible for the base case, given the pipe I.D of 5”, and no coatings. A towed installation may be an option if the metocean conditions between the shore and field allow it.

5.2 Candidate B – Carbon Steel Pipe with Concrete Weight Coat

The CWC is brittle and would yield under the bending load of reel lay. S-lay and J-lay are possible. The added unit weight requires additional top tension. A towed installation is also possible.

5.3 Candidate C – Carbon Steel Pipe with Thermal Insulation Coating

All installation methods are possible with the thermal insulation coating, as the coating is applied onshore to each linepipe, and a field joint coating is applied in the firing line The coating has sufficient flexibility to enable spooling onto a reel (BREDERO-SHAW, 2016).

5.4 Candidate D – Duplex Pipe

All installation methods are possible with plain Duplex pipe; however, specialty welding techniques may be used offshore.

5.5 Candidate E – Pipe-in-Pipe (Carbon Steel)

All installation options are possible for PIP, however the larger diameter outer pipe would govern the bending limit of the system. Laying speed would be slower due to the increased welding of both pipes, and the top tension would be high, given the added submerged weight per unit length.

6.0 DESIGN METHODOLOGY

The following design methodology has been followed to analyze three chosen candidates from Section 4.0. The J-Lay installation method is the base case for installation method, with an additional check for Reel Lay loads in case it is required.

Basis of Design

↓

Flow Assurance (Section 6.1)
Determine minimum **Pipe I.D**. to minimise frictional pressure loss and achieve outlet pressure.

↓

Installation Loads (Section 6.2)
Determine minimum **Pipe W.T.** to resist Collapse Pressure, Axial Force, Local Buckling

↓

Reel Lay Loads (Section 6.3)
Check Pipe W.T. against loading during spooling onto reel

↓

Ovality Check (Section 6.4)
Check Pipe Ovality due to installation loads

↓

Thermal Performance (Section 6.5)
Check steady state heat transfer to ensure minimum outlet temperature, and transient heat loss to prevent hydrate issues during shutdown period

↓

Stability Check (Section 6.6)
Compare lift, drag, submerged weight and friction to check the vertical and lateral stability.

Other design analyses that have not been performed in this study include:

- Wave and current loading during installation;
- Thermal stress due to expansion / contraction;
- Snag loads;
- Dropped object impact resistance.

6.1 Flow Assurance

The minimum pipeline internal diameter is determined by considering the allowable frictional pressure drop. The terrain is assumed to be flat, so no head loss is considered. The Darcy-Weisbach formula is typically used, which is an implicit equation relating the friction factor to the energy loss along the pipeline. This equation requires use of convergence methods such as Newton-Raphson method or similar to solve. The far simpler T.R. Aude equation is used instead for this case. It is an explicit formula, independent of pipe roughness (MENON, 2004).

T.R. Aude equation (re-arranged in terms of internal diameter):

$$Pipeline\ Internal\ Diameter\ (D) = \left(\frac{Q\ \mu^{0.104}\ S_g^{0.448}}{\left(\frac{P}{8.888 * 10^8}\right)^{0.5518} k} \right)^{0.376} \qquad \text{Eq. A1}$$

Where:
Q = Flowrate (m^3/hr)
μ = Dynamic Viscosity of Oil (cP)
Sg = Liquid Specific Gravity
P = Frictional Pressure Loss (kPa/km)
k = T.R Aude Factor, typically between 0.9 to 0.95.

The oil viscosity is taken from empirical data provided in the chart in Appendix B. The minimum pipeline temperature is used in order to select a conservatively higher viscosity, and hence a larger internal diameter requirement. The T.R. Aude Factor is similarly taken as 0.90 to remain conservative.

The internal diameter calculation is common for all of the pipeline options, and resulted in a minimum of 115.3 mm. Full calculation is provided in Appendix B. Based on Nominal Pipe Sizes (NPS), the minimum pipe must be 5” (see below).

Table 4 - Suitable pipe sizes based on minimum Pipe I.D. only

				Wall Thickness / Inside Diameter						
NPS	**DN**	**OD (mm)**		**SCH 5**	**SCH 10s/10**	**SCH 40s/40**	**SCH 80s/80**	**SCH 120**	**SCH 160**	**XXS**
4"	100	114.3	WT	2.1	3.0	6.0	8.6	11.1	13.5	17.1
			ID	110.1	108.2	102.3	97.2	92.1	87.3	80.1
4½"	115	127	WT	—	—	6.3	9.0	—	—	18.0
			ID	—	—	114.5	109.0	—	—	90.9
5"	125	141.3	WT	2.8	3.4	6.6	9.5	12.7	15.9	19.1
			ID	135.8	134.5	128.2	122.3	115.9	109.6	103.2
6"	150	168.3	WT	2.8	3.4	7.1	11.0	14.3	18.3	21.9
			ID	162.7	161.5	154.1	146.3	139.7	131.8	124.4

6.2 Installation Loads

The loads placed on the pipe during installation are considered the most severe. A typical catenary J-Lay scenario was modelled, and the combined effects of hydrostatic pressure (hoop stress and axial endcap stresses), and bending were analysed. Current effects, and pipe bending stiffness are both ignored. A nominal ovality of 1.5% was used at this stage, but further analysed later.

The pipe wall thickness (W.T.) remained a variable parameter during the calculations, and was incrementally increased until the Buckle Factor equation was satisfied, giving the minimum W.T. to prevent local buckling during combined bending and hydrostatic pressure. The following calculation method was derived from both DNV-OS-F101 and (JEE, 2006). The full calculations for each of the three candidates are provided in Appendix C, D and E.

<u>Catenary Geometry</u>:

$$Stinger\ Angle\ (a) = \operatorname{acos}\left(\frac{H}{T}\right) \qquad \text{Eq. B1}$$

$$Horizontal\ Component\ of\ Tension\ (H) = T - w\ d \qquad \text{Eq. B2}$$

$$Pipe\ Span\ Length\ (s) = \frac{H}{w}\tan(a) \qquad \text{Eq. B3}$$

$$Touchdown\ Length\ (Xs) = \frac{H}{w}\operatorname{asinh}(\tan(a)) \qquad \text{Eq. B4}$$

$$Radius\ of\ Curvature\ at\ Touchdown\ (R) = \frac{H}{w}$$ Eq. B5

Catenary Stresses:

$$Bending\ Moment\ at\ Touchdown\ (M_b) = \pm\frac{E\ I}{R}$$ Eq. B6

$$Bending\ Stress\ at\ Touchdown\ (\sigma_b) = \frac{E\ D}{2\ R}$$ Eq. B7

$$Axial\ Forces\ at\ Touchdown\ (F_a) = T - (w\ d) - \left(\rho_{sw}\ g\ d\ \pi\ \frac{D^2}{4}\right)$$ Eq. B8

$$Axial\ Stress\ at\ Touchdown(\sigma_a) = \frac{F_a}{A}$$ Eq. B9

$$Hydrostatic\ Pressure\ at\ Touchdown\ (P_e) = \rho_{sw}\ g\ d$$ Eq. B10

$$Hoop\ Stress\ at\ Touchdown\ (\sigma_h) = \frac{-P_e\ D}{2\ t}$$ Eq. B11

Von Mises equivalent stress was checked for both ± Mb:

$$Von\ Mises\ Equiv.Stress\ \left(\sigma_{eq}\right) = \sqrt{(\ \sigma_a + \sigma_b)^2 + {\sigma_h}^2 - (\sigma_a + \sigma_b)\sigma_h}$$ Eq. B12

Plastic Resistances:

$$Characteristic\ Plastic\ Axial\ Resistance\ \left(S_p\right) = f_y\ \pi\ (D - t)\ t$$ Eq. B13

$$Plastic\ Moment\ Resistance\ (M_p) = f_y\ (D - t)^2\ t$$ Eq. B14

Factored Axial Force and Moment:

$$Axial\ Endcap\ Force\ (F_{ec}) = \frac{\pi}{4} P_e\ D^2$$ Eq. B15

$$Factored\ Net\ Axial\ Force\ (S_a) = (H - F_{ec})\ \gamma_f\ \gamma_c$$ Eq. B16

$$Factored\ Bending\ Moment\ (M_d) = M_b\ \gamma_f\ \gamma_c$$ Eq. B17

Collapse Pressures:

$$Elastic\ Collapse\ Pressure\ (P_{el}) = \frac{2\ E}{1 -\ \vartheta^2}\left(\frac{t}{D}\right)^3$$ Eq. B18

$$Plastic\ Collapse\ Pressure\ \left(P_p\right) = 2\ f_y\ \alpha_{fab}\frac{t}{D}$$ Eq. B19

The Collapse Pressure (P_c) was solved using Excel "Goal Seek":

$$(P_c - P_{el})(P_c{}^2 - P_p{}^2) = P_c\, P_{el}\, P_p\, f_o\, \frac{D}{t}$$ Eq. 20

Buckling Factor:

The Pipe W.T. was manipulated to determine the minimum required to satisfy the Buckling Factor expression:

Eq. B21

$$\left(\gamma_{SC}\, \gamma_m \left(\frac{M_d}{\alpha_c M_p}\right) + \gamma_{SC}\, \gamma_m \left(\frac{S_a}{\alpha_c S_p}\right)^2\right)^2 + \left(\gamma_{SC}\, \gamma_m \left(\frac{P_e}{P_c}\right)\right)^2 \leq 1$$

Where:

T = Top Tension (N) – a nominal 500,000 N is used given the small diameter pipe.
w = Submerged Weight of Pipe per Unit Length (N/m)
E = Modulus of Elasticity (Pa)
I – Second Moment of Inertia (m4)
D = Pipe Outside Diameter (m)
d = Water Depth (m)
ρ_{sw} = Density of Seawater (kg/m3)
f_y = Characteristic Yield Strength (Pa) = 0.96 * SMYS
t = Pipe Wall Thickness (m)
v = Poisson's Ratio (= 0.3)
f_o = Ovality (a nominal 1.5% is used, then verified later)

6.3 Reel Lay Loads

The loads involved in spooling onto a reel were checked for the pipeline candidates where reel lay is an option. The following combined expression was derived from DNV-OS-F101 guidance (RGU, 2016).

$$Minimum\ Wall\ Thickness\ (t) = D\left[\left(\frac{D}{1.56\ R}\right)\left(\frac{\gamma_e}{\alpha_h^{-1.5}\ \alpha_{gw}}\right) + 0.01\right]$$ Eq. C1

Where:

D = Pipe Outside Diameter (m)

R = Radius of reel (m) - taken as nominal 8m (MEENAGHAN, 2012)

γ_e = Strain resistance factor

α_h = Maximum allowable yield / tensile stress ratio

α_{gw} = Girth weld reduction factor

6.4 Ovality Check

Bending loads during installation cause increased ovality. This reduces the buckling hoop stress resistances, and can prevent the passage of pigs during maintenance activities. A check was performed to ensure the ovality caused by installation loads remained below the limit prescribed by DNV-OS-F101 of 3%. The following calculations were used based on DNV-OS-F101 (RGU, 2016).

$$Maximum\ Allowable\ Ovality\ (f_o) = \frac{D_{max} - D_{min}}{D} \leq 0.03 \qquad \text{Eq. D1}$$

$$Maximum\ Bending\ Strain\ (\varepsilon_b) = \frac{D}{2\ R} \qquad \text{Eq. D2}$$

$$Ovality\ from\ Bending\ \left(f'_o\right) = 0.03\left(1 + \frac{D}{120\ t}\right)\left(2\varepsilon_b \frac{D}{t}\right)^2 \qquad \text{Eq. D3}$$

$$Cummulative\ Ovality\ (f_{Total}) = f'_o + f_{fab} \qquad \text{Eq. D4}$$

Where:

D = Pipe Outside Diameter (m)

R = Radius of Curvature (m)

t = Pipe Wall Thickness (m)

f_{fab} = Average Ovality at Fabrication – assumed 1.6% based on industry experience.

The installation ovality would typically reduce by 75% once straightened on the seabed, however DNV-OS-F101 requires < 3% at all times including installation (RGU, 2016).

6.5 Thermal Performance

Each of the options were analysed for thermal performance in comparison with the requirements set as the basis of design.

6.5.1 Steady State Heat Transfer

The steady state system was modelled first, using the provided Overall Heat Transfer Coefficient (OHTC) of 1.5 W/m.K. The calculations were set, and then parameters such as coating thickness were increased until the OHTC was reached. The effects of partial contact with the seabed are ignored for simplicity, given the soil type. The external convection coefficient was taken as a nominal 200 W/m.K for seawater (BAI, 2005, p. 323). The following were used in the calculations provided in Appendix C, D and E.

$$Reynold's\ Number\ (Re) = \frac{V_{Oil}\ D}{v}$$ Eq. E1

$$Prandtl\ Number\ (Pr) = \frac{c_p\ \mu}{k_{Oil}}$$ Eq. E2

$$Nusselt\ Number\ (Nu) = 0.0255\ Re^{0.8}\ Pr^{0.3}$$ (BAI, 2005) Eq. E3

$$Internal\ Convection\ Coefficient\ (h_i) = \frac{Nu\ k_{Oil}}{D}$$ Eq. E4

$$External\ Convection\ Coefficient\ (h_o) = 200\ W/m.K$$ (BAI,2005) Eq. E5

$$Convection\ Heat\ Transfer\ Rate\ (Q_R) = \frac{T_i - T_o}{\frac{1}{2\,\pi\, r_i\, L\, h_i} + \frac{\ln(r_1/r_i)}{2\,\pi\, k_1\, L} + \frac{\ln(r_2/r_1)}{2\,\pi\, k_2\, L} + \frac{\ln(r_3/r_2)}{2\,\pi\, k_3\, L} + \frac{1}{2\,\pi\, r_o\, L\, h_o}}$$ Eq. E6

$$Overall\ Heat\ Transfer\ Coefficient\ (U) = \frac{Q_R}{A\ (T_i - T_o)}$$ Eq. E7

Where:

V_{Oil} = Velocity of Oil (m/sec)

D = Pipeline Inside Diameter (m) – as per typical 'Pipeline Designer Choice" (BAI, 2005)

v = Kinematic Viscosity of Oil (m2/sec)

cp = Specific Heat Capacity of Oil (J/kg°C)

μ = Dynamic Viscosity of Oil (kg/m.sec)

k_{Oil} = Conductivity of Oil (W/m.°C)

k_1 = Conductivity of Steel (W/m.°C)

k_2 = Conductivity of Thermal Insulation = 0.11 W/m.°C (BREDERO,2016)

k_3 = Conductivity of CWC (W/m.°C)

L = Pipeline Length (m)

A = Internal Area of Pipeline (m2)

T_i = Internal Temperature of Oil (°C) – Taken as maximum of 120 °C.

T_o = External Temperature – Seawater (°C)

T_{out} = Outlet Temperature of Oil (°C) – Taken as 67 °C.

6.5.2 Temperature Across Pipeline

The temperature across the pipeline was modelled and compared with the minimum outlet temperature requirement of 27°C. For this analysis, Joules-Thompson cooling effects are ignored due to lack of information on inline components such as valves and other flow disruptions.

$$Thermal\ Decay\ Constant\ (\beta) = \frac{U\,\pi\,D\,L}{m.c_p} \qquad \text{Eq. E8}$$

$$Fluid\ Temperature\ at\ location\ x, T(x) = T_{out} + (T_{in} - T_{out})e^{\frac{-x\,\beta}{L}} \qquad \text{Eq. E9}$$

6.5.3 Transient Heat Loss

A transient heat loss calculation was performed using the lumped capacitance method to ensure the fluid temperature remains above the gas hydrate-forming temperature (assumed to be 4°C) after a maximum shutdown duration of 32 hours. The following formula was used to chart the temperature drop against time. The lowest temperature is used from the calculations above, which is the starting temperature of the pip outlet. A uniform temperature distribution is assumed through the layers.

$$Temperature\ at\ time\ t, T(t) = (T_i - T_o)\,e^{\frac{-U\,\pi\,D\,L\,t}{m.\ c_p}} + T_o \qquad \text{Eq. E10}$$

6.6 Stability

A stability check was performed on the pipelines, and steel and / or concrete thicknesses were adjusted. The check involved a rudimentary balancing of lateral and vertical forces, as shown in the diagram below. The Morison Equations are used to calculate the lift and drag, using the provided coefficients. Particle velocity due to current is estimated at 0.4 m/sec for 100-year storm. Wave effects are ignored due to the water depth. The pipeline corridor is not trenched, and effects of sediment transport are ignored given that the seabed is densely compacted sand. This calculation is considered highly conservative, as it is expected that the pipeline would eventually sink into the seabed and resist lateral movement even further.
The vertical and lateral forces were calculated, and then the thickness of steel (or concrete) was increased incrementally until the forces balanced. The calculations in Appendix C, D and E reflect the minimum thicknesses to achieve a Factor of Safety of 1.25.

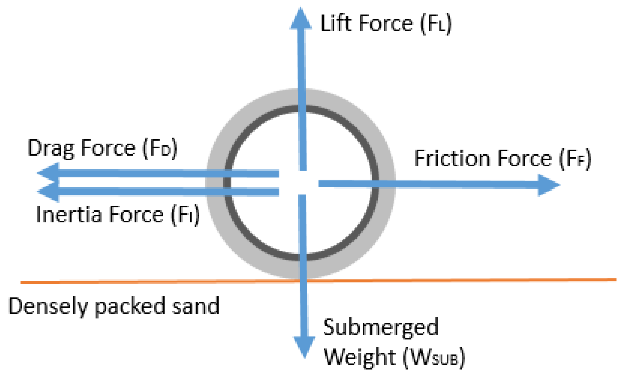


Figure 2 – Stability forces in vertical and lateral

$$Drag\ Force\ (F_D) = 0.5\ \rho_{sw}\ D\ C_D\ U\ |U| \qquad \text{Eq. F1}$$

$$Lift\ Force\ (F_L) = 0.5\ \rho_{sw}\ D\ C_L\ U^2 \qquad \text{Eq. F2}$$

$$Inertia\ Force\ (F_I) = A\ \rho_{sw} C_M\ a \qquad \text{Eq. F3}$$

$$Friction\ Force\ (F_F) = \mu\ (W_{Sub} - F_L) \qquad \text{Eq. F4}$$

$$Instantaneous\ Particle\ Velocity\ (U) = U_{st} + U_{wi}\cos(\theta) \qquad \text{Eq. F5}$$

$$Particle\ Acceleration\ (a) = \frac{2\,\pi}{T} U_{wi}\sin(\theta) \qquad \text{Eq. F6}$$

Stability criteria for Vertical Forces: $W_{SUB} > F_L$

Stability criteria for Lateral Forces: $F_F > F_D + F_I$

Where:

ρ_{sw} = Density of seawater (assumed 1025 kg/m^3)

D = Outside Diameter including Concrete Weight Coat (m)

C_D = Drag Coefficient (0.7)

C_M = Coefficient of Inertia (3.29)

C_L = Coefficient of Lift (0.9)

U = Instantaneous Particle Velocity (m/sec)

U_{st} = Steady state particle velocity (m/sec)

U_{wi} = Wave induced velocity (m/sec)

T = Wave Period (sec)

Θ = Wave phase angle (deg)

W_{SUB} = Submerged weight, assuming empty during pre-commissioning (N)

A_{ext} = Total cross sectional area (m^2)

μ = Friction Factor between pipe and soil

7.0 ANALYSIS RESULTS

The following sections discuss the results of the analyses on each candidate pipeline system. As discussed in Section 6.1, the minimum pipe I.D. was determined as 115.3 mm, which required a DN125 (5”) pipe or greater.

7.1 Candidate A – Carbon Steel Pipe

The base case carbon steel pipe was first checked using the installation loads. Several available pipe sizes from Table 1 were inputted in to the Installation Loads calculation sheet in order to determine the minimum wall thickness to satisfied the Buckle Factor equation. The result was a DN125 (5”) Schedule 40 pipe, with 141.3 mm O.D., 6.6 mm W.T. The next size smaller resulted in a negative submerged weight (when empty), so was not considered.

The loads due to spooling onto a typical reel were analysed out of interest, in case this method is chosen. The DN125 pipe was inputted into the calculation sheet which outputted a minimum W.T. of 4.0 mm. Thus the DN125 Schedule 40 (6.6 mm W.T.) pipe can resist spooling loads.

The cumulative ovality during J-lay installation was checked to ensure that the DNV-OS-F101 limit of 3% is not exceeded during installation. The result was 2.1%.

The DN125 Schedule 40 carbon steel pipe did not meet the thermal performance requirements. Figure 3 shows the steady state oil temperature dropping to near-ambient (4°C) by midway along the pipeline. Figure 4 shows the outlet temperature dropping from the idealized 27°C down to ambient within approximately 1 hour of shutdown. Increasing the wall thickness dramatically had negligible effect on the performance. Thus, a plain carbon steel pipe will require thermal insulation.

The stability check showed that the DN125 Schedule 40 pipe is not sufficiently weighted to prevent lift, thus it is both vertically and laterally unstable. Solutions could include increasing the wall thickness, adding a weight coating, burying the pipe, or preventing the pipe from being empty at any point during the pipe life.

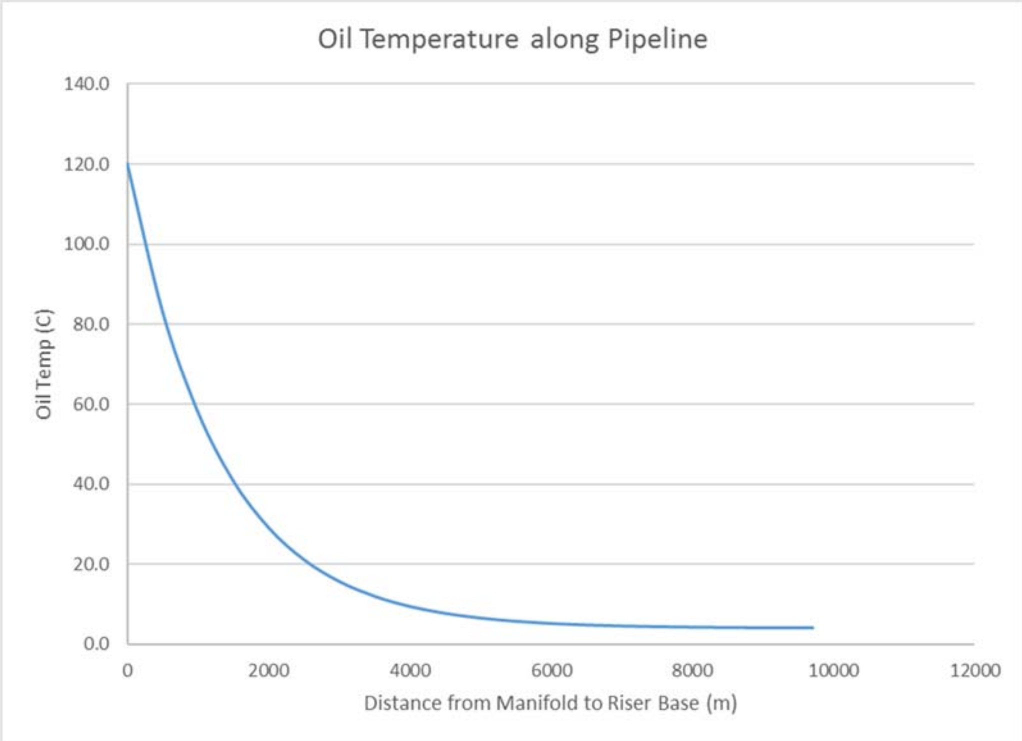


Figure 3 – Candidate A – Carbon Steel Pipe – Steady State Temperature

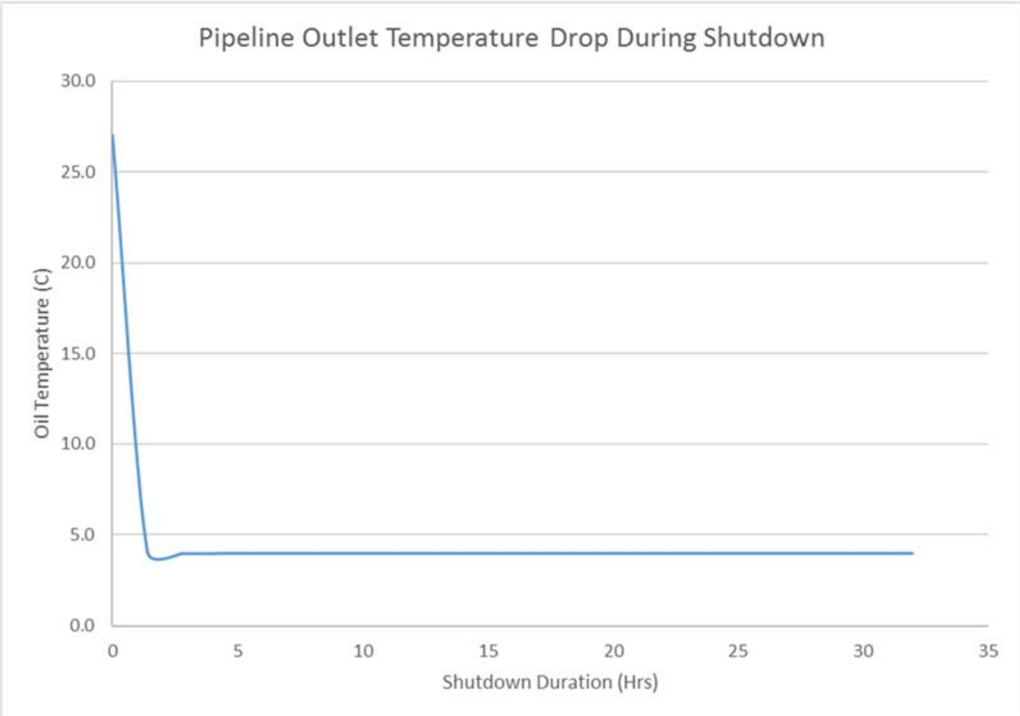


Figure 4 – Candidate A – Carbon Steel Pipe – Shutdown Temperature Drop

7.2 Candidate B – Carbon Steel with Concrete Weight Coat

The DN125 Schedule 40 carbon steel pipe was used, with the addition of a concrete weight coat. The first step was to use the stability check calculations to determine the minimum CWC thickness to ensure vertical and lateral stability. The minimum was approximately 10 mm; however, it is assumed that in practice a thicker coat would be used to ensure structural strength.

The thermal performance of the CWC was then checked. The CWC thickness was again incrementally increased until the steady state outlet temperature reached the target of 27°C. This resulted in a minimum CWC thickness of 80 mm. The target for shutdown heat containment was not met, even with significant increases in CWC thickness (see Figure 6 and Figure 5).

The installation loads were checked against the increased submerged weight, however the stresses in the concrete were not analysed. Reel lay analysis was not performed for the CWC pipe, as it is recognized that CWC pipe is not spooled in the industry.

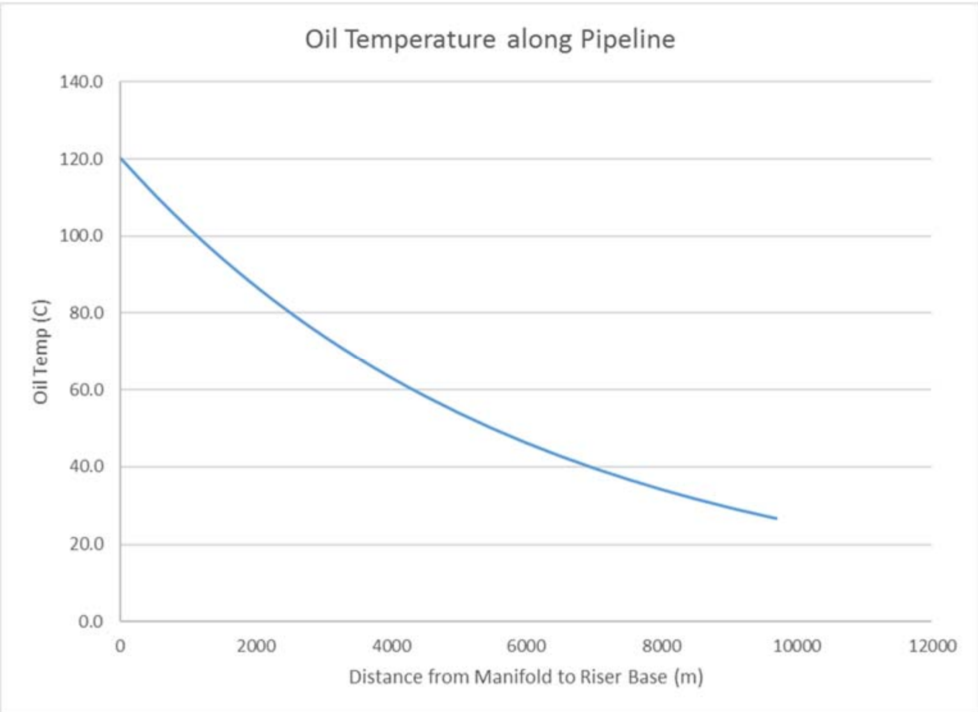


Figure 5 – Candidate B – Concrete Weight Coat – Steady State Temperature

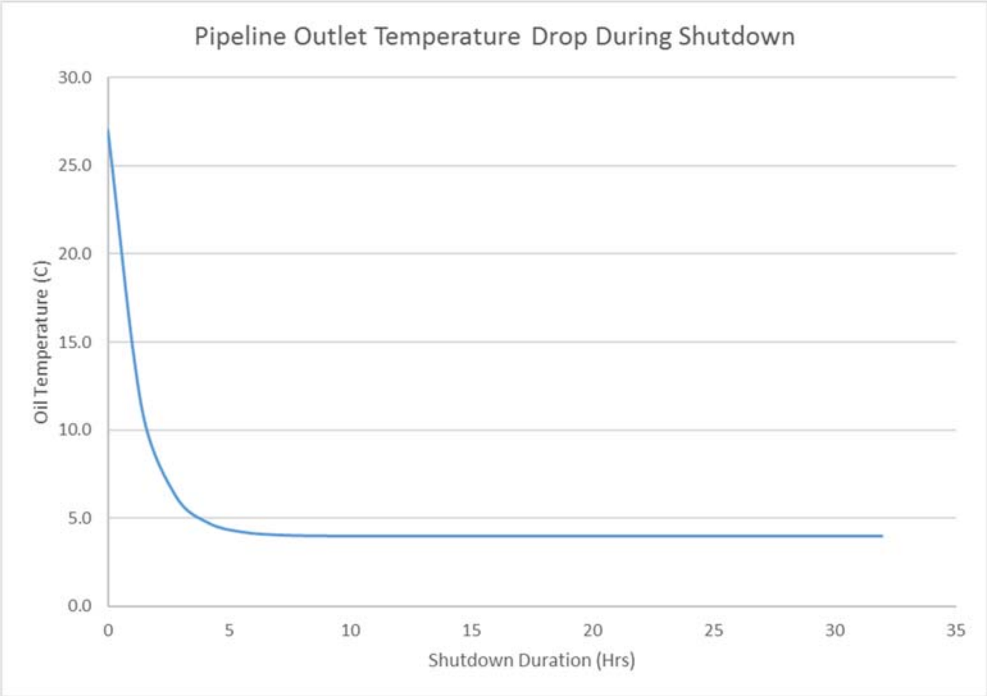


Figure 6 – Candidate B – Concrete Weight Coat – Shutdown Temperature Drop

7.3 Candidate C – Carbon Steel with Thermal Insulation

The thermal performance calculation as used first, and the thickness of the Thermotite ULTRA insulation was increased until both the steady state outlet temperature and the shutdown heat containment requirements were met (see Figure 7 and Figure 8). The minimum insulation thickness was 50 mm.

The stability check was then performed and it was found that the negatively buoyant insulation caused vertical instability at 50 mm thickness. This could be countered by increasing steel wall thickness, or adding approximately 7 kg per meter of other weights or coatings.

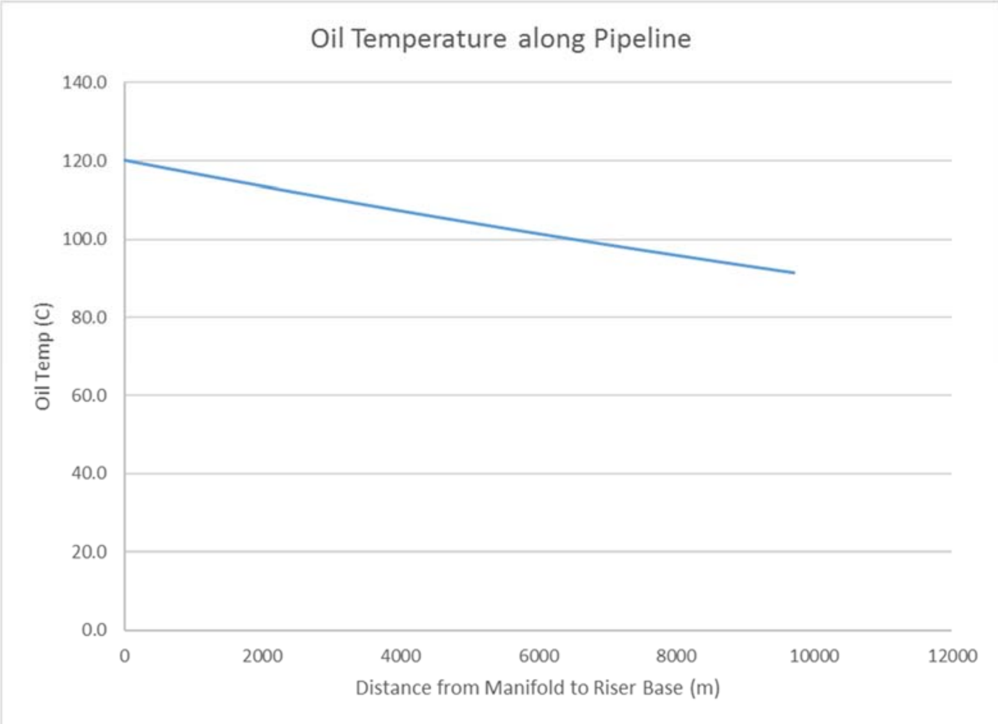


Figure 7 - Candidate C – Thermal Insulation – Shutdown Temperature Drop

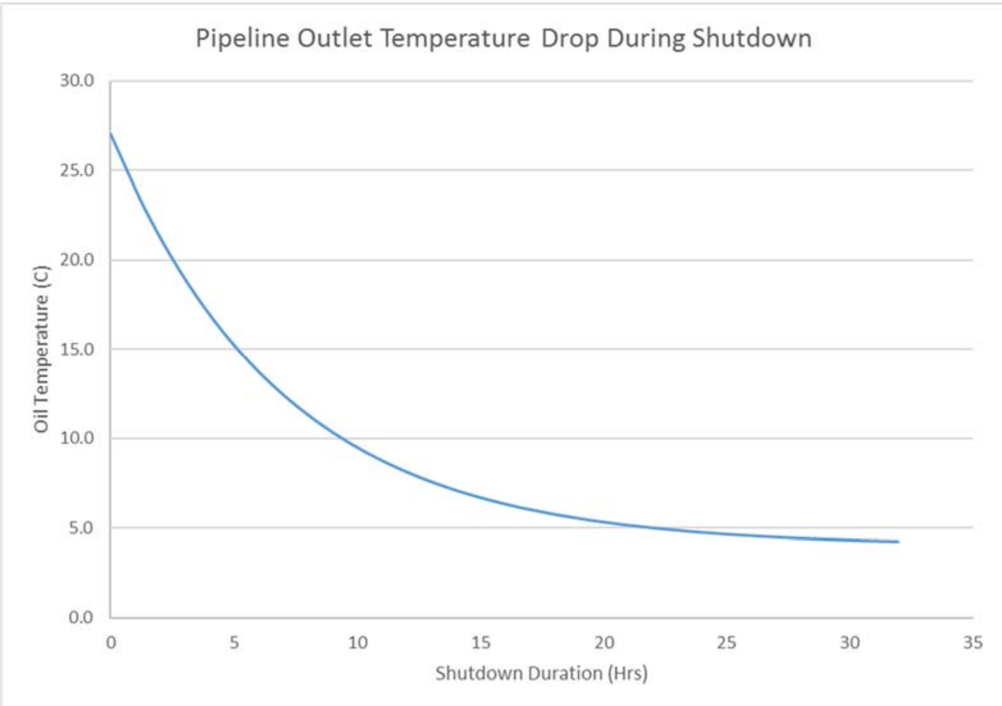


Figure 8 - Candidate C – Thermal Insulation – Shutdown Temperature Drop

8.0 CONCLUSIONS

Several candidate pipeline systems were qualitatively compared, then three candidates underwent further design analysis. The following conclusions were made with regard to the project requirements:

- The minimum pipe size to ensure outlet pressure and resist collapse pressure and buckling is DN125 (5”) Schedule 40 pipe, with 141.3 mm O.D. and 6.6 mm W.T.
- Plain carbon steel pipe requires additional weight to counter lift force, and thermal insulation to meet the outlet temperature and shutdown heat containment requirements.
- Hevicote Concrete Weight Coat would ensure stability at a thickness of 10 mm, and help with steady state temperature at 80 mm. It cannot hold the heat during shutdown.
- Thermotite ULTRA can meet all the thermal performance requirements at a thickness of 50 mm, however it is negatively buoyant and results in vertical instability. Additional weight is required.

Further study should include consideration of a pipeline system with both weight coat and thermal insulation.

9.0 REFERENCES

- API, 2004. *API 5L Specifications for Line Pipe 43rd Ed.* American Petroleum Institute. Washington, D.C. 2004.
- BAI, Y. & BAI, Q., 2012. *Subsea Engineering Handbook.* Elsevier
- BAI, Y. & BAI, Q., 2005. *Subsea Pipelines and Risers.* Elsevier
- ELAM, S.K., 1989. *Thermal Conductivity of Crude Oils*. Experimental Thermal and Fluid Science 2(1):1-6. January, 1989.
- JEE, T. 2006. *Subsea Pipeline Installation.* Trevor Jee Associates. Kent, England, 2006.
- DET NORSKE VERITAS, 2012. *DNV-OS-F101 Submarine Pipeline Systems.* Det Norske Veritas. Norway, August 2012.
- ROBERT GORDON UNIVERSITY, 2016a. *ENM229: Subsea Pipeline and Riser Design [Lecture Notes – Topic 7]* Delivered May 2016.
- MENON, E. S. 2004. *Liquid Pipeline Hydraulics*. Systek Technologies Inc. Arizona, U.S.A. (p. 56)
- MEENAGHAN, J. 2012. *The Next Generation of Reeled Pipe Lay Vessels: For Ultra Deep Water Field Developments in Remote Locations*. Kuala Lumpur. EMAS [Online] http://www.subseauk.com/documents/presentations/the_next_generation_of_reeled_pipelay_vessels.pdf [Accessed 10 July 2016]
- BREDERO-SHAW, 2016. *Thermotite ULTRA Product Data Sheet*. Bredero Shaw. [Online] http://www.brederoshaw.com/non_html/pds/BrederoShaw_PDS_ThermotiteULTRA.pdf [Accessed 20 July 2016]

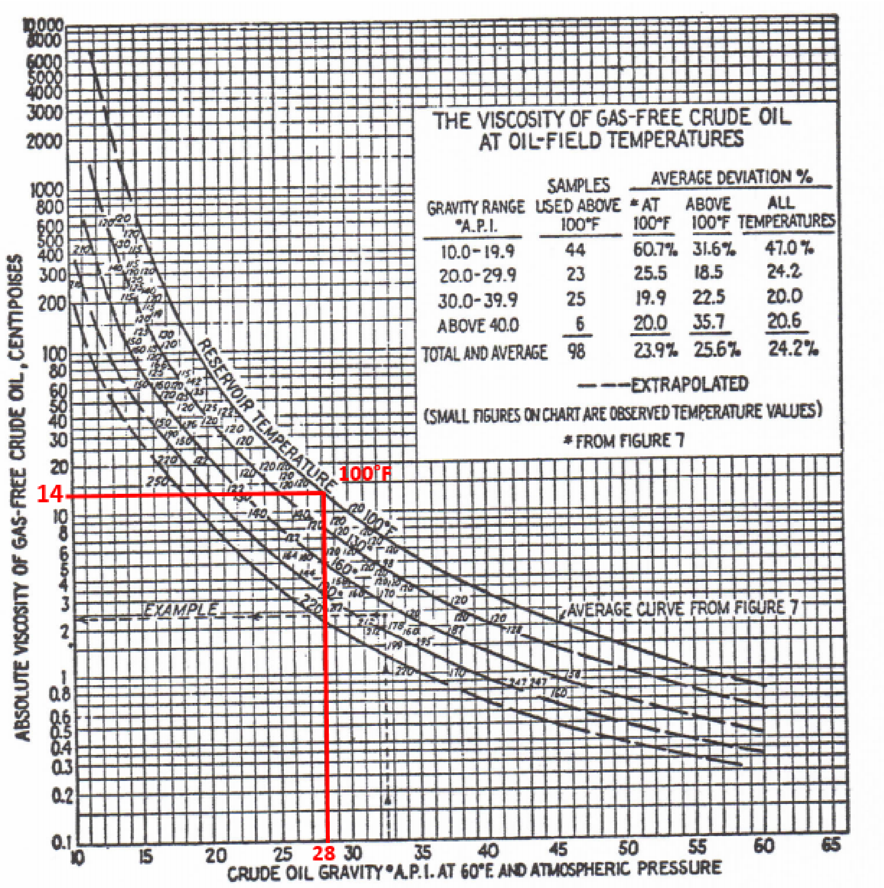
APPENDIX A PIPELINE SYSTEM OPTIONS – QUALITATIVE COMPARISON

Pipeline System	Thermal Performance	Corrosion Protection	Seabed Stability	Installation Options	CAPEX	Other Considerations
Candidate A Carbon Steel Pipe only	**Poor** Steel has high conductivity.	**Poor** Higher W.T. required to allow for corrosion losses	**Poor** If empty, low submerged weight. Higher W.T. required to weigh down against drag / lift.	S-Lay, J-Lay, Reel Lay, Towed are all possible.	**Low** Standard materials, standard installation methods.	Not economical to increase steel thickness purely for weight purposes.
Candidate B Carbon Steel Pipe with CWC	**Average** Concrete provides some insulation.	**Poor** Mild external protection, usually paired with PP or PE coating.	**Good** Concrete thickness chosen to ensure stability.	S-Lay, J-Lay, Towed are all possible. Reel Lay not possible	**Medium** Onshore fabrication time to apply CWC. Heavier linepipe, higher top tensions etc.	Cannot inspect external steel condition without removing CWC.
Candidate C Carbon Steel Pipe with Thermal Insulation	**Good** Specially engineered materials to ensure thermal performance.	**Poor** Mild external protection. No additional protection on internal.	**Poor** Insulation material typically close to seawater density (or positively buoyant). Large diameter increases Drag and Lift Forces.	S-Lay, J-Lay, Reel Lay, Towed are all possible.	**Medium** Additional cost of specialty coatings, and time to perform field-joints (longer lay barge duration).	Cannot inspect external steel condition without removing insulation.
Candidate D Duplex Pipe	**Poor** Duplex also highly conductive.	**Good** High resistance to corrosion. Note: Some grades not ideal for sour service – prone to hydrogen-induced cracking.	**Poor** Similar submerged weight to carbon steel.	S-Lay, J-Lay, Reel Lay, Towed are all possible.	**High** Expensive steel materials, special welding methods.	Can reduce cost by cladding internal carbon steel only.
Candidate E Carbon Steel Pipe-in-Pipe	**Good** Hot fluid removes temperature differential, preventing heat transfer. Keeps product hot during shutdown.	**Poor** No additional protection for internal. External may be protected by corrosion inhibitor in annulus.	**Good** Dual pipe provides significant weight.	S-Lay, J-Lay, Reel Lay, Towed are all possible.	**High** Significantly more steel material. Additional facilities for circulating annulus fluid.	Installation limits governed by outer pipe size. Not possible to inspect external of inner pipe.

APPENDIX B – FLOW ASSURANCE CALCULATION

The following calculation is common for all three pipeline system candidates:

FLOW ASSURANCE - PIPE I.D.				
Inputs				
Flowing Pressure at Manifold	P_{in}	6400	kPa	*from BOD*
Flowing Pressure at Riser Base	P_{out}	3100	kPa	*from BOD*
Length of Pipeline (direct)	L	9.7	km	*from BOD*
Flow Rate	Q_{Oil}	9,545	stb/day	*from BOD*
		63.2	m3/hr	*Unit Conversion*
Specific Gravity	S	28	°API	*from BOD*
		0.887	--	*Unit Conversion*
Dynamic Viscosity	z	14	cP	*from Empirical Data Chart (see below)*
TR Aude K-Factor	k	0.9	--	*from Ref: MENON, 2004. (between 0.90 - 0.95)*
Calculations				
Pressure Drop	Pm	340.2	kPa/km	*Calc: (Pout - Pin) / L*
Minimum Pipe Internal Diameter	D	115.3	mm	*Calc:* ***Eq. A1*** *(T.R. Aude Equation)*



APPENDIX C – CALCULATIONS - CANDIDATE A: CARBON STEEL

INSTALLTION LOADS - WALL THICKNESS CHECK				
Installation Features				
Water Depth	d	350	m	*from BOD*
Lay Tension	T	500,000	N	*Assumption, based on typical capacities*
Density of Seawater	ρ_{sw}	1,025	kg/m3	*Typical*
Material Properties				
Steel - Yield Strength	σ_{Steel}	448,000,000	Pa	*Assume API 5L X65 Pipe = 65,000 Psi*
Steel - Youngs Modulus of Elasticity	E	2.07E+11	Pa	*Typical*
Steel - Poissons ratio	v	0.3	--	*Typical*
Steel - Density	ρ_{Steel}	7,850	kg/m3	*Typical*
Insulation - Density	ρ_{Ins}	910	kg/m3	*Ref: BREDERO Thermotite ULTRA*
Concrete - Density	ρ_{CWC}	2,750	kg/m3	*Typical*
Partial Safety Factors				
Safety Class Resistance Factor	γ_{SC}	1.26	--	*DNV-OS-F101 Sec 5 Table 5-3 - Pressure Containment "High"*
Load Effect Factor - Functional	γ_F	1.20	--	*DNV-OS-F101 Sec 4 Table 4-4 -(Highest value)*
Condition Load Effect Factor	γ_C	1.00	--	*DNV-OS-F101 Sec 4 Table 4-5 - "Otherwise"*
Material Strength Factor	α_u	0.96	--	*DNV-OS-F101 Sec 5 Table 5-4 - "Normally"*
Characteristic Material Strength	fy	430,080,000	Pa	*Calc: fy = σSteel * au*
Material Fabrication Factor	α_{fab}	0.85	--	*DNV-OS-F101 Sec 5 Table 5-5 - "UOE"*
Flow Stress Parameter	α_c	1.20	--	*DNV-OS-F101 Sec 5 D605 (assumed, Ref: JEE, 2006)*
Material Resistance Factor	γ_m	1.15	--	*DNV-OS-F101 Sec 5 Table 5-2 - "Limit State = SLS/ULS/ALS"*
Pipe Dimensions				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	***Parameter***
Steel - Wall Thickness	t_{Steel}	0.0066	m	***Parameter***
Steel - Outside Diameter	OD_{Steel}	0.1414	m	***Parameter***
Insulation - Thickness	t_{Ins}	-	m	*(NA - No insulation)*
Insulation - Outside Diameter	OD_{Ins}	0.1414	m	*(NA - No insulation)*
Concrete - Thickness	t_{CWC}	-	m	*(NA - No CWC)*
Concrete - Outside Diameter	OD_{CWC}	0.1414	m	*(NA - No CWC)*
Ovality	fo	0.03	--	*DNV-OS-F101 Limit of 3%*
Second Moment Area for Pipe	I	6.364E-06	m4	*Calc: $I = \pi/64 * (OD_{steel}$^4 - ID_{steel}^4)*

Submerged Weight				
Cross Section Area - Steel	A_{steel}	0.002795	m2	*Calc*
Cross Section Area - Insulation	A_{ins}	-	m2	*(NA - No insulation)*
Cross Section Area - Concrete	A_{CWC}	-	m2	*(NA - No CWC)*
Cross Section Area - Displaced Seawater	Ao	0.015703	m2	*Calc*
Unit Mass - Steel	m_{steel}	21.94	kg/m	*Calc:* $m_{steel} = A_{steel} * \rho_{steel}$
Unit Mass - Insulation	m_{ins}	-	kg/m	*(NA - No insulation)*
Unit Mass - Concrete	m_{CWC}	-	kg/m	*(NA - No CWC)*
Unit Mass - Displaced Seawater	m_{sw}	16.10	kg/m	*Calc:* $m_{sw} = A_O * \rho_{sw}$
Submerged Weight	w	57.34	N/m	*Calc:* $w = (m_{steel} + M_{ins} + M_{CWC} - m_{sw}) * 9.81$
Catenary Equations				
Stinger Departure Angle	a	0.284	rad	*Calc:* ***Eq. B1*** *, a = acos(H/T)*
Horizontal Component of Tension	H	479,931	N	*Calc:* ***Eq. B2*** *, H = T - w*d*
Pipe Span Length	s	2,445.7	m	*Calc:* ***Eq. B3*** *, s = (H/w) * tan(a)*
Touchdown Length	Xs	2,412.2	m	*Calc:* ***Eq. B4*** *, Xs = (H/w) *Asinh(tan(a))*
Radius at Touchtown (x = 0)	R_{TDP}	8,369.9	m	*Calc:* ***Eq. B5*** *,* $R_{TDP} = H/w$
Catenary Stresses				
Bending Moment at Touchdown	Mb	157.4	Nm	*Calc:* ***Eq. B6*** *, Mb = E * I / R*
Bending Stress at Touchdown (x=0)	σb_{TDP}	1,748,509	Pa	*Calc:* ***Eq. B7*** *,* $\sigma b_{TDP} = E * D / (2 * R)$
Axial Forces at Touchdown (Hydro + End cap)	F_a	434,503	N	*Calc:* ***Eq. B8*** *, Fa = T - w*d - (psw*g*d*pi*D^2/4)*
Axial Stress at Touchdown	σ_a	155,456,461	Pa	*Calc:* ***Eq. B9*** *, σa = Fa / Asteel*
Hydrostatic Pressure	Pe	3,519,338	Pa	*Calc:* ***Eq. B10*** *, ρsw * 9.81 / d*
Hoop Stress at Touchdown	σ_h	- 34,180,232	Pa	*Calc:* ***Eq. B11*** *, σh = - Pe*D / 2t*
Von Mises Equivalent Stress (Alt 1)	seq	176,790,818	Pa	*Calc:* ***Eq. B12*** *(using +ve Bend Stress)*
Von Mises Equivalent Stress (Alt 2)	seq	173,344,156	Pa	*Calc:* ***Eq. B12*** *(using -ve Bend Stress)*
Utilisation Check		0.39	**OK**	*Calc: max(Von Mises) / Yield Stress*
Plastic Resistances				
Characteristic Plastic Axial Resistance	Sp	1,202,079	N	*Calc:* ***Eq. B13*** *(DNV Eq. 5.20)*
Plastic Moment Resistance	Mp	51,579	Nm	*Calc:* ***Eq. B14*** *(DNV Eq. 5.21)*
Factored Axial Force and Moment				
Axial Endcap Force	Fec	55,265	N	*Calc:* ***Eq. B15***
Factored Net Axial Force	Sa	509,599	N	*Calc:* ***Eq. B16***
Factored Bending Moment	Md	188.9	N	*Calc:* ***Eq. B17***
Collapse Pressures				
Elastic Collapse Pressure	Pel	46,263,931	Pa	*Calc:* ***Eq. B18***
Plastic Collapse Pressure	Pp	34,126,574	Pa	*Calc:* ***Eq. B19***
Collapse Pressure	Pc	19,890,236	Pa	*Calc:* ***Eq. B20*** *(solved with Goal Seek - equating Left and Right)*
		Left Side	*Right Side*	
	GOAL SEEK	1.020E+15	1.015E+15	
Buckling Factor < 1 ?		0.100	**OK**	*Calc:* ***Eq. B21***

REEL LAY LOADS - WALL THICKNESS CHECK				
Pipe Wall Thickness	t	0.0066	m	*from "Installation Loads"*
Pipe Outside Diameter	O.D.	0.1414	m	*from "Installation Loads"*
Radius of Reel	R_{reel}	8.0	m	*Typical, Ref: MEENEGHAN, 2012*
Max. Allowable Yield/Tensile Stress Ratio	α_h	0.87	--	*Assumption, Ref: RGU, 2016*
Girth Weld Reduction Factor	α_{gw}	1	--	*Assumption, Ref: RGU, 2016*
Strain Resistance Factor	γ_e	2	--	*Assumption, Ref: RGU, 2016*
Radius of Pipe Neutral Axis	R	8.07	m	*Calc: $R = R_{reel} + (O.D./2)$*
Minimum Wall Thickness	t	0.0040	m	*Calc:* ***Eq. C1***
	OK?	**YES**	--	*Check against "Installation Load" WT*

OVALITY CHECK				
Pipe Data				
Pipe Outside Diameter	OD_{Steel}	0.141	m	*from "Installation Loads"*
Wall Thickness	t	0.007	m	*from "Installation Loads"*
Radius of Curvature	R	8.0	m	*Reel Lay - Typical drum, Ref: MEENEGHAN, 2012*
Fabrication Ovality	f_i	0.016		*Assumption*
Calculation				
Total Allowable Ovality	f_{all}	3.0%	--	*Ref:* ***Eq. D1*** *- DNV-OS-F101*
Maximum Bending Strain	ε_b	0.0088	--	*Calc:* ***Eq. D2***
Ovality - Caused by bending	f'_o	0.5%	--	*Calc:* ***Eq. D3***
Cummlative Ovality	f_{cum}	2.1%	--	*Calc:* ***Eq. D4*** *$f_{cum} = fi + f'o$*
Less than 3% ?		OK		

THERMAL PERFORMANCE				
Input Data				
Pipeline Length	L	9700	m	from BOD
Specific Heat of Oil	S	4005	J/kg°C	from BOD
Volume Flowrate	Q	0.0176	m3/sec	from BOD (Converted)
Oil Density	ρ	885.4	kg/m3	from BOD (Converted)
Oil Mass Flowrate	m.	15.55	kg/sec	Calc: m. = ρ * Q
Manifold Inlet Design Temp.	Tin (max)	120	°C	from BOD
		393.1	K	from BOD (Converted)
Pipeline Outlet Temp. (Min.)	Tout (min)	27	°C	from BOD
		300.1	K	from BOD (Converted)
External (seawater) temperature	Te	4	°C	from BOD
		277.1	k	from BOD (Converted)
Oil Kinematic Viscosity	v	1.50E-05	m2/sec	Typical
Oil Dynamic Viscosity	u	0.013280596	kg/m.sec	Calc: u = v * ρ
Pipe Dimensions				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	from "Installation Loads"
Steel - Wall Thickness	t_{Steel}	0.0066	m	from "Installation Loads"
Steel - Outside Diameter	OD_{Steel}	0.1414	m	from "Installation Loads"
Insulation - Thickness	t_{Ins}	-	m	(N/A)
Insulation - Outside Diameter	OD_{Ins}	0.1414	m	(N/A)
Concrete - Thickness	t_{CWC}	-	m	(N/A)
Concrete - Outside Diameter	OD_{CWC}	0.1414	m	(N/A)
Cross Sectional Area (internal)	Ai	0.0129	m2	Calc: Ai = п * ID^2 / 4
Fluid Velocity	V_{oil}	1.361	m/sec	Calc: V_{oil} = Q / Ai

Steady State Heat Transfer				
Overall Heat Transfer Coefficient	U_{Ideal}	1.5	W/m^{2}K	from BOD
Conductivity - Oil	koil	0.12	W/mK	Ref: ELAM, 1989
Conductivity - Steel	k-steel	43	W/mK	Typical, Ref: RGU, 2016
Conductivity - Insulation	k-pp	0.16	W/mK	Thermotite ULTRA (Ref: BREDERO, 2016)
Conductivity - concrete	k-concrete	1.5	W/mK	Typical
R 1 - Steel ID	ri	0.0641	m	Calc: ri = I.D. / 2
R 2 - Steel OD	r2	0.0707	m	Calc: r2 = O.D. / 2
R 3 - Insulation OD	r3	0.0707	m	Calc: r3 = $O.D._{Ins}$ / 2
R 4 - CWC OD	r4	0.0707	m	Calc: r4 = $O.D._{CWC}$ / 2
Reynolds Number	Re	11,630		Calc: **Eq. E1**
Prandtl Number	Pr	443.2		Calc: **Eq. E2**
Nusselt Number	Nu	283.8		Calc: **Eq. E3**
Internal Convection Coefficient	h_i	265.6	W/m2K	Calc: **Eq. E4,** Typ. 55 - 680 (BAI, 2005 Table 19.1)
Natural Convection in Water	h_o	200	W/m2K	Ref: BAI, 2005 - Eq. 19.13
Convection Heat Transfer Rate	Qr	53,669,824	W	Calc: **Eq. E6**
Overall Heat Transfer Coefficient	U	118.4	W/m2K	Calc: **Eq. E7**
		FAIL		
Transient Heat Loss				
Thermal Decay Constant	β	7.43	--	Calc: **Eq. E8**
Area of Heat Transfer (internal)	A	3906.7	m2	Used I.D., as 'Pipeline Designers Choice' (BAI, 2005)
Max. Cooldown Time Until Restart	tmax	32	hrs	from BOD
		115,200	sec	from BOD (converted)
Mass of Oil in Pipe	m	110,857	kg	Calc: m = A * L
Initial Temperature (Oil at Outlet)	Ti	27	C	Used Min. Outlet Temp - regardless of Steady State re

Steady State Temp (**Eq. E9**)		
	Oil Temp	
x	T(x) K	T (C)
0	393.1	120.1
500	356.2	83.2
1000	331.0	58.0
1500	313.9	40.9
2000	302.2	29.2
2500	294.2	21.2
3000	288.8	15.8
3500	285.1	12.1
4000	282.5	9.5
4500	280.8	7.8
5000	279.6	6.6
5500	278.8	5.8
6000	278.3	5.3
6500	277.9	4.9
7000	277.6	4.6
7500	277.5	4.5
8000	277.4	4.4
8500	277.3	4.3
9000	277.2	4.2
9500	277.2	4.2
9700	277.2	4.2

Thermal Decay (**Eq. E10**)		
Hrs	t (sec)	T (C)
0	0	27.0
1	5000	4.1
3	10000	4.0
4	15000	4.0
6	20000	4.0
7	25000	4.0
8	30000	4.0
10	35000	4.0
11	40000	4.0
13	45000	4.0
14	50000	4.0
15	55000	4.0
17	60000	4.0
18	65000	4.0
19	70000	4.0
21	75000	4.0
22	80000	4.0
24	85000	4.0
25	90000	4.0
26	95000	4.0
28	100000	4.0
29	105000	4.0
31	110000	4.0
32	115000	4.0

STABILITY CHECK				
Field Data				
Sig. Wave Height (Omni-directional, 100 yr)	Hs	13.7	m	*from BOD*
Wave Period	T	15	sec	*from BOD*
Friction Factor – seabed / pipe	µ	0.74	--	*from BOD*
Seawater Density	ρw	1025	kg/m3	*Typical*
Steady State Velocity	Ust	0.4	m/sec	*Assumption*
Wave Induced Velocity	Uwi	0	m/sec	*Assume no effect of surface wave*
Phase Angle	θ	338	deg	*Assumed*
		5.90	rad	*Converted*
Instantaneous Particle Velocity	U	0.4	m/sec	*Calc:* ***Eq. F5***
Particle Acceleration	a	0	m/sec	*Calc:* ***Eq. F6***
Pipe Data				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	*from "Thermal Performance"*
Steel - Wall Thickness	t_{Steel}	0.0066	m	*from "Thermal Performance"*
Steel - Outside Diameter	OD_{Steel}	0.1414	m	*from "Thermal Performance"*
Insulation - Thickness	t_{Ins}	0	m	*from "Thermal Performance"*
Insulation - Outside Diameter	OD_{Ins}	0.1414	m	*from "Thermal Performance"*
Concrete - Thickness	t_{CWC}	0	m	*from "Thermal Performance"*
Concrete - Outside Diameter	OD_{CWC}	0.1414	m	*from "Thermal Performance"*
Cross Sectional Area (internal)	Ai	0.0129	m2	*from "Thermal Performance"*
Corrosion Allowance	--	0.0016	m	*Ref: DNV-OS-F101*
Pipe I.D. after Corrosion	IDca	0.1314	m	*Calc*
Density of Steel	ρ_{Steel}	7850	kg/m3	*Typical*
Density - Thermal Insulation	ρ_{Ins}	910	kg/m3	*Ref: BREDERO-SHAW Thermotite ULTRA*
Density - Concrete	ρ_{CWC}	2750	kg/m3	*Ref: BREDERO-SHAW Hevicote*
Density - Air in Pipe	ρ_{air}	1	kg/m3	*Assume pipe empty (worse case)*
Coefficient of Drag	C_D	0.7	--	*from BOD*
Coefficient of Inertia	C_M	3.29	--	*from BOD*
Coefficient of Lift	C_L	0.9	--	*from BOD*

Submerged Weight				
Cross Section of Steel - after Corrosion	A_{steel}	0.00214	m2	*calc*
Mass of Steel / unit length	W_{steel}	16.82	kg/m	*calc*
Cross Section - Thermal Insulation	A_{ins}	0	m2	*calc*
Mass of Insulation / unit length	W_{ins}	0	kg/m	*calc*
Cross Section of CWC	A_{cwc}	0	m2	*calc*
Mass of CWC / unit length	W_{cwc}	0	kg/m	*calc*
Cross Section of Content	A_{air}	0.0136	m2	*calc*
Mass of Content / unit length	W_{air}	0.014	kg/m	*calc*
Total Mass / unit length	W_{TOT}	16.83	kg/m	*calc*
External Cross Section	A_{ext}	0.0157	m2	*calc*
Seawater Displacement	W_{disp}	16.10	kg/m	*Calc*
Submerged Unit Weight of Pipe	W_{sub}	0.74	kg/m	*Calc*
		7.23	N/m	*Converted*
Vertical Forces				
Lift Force	F_L	30.33	N/m	*Calc:* ***Eq. F2***
Sum of Vertical Forces	F_{VERT}	-23.10	N/m	*calc*
Sufficiently Weighted?		**NO**		
Lateral Forces				
Intertia Force	F_I	0	N/m	*Calc:* ***Eq. F3***
Friction Resistance	FF	-17.10	N/m	*Calc:* ***Eq. F4***
Drag Force	F_D	23.59	N/m	*Calc:* ***Eq. F1***
Sum of Lateral Forces	F_{LAT}	6.50	N/m	*Calc: = FI + FF + FD*
Laterally Stable?		**UNSTABLE**		

APPENDIX D – CALCULATIONS – CANDIDATE B: CONCRETE WEIGHT COAT

INSTALLTION LOADS - WALL THICKNESS CHECK				
Installation Features				
Water Depth	d	350	m	*from BOD*
Lay Tension	T	500,000	N	*Assumption, based on typical capacities*
Density of Seawater	ρ_{sw}	1,025	kg/m3	*Typical*
Material Properties				
Steel - Yield Strength	σ_{Steel}	448,000,000	Pa	*Assume API 5L X65 Pipe = 65,000 Psi*
Steel - Youngs Modulus of Elasticity	E	2.07E+11	Pa	*Typical*
Steel - Poissons ratio	v	0.3	--	*Typical*
Steel - Density	ρ_{Steel}	7,850	kg/m3	*Typical*
Insulation - Density	ρ_{Ins}	910	kg/m3	*Ref: BREDERO Thermotite ULTRA*
Concrete - Density	ρ_{CWC}	2,750	kg/m3	*Typical*
Partial Safety Factors				
Safety Class Resistance Factor	γ_{SC}	1.26	--	*DNV-OS-F101 Sec 5 Table 5-3 - Pressure Containment "High"*
Load Effect Factor - Functional	γ_F	1.20	--	*DNV-OS-F101 Sec 4 Table 4-4 -(Highest value)*
Condition Load Effect Factor	γ_C	1.00	--	*DNV-OS-F101 Sec 4 Table 4-5 - "Otherwise"*
Material Strength Factor	α_u	0.96	--	*DNV-OS-F101 Sec 5 Table 5-4 - "Normally"*
Characteristic Material Strength	fy	430,080,000	Pa	*Calc: fy = σSteel * au*
Material Fabrication Factor	α_{fab}	0.85	--	*DNV-OS-F101 Sec 5 Table 5-5 - "UOE"*
Flow Stress Parameter	α_c	1.20	--	*DNV-OS-F101 Sec 5 D605 (assumed, Ref: JEE, 2006)*
Material Resistance Factor	γ_m	1.15	--	*DNV-OS-F101 Sec 5 Table 5-2 - "Limit State = SLS/ULS/ALS"*
Pipe Dimensions				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	***Parameter***
Steel - Wall Thickness	t_{Steel}	0.0066	m	***Parameter***
Steel - Outside Diameter	OD_{Steel}	0.1414	m	***Parameter***
Insulation - Thickness	t_{Ins}	-	m	*(NA - No insulation)*
Insulation - Outside Diameter	OD_{Ins}	0.1414	m	*(NA - No insulation)*
Concrete - Thickness	t_{CWC}	0.02	m	***Parameter***
Concrete - Outside Diameter	OD_{CWC}	0.1814	m	***Parameter***
Ovality	fo	0.03	--	*DNV-OS-F101 Limit of 3%*
Second Moment Area for Pipe	I	6.364E-06	m4	*Calc: $I = \pi/64 * (OD_{steel}\text{^}4 - ID_{steel}\text{^}4)$*

Submerged Weight				
Cross Section Area - Steel	A_{steel}	0.002795	m2	*Calc*
Cross Section Area - Insulation	A_{ins}	-	m2	*(NA - No insulation)*
Cross Section Area - Concrete	A_{CWC}	0.010141	m2	*(NA - No CWC)*
Cross Section Area - Displaced Seawater	Ao	0.025844	m2	*Calc*
Unit Mass - Steel	m_{steel}	21.94	kg/m	*Calc:* $m_{steel} = A_{steel} * \rho_{steel}$
Unit Mass - Insulation	m_{ins}	-	kg/m	*(NA - No insulation)*
Unit Mass - Concrete	m_{CWC}	27.89	kg/m	*(NA - No CWC)*
Unit Mass - Displaced Seawater	m_{sw}	26.49	kg/m	*Calc:* $m_{sw} = A_O * \rho_{sw}$
Submerged Weight	w	228.95	N/m	*Calc:* $w = (m_{steel} + M_{ins} + M_{CWC} - m_{sw}) * 9.81$
Catenary Equations				
Stinger Departure Angle	a	0.574	rad	*Calc:* ***Eq. B1*** *, a = acos(H/T)*
Horizontal Component of Tension	H	419,868	N	*Calc:* ***Eq. B2*** *, H = T - w*d*
Pipe Span Length	s	1,185.8	m	*Calc:* ***Eq. B3*** *, s = (H/w) * tan(a)*
Touchdown Length	Xs	1,115.7	m	*Calc:* ***Eq. B4*** *, Xs = (H/w) *Asinh(tan(a))*
Radius at Touchtown (x = 0)	R_{TDP}	1,833.9	m	*Calc:* ***Eq. B5*** *,* $R_{TDP} = H/w$
Catenary Stresses				
Bending Moment at Touchdown	Mb	718.3	Nm	*Calc:* ***Eq. B6*** *, Mb = E * I / R*
Bending Stress at Touchdown (x=0)	σb_{TDP}	7,980,258	Pa	*Calc:* ***Eq. B7*** *,* $\sigma b_{TDP} = E * D / (2 * R)$
Axial Forces at Touchdown (Hydro + End cap)	F_a	374,439	N	*Calc:* ***Eq. B8*** *, Fa = T - w*d - (psw*g*d*pi*D^2/4)*
Axial Stress at Touchdown	σ_a	133,966,984	Pa	*Calc:* ***Eq. B9*** *, σa = Fa / Asteel*
Hydrostatic Pressure	Pe	3,519,338	Pa	*Calc:* ***Eq. B10*** *, ρsw * 9.81 / d*
Hoop Stress at Touchdown	σ_h	- 34,180,232	Pa	*Calc:* ***Eq. B11*** *, σh = - Pe*D / 2t*
Von Mises Equivalent Stress (Alt 1)	seq	161,768,655	Pa	*Calc:* ***Eq. B12*** *(using +ve Bend Stress)*
Von Mises Equivalent Stress (Alt 2)	seq	146,106,807	Pa	*Calc:* ***Eq. B12*** *(using -ve Bend Stress)*
Utilisation Check		0.36	**OK**	*Calc: max(Von Mises) / Yield Stress*
Plastic Resistances				
Characteristic Plastic Axial Resistance	Sp	1,202,079	N	*Calc:* ***Eq. B13*** *(DNV Eq. 5.20)*
Plastic Moment Resistance	Mp	51,579	Nm	*Calc:* ***Eq. B14*** *(DNV Eq. 5.21)*
Factored Axial Force and Moment				
Axial Endcap Force	Fec	55,265	N	*Calc:* ***Eq. B15***
Factored Net Axial Force	Sa	437,523	N	*Calc:* ***Eq. B16***
Factored Bending Moment	Md	862.0	N	*Calc:* ***Eq. B17***
Collapse Pressures				
Elastic Collapse Pressure	Pel	46,263,931	Pa	*Calc:* ***Eq. B18***
Plastic Collapse Pressure	Pp	34,126,574	Pa	*Calc:* ***Eq. B19***
Collapse Pressure	Pc	19,923,004	Pa	*Calc:* ***Eq. B20*** *(solved with Goal Seek - equating Left and Right)*
		Left Side	*Right Side*	
	GOAL SEEK	1.015E+15	1.015E+15	
Buckling Factor < 1 ?		0.089	**OK**	*Calc:* ***Eq. B21***

THERMAL PERFORMANCE				
Input Data				
Pipeline Length	L	9700	m	from BOD
Specific Heat of Oil	S	4005	J/kg°C	from BOD
Volume Flowrate	Q	0.0176	m3/sec	from BOD (Converted)
Oil Density	ρ	885.4	kg/m3	from BOD (Converted)
Oil Mass Flowrate	m.	15.55	kg/sec	Calc: m. = ρ * Q
Manifold Inlet Design Temp.	Tin (max)	120	°C	from BOD
		393.1	K	from BOD (Converted)
Pipeline Outlet Temp. (Min.)	Tout (min)	27	°C	from BOD
		300.1	K	from BOD (Converted)
External (seawater) temperature	Te	4	°C	from BOD
		277.1	k	from BOD (Converted)
Oil Kinematic Viscosity	v	1.50E-05	m2/sec	Typical
Oil Dynamic Viscosity	u	0.01328	kg/m.sec	Calc: u = v * ρ
Pipe Dimensions				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	from "Installation Loads"
Steel - Wall Thickness	t_{Steel}	0.0066	m	from "Installation Loads"
Steel - Outside Diameter	OD_{Steel}	0.1414	m	from "Installation Loads"
Insulation - Thickness	t_{Ins}	-	m	from "Installation Loads"
Insulation - Outside Diameter	OD_{Ins}	0.1414	m	from "Installation Loads"
Concrete - Thickness	t_{CWC}	0.0800	m	from "Installation Loads"
Concrete - Outside Diameter	OD_{CWC}	0.3014	m	from "Installation Loads"
Cross Sectional Area (internal)	Ai	0.0129	m2	Calc: Ai = π * ID^2 / 4
Fluid Velocity	V_{oil}	1.361	m/sec	Calc: V_{oil} = Q / Ai

Steady State Heat Transfer				
Overall Heat Transfer Coefficient	U_{Ideal}	1.5	W/m^{2}K	from BOD
Conductivity - Oil	koil	0.12	W/mK	Ref: ELAM, 1989
Conductivity - Steel	k-steel	43	W/mK	Typical, Ref: RGU, 2016
Conductivity - Insulation	k-pp	0.16	W/mK	Thermotite ULTRA (Ref: BREDERO, 2016)
Conductivity - concrete	k-concrete	1.5	W/mK	Typical
R 1 - Steel ID	ri	0.0641	m	Calc: ri = I.D. / 2
R 2 - Steel OD	r2	0.0707	m	Calc: r2 = O.D. / 2
R 3 - Insulation OD	r3	0.0707	m	Calc: r3 = $O.D._{Ins}$ / 2
R 4 - CWC OD	r4	0.1507	m	Calc: r4 = $O.D._{CWC}$ / 2
Reynolds Number	Re	11,630		Calc: **Eq. E1**
Prandtl Number	Pr	443.2		Calc: **Eq. E2**
Nusselt Number	Nu	283.8		Calc: **Eq. E3**
Internal Convection Coefficient	h_i	265.6	W/m2K	Calc: **Eq. E4,** Typ. 55 - 680 (BAI, 2005 Table 19.1)
Natural Convection in Water	h_o	200	W/m2K	Ref: BAI, 2005 - Eq. 19.13
Convection Heat Transfer Rate	Qr	11,807,681	W	Calc: **Eq. E6**
Overall Heat Transfer Coefficient	U	26.1	W/m2K	Calc: **Eq. E7**
		FAIL		
Transient Heat Loss				
Thermal Decay Constant	β	1.63	--	Calc: **Eq. E8**
Area of Heat Transfer (internal)	A	3906.7	m2	Used I.D., as 'Pipeline Designers Choice' (BAI, 2005)
Max. Cooldown Time Until Restart	tmax	32	hrs	from BOD
		115,200	sec	from BOD (converted)
Mass of Oil in Pipe	m	110,857	kg	Calc: m = A * L
Initial Temperature (Oil at Outlet)	Ti	27	C	Used Min. Outlet Temp - regardless of Steady State re

Steady State Temp (**Eq. E9**)		
	Oil Temp	
x	T(x) K	T (C)
0	393.1	120.1
500	383.7	110.7
1000	375.1	102.1
1500	367.2	94.2
2000	359.9	86.9
2500	353.2	80.2
3000	347.1	74.1
3500	341.4	68.4
4000	336.2	63.2
4500	331.4	58.4
5000	327.1	54.1
5500	323.0	50.0
6000	319.3	46.3
6500	315.9	42.9
7000	312.8	39.8
7500	309.9	36.9
8000	307.2	34.2
8500	304.8	31.8
9000	302.6	29.6
9500	300.5	27.5
9700	299.7	26.7

Thermal Decay (**Eq. E10**)		
Hrs	t (sec)	T (C)
0	0	27.0
1	5000	11.3
3	10000	6.3
4	15000	4.7
6	20000	4.2
7	25000	4.1
8	30000	4.0
10	35000	4.0
11	40000	4.0
13	45000	4.0
14	50000	4.0
15	55000	4.0
17	60000	4.0
18	65000	4.0
19	70000	4.0
21	75000	4.0
22	80000	4.0
24	85000	4.0
25	90000	4.0
26	95000	4.0
28	100000	4.0
29	105000	4.0
31	110000	4.0
32	115000	4.0

STABILITY CHECK				
Field Data				
Sig. Wave Height (Omni-directional, 100 yr)	Hs	13.7	m	*from BOD*
Wave Period	T	15	sec	*from BOD*
Friction Factor – seabed / pipe	µ	0.74	--	*from BOD*
Seawater Density	pw	1025	kg/m3	*Typical*
Steady State Velocity	Ust	0.4	m/sec	*Assumption*
Wave Induced Velocity	Uwi	0	m/sec	*Assume no effect of surface wave*
Phase Angle	θ	338	deg	*Assumed*
		5.90	rad	*Converted*
Instantaneous Particle Velocity	U	0.4	m/sec	*Calc:* ***Eq. F5***
Particle Acceleration	a	0	m/sec	*Calc:* ***Eq. F6***
Pipe Data				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	*from "Thermal Performance"*
Steel - Wall Thickness	t_{Steel}	0.0066	m	*from "Thermal Performance"*
Steel - Outside Diameter	OD_{Steel}	0.1414	m	*from "Thermal Performance"*
Insulation - Thickness	t_{Ins}	0	m	*from "Thermal Performance"*
Insulation - Outside Diameter	OD_{Ins}	0.1414	m	*from "Thermal Performance"*
Concrete - Thickness	t_{CWC}	0.02	m	*from "Thermal Performance"*
Concrete - Outside Diameter	OD_{CWC}	0.3014	m	*from "Thermal Performance"*
Cross Sectional Area (internal)	Ai	0.0129	m2	*from "Thermal Performance"*
Corrosion Allowance	--	0.0016	m	*Ref: DNV-OS-F101*
Pipe I.D. after Corrosion	IDca	0.1314	m	*Calc*
Density of Steel	ρ_{Steel}	7850	kg/m3	*Typical*
Density - Thermal Insulation	ρ_{Ins}	910	kg/m3	*Ref: BREDERO-SHAW Thermotite ULTRA*
Density - Concrete	ρ_{CWC}	2750	kg/m3	*Ref: BREDERO-SHAW Hevicote*
Density - Air in Pipe	ρ_{air}	1	kg/m3	*Assume pipe empty (worse case)*
Coefficient of Drag	C_D	0.7	--	*from BOD*
Coefficient of Inertia	C_M	3.29	--	*from BOD*
Coefficient of Lift	C_L	0.9	--	*from BOD*

Submerged Weight				
Cross Section of Steel - after Corrosion	A_{steel}	0.00214	m2	*calc*
Mass of Steel / unit length	W_{steel}	16.82	kg/m	*calc*
Cross Section - Thermal Insulation	A_{ins}	0	m2	*calc*
Mass of Insulation / unit length	W_{ins}	0	kg/m	*calc*
Cross Section of CWC	A_{cwc}	0.05564	m2	*calc*
Mass of CWC / unit length	W_{cwc}	153.02	kg/m	*calc*
Cross Section of Content	A_{air}	0.0136	m2	*calc*
Mass of Content / unit length	W_{air}	0.014	kg/m	*calc*
Total Mass / unit length	W_{TOT}	169.85	kg/m	*calc*
External Cross Section	A_{ext}	0.0713	m2	*calc*
Seawater Displacement	W_{disp}	73.13	kg/m	*Calc*
Submerged Unit Weight of Pipe	W_{sub}	96.72	kg/m	*Calc*
		948.85	N/m	*Converted*
Vertical Forces				
Lift Force	F_L	30.33	N/m	*Calc:* ***Eq. F2***
Sum of Vertical Forces	F_{VERT}	918.52	N/m	*calc*
Sufficiently Weighted?		**OK**		
Lateral Forces				
Intertia Force	F_I	0	N/m	*Calc:* ***Eq. F3***
Friction Resistance	FF	679.70	N/m	*Calc:* ***Eq. F4***
Drag Force	F_D	-23.59	N/m	*Calc:* ***Eq. F1***
Sum of Lateral Forces	F_{LAT}	656.11	N/m	*Calc: = FI + FF + FD*
Laterally Stable?		**OK**		

APPENDIX E – CALCULATIONS – CANDIDATE C: THERMAL INSULATION

INSTALLTION LOADS - WALL THICKNESS CHECK				
Installation Features				
Water Depth	d	350	m	*from BOD*
Lay Tension	T	500,000	N	*Assumption, based on typical capacities*
Density of Seawater	ρ_{sw}	1,025	kg/m3	*Typical*
Material Properties				
Steel - Yield Strength	σ_{Steel}	448,000,000	Pa	*Assume API 5L X65 Pipe = 65,000 Psi*
Steel - Youngs Modulus of Elasticity	E	2.07E+11	Pa	*Typical*
Steel - Poissons ratio	v	0.3	--	*Typical*
Steel - Density	ρ_{Steel}	7,850	kg/m3	*Typical*
Insulation - Density	ρ_{Ins}	910	kg/m3	*Ref: BREDERO Thermotite ULTRA*
Concrete - Density	ρ_{CWC}	2,750	kg/m3	*Typical*
Partial Safety Factors				
Safety Class Resistance Factor	γ_{SC}	1.26	--	*DNV-OS-F101 Sec 5 Table 5-3 - Pressure Containment "High"*
Load Effect Factor - Functional	γ_F	1.20	--	*DNV-OS-F101 Sec 4 Table 4-4 -(Highest value)*
Condition Load Effect Factor	γ_C	1.00	--	*DNV-OS-F101 Sec 4 Table 4-5 - "Otherwise"*
Material Strength Factor	α_u	0.96	--	*DNV-OS-F101 Sec 5 Table 5-4 - "Normally"*
Characteristic Material Strength	fy	430,080,000	Pa	*Calc: fy = σSteel * au*
Material Fabrication Factor	α_{fab}	0.85	--	*DNV-OS-F101 Sec 5 Table 5-5 - "UOE"*
Flow Stress Parameter	α_c	1.20	--	*DNV-OS-F101 Sec 5 D605 (assumed, Ref: JEE, 2006)*
Material Resistance Factor	γ_m	1.15	--	*DNV-OS-F101 Sec 5 Table 5-2 - "Limit State = SLS/ULS/ALS"*
Pipe Dimensions				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	***Parameter***
Steel - Wall Thickness	t_{Steel}	0.0066	m	***Parameter***
Steel - Outside Diameter	OD_{Steel}	0.1414	m	***Parameter***
Insulation - Thickness	t_{Ins}	0.05	m	***Parameter***
Insulation - Outside Diameter	OD_{Ins}	0.2414	m	***Parameter***
Concrete - Thickness	t_{CWC}	-	m	*(NA - No CWC)*
Concrete - Outside Diameter	OD_{CWC}	0.2414	m	*(NA - No CWC)*
Ovality	fo	0.03	--	*DNV-OS-F101 Limit of 3%*
Second Moment Area for Pipe	I	6.364E-06	m4	*Calc: I = π/64 * (OD_{steel}^4 - ID_{steel}^4)*

Submerged Weight				
Cross Section Area - Steel	A_{steel}	0.002795	m2	*Calc*
Cross Section Area - Insulation	A_{ins}	0.03	m2	*(NA - No insulation)*
Cross Section Area - Concrete	A_{CWC}	-	m2	*(NA - No CWC)*
Cross Section Area - Displaced Seawater	Ao	0.045768	m2	*Calc*
Unit Mass - Steel	m_{steel}	21.94	kg/m	*Calc:* $m_{steel} = A_{steel} * \rho_{steel}$
Unit Mass - Insulation	m_{ins}	27.36	kg/m	*(NA - No insulation)*
Unit Mass - Concrete	m_{CWC}	82.68	kg/m	*(NA - No CWC)*
Unit Mass - Displaced Seawater	m_{sw}	46.91	kg/m	*Calc:* $m_{sw} = A_O * \rho_{sw}$
Submerged Weight	w	566.11	N/m	*Calc:* $w = (m_{steel} + M_{ins} + M_{CWC} - m_{sw}) * 9.81$
Catenary Equations				
Stinger Departure Angle	a	0.923	rad	*Calc:* ***Eq. B1*** *, a = acos(H/T)*
Horizontal Component of Tension	H	301,862	N	*Calc:* ***Eq. B2*** *, H = T - w*d*
Pipe Span Length	s	704.1	m	*Calc:* ***Eq. B3*** *, s = (H/w) * tan(a)*
Touchdown Length	Xs	581.7	m	*Calc:* ***Eq. B4*** *, Xs = (H/w) *Asinh(tan(a))*
Radius at Touchtown (x = 0)	R_{TDP}	533.2	m	*Calc:* ***Eq. B5*** *,* $R_{TDP} = H/w$
Catenary Stresses				
Bending Moment at Touchdown	Mb	2,470.4	Nm	*Calc:* ***Eq. B6*** *, Mb = E * I / R*
Bending Stress at Touchdown (x=0)	σb_{TDP}	27,446,083	Pa	*Calc:* ***Eq. B7*** *,* $\sigma b_{TDP} = E * D / (2 * R)$
Axial Forces at Touchdown (Hydro + End cap)	F_a	256,434	N	*Calc:* ***Eq. B8*** *, Fa = T - w*d - (psw*g*d*pi*D^2/4)*
Axial Stress at Touchdown	σ_a	91,746,952	Pa	*Calc:* ***Eq. B9*** *, σa = Fa / Asteel*
Hydrostatic Pressure	Pe	3,519,338	Pa	*Calc:* ***Eq. B10*** *, ρsw * 9.81 / d*
Hoop Stress at Touchdown	σ_h	- 34,180,232	Pa	*Calc:* ***Eq. B11*** *, σh = - Pe*D / 2t*
Von Mises Equivalent Stress (Alt 1)	seq	139,460,796	Pa	*Calc:* ***Eq. B12*** *(using +ve Bend Stress)*
Von Mises Equivalent Stress (Alt 2)	seq	86,606,631	Pa	*Calc:* ***Eq. B12*** *(using -ve Bend Stress)*
Utilisation Check		0.31	**OK**	*Calc: max(Von Mises) / Yield Stress*
Plastic Resistances				
Characteristic Plastic Axial Resistance	Sp	1,202,079	N	*Calc:* ***Eq. B13*** *(DNV Eq. 5.20)*
Plastic Moment Resistance	Mp	51,579	Nm	*Calc:* ***Eq. B14*** *(DNV Eq. 5.21)*
Factored Axial Force and Moment				
Axial Endcap Force	Fec	55,265	N	*Calc:* ***Eq. B15***
Factored Net Axial Force	Sa	295,917	N	*Calc:* ***Eq. B16***
Factored Bending Moment	Md	2,964.5	N	*Calc:* ***Eq. B17***
Collapse Pressures				
Elastic Collapse Pressure	Pel	46,263,931	Pa	*Calc:* ***Eq. B18***
Plastic Collapse Pressure	Pp	34,126,574	Pa	*Calc:* ***Eq. B19***
Collapse Pressure	Pc	19,923,004	Pa	*Calc:* ***Eq. B20*** *(solved with Goal Seek - equating Left and Right)*
		Left Side	*Right Side*	
	GOAL SEEK	1.015E+15	1.015E+15	
Buckling Factor < 1 ?		0.083	**OK**	*Calc:* ***Eq. B21***

REEL LAY LOADS - WALL THICKNESS CHECK				
Pipe Wall Thickness	t	0.0066	m	*from "Installation Loads"*
Pipe Outside Diameter	O.D.	0.1414	m	*from "Installation Loads"*
Radius of Reel	R_{reel}	8.0	m	*Typical, Ref: MEENEGHAN, 2012*
Max. Allowable Yield/Tensile Stress Ratio	α_h	0.87	--	*Assumption, Ref: RGU, 2016*
Girth Weld Reduction Factor	α_{gw}	1	--	*Assumption, Ref: RGU, 2016*
Strain Resistance Factor	γ_e	2	--	*Assumption, Ref: RGU, 2016*
Radius of Pipe Neutral Axis	R	8.07	m	*Calc: $R = R_{reel} + (O.D./2)$*
Minimum Wall Thickness	t	0.0040	m	*Calc:* ***Eq. C1***
	OK?	**YES**	--	*Check against "Installation Load" WT*

OVALITY CHECK				
Pipe Data				
Pipe Outside Diameter	OD_{Steel}	0.141	m	*from "Installation Loads"*
Wall Thickness	t	0.007	m	*from "Installation Loads"*
Radius of Curvature	R	8.0	m	*Reel Lay - Typical drum, Ref: MEENEGHAN, 2012*
Fabrication Ovality	f_i	0.016		*Assumption*
Calculation				
Total Allowable Ovality	f_{all}	3.0%	--	*Ref:* ***Eq. D1*** *- DNV-OS-F101*
Maximum Bending Strain	ε_b	0.0088	--	*Calc:* ***Eq. D2***
Ovality - Caused by bending	f'_o	0.5%	--	*Calc:* ***Eq. D3***
Cummlative Ovality	f_{cum}	2.1%	--	*Calc:* ***Eq. D4*** *$f_{cum} = fi + f'o$*
Less than 3% ?		OK		

THERMAL PERFORMANCE				
Input Data				
Pipeline Length	L	9700	m	from BOD
Specific Heat of Oil	S	4005	J/kg°C	from BOD
Volume Flowrate	Q	0.0176	m3/sec	from BOD (Converted)
Oil Density	ρ	885.4	kg/m3	from BOD (Converted)
Oil Mass Flowrate	m.	15.55	kg/sec	Calc: m. = ρ * Q
Manifold Inlet Design Temp.	Tin (max)	120	°C	from BOD
		393.1	K	from BOD (Converted)
Pipeline Outlet Temp. (Min.)	Tout (min)	27	°C	from BOD
		300.1	K	from BOD (Converted)
External (seawater) temperature	Te	4	°C	from BOD
		277.1	k	from BOD (Converted)
Oil Kinematic Viscosity	v	1.50E-05	m2/sec	Typical
Oil Dynamic Viscosity	u	0.0133	kg/m.sec	Calc: u = v * ρ
Pipe Dimensions				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	from "Installation Loads"
Steel - Wall Thickness	t_{Steel}	0.0066	m	from "Installation Loads"
Steel - Outside Diameter	OD_{Steel}	0.1414	m	from "Installation Loads"
Insulation - Thickness	t_{Ins}	0.0500	m	**Parameter**
Insulation - Outside Diameter	OD_{Ins}	0.2414	m	**Parameter**
Concrete - Thickness	t_{CWC}	-	m	(N/A)
Concrete - Outside Diameter	OD_{CWC}	0.2414	m	(N/A)
Cross Sectional Area (internal)	Ai	0.0129	m2	Calc: Ai = π * ID^2 / 4
Fluid Velocity	V_{oil}	1.361	m/sec	Calc: V_{oil} = Q / Ai

Steady State Heat Transfer				
Overall Heat Transfer Coefficient	U_{Ideal}	1.5	W/m^{2}K	from BOD
Conductivity - Oil	koil	0.12	W/mK	Ref: ELAM, 1989
Conductivity - Steel	k-steel	43	W/mK	Typical, Ref: RGU, 2016
Conductivity - Insulation	k-pp	0.16	W/mK	Thermotite ULTRA (Ref: BREDERO, 2016)
Conductivity - concrete	k-concrete	1.5	W/mK	Typical
R 1 - Steel ID	ri	0.0641	m	Calc: ri = I.D. / 2
R 2 - Steel OD	r2	0.0707	m	Calc: r2 = O.D. / 2
R 3 - Insulation OD	r3	0.1207	m	Calc: r3 = $O.D._{Ins}$ / 2
R 4 - CWC OD	r4	0.1207	m	Calc: r4 = $O.D._{CWC}$ / 2
Reynolds Number	Re	11,630		Calc: **Eq. E1**
Prandtl Number	Pr	443.2		Calc: **Eq. E2**
Nusselt Number	Nu	283.8		Calc: **Eq. E3**
Internal Convection Coefficient	h_i	265.6	W/m2K	Calc: **Eq. E4,** Typ. 55 - 680 (BAI, 2005 Table 19.1)
Natural Convection in Water	h_o	200	W/m2K	Ref: BAI, 2005 - Eq. 19.13
Convection Heat Transfer Rate	Qr	2,052,011	W	Calc: **Eq. E6**
Overall Heat Transfer Coefficient	U	4.5	W/m2K	Calc: **Eq. E7**
		FAIL		
Transient Heat Loss				
Thermal Decay Constant	β	0.28	--	Calc: **Eq. E8**
Area of Heat Transfer (internal)	A	3906.7	m2	Used I.D., as 'Pipeline Designers Choice' (BAI, 2005)
Max. Cooldown Time Until Restart	tmax	32	hrs	from BOD
		115,200	sec	from BOD (converted)
Mass of Oil in Pipe	m	110,857	kg	Calc: m = A * L
Initial Temperature (Oil at Outlet)	Ti	27	C	Used Min. Outlet Temp - regardless of Steady State re

Steady State Temp (**Eq. E9**)		
	Oil Temp	
x	T(x) K	T (C)
0	393.1	120.1
500	391.4	118.4
1000	389.8	116.8
1500	388.1	115.1
2000	386.5	113.5
2500	384.9	111.9
3000	383.3	110.3
3500	381.8	108.8
4000	380.3	107.3
4500	378.8	105.8
5000	377.3	104.3
5500	375.8	102.8
6000	374.4	101.4
6500	373.0	100.0
7000	371.6	98.6
7500	370.2	97.2
8000	368.9	95.9
8500	367.5	94.5
9000	366.2	93.2
9500	364.9	91.9
9700	364.4	91.4

Thermal Decay (**Eq. E10**)		
Hrs	t (sec)	T (C)
0	0	27.0
1	5000	22.8
3	10000	19.4
4	15000	16.7
6	20000	14.4
7	25000	12.5
8	30000	11.0
10	35000	9.7
11	40000	8.7
13	45000	7.8
14	50000	7.1
15	55000	6.6
17	60000	6.1
18	65000	5.7
19	70000	5.4
21	75000	5.2
22	80000	4.9
24	85000	4.8
25	90000	4.6
26	95000	4.5
28	100000	4.4
29	105000	4.4
31	110000	4.3
32	115000	4.2

STABILITY CHECK				
Field Data				
Sig. Wave Height (Omni-directional, 100 yr)	Hs	13.7	m	*from BOD*
Wave Period	T	15	sec	*from BOD*
Friction Factor – seabed / pipe	µ	0.74	--	*from BOD*
Seawater Density	pw	1025	kg/m3	*Typical*
Steady State Velocity	Ust	0.4	m/sec	*Assumption (100-year storm condition)*
Wave Induced Velocity	Uwi	0	m/sec	*Assume no effect of surface wave*
Phase Angle	θ	338	deg	*Assumed*
		5.90	rad	*Converted*
Instantaneous Particle Velocity	U	0.4	m/sec	*Calc:* ***Eq. F5***
Particle Acceleration	a	0	m/sec	*Calc:* ***Eq. F6***
Pipe Data				
Steel - Internal Diameter	ID_{Steel}	0.1282	m	*from "Thermal Performance"*
Steel - Wall Thickness	t_{Steel}	0.0066	m	*from "Thermal Performance"*
Steel - Outside Diameter	OD_{Steel}	0.1414	m	*from "Thermal Performance"*
Insulation - Thickness	t_{Ins}	0.05	m	*from "Thermal Performance"*
Insulation - Outside Diameter	OD_{Ins}	0.2414	m	*from "Thermal Performance"*
Concrete - Thickness	t_{CWC}	0	m	*from "Thermal Performance"*
Concrete - Outside Diameter	OD_{CWC}	0.2414	m	*from "Thermal Performance"*
Cross Sectional Area (internal)	Ai	0.0129	m2	*from "Thermal Performance"*
Corrosion Allowance	--	0.0016	m	*Ref: DNV-OS-F101*
Pipe I.D. after Corrosion	IDca	0.1314	m	*Calc*
Density of Steel	ρ_{Steel}	7850	kg/m3	*Typical*
Density - Thermal Insulation	ρ_{Ins}	910	kg/m3	*Ref: BREDERO-SHAW Thermotite ULTRA*
Density - Concrete	ρ_{CWC}	2750	kg/m3	*Ref: BREDERO-SHAW Hevicote*
Density - Air in Pipe	ρ_{air}	1	kg/m3	*Assume pipe empty (worse case)*
Coefficient of Drag	C_D	0.7	--	*from BOD*
Coefficient of Inertia	C_M	3.29	--	*from BOD*
Coefficient of Lift	C_L	0.9	--	*from BOD*

Submerged Weight				
Cross Section of Steel - after Corrosion	A_{steel}	0.00214	m2	*calc*
Mass of Steel / unit length	W_{steel}	16.82	kg/m	*calc*
Cross Section - Thermal Insulation	A_{ins}	0.03007	m2	*calc*
Mass of Insulation / unit length	W_{ins}	27.36	kg/m	*calc*
Cross Section of CWC	A_{cwc}	0	m2	*calc*
Mass of CWC / unit length	W_{cwc}	0	kg/m	*calc*
Cross Section of Content	A_{air}	0.0136	m2	*calc*
Mass of Content / unit length	W_{air}	0.014	kg/m	*calc*
Total Mass / unit length	W_{TOT}	44.19	kg/m	*calc*
External Cross Section	A_{ext}	0.0458	m2	*calc*
Seawater Displacement	W_{disp}	46.91	kg/m	*Calc*
Submerged Unit Weight of Pipe	W_{sub}	-2.72	kg/m	*Calc*
		-26.69	N/m	*Converted*
Vertical Forces				
Lift Force	F_L	45.09	N/m	*Calc:* ***Eq. F2***
Sum of Vertical Forces	F_{VERT}	-71.78	N/m	*calc*
Sufficiently Weighted?		**NO**		
Lateral Forces				
Intertia Force	F_I	0	N/m	*Calc:* ***Eq. F3***
Friction Resistance	FF	-53.12	N/m	*Calc:* ***Eq. F4***
Drag Force	F_D	35.07	N/m	*Calc:* ***Eq. F1***
Sum of Lateral Forces	F_{LAT}	-18.05	N/m	*Calc: = FI + FF + FD*
Laterally Stable?		**OK**		

Robert Gordon University

ENM239 Subsea Systems Risk and Reliability

RGU Petroleum Ltd

Minimising Hydrocarbon Leakages in Subsea Systems through effective Data and Change Management

Name:	ADAM BEATON
Student No:	1418528
Date:	11/12/2016
Word Count:	2,884 *

** Excludes: Front Cover, Contents, Tables, References and Appendices (Total 1,709 words)*

1.0 EXECUTIVE SUMMARY

This document presents the case for improving subsea system reliability through data and change management strategies in order to minimise the risk of hydrocarbon releases. A review of pertinent legislation and standards revealed that guidance in this field is limited.
Two case studies of subsea releases were evaluated to highlight the risks and to demonstrate that data and change management could have prevented the incidents. Specific data and change management strategies are proposed to target the root causes of these incidents.

CONTENTS

2.0 INTRODUCTION

2.1 Background

RGU Petroleum Ltd operates numerous subsea systems in the United Kingdom Continental Shelf (UKCS) which present inherent risks of hydrocarbon releases with significant consequences. An unacceptable number of incidents on RGU assets have recently occurred, which has prompted the need for reliability improvement measures beginning with this study.

Catastrophic accidents in the past such as the Piper Alpha disaster in 1988 have shaped the petroleum industries approach to risk and reliability management (1). The fallout of the recent Deepwater Horizon spill could likely lead to further evolutions of the reliability discipline.

As projects grow in size and technologies advance, two disciplines have emerged; Data management and change management. Industry regulations and standards have begun introducing requirements in these areas, but so far remain relatively ambiguous.

2.2 Objective

The objective of this study was to present data and change management strategies to improve reliability by mitigating risks for a selection of key failure modes. The general format below has been applied:

1. **Regulation Framework** - Critical evaluation of regulations and standards relevant to subsea systems with respect to data and change management requirements.
2. **Incident Case Studies** - Investigation and root cause analyses of two subsea hydrocarbon release incidents.
3. **Key Failure Modes** – Identification of five key failure modes from the case studies which require specific risk mitigation.
4. **Risk Mitigation Strategies** – Presentation of data and change management strategies to address the targeted key failure modes.

2.3 Abbreviations

ALE	Ageing and Life Extension
API	American Petroleum Institute
DDR	Daily Drilling Report
DNV	Det Norske Veritas
ED	Energy Department
FMECA	Failure Mode Effects and Criticality Analysis
FRACAS	Failure Reporting and Corrective Action Systems
HSE	Health and Safety Executive
ISO	International Organisation for Standardization
KP	Key Process
KPI	Key Performance Indicator
MBES	Multibeam Echosounder
MFL	Magnetic Flux Leakage
MOC	Management of Change
OSD	Offshore Department
OSHAS	Occupational Health and Safety Assessment
PHMSA	Pipelines and Hazardous Materials Safety Administration
RBI	Risk Based Inspection
RCA	Root Cause Analysis
RGU	Robert Gordon University
RIM	Reliability and Integrity Management
ROV	Remotely Operated Vehicle
SCADA	Supervisory Control and Data Acquisition
SCE	Safety Critical Element
SCR	Safety Case Regulations
SSS	Sidescan Sonar
TGP	Tennessee Gas Pipeline
UKCS	United Kingdom Continental Shelf

3.0 DIRECTIVES, REGULATIONS AND KEY STANDARDS

In the United Kingdom, the *Health and Safety at Work etc. Act 1974* enables the Health and Safety Executive (HSE) to regulate the offshore oil and gas industry within the UK Continental Shelf (UKCS), through various departments such as the Energy Department (ED), and Offshore Department (OSD).

The following sections summarise regulations and standards relevant to the operation of RGU Ltd subsea assets, and evaluate how data and change management is being addressed. Guidance has been taken from the HSE's *Loss of Containment Manual*, which provides a road map to legislation related to managing risk of hydrocarbon release (1).

3.1 SCR 2015

The *Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015* (SCR 2015) requires all offshore operators to submit a Safety Case for approval. The main purpose of Safety Cases can be summarised by the following excerpt from Regulation 29 (1): "*Where an activity carried out by a duty holder significantly increases the risk of a major accident the duty holder must take suitable measures to ensure that the risk is reduced as low as is reasonably practicable*" (2).

The SCR 2015 requires the following from all operators:

- A Safety Case, as described above;
- A Corporate Major Accident Prevention Policy;
- A Safety and Environmental Management System, including plans for Management of Change;
- A 'Verification scheme' – For liaison with a 3rd party verifier, including referral of material changes to the verifier for further comment.
- 'Well Examination Scheme' - Ensuring "there can be no unplanned escape of fluids" (Regulation 11 (1) (a)), which shall be revised and re-examined with any changes to the well (2).

3.2 HSE KP4

The HSE Key Programme 4 – *Ageing and Life Extension Programme (KP4)* provides a summary and recommendations from the research performed by the HSE ED in 2013. It focuses on major accidents and causes related to ageing and life extension (ALE) of offshore installations [3].

The report makes the following criticisms of the industry pertaining to data and change management:

- "*Insufficient use of data trending to enable forecasting of when equipment is likely to fail its criteria of non-conformance*" [3].
- "*Insufficient use of data and information, which could lead to a better understanding of the consequences of creeping change*" [3].

3.3 OHSAS 18001:2007

The Occupational Health and Safety Assessment Series (OHSAS) publishes the British Standard 18001 series which defines safety management systems. The forward to this standard states that in this latest edition "*Management of Change is now more explicitly addressed*" [4]. This refers to OSHAS 18001:2007 Section 4.3.1:

> *"For the management of change, the organization shall identify the OH&S hazards and OH&S risks associated with the changes in the organization, the OH&S management system, or its activities, prior to the introduction of such changes."* [4]

Together with the related ISO 9001:2015 Quality Management Systems, these standards also address document and record control with broad, non-specific requirements.

3.4 Pipelines Safety Regulations 1996

The HSE Pipelines Safety Regulations 1996 outlines technical and management requirements for all pipelines in Great Britain. Among the 31 Regulations within the document, the following two regulations are key for this study:

- Regulation 10: Work on a Pipeline - "*The operator shall ensure that modification, maintenance or other work on a pipeline is* *carried out in such a way that its soundness and fitness for the purpose for which it has been designed will not be prejudiced*” (5).

- Regulation 22: Notification in other cases - “*Notification to HSE is required of certain changes such as changes in the operating regime, major modifications to the pipeline, changes in fluid and cessation of use of the pipeline*” (5).

3.5 DNV-RP-F116

Det Norske Veritas (DNV) Recommended Practice DNV-RP-F116 *Integrity Management of Submarine Pipeline Systems* offers guidance for developing and maintaining an Integrity Management System (IMS) for subsea pipelines, including processes for re-qualification and life extension, and promotes a Risk Based Inspection (RBI) approach to determining monitoring plans (6). This is particularly relevant for the strategies proposed in this study.

3.6 API 17N

The American Petroleum Institute (API) 17N – *Recommended Practice for Subsea Production System Reliability, Technical Risk & Integrity Management* offers 12 Key Processes (KP) for Reliability and Integrity Management (RIM). Two KPs are pertinent to the improvement strategies in this study:

- KP 9 – Performance Tracking and Data Management – defining responsibilities and requirements for Key Performance Indicator (KPI) tracking, Failure Reporting and Corrective Action Systems (FRACAS) (7).
- KP 11 – Management of Change – Guidance for ensuring design and process changes are properly assessed by management against RIM requirements (7).

4.0 INCIDENTS OF HYDROCARBON RELEASES

4.1 Hydrocarbon Release Trends

The HSE OSD Hydrocarbon Release Reduction Campaign produced a report on the *2001 Hydrocarbon Release Incident Investigation Project*, which provides statistical data for the frequency, severity and causes of hydrocarbon releases in the UKCS between April 2000 and March 2001 (8). The findings of the investigation are summarized in Table 1.

Table 1 – Summary of Findings of the 2001 Hydrocarbon Release Incident Investigation Project 2001 (8)

Taxonomy	Most Frequent Incidents
Operating Mode	1st – Normal Production (60%) 2nd – Start-Up (13%)
Release Site	1st – Open Pipe Ends (16%) 2nd – Pipe Body (13%)
Immediate Cause	1st – Material Degradation (26%) 2nd – Corrosion (19%)
Underlying Cause	1st – Inadequate Design (29%) 2nd – Inadequate Inspection (28%)
	Operational Cause – Incorrectly fitted equipment (human error)
	Procedural Cause – Non-compliance to procedures (human error)

The HSE also manages the Hydrocarbon Release System, a public database of all releases within the UKCS since 2006. The data shows a reducing trend in Minor (< 60 kg) and Significant (60 kg to 300 kg) releases, but no significant reduction in Major releases (> 300 kg) (9).

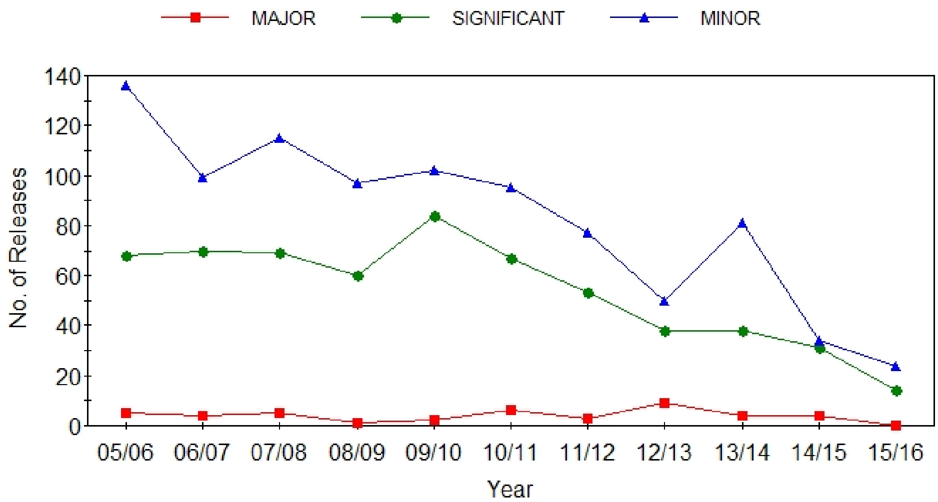


Figure 1 – Trends in UKCS Hydrocarbon Releases from the HSE Database [9]

4.2 Hydrocarbon Release Case Studies

Two cases of subsea hydrocarbon releases were selected for analysis. The analysis focuses on underlying causes related to data and change management.

The two selected case studies differ in many aspects, including: Operating modes (Operation and Drilling), regions (Gulf of Mexico and Timor Sea), spill magnitudes, and have root causes related to data and change management, respectively.

Root cause analyses (RCA) were performed on the two case studies in the form of the "5-Whys" as commonly used by several major operators (see Appendix A and Appendix B). RCAs were repeated twice for each case to demonstrate different routes that the analyses could take.

4.2.1 Whitecap Pipeline Leak - 2010

The 18" Whitecap Pipeline transmits crude oil from Chevron Ship Shoal 28 "F" platform to shore in the Gulf of Mexico, and crosses underneath the 36" Tennessee Gas Pipeline (TGP). The pipeline was commissioned in 1968, with no historical leaks. The last magnetic flux leakage (MFL) inspections were performed on the location in 2002, and visual inspection in 2004.

A hurricane is purported to have lifted and dropped the 36" TPG, impacting the 18" Whitecap Pipeline and causing a 1 inch dent. Cyclic pressure loadings induced a crack at the dent location and a subsequent oil leak was identified in March, 2010. Table 2 below summarises the Failure Investigation Report submitted to the U.S. Pipelines and Hazardous Materials Safety Administration (PHMSA) [10].

Table 2 – Summary of the 2010 Whitecap Pipeline Leak [10]

Operator	Whitecap Pipe Line Company, LLC
Location	Gulf of Mexico – Ship Shoal 28
Facility	Whitecap Pipe Line (18” crude gathering line)
Date of Release	Approx. 25/3/2010 to 29/3/2010 (5 days)
Release Type	Crude Oil
Release Quantity	5.7 barrels
Water Depth	16 m
Operating Mode	Normal Operation
Release Source	Damaged linepipe
Consequences	- Release of crude into sea - Shutdown production for 34 days - Foreign pipeline de-pressurisation - Repair cost of US$2,200,000

The following underlying causes of the incident are identified:

- The original crossing design from 1968 was not in compliance with current regulations and industry best practice. (Note: Specific details are not available in the investigation report).
- Post-Hurricane Katrina hydrographic surveys were not of high enough resolution to identify damage at the pipeline crossing.
- The leak was too small to be identified by the SCADA detection and alarm system in place.

4.2.2 Montara Blowout – 2009

In August 2009, PTTEP caused a blowout while drilling in the Timor Sea, causing a 74 day uncontrolled release of oil and subsequent fire during a plugging attempt. The basic details are below.

Table 3 – Summary of the 2009 Montara Blowout

Operator	PTTEP Australasia Pty Ltd
Location	Timor Sea – Montara Oilfield
Facility	West Atlas Jackup Drill Rig
Date of Release	21/08/2009 to 3/11/2009 (74 days)
Release Type	Crude Oil
Release Quantity	285,000 barrels (highest estimate)
Water Depth	76 m
Operating Mode	Drilling
Release Source	9-5/8” casing shoe failure
Consequences	- Approx. 90,000 km^2 oil sheen [11]. - Fire damage to drill rig - Approx. US$173million in initial response [12]. - Litigation brought by nearby countries Indonesia and Timor Leste - Fined $510,000 by Australian authorities [13].

An inquiry by the Commonwealth of Australia found that PTTEP “*did not observe sensible oilfield practices at the Montara Oilfield. Major shortcomings in the company’s procedures were widespread and systemic, directly leading to the Blowout*” [11]. Specifically, the inquiry attributed the blowout to the following:

- Poor cementing processes led to a condition known as ‘wet shoe’, which allowed the passage of fluids. This problem was evident in the Daily Drilling Reports (DDR), but site personnel and others who reviewed the DDR were not experienced in recognizing the problem.
- Anti-corrosion caps on the 9-5/8” and 13-3/8” casings were considered primary barriers. The 13-3/8” cap was not installed, leaving the system exposed. The mistake was not identified by the contractor, management or the regulator due to inadequate communication and reporting between offshore and onshore, and between day and night shifts.
- The 9-5/8” cap was then removed for cleaning, exposing the system with no redundant barriers. The removal was a change to normal processes, made without undertaking a MOC.

The inquiry made some 105 recommendations which generally fit into the following two categories:

- Technical recommendations concerning well control barriers
- Recommendations promoting better Change Management, which can be summarized by the following excerpt from Recommendation #16: “*The use/type of barriers (including any change requests relating thereto) must be the subject of consultation between licensees and rig operators... Senior onshore representatives of stakeholder entities should be involved in that certification process*” (11).

5.0 KEY FAILURE MODES OF SUBSEA SYSTEMS

Five key failure modes for subsea systems have been selected based on the two case studies analysed in Section 4.2. The failure modes have the potential to cause a subsea hydrocarbon release, and shall be risk managed with data and change management strategies.

Table 4 – Key Failure Modes of Subsea Systems with Potential for Hydrocarbon Release

Case Source	No.	Key Failure Mode	Specific Causes
Montara Blowout 2009	**1**	Well Construction Failure	Failure to identify improper well construction practices.
	2	Well Barrier Failure	Improper installation, modification or removal of critical safety components, due to human error, failure to follow procedures.
Whitecap Pipeline Leak 2010	**3**	Impact Damage	Damage by impact from foreign asset due to inadequate design.
	4	Pipeline Movement	Pipeline drag or lift during extreme weather event due to inadequate design.
	5	Operating Damaged Pipeline	Failure to identify damaged pipeline due to inadequate inspection and monitoring.

6.0 DATA AND CHANGE MANAGEMENT STRATEGY

The following data and change management strategies are proposed to mitigate the risks of the key failure modes targeted in Table 4.

6.1 Key Failure Mode 1 – Well Construction Failure

As discussed in Section 4.2.2, one cause of the Montara Blowout was the failure of the operator and regulator to identify a construction failure, which was evident on DDRs, but not reviewed.

The following data management improvements shall be introduced to address this risk:

- Automate Cementing Problem Detection - Update drilling data logging software to help detect indications of integrity problems such as the wet shoe problem, and send as alerts to operators in real-time.
- Streamline Drilling Data Circulation - DDRs and other shift data shall be transmitted via Cloud server. All required reviewers shall acknowledge their review / acceptance by electronic means (e.g. ticking a box). Senior management shall be notified automatically if data review has lapsed by more than 24 hours by any party.
- Update Training Registers - All reviewers of well construction data shall undergo dedicated training in cementing, and the training shall be added to the Personnel Qualifications register so that deficiencies can be highlighted to Senior Management.

6.2 Key Failure Mode 2 – Well Barrier Failure

The secondary cause of the Montara Blowout was the unauthorized removal of a protection barrier in the system. Accountability to a regimented Management of Change procedure is required to prevent future changes to safety-critical equipment (SCE's) without proper risk assessment by management. The proposed operational changes are as follows:

- Identify SCE's and MOC Requirements - The following documents shall identify SCE's, and explicitly specify use of the MOC Procedure prior to deviating from the plans:
  - Construction Drawings
  - Installation Procedure Documents
  - Drilling Pre-Starts / Induction presentations
- Management of Change (MOC) Procedure - Project MOC Procedures shall align to OSHAS 18001 Sec 4.3.1 and API 17N - KP11. An example flow chart is included in Appendix C.

6.3 Key Failure Mode 3 – Pipeline Impact Damage

The contact made between the Whitecap Pipeline and the TGP was attributed to the outdated engineering behind the crossing. The following data management improvements are proposed:

Manage Database of Assets vs Standards:

1. Assess all crossings designs against current design codes to identify any non-compliances.
2. Produce a data set of all crossing attribute (e.g. key dimensions, materials, pipeline features)
3. Engineering departments to track new releases of design codes and check against crossing data set.
4. All non-compliances shall be raised for risk assessment in the form of FMECA.

6.4 Key Failure Mode 4 – Pipeline Movement

A key failure of the Whitecap Pipeline incident was the undetected movement of the TGP. The following data management improvements are proposed to prevent similar movements of RGU assets:

- Align Surveying to API - Survey data collection shall align to API 17N – KP 9;
- Additional Post-Hurricane Inspections - Following all major weather events, all subsea pipeline crossing locations shall be inspected

with the technologies recommended by DNV-RP-F116 Table 5-1 – Threat Group “Natural Hazards”:

- o High resolution multibeam echosounder (MBES) and/or sidescan sonar (SSS), from towed fish or ROV;
- o Magnetometer or sub-bottom profiler for buried sections;
- o ROV visual inspection;

6.5 Key Failure Mode 5 – Operating Damaged Pipeline

A secondary cause of the Whitecap Pipeline was the failure to identify the dent caused by the TGP impact, leading to operation of the pipeline with compromised integrity. Additional data collection is proposed:

- More Frequent Inspections – Re-assess inspection schedule against RBI method in DNV-RP-F116. Inspection frequency should increase with respect to the high risk level highlighted by the Whitecap Leak case study.

7.0 CRITICAL EVALUATION

7.1 Evaluation of Regulations and Standards

The evaluation of industry regulations and standards revealed that while many had introduced data and change management requirements into recent editions, it remains generally non-prescriptive. HSEs KP4 highlighted the deficiencies explicitly.

An industry-specific guidance document or standard would be beneficial for aligning all operators with a single framework and detailed instructions.

7.2 Evaluation of Incident Case Studies

The incident case studies were reviewed with the intention to pinpoint root causes that align with this report. However, they are complicated incidents with many interrelated causes. Performing the "5 Why's" exercise revealed that there are many pathways that a RCA can take, dependent on the intention of the investigator. It is recommended that incidents be investigated using a Fault Tree Analysis type of process in order to track all the causal branches.

7.3 Evaluation of Data Management Strategies

The data management strategies presented in Section 6.0 focus on two main ideas:

- Creating accountability by closing the loop on data review processes;
- Collecting more data to increase the likelihood of detecting signs of pending failure.

Collecting more data is expensive, but the cost should be compared to the potential cost of major disasters.

7.4 Evaluation of Change Management Strategies

The change management strategies offered are essentially a reinforcement of industry best practice, which were developed to ensure the right people are involved in critical decision making. The challenge will be to ensure all personnel are able to recognize when a MOC is required. The strategy attempts to address this by explicitly highlight the MOC requirement on drawings and plans, however it is a work culture issue that will take time to develop.

8.0 CONCLUSIONS

The risk of subsea hydrocarbon release can be managed through improved reliability, in the form of the data and change management strategies presented in this study. Legislation and industry standards offer limited guidance for operators.

The two case studies showed that data and change management was at the root of hydrocarbon releases, and a number of varied strategies were proposed to target the issues raised by the incidents.

9.0 REFERENCES

(1) Health and Safety Executive. *Loss of Containment Manual – 2012*. HSE. [Cited 2016 December 5] Available from: http://www.hse.gov.uk/offshore/loss-of-containment-manual-2012.pdf

(2) Health and Safety Executive. *The Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015.* Liverpool: Health and Safety Executive; 2015.

(3) Health and Safety Executive. *Key Programme 4 – Ageing and Life Extension Programme (KP4)*. Liverpool: Health and Safety Executive; 2013.

(4) British Standards Institute. *BS OSHAS 18001:2007 Health and Safety Management System.* London: British Standards Institute; 2007.

(5) Health and Safety Executive. *A guide to the Pipelines Safety Regulations 1996* [Cited 2016 December 1] Available from: http://www.hse.gov.uk/pubns/priced/l82.pdf

(6) Det Norske Veritas. *DNV-RP-F116 Integrity Management of Submarine Pipeline Systems.* Hovik: Det Norske Veritas; 2009.

(7) The American Petroleum Institute. *API 17N – Recommended Practice for Subsea Production System Reliability, Technical Risk & Integrity Management.* Houston: API; 2014.

(8) Health and Safety Executive. *Report on the hydrocarbon release incident investigation project -1/4/2000 to 31/3/2001.* [Cited 2016 November 28]. Available from: http://www.hse.gov.uk/research/otopdf/2001/oto01055.pdf

(9) Health and Safety Executive. *Hydrocarbon Release System.* [Last Updated 2005 April 13; Cited 2016 November 28]. Available at: https://www.hse.gov.uk/hcr3/

(10) Lopez, Richard J. *Failure Investigation Report – Whitecap (Chevron), 18" Offshore Failure.* United States Pipeline and Hazardous Materials Safety Administration; 2011.

(11) Borthwick, David. *Report of the Montara Commission of Inquiry.* Commonwealth of Australia: Canberra; 2010.

(12) Sonti, C. *Oil spill finally stopped: company.* WA Today. 2009 November 3. Available at: http://www.watoday.com.au/wa-news/oil-spill-finally-stopped-company-20091103-hv56.html

(13) James, F. & Brann, M. *Indonesian fishermen want Montara oil spill investigated.* ABC News. 2014 July 15. Available at: http://www.abc.net.au/news/2014-07-15/indonesian-fishermen-want-montara-oil-spill-investigation/5598650

APPENDIX A RCA WORKSHEETS – MONTARA BLOWOUT 2010

"5 Why's" Root Cause Analysis Worksheet

Montara Blowout 2010 – Worksheet 1

Problem Definition:

Blowout occurred at Montara drilling operation, causing a major spill and explosion.

Why did it happen?

1. Product passed through the 9-5/8" cement shoe.

Why was that?

2. The 9-5/8" casing shoe was compromised during installation

Why was that?

3. Indications of the wet shoe condition were not identified

Why was that?

4. Site personnel were inexperienced in recognising the wet shoe condition

Why was that?

5. Operators did not check for such experience when resourcing for project

"5 Why's" Root Cause Analysis Worksheet

Montara Blowout 2010 – Worksheet 2

Problem Definition:

Blowout occurred at Montara drilling operation, causing a major spill and explosion.

Why did it happen?

1. Product travelled past 9-5/8" casing joint.

Why was that?

2. Primary barrier PCCC Cap was removed by site personnel at time of blowout.

Why was that?

3. Site personnel unaware of criticality of PCCC Cap as primary barrier

Why was that?

4. Site personnel did not have action authorised by Management

Why was that?

5. Management of Change procedures not being implemented for changes to primary barriers

APPENDIX B RCA WORKSHEETS - WHITECAP PIPELINE LEAK 2009

"5 Why's" Root Cause Analysis Worksheet

Whitecap Pipeline Leak 2009 – Worksheet 1

Problem Definition:

Whitecap Pipeline was dented by foreign pipeline at crossing location, leading to a leak

Why did it happen?

1. The foreign pipeline lifted and fell onto the Whitecap Pipeline during a hurricane

Why was that?

2. Crossing arrangement failed to maintain separation of pipelines

Why was that?

3. Crossing design was outdated and not compliant with current standards

Why was that?

4. Operator failed to recognise non-compliance and rectify before hurricane

Why was that?

5. Data management systems did not alert operator to non-compliance

“5 Why’s” Root Cause Analysis Worksheet

Whitecap Pipeline Leak 2009 – Worksheet 2

Problem Definition:

Whitecap Pipeline was dented by foreign pipeline at crossing location, leading to a leak

Why did it happen?

1. The pipeline was operated at pressure whilst damaged

Why was that?

2. Operators were unaware of pipeline damage

Why was that?

3. Post-hurricane surveys did not identify signs of damage

Why was that?

4. Survey and inspection methods not adequate

Why was that?

5. Operators not aware of high risk to ageing crossing locations

APPENDIX C MANAGEMENT OF CHANGE PROCEDURE

A generalised Management of Change (MOC) Procedure is presented below. Various operator MOC Procedures were reviewed to develop the process.

The general steps are as follows:

1. Determine if MOC is required → see Figure 2 – MOC Decision Tree
2. Submit MOC Request for Approval → see Figure 3 – MOC Process
3. MOC Request is Reviewed → see Figure 4 – MOC Review Matrix
4. MOC is Accepted or Rejected

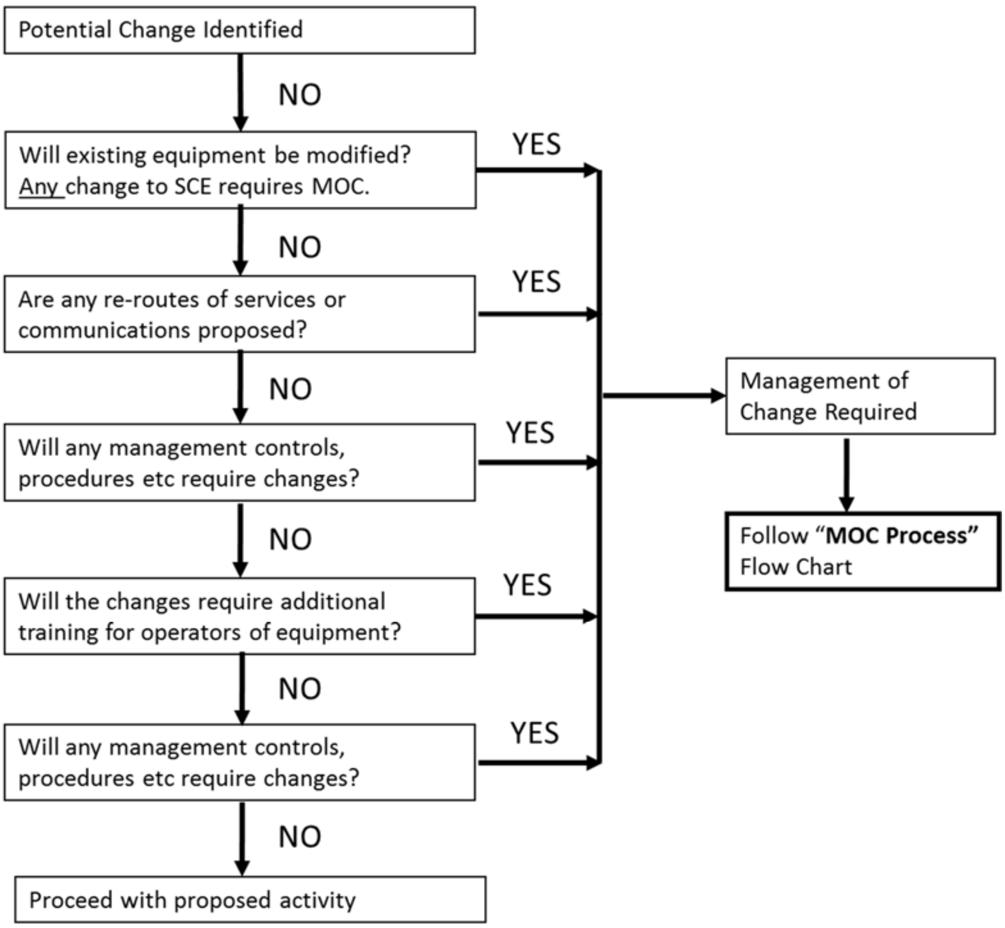


Figure 2 – MOC Decision Tree

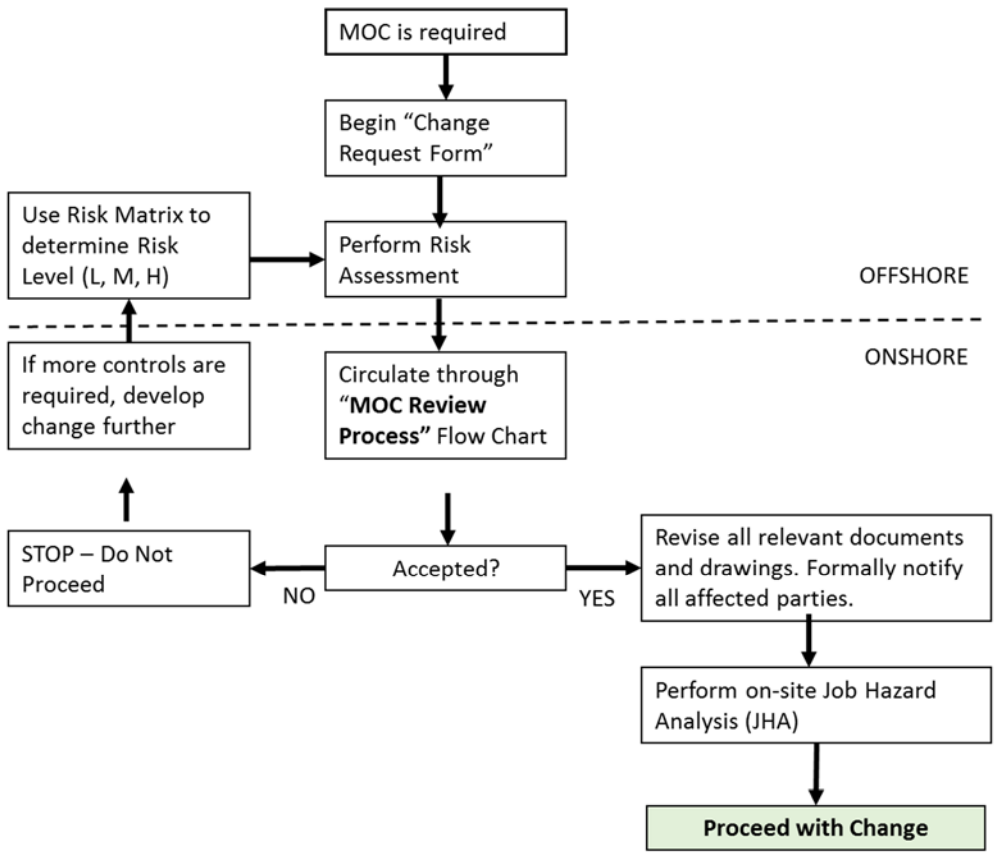


Figure 3 – MOC Process

Some notes for the example MOC Review Matrix below:

- The list of Reviewers shall be specific to each project phase, department or site, with contact details provided.
- Classification of Minor, Major or Critical to be well defined and understood by personnel.
- As stated in Section 6.2, any change to SCEs requires full review regardless of criticality.

Required Reviewers (Example)	**Change to Equipment**			**Change to Safety Critical Equipment**			**Change to Process or Procedure**		
	Minor	**Major**	**Critical**	**Minor**	**Major**	**Critical**	**Minor**	**Major**	**Critical**
Operations Manager			√	√	√	√		√	√
Project Manager		√	√	√	√	√		√	√
Offshore Construction Manager	√	√	√	√	√	√	√	√	√
Project Engineer	√	√	√	√	√	√	√	√	√
Quality Assurance Manager	√	√	√	√	√	√	√	√	√
Health and Safety Manager		√	√	√	√	√		√	√

Figure 4 – MOC Review Matrix

Robert Gordon University

ENM220 Control and Telemetry Systems

RGU Petroleum Ltd

New Field Development
Control and Telemetry Basis of Design

Name:	ADAM BEATON
Student No:	1418528
Date:	12/04/2017
Word Count:	1,941 *

** Excludes: Front Cover, Contents, Tables, References and Appendices*

1.0 EXECUTIVE SUMMARY

This document provides the basis of design for a control and telemetry system for the new subsea field development. The new field consists of 20 production and 10 injection wells, tied back to an existing rig and flowline. An electro-hydraulic multiplexed (E/H MUX) closed loop control system has been proposed. A single main control umbilical shall provide all services, including communications via optical fibre.

Other design considerations include; artificial lift methods, over-pressure protection of the flowline, flow assurance techniques and allowance for future expansion.

CONTENTS

2.0 INTRODUCTION

2.1 Background

RGU Petroleum Ltd is developing a new subsea heavy oil field which shall tie back to an existing platform and hot-tap into an unused flowline. The development shall commence with 20 production wells and 10 injection wells at a step-out distance of 50 km.

2.2 Scope

The scope of this document covers the basis of design for control and telemetry systems for the new field development.

2.3 Abbreviations

BOM	Bill of Materials
bps	Bits per second
CAPEX	Capital Expenditure
CIU	Chemical Injection Unit
DCV	Directional Control Valves
E/H	Electro-Hydraulic
EFL	Electrical Flying Lead
EOR	Enhanced Oil Recovery
EPU	Electrical Power Unit
ESD	Emergency Shutdown
ESP	Electric Submersible Pump
FO	Fibre Optic
FT	Flow Transducer
GLV	Gas Lift Valve
GOR	Gas-to-Oil Ratio
HFL	Hydraulic Flying Lead
HIPPS	High Integrity Pressure Protection System
HMI	Human Machine Interface
HP	High Pressure
HPU	Hydraulic Power Unit
HTT	Hot Tap Tee

HXT	Horizontal Xmas Tree
kBps	Kilobytes per second
LP	Low Pressure
MAOP	Maximum Allowable Operating Pressure
MCC	Motor Control Centre
MCS	Master Control Station
MEG	Monoethylene glycol
MUX	Multiplex
OPEX	Operational Expenditure
PCS	Process Control System
PLEM	Pipeline End Manifold
PSD	Process Shutdown
PTT	Pressure / Temperature Transducer
PTT	Pressure Transducer
RGU	Robert Gordon University
SAM	Subsea Accumulator Module
SCM	Subsea Control Module
SCSSV	Surface-Controlled Subsurface Valve
SD	Sand Detector
SDU	Subsea Distribution Unit
SEM	Subsea Electronics Module
SIIS	Subsea Instrumentation Interface Standardisation
SIWHP	Shut-In Wellhead Pressure
SSPL/R	Subsea Pig Launcher / Receiver
SSS	Subsea Separator
TUTA	Topside Umbilical Termination Assembly
UPS	Uninterrupted Power Supply
UTA	Umbilical Termination Assembly
VSD	Variable Speed Drive
XT	Xmas Tree

3.0 GENERAL FIELD ARCHITECTURE

The basic field architecture has been proposed in Appendix A – RGU-DWG-001. Options considered for connecting the 30 wells include subsea templates or several clusters of wells feeding into manifolds.

A cluster configuration has been chosen due to the large number of wells. The new development shall comprise 3 clusters, each having approximately 6 to 7 Production Wells and 3 to 4 Water Injection Wells feeding into manifolds. Production fluids from the cluster manifolds shall gather at a central Pipeline End Manifold (PLEM) before hot tapping into the currently unused flowline.

Produced water reinjection shall be employed for enhanced oil recovery (EOR). Water shall be pumped from the rig through a new dedicated water injection line to the PLEM, and out to the clusters via flexible jumpers.

Other options were considered, such as;

- Subsea separator (SSS), which could separate water at the seabed and reinject directly.
- Subsea pumps could draw seawater directly.

Both options eliminate topside equipment and pumping to surface, however the technologies are still developing and expensive to supply and qualify.

4.0 CONTROL AND TELEMETRY DESIGN BASIS

4.1 General Architecture

A single control umbilical shall connect the field to the rig and interface with existing topside control system facilities, and shall transmit electrical power, hydraulic lines, communications and chemical injection fluids.
Drawings RGU-DWG-001 through 003 in Appendix A show the basic design, including topside and subsea components and connections.

4.2 Hydraulic Power

The complexity of the field prohibits using a direct hydraulic system, and the step-out distance of 50 km prohibits piloted hydraulic due to pressure losses (Bai, 2012). Thus, the new field shall be controlled and monitored using an electro-hydraulic multiplex system (E/H MUX). An all-electric system could eliminate pressure loss and charge-up time, but is not proposed due to the expense and difficulties in qualifying the new technologies. It is also assumed that the topside facilities are not suitable for all-electric.
A closed-loop hydraulic system shall be used due to the large number of actuators, long step-out, and environmental concerns of releasing fluid to sea. The closed-loop option requires a return line which adds to the umbilical size, cost and installation complexity.
A low pressure (LP) supply shall actuate the majority of XT valves, while a separate high pressure (HP) supply shall be used for components such as the surface-controlled subsurface safety valve (SCSSV).
A subsea accumulator module (SAM) shall be located on each XT to alleviate pressure lag along the 50 km umbilical during busy operations such as start-up.

4.3 Electrical Power

Electrical power is used in the subsea field for the following main functions:

- Actuate the solenoids within the subsea control modules (SCM) to distribute hydraulic fluid
- Power sensors

- Power downhole pumps
- Power subsea booster pumps

The electrical power supply shall be "floating", so as to include a return line (rather than utilising the armouring or sea as return path). The floating option is more expensive, but prevents a total loss of power if the umbilical is shorted (RGU, 2017b). A calculation is provided in Appendix D to demonstrate the maximum allowable resistance of the conductor for powering a subsea booster.

4.4 Communications

The subsea XTs shall be monitored by various sensors. Data shall be transmitted as follows:

1. Sensors output continuous 4-20 mA analogue signals
2. The SEM code-division multiplexer receives multiple signals, converts to binary, encodes according to RS-485 and adds addressing code.
3. The SEM transmits serial data from the XT to cluster SDU
4. The SDU bundles data from all cluster XTs and transmits to UTA
5. The UTA combines all three SDU data and sends through the main control umbilical via Fibre Optic
6. Data is received at TUTA and forwarded to MCS for display on Human Machine Interface (HMI), e.g. a desktop computer monitor with XT 'mimic' diagram.

RS-485 serial databus is recommended for the infield connections due to the low bandwidth requirement and short ranges. It is a multi-drop protocol which could be used for parts of the field where a XT SCM may control a nearby manifold.

For the main control umbilical spanning 50 km it is recommended to use Fibre Optic (FO) for the following reasons:

- No need for repeaters or other signal aids
- Massive bandwidth available for future upgrades (such as video monitors, etc)

- Easy to add multiple redundant lines
- FO is not much more expensive than copper

Table 4-1 summarizes the proposed communication media.

Table 4-1 Communication Media

From	To	Type	SIIS Category	Approx. Span	Data Rate (bps)
Sensors	SEM	4-20mA	SIIS I	~ 1m	N/A
SEM	SDU	RS-485 Serial	SIIS II	~ 50 m	3,430 bps
SDU	UTA	RS-485 Serial	SIIS II	~ 200 m	29,867 bps
UTA	TUTA	Fibre Optic (FO)	SIIS III	50 km	89,600 bps

4.5 Topside Components

Existing topside facilities shall be utilized, and they are not upgradable. The master control station (MCS) controls the electrical and hydraulic power supplies (EPU and HPU respectively), which feed into the topside umbilical termination unit (TUTA).

A P&ID is provided in Appendix A, and detailed component descriptions in Appendix E.

4.6 Subsea Components

The umbilical shall terminate at the umbilical termination assembly (UTA), split off to three manifold-mounted Subsea Distribution Modules (SDU), and out to the XTs in each cluster. Each XT shall have a dedicated subsea control module (SCM) to avoid shutdown of the whole field or cluster in the event of failure. It shall also reduce the number of jumpers and simplify installation and maintenance.

Data from XT sensors shall be multiplexed by the subsea electronics module (SEM) and sent topside via RS-485, then fibre optic for the long-haul 50 km span. The SEMs shall control solenoids in the SCM to distribute hydraulic power to actuate XT valves.

A P&ID is provided in Appendix A, and detailed component descriptions in Appendix E.

5.0 ARTIFICIAL LIFT

The heavy oil will require artificial lift immediately to ensure steady production flowrates. Three techniques have been assessed below.

5.1 ESP

Electric submersible pumps (ESP) are used downhole to increase the production pressure, comprising a multi-stage centrifugal pump designed for high temperatures, sour service and sand erosion. Typical power requirements can be up to 750 kW at 4,900 V 3-phase (Baker Hughes, 2017). Variable speed drives (VSD) allow adjustment to optimize the production rate, reduce cavitation and minimize erosion (Gate, Inc. 2015). Multiple ESP's can be installed in a wellbore in series to boost pressure and increase availability.

The main additional components required for ESP are as follows:

- **Subsurface**
    - ESP Assembly (1 or 2 per Well)
- **Subsea**
    - High Voltage power capacity within subsea Umbilical
    - ESP Sensor data capacity within SCM and jumpers
- **Topside**
    - ESP Control Station
    - VSD

5.2 Gas Lift

Gas lift is a technique by which the produced gas is separated topside, compressed and fed down to the well annulus in order to diffuse into the production fluids and reduce the density (Gate, Inc. 2015). The lighter fluid can then reach the surface by well pressure alone. Gas lift can also be used at the riser base to reduce static head. Employing gas lift would require topside compressors and a riser and flowline system. Wells are also fitted with subsurface gas lift valves.

The main additional components required for Gas Lift are as follows:

- **Subsurface**
  - Gas Lift Valves (GLV)
- **Subsea**
  - Gas Lift riser and flowline
  - Gas Lift jumpers
- **Topside**
  - Gas compressors

5.3 Subsea Boosting

The production flow back pressure can be alleviated with a subsea boosting unit placed downstream of the wells. The unit consists of a helico-axial or centrifugal pump designed for multi-phase flow. A typical system can require up to 6 MW (FMC, 2015).

The main additional components required for subsea boosting are as follows:

- **Subsurface**
  - Nil
- **Subsea**
  - Subsea Booster Module
  - High power capacity in subsea umbilical
  - Associated EFL's, etc
- **Topside**
  - Additional electrical power and controls only

Table 5-1 Artificial Lift Technique Comparison

Technology	Advantages	Disadvantages
ESP	• No additional flowlines etc required • Small topside footprint (electrical modules only) • No environmental impact	• High CAPEX • High maintenance cost, production shut down to retrieve • Increased power required through subsea umbilical • Susceptible to sand fouling / erosion
Gas Lift	• Lower CAPEX and OPEX • Not affected by sands • Lower power requirement	• Requires gas pipeline from rig to subsea • Requires a minimum GOR to be effective • Pressure drop issues over long tie-back distance (Bai, 2012. p. 44)
Subsea Booster	• Single unit in one location, less maintenance than multiple ESP's • No overpressure risk at XT or jumpers etc.	• Single-point failure on the main flowline • High CAPEX

6.0 OVER-PRESSURE PROTECTION

Due to the introduction of artificial lift, the risk of over-pressurizing the flowline must be mitigated. A high integrity pressure protection system (HIPPS) shall be integrated into the PLEM. All infield lines and jumpers shall have MAOP above the shut in wellhead pressure (SIWHP), whilst the 50 km of flowline can remain as a lower rated pipe to save CAPEX.

The HIPPS shall comprise three independent pressure transducers and two redundant isolation valves. The three pressure readings shall be processed by a "2 out of 3" (2003) voting logic solver within the HIPPS SCM, which shall send the command to shut the isolation valves.

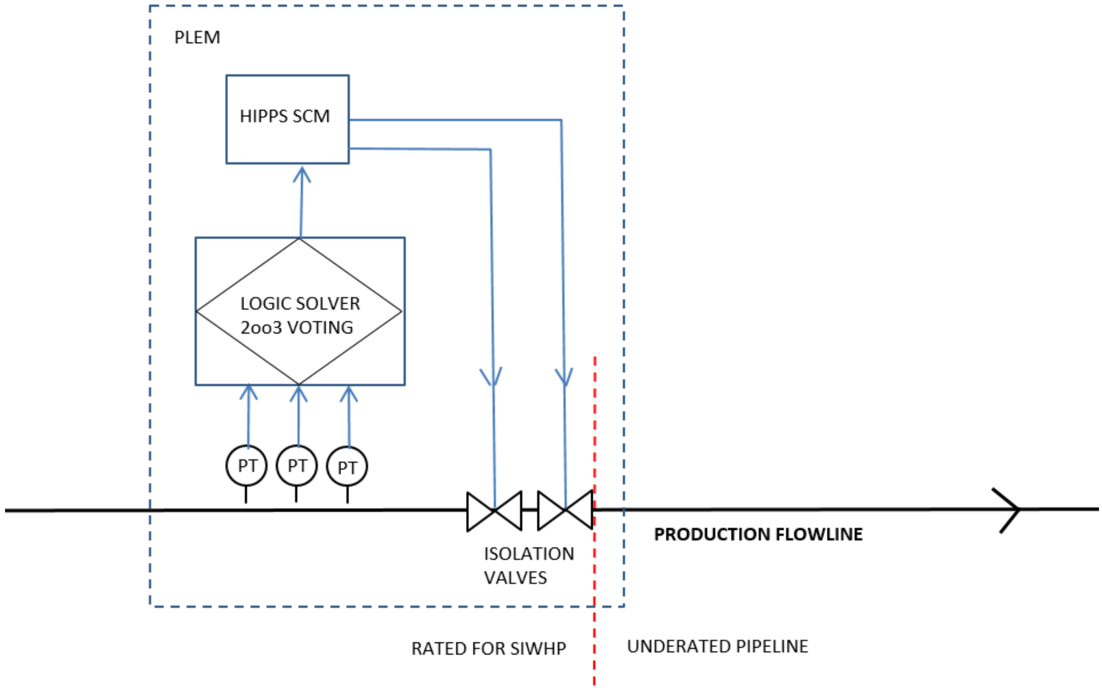


Figure 1 HIPPS Schematic

The HIPPS system will require the following additional hardware and instrumentation:

- 2 off Large Bore Isolation Valves
- HIPPS SCM
- Integrated Logic Solver within SEM
- 3 off inline PTs

7.0 FLOW ASSURANCE

Flow could be hindered by several common problems including hydrate formation, wax and asphaltenes, scale, corrosion or high viscosity due to cooling. Some common flow assurance techniques are considered below.

7.1 Chemical Injection

Chemicals injected into the production tubing or flowline can help prevent many flow problems. Methanol and monoethylene glycol (MEG) are commonly used to lower the hydrate-forming temperature and prevent blockages during pipeline shut-ins or at choke valves due to Joules-Thompson Cooling. Methanol is cheap but cannot be recycled. MEG typically requires a large regeneration plant on topside.
Other chemical dosages are anti-corrosion, anti-microbial and tracer dyes.

Chemical injection introduces the following to the design:

- **Subsurface**
  - Chemical Injection Valve (CIV)
- **Subsea**
  - Chemical Injection tubing within Umbilical
  - Additional valve actuator controls (hydraulic and signalling)
- **Topside**
  - Chemical Injection Unit (CUI) – feeds into TUTA
  - Storage of chemicals
  - MEG regeneration plant (if using MEG)

7.2 Heat Management

Flow assurance can be managed by ensuring the fluid temperature remains above hydrate-formation and wax pour-point. Lowering the viscosity also reduces back pressure. This can be achieved with insulation, burying, or using active heating methods such as electrical tracer wires or pipe-in-pipe designs. The later involves hot fluid pumped though the annulus.

For this new development it is unlikely that the existing 50 km flowline could be upgraded besides possibly installing an electric heating system. It would be extremely expensive, only possible at diver-friendly water depths, and the step-out distance may still be prohibitive (Bai, 2012. p. 441).

7.3 Pigging

The PLEM shall have allowance for mating a subsea pig launcher / receiver (SSPL/R) to run inspection and cleaning pigs along the 50 km flowline. Regular cleaning shall reduce scale build up and improve flow. A SSPL/R facility shall introduce several additional PTs on the ‘kicker’ line and barrel. Pig detector sensors shall be installed at various points along the pipeline.

8.0 SPARE CAPACITY AND GROWTH ALLOWANCE

The following features shall be included in the development to provide spare capacity in the event of component failure or future field expansion.

- **Main Control Umbilical**:
  - Spares HP and LP hoses,
  - Spare FO fibres
  - Spare electrical conductor
- **SDUs**:
  - Spare connectors to service future XTs
- **SCMs**:
  - Dual-SEM, spare on hot-standby with independent routing
  - Electrical coupler is 9-pin to provide 2 spare pins
  - SEM with 100% spare capacity so it can control a second XT via spare HFL and EFL connectors if required

Note that there is no redundant umbilical. In the event of catastrophic damage, all production controls are designed as fail-closed.

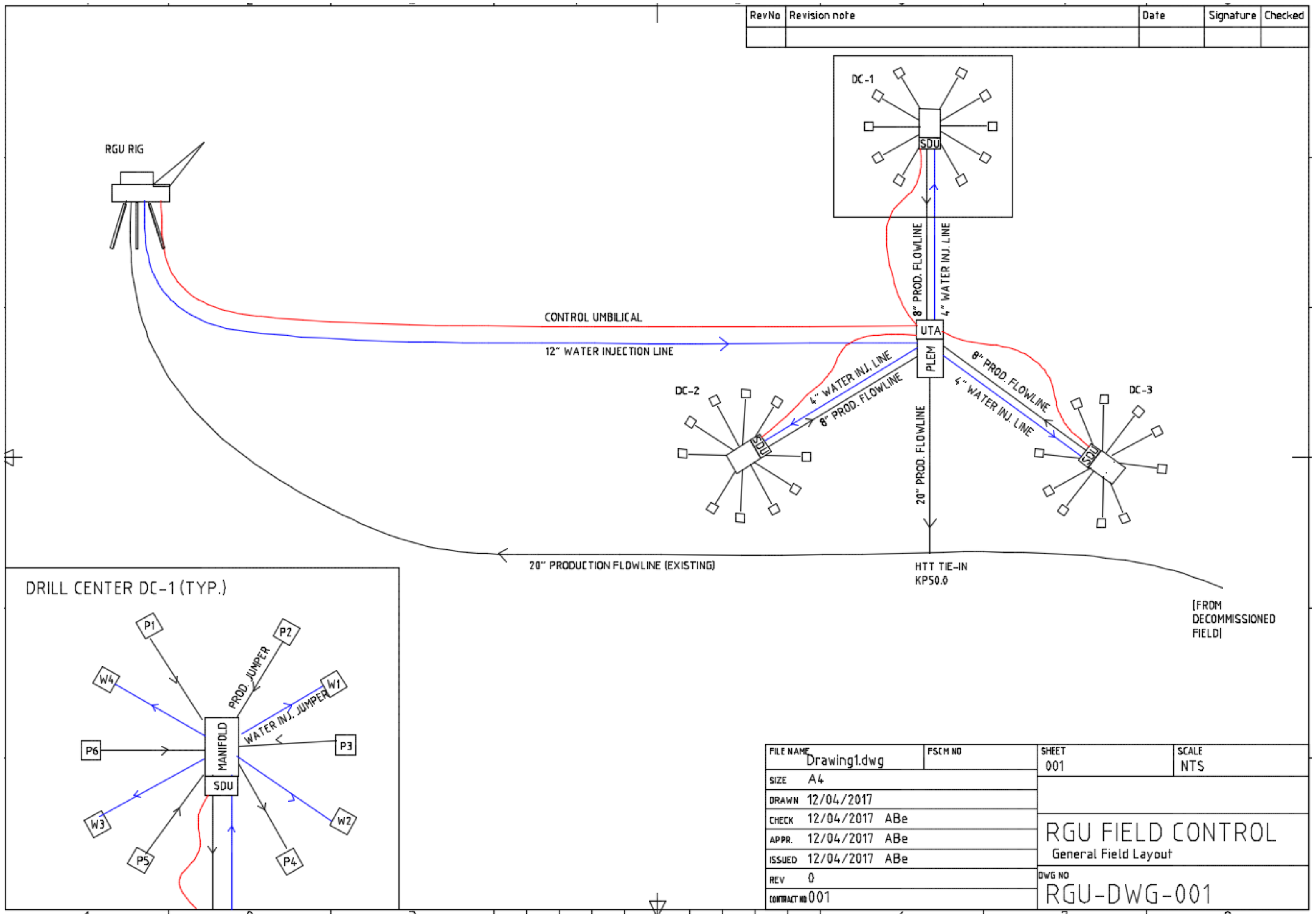
9.0 CONCLUSIONS

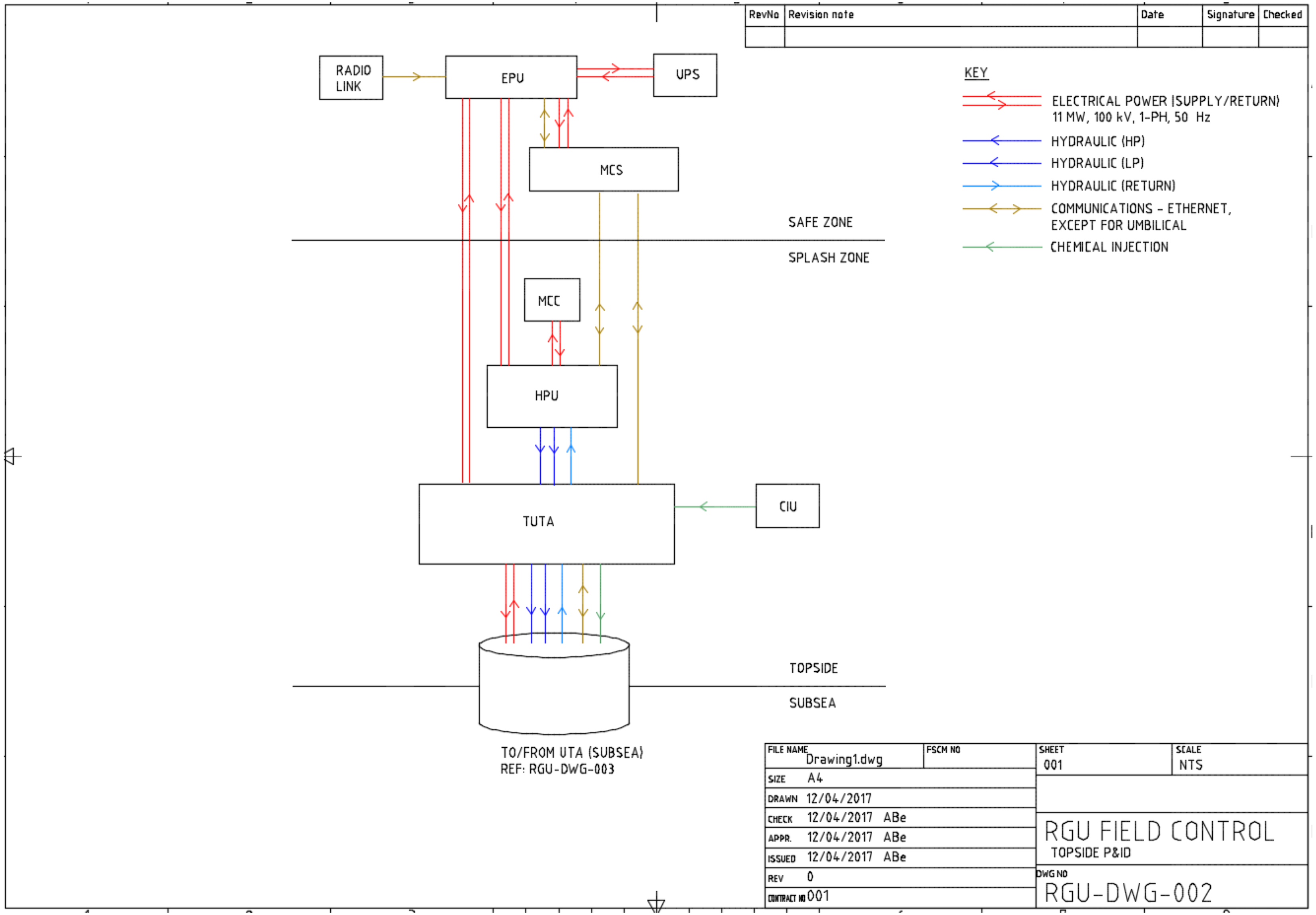
The basis of design proposes the commonly used E/H MUX system, utilizing fibre optic communications for the long step-out distance. Several other design considerations have been provided which impact the control and telemetry system. The development could benefit from emerging technologies such as subsea separation (SSS), boosting or all-electric control to address challenges with heavy oil and long tie-back distance.
It is recommended to include a number of redundancies within the design to allow for component failures, as well as preparing for future expansion.

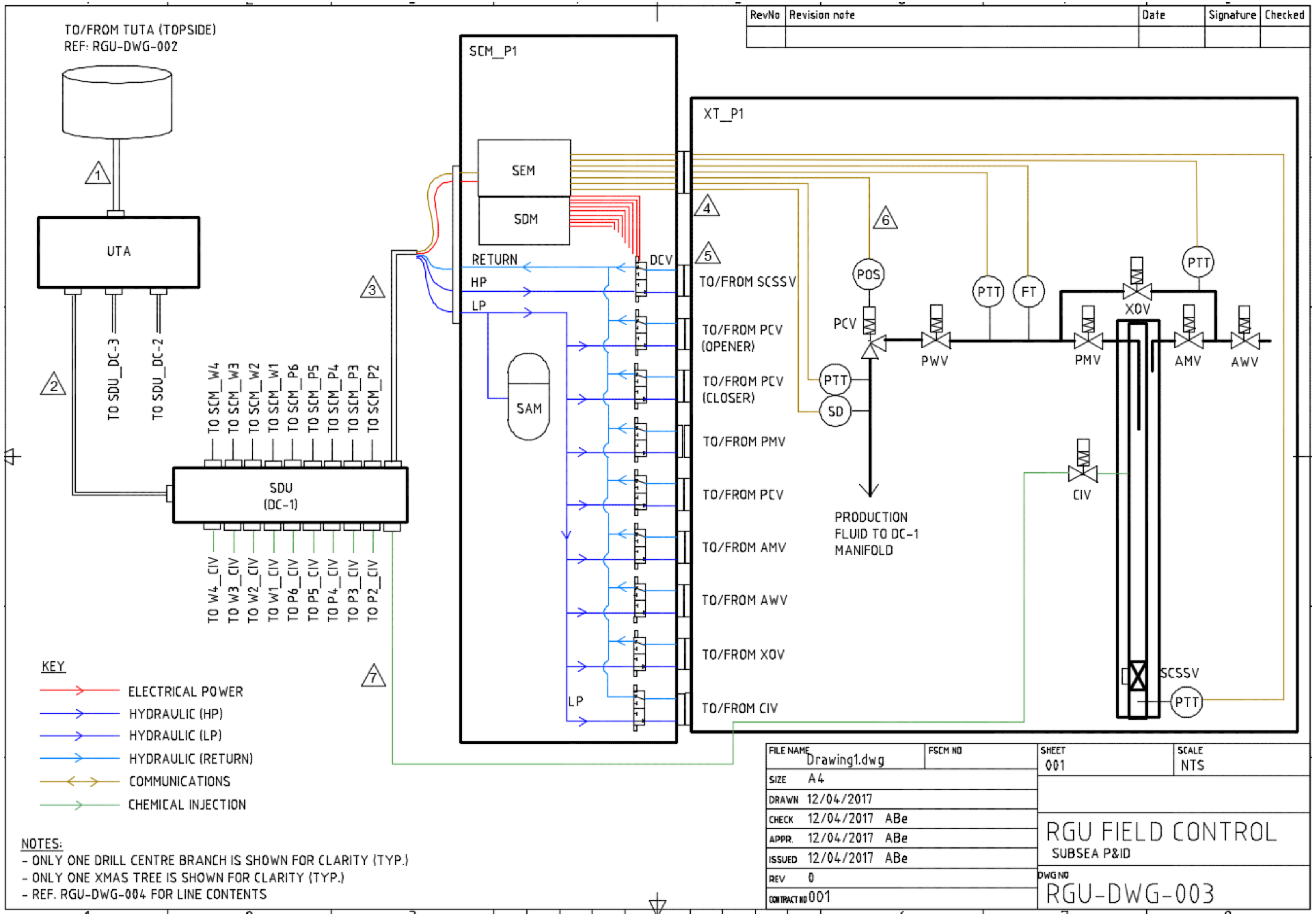
10.0 REFERENCES

- BAI, Y. & BAI, Q., 2012. *Subsea Engineering Handbook.* Elsevier
- BAKER HUGHES. 2017. *CENtrilift Xtreme Performance Series Motors.* Available at: https://assets.www.bakerhughes.com/system/8d/2c36705e6d11e6b6f131b6580b07d2/41883.450XP.Motor_OV.pdf [Accessed 2 April 2017]
- CLAMPON, 2017. *Compact DSP-06 Particle Monitor Datasheet.* Available at: http://www.clampon.com/wp-content/uploads/2013/04/62-421-0006-08-Rev1-Instrument-Datasheet-ClampOn-Compact-DSP-06-Particle-Monitor.pdf [Accessed 4 April 2017]
- FMC, 2015. Subsea Pumping Brochure. Available at: http://www.fmctechnologies.com/en/SubseaSystems/Technologies/SubseaProcessingSystems/SubseaPumping.aspx# [Accessed 30 March 2017]
- FMC, 2017. *Landmark: First Gulf of Mexico Full Field Subsea Separation & Pumping System*. Available at: http://www.fmctechnologies.com/en/SubseaSystems/GlobalProjects/NorthAmerica/US/ShellPerdido.aspx?tab={63009246-FA3F-4A2C-A180-CE53722567A7} [Accessed 30 March 2017]
- GATE, INC. 2015. Artificial Lift for Subsea Applications. Available at: http://www.gateinc.com/gatekeeper/gat2004-gkp-2015-12 [Accessed 2 April 2017]
- GE MEASUREMENT, 2017. *Subsea Sensors Brochure.* Available at: https://www.gemeasurement.com/sites/gemc.dev/files/ptx_400_brochure_english.pdf [Accessed 3 April 2017]
- RMS PUMPTOOLS, 2017. *Subsea Valve Position Sensors.* Available at: http://www.rmspumptools.com/perch/resources/product%20docs/subsea-valve-position-sensors.pdf [Accessed 3 April 2017]
- ROBERT GORDON UNIVERSITY, 2017a. *ENM220: Control and Telemetry Systems [Lecture Notes – Topic 3 – Subsea Control Equipment]* Delivered February 2017.
- ROBERT GORDON UNIVERSITY, 2017b. *ENM220: Control and Telemetry Systems [Lecture Notes – Topic 4 – Electrical Power Unit]* Delivered February 2017.

APPENDIX A PROCESS & INSTRUMENTATION DIAGRAMS




RevNo
Revision note
Date
Signature
Checked
RADIO LINK
EPU
UPS
MCS
SAFE ZONE
SPLASH ZONE
MCC
HPU
TUTA
CIU
TOPSIDE
SUBSEA
TO/FROM UTA (SUBSEA)
REF: RGU-DWG-003
KEY
ELECTRICAL POWER (SUPPLY/RETURN)
11 MW, 100 kV, 1-PH, 50 Hz
HYDRAULIC (HP)
HYDRAULIC (LP)
HYDRAULIC (RETURN)
COMMUNICATIONS – ETHERNET,
EXCEPT FOR UMBILICAL
CHEMICAL INJECTION
FILE NAME Drawing1.dwg
FSCM NO
SHEET 001
SCALE NTS
SIZE A4
DRAWN 12/04/2017
CHECK 12/04/2017 ABe
APPR. 12/04/2017 ABe
ISSUED 12/04/2017 ABe
REV 0
CONTRACT NO 001
RGU FIELD CONTROL
TOPSIDE P&ID
DWG NO
RGU-DWG-002


TO/FROM TUTA (TOPSIDE)
REF: RGU-DWG-002
UTA
TO SDU_DC-3
TO SDU_DC-2
SDU
(DC-1)
TO SCM_W4
TO SCM_W3
TO SCM_W2
TO SCM_W1
TO SCM_P6
TO SCM_P5
TO SCM_P4
TO SCM_P3
TO SCM_P2
TO W4_CIV
TO W3_CIV
TO W2_CIV
TO W1_CIV
TO P6_CIV
TO P5_CIV
TO P4_CIV
TO P3_CIV
TO P2_CIV
SCM_P1
SEM
SDM
RETURN
HP
LP
DCV
SAM
XT_P1
TO/FROM SCSSV
TO/FROM PCV
(OPENER)
TO/FROM PCV
(CLOSER)
TO/FROM PMV
TO/FROM PCV
TO/FROM AMV
TO/FROM AWV
TO/FROM XOV
TO/FROM CIV
POS
PCV
PTT
SD
PWV
PTT
FT
PMV
XOV
PTT
AMV
AWV
CIV
SCSSV
PTT
PRODUCTION
FLUID TO DC-1
MANIFOLD
KEY
ELECTRICAL POWER
HYDRAULIC (HP)
HYDRAULIC (LP)
HYDRAULIC (RETURN)
COMMUNICATIONS
CHEMICAL INJECTION
NOTES:
- ONLY ONE DRILL CENTRE BRANCH IS SHOWN FOR CLARITY (TYP.)
- ONLY ONE XMAS TREE IS SHOWN FOR CLARITY (TYP.)
- REF. RGU-DWG-004 FOR LINE CONTENTS
RevNo
Revision note
Date
Signature
Checked
FILE NAME Drawing1.dwg
FSCM NO
SHEET 001
SCALE NTS
SIZE A4
DRAWN 12/04/2017
CHECK 12/04/2017 ABe
APPR. 12/04/2017 ABe
ISSUED 12/04/2017 ABe
REV 0
CONTRACT NO 001
RGU FIELD CONTROL
SUBSEA P&ID
DWG NO
RGU-DWG-003

RevNo	Revision note	Date	Signature	Checked

KEY:

AMV	ANNULUS MAIN VALVE
AWV	ANNULUS WING VALVE
CIV	CHEMICAL INJECTION VALVE
CIU	CHEMICAL INJECTION UNIT
DCV	DIRECTIONAL CONTROL VALVE
DC	DRILL CENTRE
EFL	ELECTRICAL FLYING LEAD
EPU	ELECTRICAL POWER UNIT
ESD	EMERGENCY SHUTDOWN
FO	FIBRE OPTIC
FT	FLOW TRANSMITTER
HFL	HYDRAULIC FLYING LEAD
HPU	HYDRAULIC POWER UNIT
HTT	HOT TAP TEE
HP	HIGH PRESSURE
KP	KILOMETER POST
LP	LOW PRESSURE
MCC	MOTOR CONTROL CENTRE
MCS	MASTER CONTROL STATION
P	PRODUCTION (WELL)
PCV	PRODUCTION CHOKE VALVE
PLEM	PIPELINE END MANIFOLD
PMV	PRODUCTION MAIN VALVE
PWV	PRODUCTION WING VALVE
PT	PRESSURE TRANSDUCER
SAM	SUBSEA ACCUMULATOR MODULE
SCM	SUBSEA CONTROL MODULE
SDU	SUBSEA DISTRIBUTION UNIT
SCSSV	SURFACE-CONTROLLED SUBSURFACE SAFETY VALVE
SD	SAND DETECTOR
SDM	SOLENOID DRIVER MODULE
SEM	SUBSEA ELECTRONICS MODULE
TT	TEMPERATURE TRANSDUCER
TUTA	TOPSIDE UMBILICAL TERMINATION ASSEMBLY
UPS	UNINTERRUPTED POWER SUPPLY
UTA	UMBILICAL TERMINATION ASSEMBLY
W	WATER INJECTION (WELL)
XOV	CROSSOVER VALVE
XT	XMAS TREE

NOTE No.	NAME	QTY (PER XT)	QTY (TOTAL)	START	END	DESCRIPTION / CONTENTS
1	MAIN UMBILICAL	--	1	TUTA	UTA	POWER: 11 MW / 100kV / 1-PH COMMS: FIBRE OPTIC (1 Gbps) HYD. LP: 5,000 PSI HYD. HP: 10,000 PSI HYD. RETURN CHEM INJ: 3" BORE
2	INFIELD UMBILICALS	--	3	UTA	SDU	POWER: 3.3 MW / 100kV / 1-PH COMMS: SERIAL RS485 HYD. LP: 5,000 PSI HYD. HP: 10,000 PSI HYD. RETURN CHEM INJ: 1" BORE
3	INFIELD UMBILICALS	1	30	SDU	SCM	POWER: 330 kW / 100kV / 1-PH COMMS: SERIAL RS485 HYD. LP: 5,000 PSI HYD. HP: 10,000 PSI HYD. RETURN
4	COUPLERS - ELECTRIC	1	30	SCM	SCMMB (XT)	WET-MATE 9-PIN SERIAL CONNECTOR 7 OFF 4-20m ANALOGUE SIGNALS
5	COUPLERS - HYDRAULIC	9	270	SCM	SCMMB (XT)	WET-MATE HYD. COUPLER HYD. LP: 5,000 PSI HYD. HP: 10,000 PSI HYD. RETURN
6	SENSOR WIRES	7	210	SENSOR	SEM	COMMS: 4-20mA ANALOGUE SIGNAL INBUILT WITHIN TREE.
7	CHEM. INJ. FLYING LEAD	1	20	SDU	XT	CHEM INJ: 1" BORE ROV WET-MATEABLE J-PLATE CONNECTORS

FILE NAME Drawing1.dwg	FSCM NO	SHEET 001	SCALE NTS
SIZE A4			
DRAWN 12/04/2017			
CHECK 12/04/2017 ABe		RGU FIELD CONTROL Legend	
APPR. 12/04/2017 ABe			
ISSUED 12/04/2017 ABe			
REV 0		DWG NO RGU-DWG-004	
CONTRACT NO 001			

APPENDIX B WELL CONTROL BILL OF MATERIALS

TAG I.D.	TYPE	LOCATION	QTY PER WELL	QTY TOTAL
Px_AMV	BARRIER VALVE	PROD. XT - ANNULUS PIPING	1	20
Px_AMV_ACC	HYD. ACTUATOR	PROD. XT - AMV	1	20
Px_AWV	BARRIER VALVE	PROD. XT - ANNULUS PIPING	1	20
Px_AWV_ACC	HYD. ACTUATOR	PROD. XT - AWV	1	20
Px_PMV	BARRIER VALVE	PROD. XT - PRODUCTION PIPING	1	20
Px_PMV_ACC	HYD. ACTUATOR	PROD. XT - PMV	1	20
Px_PWV	BARRIER VALVE	PROD. XT - PRODUCTION PIPING	1	20
Px_PWV_ACC	HYD. ACTUATOR	PROD. XT - PWV	1	20
Px_XOV	BARRIER VALVE	PROD. XT - CROSSOVER PIPING	1	20
Px_XOV_ACC	HYD. ACTUATOR	PROD. XT - VOX	1	20
Px_PCV	CHOKE VALVE	PROD. XT - PRODUCTION PIPING	1	20
Px_PCV_ACC	HYD. ACTUATOR	PROD. XT - PCV	1	20
Px_CIV	BARRIER VALVE	PROD. XT - SUBSURFACE	1	20
Px_CIV_ACC	HYD. ACTUATOR	PROD. XT - CIV	1	20
Px_SCSSV	BARRIER VALVE	PROD. XT - SUBSURFACE	1	20
Px_SCSSV_ACC	HYD. ACTUATOR	PROD. XT - SCSSV	1	20
Px_PTT_PROD	PRESS. / TEMP TRANSDUCER	PROD. XT - PRODUCTION PIPING	1	20
Px_PTT_ANN	PRESS. / TEMP TRANSDUCER	PROD. XT - ANNULUS PIPING	1	20
Px_PTT_XO	PRESS. / TEMP TRANSDUCER	PROD. XT - CROSSOVER PIPING	1	20
Px_PTT_SUB	PRESS. / TEMP TRANSDUCER	PROD. XT - SUBSURFACE	1	20
Px_PTT_CHOKE	PRESS. / TEMP TRANSDUCER	PROD. XT - PRODUCTION PIPING (AFTER PCV)	1	20
Px_FT	FLOW TRANSDUCER	PROD. XT - PRODUCTION PIPING	1	20
Px_SD	SAND DETECTOR	PROD. XT - PRODUCTION PIPING (AFTER PCV)	1	20
Px_POS	VALVE POSITION SENSOR	PROD. XT - PCV	1	20
Px_SCM	SUBSEA CONTROL MODULE	PROD. XT	1	20
Px_SEM	SUBSEA ELECTRONICS MODULE	PROD. XT - SCM	1	20
Px_SAM	SUBSEA ACCUMULATION MODULE	PROD. XT - SCM	1	20
Wx_AMV	BARRIER VALVE	WATER INJ. XT - ANNULUS PIPING	1	10
Wx_AMV_ACC	HYD. ACTUATOR	WATER INJ. XT - AMV	1	10
Wx_AWV	BARRIER VALVE	WATER INJ. XT - ANNULUS PIPING	1	10
Wx_AWV_ACC	HYD. ACTUATOR	WATER INJ. XT - AWV	1	10
Wx_PMV	BARRIER VALVE	WATER INJ. XT - INJECTION PIPING	1	10
Wx_PMV_ACC	HYD. ACTUATOR	WATER INJ. XT - PMV	1	10
Wx_PWV	BARRIER VALVE	WATER INJ. XT - INJECTION PIPING	1	10
Wx_PWV_ACC	HYD. ACTUATOR	WATER INJ. XT - PWV	1	10
Wx_XOV	BARRIER VALVE	WATER INJ. XT - CROSSOVER PIPING	1	10
Wx_XOV_ACC	HYD. ACTUATOR	WATER INJ. XT - VOX	1	10
Wx_PT_INJ	PRESS. TRANSDUCER	WATER INJ. XT - INJECTION PIPING	1	10
Wx_PT_ANN	PRESS. TRANSDUCER	WATER INJ. XT - ANNULUS PIPING	1	10
Wx_PT_XO	PRESS. TRANSDUCER	WATER INJ. XT - CROSSOVER PIPING	1	10
Wx_FT	FLOW TRANSDUCER	WATER INJ. XT - PRODUCTION PIPING	1	10
Wx_SCM	SUBSEA CONTROL MODULE	WATER INJ. XT	1	10
Wx_SEM	SUBSEA ELECTRONICS MODULE	WATER INJ. XT - SCM	1	10
Wx_SAM	SUBSEA ACCUMULATION MODULE	WATER INJ. XT - SCM	1	10

APPENDIX C WELL CONTROL DATA RATE CALCULATION

SENSOR	QTY PER WELL	PER CLUSTER	QTY TOTAL	DATA SOURCE	RANGE	INSTRUMENT RESOLUTION	No. LEVELS	BITS PER SAMPLE	SAMPLE RATE	BAUDRATE (bps)
Px_PTT_PROD	1	6	20	PRESSURE	0 - 10,000 PSI	0.025%	4000	14	10	140
				TEMP	-40°C - 150°C	0.03%	3333	14	10	140
Px_PTT_ANN	1	6	20	PRESSURE	0 - 10,000 PSI	0.025%	4000	14	10	140
				TEMP	-40°C - 150°C	0.03%	3333	14	10	140
Px_PTT_XO	1	6	20	PRESSURE	0 - 10,000 PSI	0.025%	4000	14	10	140
				TEMP	-40°C - 150°C	0.03%	3333	14	10	140
Px_PTT_SUB	1	6	20	PRESSURE	0 - 10,000 PSI	0.025%	4000	14	10	140
				TEMP	-40°C - 150°C	0.03%	3333	14	10	140
Px_PTT_CHOKE	1	6	20	PRESSURE	0 - 10,000 PSI	0.025%	4000	14	10	140
				TEMP	-40°C - 150°C	0.03%	3333	14	10	140
Px_FT	1	6	20	FLOW	--	2%	50	8	10	80
Px_SD	1	6	20	SAND %	--	--	--	21	10	210
Px_POS	1	4	10	VALVE POSITION	0 - 360°	0.04%	2500	14	10	140
Px_SCM	1	4	10	ADDRESSING	--	--	--	160	10	1600
									TOTAL FOR PRODUCTION TREE	**3430**
Wx_PT_INJ	1	4	10	PRESSURE	0 - 10,000 PSI	0.025%	4000	14	10	140
Wx_PT_ANN	1	4	10	PRESSURE	0 - 10,000 PSI	0.025%	4000	14	10	140
Wx_PT_XO	1	4	10	PRESSURE	0 - 10,000 PSI	0.025%	4000	14	10	140
Wx_FT	1	4	10	FLOW	--	2%	50	8	10	80
Wx_SCM	1	4	10	ADDRESSING	--	--	--	160	10	1600
									TOTAL FOR WATER INJ. TREE TREE	**2100**

TOTAL FOR FIELD	89,600	bps
	11.20	**kBps**

NOTES:

1) Px and Wx are Production Wells and Water Injection Wells, respectively.
2) Instrumentation for Manifolds, UTA, SDU, HIPPS not included.
3) PTT Sensors output pressure and temperature as two separate 4 – 20 mA signals.
4) "No. of Levels" is the quantization, calculated by: 100% / 'Instrument Resolution'.
5) "Bits per Sample" – Calculated as follows (Example – Px_PTT_PROD):
   - 2^n = 4,000, where n = Minimum number of Bits required to code the number 4,000.
   - Rearranging, n = $\log_2(4{,}000)$ = 11.96 ~ 12 bits
   - 1 x bit is added as a Parity Check, for the receiver to check for errors
   - 1 x bit is added as a spacer between datasets.
   - Total number of bits is 14.
6) The additional "Addressing data" applied by each SCM acts to code all of the XT sensors' data as a single string, so that no other addressing data is required.

7) Sensor ranges and accuracies taken from examples (see References for more details):
   - **PTT Sensor –** GE Measurements PTX400 (Ref: GE, 2017)
   - **Valve Position Sensor –**PM1 Pillar-mounted Single Output (Ref: RMS PUMPTOOLS, 2017)
   - **Sand Detector –** Clampon DSP-06 Particle Monitor (Ref: CLAMPON, 2017)

APPENDIX D ELECTRICAL POWER CALCULATIONS

P_{SB} = Power at Subsea Booster = 10 MW

P_{LOSS} = Power Loss (allowable) = 10%, or 1 MW

P_{SUPPLY} = Power at EPU = 10 + 1 = 11 MW

V = Voltage at EPU = 100 kW

I = Current (Amps)

R = Resistance (Ohms)

L = Length of circuit = 2 x 50 km (including return line)

Current, I = P_{SUPPLY} / V

= 11,000,000 W / 100,000 V

= 110 A

P_{LOSS} = I^2 * R,...

Rearranging...

R = P_{LOSS} / (I^2)

= 1,000,000 W / (110 * 110)

= 82.6 Ω

Resistance per km = 82.6 / 100 km

= 0.83 Ω/km

APPENDIX E DETAILED COMPONENT DESCRIPTIONS

Topside Components

Electrical Power Unit (EPU) – Powers all topside control equipment and the subsea control system. Backed by an uninterrupted power supply (UPS), essentially a battery back-up on hot standby.

Hydraulic Power Unit (HPU) – Feeds high and low pressure (LP and HP) hydraulic oil. Pumps are controlled via the Motor Control Centre (MCC).

Topside Umbilical Termination Unit (TUTA) – Receives power, hydraulics, communications and chemical injection fluids and feeds into the main control umbilical.

Master Control Station (MCS) – Receives data and sends commands to field via the Human Machine Interface (HMI), the operator's desktop computer system which displays the information on a XT 'mimic' diagram.

Subsea Components

Umbilical Termination Assembly (UTA)

The UTA shall be mounted to the main PLEM to reduce the structure size by relying on the PLEM for stability. The main control umbilical shall terminate at the UTA, and split into three infield umbilicals running to the clusters.

Subsea Distribution Units (SDU)

Three SDUs shall be mounted to the cluster manifolds to receive and distribute the infield umbilicals. Bundled electrical flying lead (EFL) and hydraulic flying leads (HFL) shall run from the SDU out to each of the 10 Wells in the cluster.

Subsea Control Modules (SCM)

The SCM provides the following main functions:

- Hydraulic power distribution – Routes the main supply through an array of solenoid directional control valves (DCV) dedicated to each XT valve actuator.
  A subsea accumulator module (SAM) shall be fitted to the SCM. The SAM provides local pressure while the flexible umbilical hosing is 'charged' after major depletion during busy events such as start-up and commissioning.
- Subsea Electronics Module (SEM) – A 1 atmosphere enclosure, housing electronics such as a digital-to-analogue converter. The SEM processes incoming Tree sensor data, sends to topside, receives commands from topside and actuates the solenoid DCVs.

The SCMs can either be mounted to each Tree, or mounted to a nearby manifold and used to control several Trees and the manifold itself. Below is a comparison.

SCM Location	Advantages	Disadvantages
Dedicated SCMs on Each Tree	• Only one XT shutdown during failure • Less jumpers	• High CAPEX (30 off SCMs) • High OPEX – maintenance costs • XTs are heavier
SCM on Each Manifold only	• Lower CAPEX (Perhaps 3 off SCMs only)	• Whole cluster shutdown during SCM failure • Large number of jumpers (several per XT)

Tree Sensors

The following Tree sensors shall be required. A full Bill of Materials (BOM) for Tree components is included in Appendix B:

- **Pressure / Temperature Transducers (PTT)** – Provides SIIS I 4-20mA analogue signals. Located as follows:
    - Subsurface – to monitor SIWHP, particularly if SCSSC is closed
    - Production Line – before and after the choke valve to aid in controlling flow
    - Annulus Line and Crossover Line
- **Valve Position Sensor** – To monitor rotation of the choke valve for precise flow control
- **Sand Detector (SD)** – An acoustic instrument for measuring sand content. Flow can be adjusted to minimize sand to prevent erosion and other problems.
- **Flow Transducer (FT)** – A multi-phase non-intrusive flow detector placed on the production piping.

Robert Gordon University

ENM233 Materials and Corrosion Science

Zonko Petroleum PLC

Zonko Sporran Delta – Seawater Injection Failure Analysis Report

Directed to:

Zonko Sporran Delta

Facilities Superintendant

Author: **GB Labs**

Date: 27/07/2017

Word Count: 1,797 *

** Excludes: Front Cover, Contents, Tables, References and Appendices*

1.0 EXECUTIVE SUMMARY

This document is a report on the failure analysis undertaken for the Zonko Sporran Delta seawater injection piping. The analysis has identified that a combination of incorrect material grade, lack of post-weld heat treatment and the submergence in stagnant seawater has led to through-wall pitting corrosion along the heat affected zone at the Tee and Riser welded joint. The pitting corrosion was likely caused by sensitization of the high-carbon grade 316 material incorrectly used for the Tee.

The report includes recommendations to prevent re-occurrence, including; review of quality control processes, consideration of alternative material grades to prevent sensitisation, and suitable post-weld heat treatment.

CONTENTS

2.0 INTRODUCTION

2.1 Purpose

Zonko Petroleum PLC have engaged GB Labs to perform failure analysis for a corrosion-affected seawater injection pipe fitting and provide recommendations for preventing further incidents on Zonko assets.

2.2 Background

Zonko Petroleum PLC are commissioning the platform Zonko Sporran Delta in the North Sea. A seawater injection (SWI) system was installed six months ago for enhanced oil recovery (EOR). The SWI piping was field-welded, hydrotested and stored full of stagnant seawater for six months. Upon start-up, leaks were discovered on several topside Tee fittings at each of the SWI 16" riser tie-ins to the main 24" header (see Appendix A – Seawater Injection System P&ID).
One Tee and riser section has been removed for analysis. It showed through-wall anomalies located on the Tee fitting only but not the riser section (see Figure 1 and Figure 2).

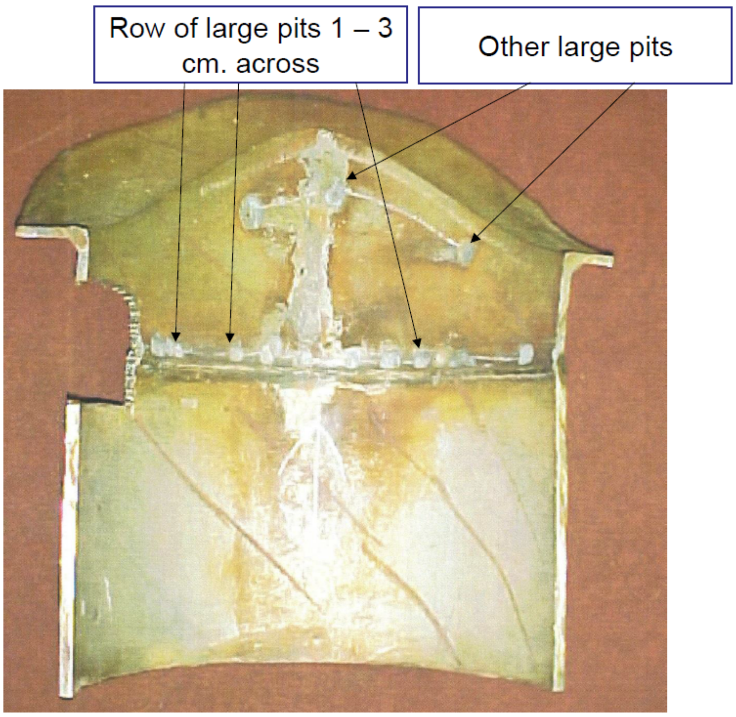


Figure 1 – SWI Piping Section showing pitting on Tee Fitting

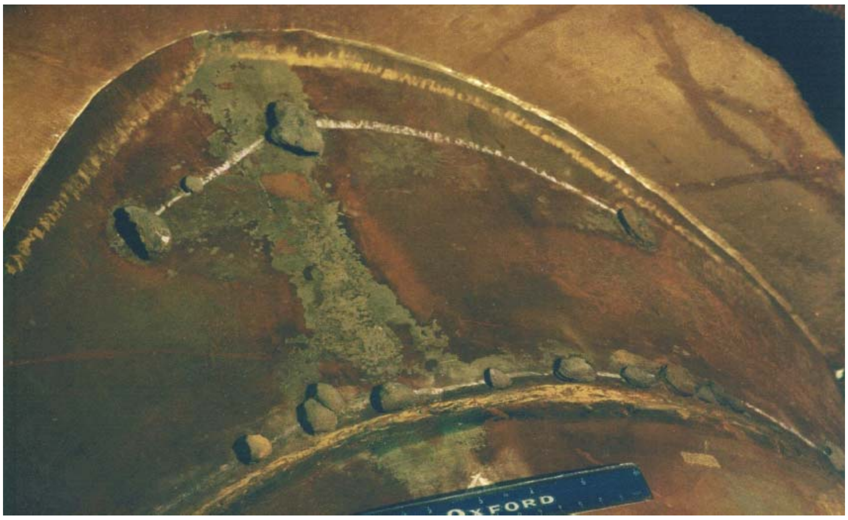


Figure 2 – SWI Tee Fitting showing internal pitting

2.3 Abbreviations

EOR	Enhanced Oil Recovery
HAZ	Heat Affected Zone
IGC	Intergranular Corrosion
P&ID	Process and Instrumentation Diagram
PWHT	Post Weld Heat Treatment
SWI	Seawater Injection
SOB	Sulphide oxidizing bacteria
SRB	Sulphate reducing bacteria
TQ	Technical Query
WPS	Weld Procedure Specifications

3.0 BASIS OF ANALYSIS

This analysis is based on the following pertinent information provided by Zonko Petroleum PLC. Zonko responses to Technical Queries (TQ) are included in Appendix B.

- SWI piping was designed as stainless steel grade 316L, as referenced in the P&ID (Appendix A), and the Material Test Certificate provided by Spray Engineering and accepted by Zonko shows a 316L Tee (see Appendix C).
- Zonko performed spectrographic analysis of the recovered Tee and riser section which showed conflicting chemical composition of the Tee to that provided in the Spray Engineering Material Test Certificate (see Appendix D).
- SWI piping was field-welded using 316L weld rods. No post-weld heat treatment (PWHT) was applied (see Weld Procedure in Appendix E).
- SWI piping was hydrotested with seawater and left flooded for 6 months. It is not known if the water was chemically treated.
- Pitting on the recovered piping section appear to be localised to the Tee fitting only, and are generally adjacent to the in-field weld and the internal fabricated Tee weld.

4.0 FAILURE ANALYSIS

4.1 Methodology

A Fishbone (or *ishkawa*) Cause and Effect Diagram has been used to assist in identifying possible causes of the corrosion. Each cause has been assigned a likelihood of relevance based on the supplied information from Zonko. The following causes were considered '*Likely*' or '*Most Likely'*, and are further discussed below. Refer to Appendix F for the Fishbone Diagram.

- High Carbon Content of Tee;
- Lack of post-weld heat treatment;
- Extended period in stagnant seawater.

4.2 Material Identification

Zonko Petroleum PLC have performed spectrography testing on the recovered riser and Tee section. The test reports are included in Appendix D, and summarised in Table 1. The results are compared with chemical compositions specified by ASTM A312 *Standard Specification for Seamless, Welded, and Heavily Cold Worked Austenitic Stainless Steel Pipes*. The comparison shows that the Tee has a composition aligned with SAE Grade 316 rather than 316L. The Riser pipe and welding rod are compliant with SAE 316L.

Table 1 – Spectrography Test Results

Chemical Analysis (% Weight)	**ASTM A312 Grades**		**Spectography Test Results**		
	316L	316	Location X - Tee Fitting	Location Y - Riser Pipe	Weld Rod
Carbon (C)	< 0.035	< 0.08	0.052	0.023	0.024
Chromium (Cr)	16.0 - 18.0	16.0 - 18.0	17	17.04	17.5
Manganese (Mn)	< 2.00	< 2.00	1.39	1.55	1.95
Molybdenum (Mo)	2.0 - 3.0	2.0 - 3.0	2.6	2.38	2.88
Nickel (Ni)	10.0 - 14.0	10.0 - 14.0	11.6	11.32	11.2
Phosphorus (P)	< 0.045	< 0.045	0.021	0.021	0.031
Sulfur (S)	< 0.030	< 0.030	0.002	0.003	0.022
Identified Grade	**--**	**--**	**316**	**316L**	**316L**

4.3 Material Analysis

The high carbon content identified in the Tee suggests that "sensitization" may have led to weld decay in the heat affected zone (HAZ). Austenitic stainless steels like Grade 316 have a tendency to precipitate Chromium Carbides ($Cr_{23}C_6$) when heated to around 427°C to 899°C (Schweitzer, 2010). The $Cr_{23}C_6$ forms within the material grain boundaries, leeching the adjacent areas of Chromium (Corrosionpedia, 2017). This prevents the formation of Chromium III Oxide (Cr_2O_3) protective passivation layer. Intergranular corrosion (IGC) can occur once the passivation layer is damaged, leading to pitting.

Pitting corrosion is a common ailment of stainless steels. The pit acts as the anode while the surface acts as the cathode. Liquid in the pit becomes more acidic as the reaction proceeds. Iron (Fe) oxides to Fe^{2+} and migrates outward, forming a pit that eventually penetrates the plate.

Sensitization can be prevented with the addition of exotic elements such as Niobium (for example Grade 347), or Titanium (for example Grade 320 or 321) (Rajadurai, 2015). These elements form carbides more readily than the Chromium so that the material is not sensitized when heated.

4.4 Heat Treatment

The weld test procedure in Appendix E shows that no post-weld heat treatment (PWHT) was specified for the field welding of the Tee to the Riser, and the heat affected zone (HAZ) was likely left to cool naturally in the exposed North Sea environment. PWHT involves controlled quenching to relieve material stresses. In this case, it can also be used to return the Chromium Carbide precipitate back into solution (RGU, 2017a). PWHT for a weld in an offshore application typically utilises electric heating pads applied to the HAZ. A typical and suitable procedure would be to reheat the metal to above 1035°C to dissolve $Cr_{23}C_6$ back into solution and rapidly cool to prevent reforming more carbides. This method is known as solution annealing (Sastri, 2007).

4.5 Environment

The Tee was first subjected to sensitization by the welding heat input, rapidly cooled, then subjected to seawater submergence for a period of six months. The stagnant seawater provides ample Chloride as electrolyte to support the corrosion cells within pitting formations.

It is also likely that microbial growth occurred in the piping. Two types of corrosion-causing bacteria could be present: Sulphide oxidizing bacteria (SOB), or Sulphate reducing bacteria (SRB).

Without water testing it is not possible to determine exactly which processes may have been occurring.

5.0 CONCLUSIONS

The analysis has identified the most likely causes of the corrosion attack on the SWI Tees. The following sequence of events is believed to have occurred:

1. Spray Engineering have supplied a Grade 316 Tee rather than the Zonko-specified Grade 316L material. This was not recognized by Zonko because a Material Certificate showing Grade 316L was supplied. The Material Certificate was actually for a different Tee.
2. The Grade 316 (high carbon) Tee was field-welded and left to cool naturally. The heat input sensitized the HAZ and precipitated $Cr_{23}C_6$, depleting the adjacent grain boundaries of valuable passivation-forming Chromium.
3. The SWI piping was hydrostatically tested with seawater during commissioning. The seawater was then left in the piping, which provided electrolytic solution to aid in corrosion reactions.
4. The passivation layer was damaged, leading to pitting corrosion along the HAZ.

It is also noted that some pitting is observed along the internal weld within the fabricated Tee. This is a weld that was performed onshore by Spray Engineering, and is explained by the same process as described above.

6.0 RECOMMENDATIONS

The following recommendations are offered to reduce the likelihood of a re-occurrence of similar corrosion failures on Zonko assets.

6.1 Material Quality Control

Quality control processes should be reviewed to determine how the Spray Engineering Material Certificate was accepted without noticing the incorrect Tee specification. A review of all Material Certificates from Spray Engineering is recommended.

6.2 Material Contamination

The following should be implemented to avoid sensitization/intergranular attack (Wu, 1978); Strict control of contamination of components during fabrication / shipping and any contamination to be removed according to accepted procedures for the given material.

6.3 Material Selection

It is noted that the lower carbon Grade 316L (less than 0.030% w/w) was specified by the SWI piping design. This material would have significantly reduced the likelihood of sensitization during welding. However, it is recommended to investigate alternative grades such as Grade 320, 321 or 347 for field-welded materials, particularly if quench annealing is impractical. The additional elements in these grades such as titanium and niobium form carbides at higher temperatures than chromium (Schweitzer, 2010). These stabilized grades increase the material resistance to corrosion.

6.4 Post Weld Heat Treatment

Weld procedure specifications (WPS) should consider PWHT methods for all Austenitic stainless steel welding. Solution annealing is recommended to ensure carbides are returned to solution. The heat treatment process should be qualified by applying the proposed treatment to a sample of the same grade and weld rod material, then performing mechanical and chemical testing to verify the final material properties.

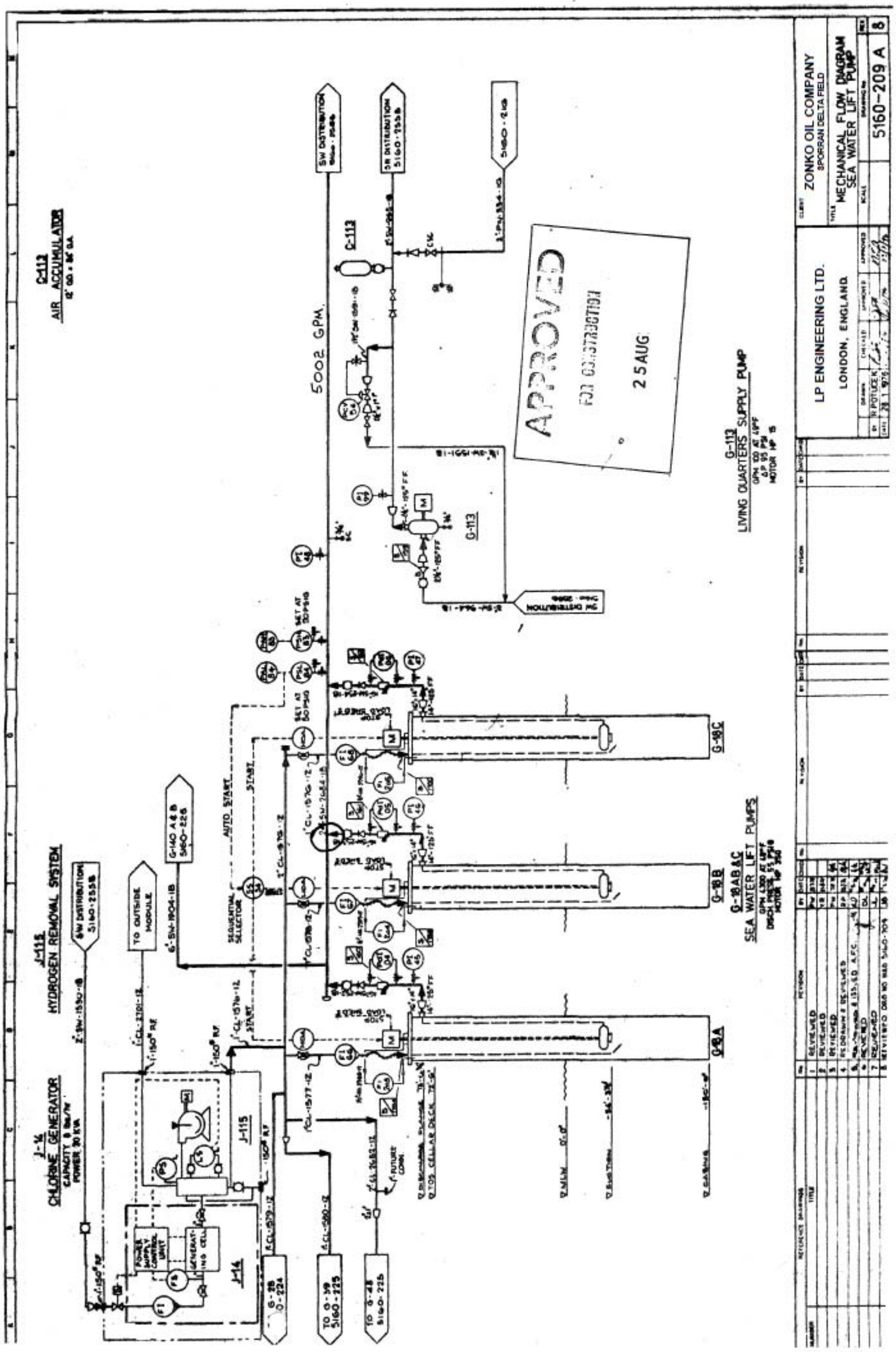
6.5 Water Treatment

If seawater is to be stored in piping in the future, dosing with corrosion inhibitors and antimicrobial agents should be considered. This can reduce the likelihood and severity of pitting corrosion occurring. The stored water should be tested to determine the likely bacteria so that suitable agents can be selected.

7.0 REFERENCES

- ASTM, 2017. *A312 Standard Specification for Seamless, Welded, and Heavily Cold Worked Austenitic Stainless Steel Pipes.* American Society for Testing Materials. Philadelphia.
- CORROSIONPEDIA, 2017. *Sensitization.* Available at: https://www.corrosionpedia.com/definition/1334/sensitization-stainless-steel [Accessed 24 July 2017]
- RAJADURAI, S. Et Al. 2015. *Methods to Avoid Material Sensitization During Welding for Developing Corrosion Resistant Exhaustive System.* International Journal of Recent Development in Engineering and Technology: Volume 4, Issue 7. 7 July 2015.
- ROBERT GORDON UNIVERSITY, 2017a. *ENM233: Material and Corrosion Science [Lecture Notes – Topic 7a]* Delivered June 2017.
- ROBERT GORDON UNIVERSITY, 2017b. *ENM233: Material and Corrosion Science [Lecture Notes – Topic 7b]* Delivered June 2017.
- SASTRI, V.S, GHALI, E & ELBOUJDAINI, M, 2007. *Corrosion Prevention and Protection Practical Solution*., John Wiley & Sons, Ltd
- SCHWEITZER, P.A, 2010. *Fundamentals of corrosion – mechanisms, causes and prevention*., CRC Press.
- *TW METALS, 2017. 316 / 316L Stainless Steel Pipe. Available at: https://www.twmetals.com/316-316l-stainless-steel-pipe.html [Accessed 30 June 2017]*
- WU, PAUL C. S. 1978. *Sensitization, Intergranular Attack, Stress Corrosion Cracking and Irradiation Effects on the Corrosion of Iron-Chromium-Nickel Alloys.* Westinghouse Electric Corporation. 1978

APPENDIX A SEAWATER INJECTION SYSTEM P&ID



APPENDIX B TECHNICAL QUERY REGISTER

TQ No.	CONSULTANT QUERY	CLIENT RESPONSE
TQ-01	Please confirm that the location of the leak is limited to the Tee circled on the P&ID?	*Confirmed*
	In the case description which you provided "Seawater injection Case Study - Item 5" you stated the following: "yesterday, when the system was to be used for the first time to enhance production, it was found to be leaking in a number of places". Do you mean several points of leakages from the Tee identified, or there where other points of leakages in the piping system other the the already identified Tee (circled in red)	*You will see that there are two other tees in the 24" header, connected to the other two seawater lift pumps – they came from the same source as the one you are studying and similarly failed with large pits and pinholes.*
TQ-02	Please advise how the SWI Piping has been stored between Installation and Commissioning? (i.e. was it air-dried? Was it filled with N2 or Corrosion-inhibited Water?).	*Once installed, the pipe was hydrotested using seawater, then left full of seawater until start-up, in the expectation that it would be "ready to run" and save time. This resulted in it being left full of stagnant seawater for 6 months. I have no information about storage prior to that time*
TQ-03	Please issue Bill of Materials (or similar) showing Part Specifications and Material Grades for the Tee and adjacent piping (cannot read the Part Numbers in P&ID - see below circled)	*AISI 316L stainless steel was specified both for the riser pipe from the pump and the main 24" header. The riser pipe from the pump was field welded to the prefabricated tee. The supplier's material certificate for the fabricated tee is attached. I do not have a supplier's material certificate for the riser pipe, but you will note that it is the brighter piece of metal which has not corroded. Some analysis work was done after the event to try and ascertain what happened*
TQ-04	Normally during the project execution for the SWI system which was fitted shortly after the Platform was installed in the N.sea about six months ago, The "Piping Material Specification" is supposed to be provided during the detailed design by LP Engineering. Please could you provide us this document?	*Unfortunately, it is not available. I can tell you that the material specified for the header and its components was AISI 316L*

TQ-05	In the P&ID provide the line specification for the header and the risers are not visible enough, so could you provide a clear picture of the line spec for the WI header and riser. We need to ascertain if they are the same or there is a Spec. break between the riser and the WI header. We need to be sure of what were the initial piping line spec. selected by the material engineer during the design phase.	*There is no spec. break between the header and riser, all that changes is the diameter. The header is 24” OD and the riser 16”. AISI 316L was specified for both.*
TQ-06	In your response to TQ-03 you stated the following "The riser pipe from the pump was field welded to the prefabricated tee. The supplier’s material certificate for the fabricated tee is attached." Please could provide the Welding Procedure Qualifications and Specification that was utilized for the "field Welding". Provide us the "WPS" and "WPQR" utilized for field installation.	*Please find attached the weld procedure for the field weld. This is the only welding specification that I have*
TQ-07	Also provide us any available Quality Control Specification (QA/QC) and records of Quality control checks that was prepared during the installation at site	*Sorry, nothing of that sort available.*
TQ-08	Provide us site data including seawater composition which was used for hydrotesting of the piping system and flooding of the piping system for six month prior to start-up of the SWI system.	*The seawater was northern North Sea water. You will be able to find a relevant composition on the internet.*
TQ-09	Zonko response to TQ-05 states "The header is 24” OD and the riser 16”, but the Material Cert for the Tee states it is an "18" equal Tee". Can you confirm these sizes are correct - was there reducers used on each of the Tee ends?	*That is what the supplier gave us as a certificate for this tee. I can assure you that it is 16" x 24", having measured it myself.*
TQ-10	Refer to sketch below. Was this the orientation of the installed Tee? (i.e. the corrosion pitting is higher in elevation to the Riser/Tee weld bead? Do you have any photos of the Tee installed on site?	*he tee was arranged with both the main 24” header and the 16” branch horizontal. The latter turned to vertical further upstream (i.e. closer to the seawater lift pump). No photos are available from the site, unfortunately. In the photos supplied, for some reason, the pipe is shown upside-down in one case. The section we have, which is shown in the photos, is the lower half of the pipe*

TQ-11	Zonko response to TQ-02 states that the piping was "left full of seawater". Assuming the sketch below is correct, can you confirm that the seawater would indeed have remained "trapped" inside the riser and header - rather than perhaps gravity draining back down the riser and leaving the Tee region empty?	*The pipe remained full of water until the SW lift pump was turned on. You may have noticed that there is a check valve which prevented it draining back through the pump.*
TQ-12	Galvanic (Bimetallic) Corrosion: When dissimilar metals are immersed in a conducting solution they usually develop different corrosion potentials. If the metals are in contact, this potential difference provide the driving force for increased corrosion. The less noble of the two metals corroding more rapidly, while the more noble corrodes less.[1] The presence of AC or DC current (impressed current) flow between dissimilar metal in the galvanic coupling of dissimilar metals could generate accelerated galvanic corrosion rate which may lead to rapid corrosion e.g. localised pitting corrosion of the more active-metal. We did like to check if stray current test has been evaluated by Zonko Petroleum. If some data regarding stray impressed current are available, please share? Otherwise we will need to inspect the applicable piping system for possible source(s) of AC or DC current flow. The need to perform this check, is to consider the possibility of failed tee been engaged as sacrificial anode which may have resulted in localised pitting corrosion of the tees? Please do share with GB lab any available or related document?	*No information available about stray currents. I struggle to see what this has to do with the failure you are investigating. There is nothing of this kind available*
TQ-13	Please could you share with us the pH value test of the stagnant seawater inside the Tees? And any available data regarding this will be helpful?	*Nothing of this sort available*

TQ-14	Microbiology Analysis of stagnant water, to determine what type of microbiological species are present in the water after about 6 months of stagnant flooding the completed piping system? Please could you share with us any available microbiological analysis report of stagnant flooding seawater inside the completed piping system?	*Unfortunately, by the time the failed component was delivered for further examination, it had been cleaned up and all the original water drained away, so no samples were retained for analysis. Trying to get those in the field to understand that they are not helping by so doing is not a lesson that is easy to get across. Destruction of evidence while trying to be helpful is very common in failure investigations*
TQ-16	As noted in other discussions, the Tee diameters on the Material Cert do not match the actual component. Therefore, we do not have reliable evidence of the Tee material grade. Has Zonko performed any chemical testing or analysis such as gas-chromatography/mass-spectometry (GC-MS) to determine the actual composition of the Tee? My suspicion is that it may be the higher-Carbon grade "316" rather than 316L. (i.e. C = 0.08%)	*While no gas chromatography was performed - this is a technique designed to analyse fluids rather solids - some chemical analysis was performed. See 3 attached certificates*

APPENDIX C MATERIAL TEST CERTIFICATE (SPRAY ENGINEERING)

25

Works Certificate to

Din 50049

J Smit

SPRAY ENGINEERING (STAINLESS) LIMITED

G.O.C. Ltd.,
Grand Buildings
Trafalgar Square
LONDON WC.2.

WATERLOO ROAD
WIDNES, CHESHIRE, WA8 0QR.
ENGLAND
Telephone: 061-424 5588
Telex: 627649

TEST CERTIFICATE

F.A.O. Mr Short.

DATE 15.1.80 | OUR ADVICE No. A 16495 | CUSTOMERS O/N JG 76-0339-01

Item No.	Qty.	Heat No.	Description	C%	Si%	Mn%	S%	P%	Ni%	Cr%	Mo%	Ti%	Nb%
6	1	660178	18" NB 0.375" WT Equal Tees	.024	.26	1.57	.003	.023	11.36	17.00	2.38		

WP Ltd.8/77(1988)

DIMENSIONAL SPECIFICATION

SUPPLEMENTARY REQUIREMENTS

MANUFACTURING SPECIFICATION A 312 TP 316L S/S

Heat No.	Yield	Tensile	% Elongation	Red. of Area
	N/mm^2	N/mm^2		
660178	304	558	47.8	

The chemical and mechanical values are a true and correct copy of the certificate issued by the suppliers of the raw material, or by the laboratory which has determined them.

INSPECTOR
For and on behalf of Spray Engineering (Stainless) Ltd.

J.ROberts.

APPENDIX D SPECTROGRAPHY TEST RESULTS (ZONKO)

RGIT - SMOE

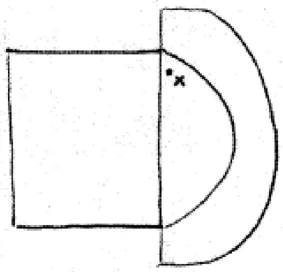
CHEMICAL ANALYSIS AND CONSTITUTION REPORT (CAC/DK/1)

RGIT - SMOE

Customer —
Customer Ref. No. 1
Customer Job No.
Report Reference
Analytical Technique(s) Used SPECTROGRAPHIC , COMBUSTION FOR C + S.

Sample(s) Description Stainless Steel.
Sample(s) Reference
Sample(s) Form
Prior Treatment(s)

SKETCH OF SAMPLE LOCATIONS



Comments:
Analysis taken from point X

COMPOSITION (weight %) OF SAMPLES TAKEN

Constituent	1	2	3
Aluminium			
Cadmium			
Carbon	0.052 %		
Chromium	17.0 %		
Cobalt			
Copper			
Iron			
Lead			
Manganese	1.39 %		
Molybdenum	2.60 %		
Nickel	11.6 %		
Niobium			
Phosphorus	0.021%		
Silicon			
Sulphur	0.002 %		
Tin			
Titanium			
Vanadium			
Zinc			

TEST WITNESSED BY:

Lloyd's Register of Shipping H. Winst

Det Norske Veritas

Other (Specify)

Tested by

Report Checked by

23. 1. 87

RGIT - SMOE

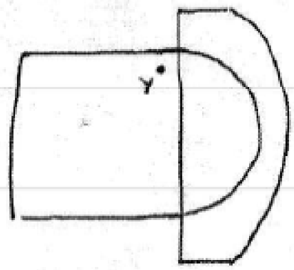
CHEMICAL ANALYSIS AND CONSTITUTION REPORT (CAC/DK/1)

RGIT - SMOE

Customer ____________________
Customer Ref. No. 2
Customer Job No. ____________________
Report Reference ____________________
Analytical Technique(s) Used SPECTROGRAPHIC, COMBUSTION FOR C+S

Sample(s) Description Stainless Steel
Sample(s) Reference ____________________
Sample(s) Form ____________________
Prior Treatment(s) ____________________

SKETCH OF SAMPLE LOCATIONS



Comments:
Analysis taken from point Y

COMPOSITION (weight %) OF SAMPLES TAKEN

Constituent	1	2	3
Aluminium			
Cadmium			
Carbon	0.023		
Chromium	17.04		
Cobalt			
Copper			
Iron			
Lead			
Manganese	1.56		
Molybdenum	2.38		
Nickel	11.32		
Niobium			
Phosphorus	0.021		
Silicon	0.26		
Sulphur	0.003		
Tin			
Titanium			
Vanadium			
Zinc			

TEST WITNESSED BY.
Lloyd's Register of Shipping [signature]
Det Norske Veritas ____________________
Other (Specify)

Tested by ____________________
Report Checked by ____________________
Date of Issue 23.1.87

THE ROBERT GORDON UNIVERSITY, ABERDEEN

FACULTY OF SCIENCE AND TECHNOLOGY

SCHOOL OF MECHANICAL AND OFFSHORE ENGINEERING

Chemical Analysis of Weld Metal

Carbon	0.024
Silicon	0.68
Manganese	1.95
Phosphorus	0.031
Sulphur	0.022
Chromium	17.5
Molybdenum	2.88
Nickel	11.2

All values are weight percent

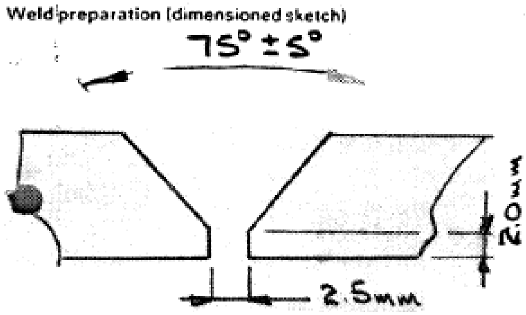
APPENDIX E WELD TEST PROCEDURE

's symbol or logo)	Record of approval test of welding procedure (BS 4870 : Part 1 : 1981) 1. Procedure details	Page 1 of Test record no.

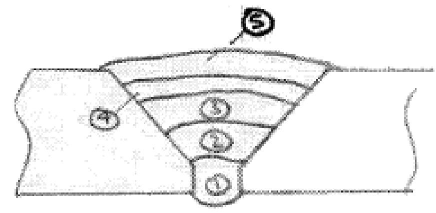
Manufacturer's name	Location of test Shop or site	Manufacturer's procedure no. (and revision no.)

Welding process(es)	MMA	Parent material(s)	316L
Joint type	BUTT. (PIPE)	Specifications	
Welding position(s)	5G	Material group(s) (see table 1)	T.
Test piece position	5G	Dimensions of test piece	250mm OD x 12 mm WT.

Weld preparation (dimensioned sketch)



Run sequence and completed weld dimensions (sketch)



Method of preparation and cleaning
MANUAL, AS ABOVE, TO BRIGHT METAL

Welding consumables

Filler material
Make and type: BOC 316L
Composition: 316L

Shielding gas/flux
Make and type: N/A
Composition: N/A.

...ing treatment: AS RECOMMENDED BY MANUFACTURES.

Welding conditions

Run no.	1	2 – 4	5
Size(s)	2.4.	3.2	4.0
Current	60-80A.	90–110A	130A
Voltage	—	—	—
Polarity	DCEP.	DCEP	DCEP
Travel speed – R.O.L.	—	—	—
Wire feed speed	—		—
Gas flow rate:	—		
Shield	—	—	—
Purge			—

Second side treatment

	Temperature	Method	Control
Preheat	N/A	N/A	N/A.
Interpass	250°C.	CRAYON.	

Post-weld heat treatment
Specification
Method
Control
Soak temperature
Soak time
N/A

Other information. See 4.2 and 4.3. Use supplementary sheets if necessary.

Originator	Date	Welder's identity AA. Name A. Walder. Mark X

APPENDIX F FISHBONE DIAGRAM