Smart Solutions for Engineering,
Science and Computing

Development of Marginal Fields for Offshore Nova Scotia Phase 2 of 2

FINAL REPORT

Martec Technical Report #TR-10-15

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Prepared for:

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SIGNATURE PAGE

DEVELOPMENT OF MARGINAL FIELDS FOR OFFSHORE NOVA SCOTIA PHASE 2 OF 2

Technical Report # TR-10-15 Rev 01
25 June 2010

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EXECUTIVE SUMMARY

The main scope and tasks for this project have been completed, and the envisioned Sable Offshore Minimal Infrastructure Tool (SOMIT) has been developed and issued to NSDOE. The tool is capable of evaluating various subsea and standard production type developments simultaneously for a full evaluation of the development of single- and multiple-SDA developments.

The following main tasks of the original scope of work have been completed:

1. Trend Analyses of the Proposed Minimal Structures
2. Evaluation and Development of Subsea Tie Back Development Concepts
3. Evaluation of a Larger Range of Production Process Scenarios
4. Evaluation of Various Field Development Requirements for Offshore Infrastructure
5. Development of the Tool Interface and Output Requirements
6. Develop Schedule of Rates for use in the tool to derive overall infrastructure costs
7. Interface with CNSOPB

While SOMIT fills an informational gap with regard to the evaluation of Nova Scotian SDAs, further study is required in the following areas:

Oil Production – to consider oil production, a similar effort would be needed to determine the required equipment and processing for the production types anticipated for Nova Scotia Offshore.

Drilling – this remains the largest portion of the overall development costs, and was not considered in great detail in the current study's scope of work. Therefore, the estimation of this cost is based on high-level analysis only. An evaluation tool should be created to suit SOMIT, which could be based on SDA reservoir and geological information, and present drilling/well production options and costs for the various SDAs. As the most expensive portion of the overall field development cost, drilling represents the largest impediment to development of Nova Scotia's SDAs.

Deep Water – the scope of the current study has focused on the known reserves, and, therefore, has been limited to shallow water development. Much of Nova Scotia resource potential lies in water depths of >500m. Infrastructure required to explore and develop resources at such depths are far different from those used at the shallower depths.

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1.0 INTRODUCTION

The determination of the economic viability of an offshore development is largely related to the cost of the offshore facility that will extract and distribute the gas. Offshore fields, which have questionable economic viability, are considered 'marginal fields'. Nova Scotia's remaining known offshore fields fall into the marginal field category, as the recoverable reserves are not as significant as the Sable Offshore Energy Project or Deep Panuke fields. Other areas of the world have faced similar issues regarding the economics of developing 'marginal fields'. Some of these fields have become economically viable by reducing the cost of the offshore facility used to extract and distribute the gas or oil.

To encourage development of these marginal fields, the Nova Scotia Department of Energy (NSDOE) has been working to reduce development risk and increase resource profitability. Part of this strategy includes development of tools aimed at assisting potential developers in understanding the local resources, and economic environment. One such model that has been created is the Nova Scotia Oil and Gas Exploration Economic Model developed by Indeva. This economic tool provides a cost model for potential developments with respect to life cycle costs, recovery, risk, and potential margins of investment.

Prior to 2008, however, no specific work had been completed on the requirements associated with the physical infrastructure that new development would require. Therefore, in April 2008, NSDOE awarded Phase 1 of a two-phase project to Martec Limited.

1.1 PHASE 1 OF 2 - FEASIBILITY OF MINIMAL STRUCTURES OFFSHORE NOVA SCOTIA

The reduction in cost of a marginal development is largely attributed to the potential reduction in size of the offshore installation. These types of installations are referred to as 'minimal platforms'. Minimal platforms may reduce the cost of the facility in a number of ways, including:

- Reduction in steel weight;
- Simplified fabrication methods; and
- Elimination of Heavy Lift Vessels (HLV).

Phase 1 focused on investigating the known types of minimal platforms and their suitability for use in the harsh environment offshore Nova Scotia. Existing minimal platforms are less robust than standard fixed platforms, as they have been developed for use in relatively calm waters and could be unsuitable for Nova Scotia's severe wave environment. However, the Phase 1 work has shown that, with some modifications, platforms meeting the minimal platform definition above are suitable for the Nova Scotia wave environment. Figures 1-1 and 1-2 show two of these structures, Single Caisson and Minimal Satellite.

Figure 1-1: Single Caisson Structure for use in the Nova Scotia Offshore

Figure 1-2: Minimal Satellite Structure for use in the Nova Scotia Offshore

In addition to this, Phase 1 work summarized the various Significant Discovery Areas (SDAs) and their general characteristics. Conceptual field development scenarios have been created, as well as fabrication and installation scenarios for the various minimal platform types. All indications from Phase 1 have supported the potential use of several different types of minimal platforms, each offering a different set of capabilities and advantages for field development, collectively presenting a new set of development options within the Nova Scotia Offshore.

To this end, at the request of NSDOE, a technical paper outlining Phase 1 study results was presented by Martec Limited at the OTC 2009 conference in Houston, Texas. Presentation at such a venue was a great opportunity to highlight these new lower-cost options for offshore development in Nova Scotia.

Phase 1 of this two-phase study was completed in Summer of 2009.

1.2 PHASE 2OF 2 - SABLE OFFSHORE MINIMUM INFRASTRUCTURE TOOL

Phase 2 of this study has used the Phase 1 minimal platforms, in concert with production studies, operational and fabrication requirements, and a collection of both existing infrastructure and potentially new infrastructure to determine the ***cost impact*** of developing the Nova Scotia marginal fields. To achieve this goal, a cost estimation tool, the Sable Offshore

Minimum Infrastructure Tool (SOMIT), will be developed to provide an estimate of the ***cost of infrastructure*** required to develop the marginal SDA's of the Nova Scotian Offshore.

The driving force behind the development of SOMIT was the need to provide basic, yet specific, infrastructure-related data and information which could then be used to estimate the associated costs and outline the physical facilities required for a specific field development. Costs are generated based on a matrix of specified rates and estimated quantities.

To complete the SOMIT tool, several tasks were required, namely:

1. *Trend Analyses of the Proposed Minimal Structures*: Phase 1 work was limited to concept development and testing for a single offshore case study. This Phase 2 task was aimed at determining ranges of applicable use, including trends in required steel, fabrication requirements, limitations and local capabilities, with respect to various production requirements and field locations around Sable Island.

2. *Evaluation and Development of Subsea Tie Back Development Concepts*: The exclusive use of subsea tie back developments for the current SDAs was evaluated with regard to required infrastructure, green- and brown-field requirements, production efficiencies and limitations, cost, and operational benefits and risks. The exclusively-subsea options were compared with the minimal platforms and other development concepts presented herein and included in the SOMIT costing tool.

3. *Evaluation of a Larger Range of Production Process Scenarios*: Phase 1 considered only three likely scenarios, resulting in equipment, layout, and weight requirements. Many more production scenarios were applicable for offshore Nova Scotia, as well as production modifications for existing offshore platforms.

4. *Evaluation of Various Field Development Requirements for Offshore Infrastructure*: This task considered offshore interfield pipeline, umbilical, and brown-field requirements. Phase 1 work was expanded to include possible development scenarios for each of the SDAs, as well as various interfield and export options.

5. *Development of theTtool Interface and Output Requirements*: This task involved the development of a user-interface to select relevant costing and infrastructure requirements for a given development. Output includes cost estimates, as well as a description of infrastructure requirements. It is expected that the interface will compliment current NSDOE modeling tools focused on the Nova Scotia Offshore.

6. *Develop Schedule of Rates for Use in the Tool to Derive Overall Infrastructure Costs*: This task involved assembling a matrix of various cost and rate information from global and local service companies that is then used to derive the infrastructure costs for a selected development scenario.

7. *Interface with Canada Nova Scotia Offshore Petroleum Board (CNSOPB)*: Interfacing with CNSOPB was required to ensure that all development and planning scenarios,

including operational requirements, are suitable for use in the Nova Scotian Offshore sector.

With this tool, the user, with specific yet high level input, can quickly generate a viable cost for minimum offshore infrastructure that could be priced locally as well as from foreign sources, and that includes infrastructure developed specifically for the Nova Scotia Offshore industry.

2.0 PHASE 2

The following subsections describe in more detail each task performed during the work and the corresponding results.

2.1 TREND ANALYSIS

A structural trending study was carried out for each of the minimal platform groups identified during Phase 1 to evaluate the structural feasibility of the particular concept for operation in varying water depths and locations around Sable Island. Minimal platform categories studied here include:

1. **Caisson** - trending carried out based on expansion of Phase 1 study.
2. **Braced Caisson** - trending carried out based on expansion of Phase 1 study.
3. **Barge Assisted Jacket** - trending carried out based on expansion of Phase 1 study.
4. **Self-Elevating Platform** - model was developed to determined range of practicality.
5. **Standard Jacket** - trend analysis carried out based on existing platform data.

Figure 2-1 below shows the results of the trending study.

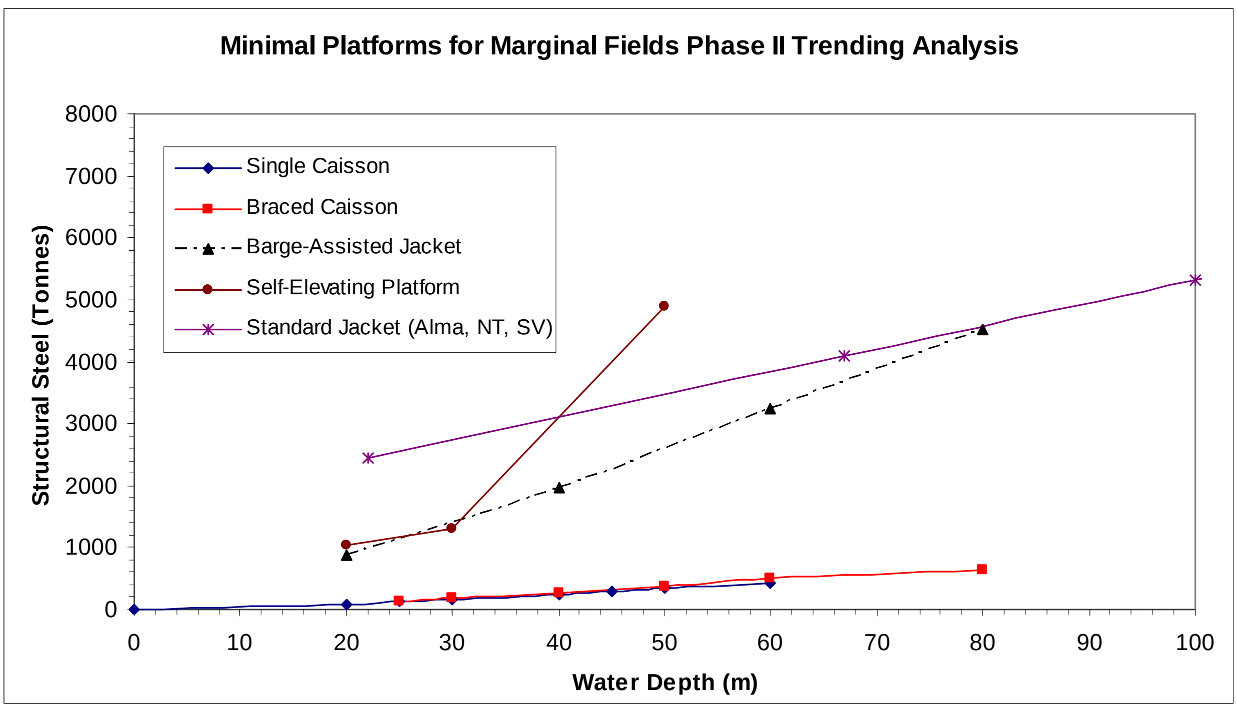


Figure 2-1: Results of Trending Analysis for Offshore Fixed Structures

2.2 EVALUATION AND DEVELOPMENT OF SUBSEA TIE BACK DEVELOPMENT CONCEPTS

Subsea field developments have particular concerns and requirements to overcome to be reliable and cost effective. In this task, field development concepts for the current SDAs were generated based on exclusive use of subsea systems. Viable rates of production, equipment requirements, and brownfield modifications to existing platforms were evaluated, with consideration also given to tie back distances, and their impact on flow assurance. The results of the task were viable subsea development concepts for the current SDAs.

Appendix A contains the resulting single field development options for subsea development. The results of tie back limitations and requirements for equipment and brownfield modifications were transferred to the production and cost rates portion of SOMIT.

2.3 EVALUATION OF A LARGER RANGE OF PRODUCTION PROCESS SCENARIOS

Phase 1 included the evaluation of three production cases, which has been expanded here in Phase 2. Table 2-1 shows the production cases included in the study. Each case also considered an option to include a helideck and saferoom.

Further details of the production cases and results are presented in Appendices B & C.

Table 2-1: Production Case Matrix

	Production Rate MMscfd	Type 1	Type 2	Type 3
1 Well	15	Case 1		
2 Wells	30	Case 2		
4 Wells w/ On Board Power	60	Case 3	Case 5	Case 9
4 Wells w/ Power Cable from CPF	60		Case 6	Case 10
6 Wells w/ On Board Power	90	Case 4	Case 7	Case 11
6 Wells w/ Power Cable from CPF	90		Case 8	Case 12
Helideck / Saferoom	-	OPTION		

Note, some of the preliminary cases were eliminated due to duplication or redundancy.

2.3.1 Production Types

The tie-back facilities configuration has been largely based on the flow assurance scheme used to prevent hydrate formation in the flowlines between the wells and the existing facility where full gas, condensate, and water treating can be provided. Three different primary configurations were considered in the study. Appendix D contains schematic process diagrams of the various types, as described below:

- **Type 1 – No Treating**
  This configuration will require the least amount of topsides equipment. For this configuration, wells will produce into a production header. MEG supplied by a pipeline from the central processing facility (CPF) will be injected into the production header in quantities sufficient to inhibit hydrate formation. As produced water is not removed from the production stream, the MEG will require vacuum distillation type recovery (MEG Reclamation) at the CPF. If quantities of produced water are high, then this option will not be feasible. A topsides HIPPS system may be required to protect the subsea pipeline from overpressure.

- **Type 2 – Partial Treating**
  For this configuration, partial dehydration of gas and condensate is provided at the production facility. Water is removed via conventional separation and then treated for overboard disposal. Like the Type 1 configuration, glycol provided via pipeline from the CPF is injected into the production stream to inhibit hydrate formation in the flowline. However, since free water is removed, less glycol is required and therefore conventional glycol dehydration at the CPF can be used to regenerate the glycol.

- **Type 3 – Full Treating**
  This configuration, like the partial treating NUI, removes free water. However, this facility includes a glycol contactor and glycol regeneration package, and subsequently does not require a glycol supply from the CPF.

2.3.2 Production Types Not Included

The original scope of work included the evaluation of production cases which included the production of oil resources. However, upon commencement of the work, it became apparent that both topsides production and subsea production would require entirely separate and specific equipment studies to understand both gas and oil developments. The scope was therefore modified, with agreement from NSDOE, to focus the work on the production of natural gas reserves.

2.4 EVALUATION OF VARIOUS FIELD DEVELOPMENT REQUIREMENTS FOR OFFSHORE INFRASTRUCTURE

Field development options, including subsea options, have been developed. The conceptual scenarios have mapped out reasonable plans for an entire extraction-to-market case for field development. These form the basis of SOMIT for each of the platform concepts and subsea developments evaluated.

Appendix A contains the resulting single field development options for subsea development.

Note the SOMIT deliverable has incorporated an additional development scenario for multiple SDAs. At the request of NSDOE, additional scope was added to the work to provide an additional evaluation tool for the development of multiple fields during a single development cycle.

2.5 DEVELOPMENT OF THE TOOL INTERFACE AND OUTPUT REQUIREMENTS

SOMIT has been developed in Microsoft Excel 2003 as a protected worksheet application. Excel is widely available to most users and has the functionality required to produce the interactive nature of the tool. Initial development of the input and output requirements began prior the completion of the Phase 2 analysis, to ensure that the tool met with approval.

The first draft of SOMIT was provided to NSDOE on April 22nd, 2010, and the final draft version of SOMIT was provided to NSDOE May 25th, 2010.

2.6 DEVELOP SCHEDULE OF RATES FOR USE IN THE TOOL TO DERIVE OVERALL INFRASTRUCTURE COSTS

As part of the development of the tool, a sample schedule of rates was produced for use in SOMIT. In this task, manufacturers and contractors were solicited for quotations on the field development concept created by the tool. The expectation was to receive rough estimates from fabricators with sufficient detail to construct a table of costs.

Martec used consultant Len Perry to obtain the local fabrication estimates. The results of the schedule of rates can be found in Appendix E, and has been inserted as the default costs in SOMIT.

Costs related to the development of subsea were provided by Cameron Subsea, and can be found in Appendix E. Mustang Engineering, as part of their process production study scope, provided development costs for the various scenarios studied, which have also been included in Appendix E.

2.7 INTERFACE WITH CNSOPB

Once the field development scenarios were initially developed, CNSOPB had the opportunity to review the plans, in particular to comment on issues with operations. As part of the focus of this study, the fact that minimal platforms offer operational as well as structural alternatives/limitations compared to standard practice (i.e., requirement for de-manning of platforms, access requirement, etc.) has been considered. While these have been accepted in other sectors, there may be sensitive changes which would require review and discussion. Involving CNSOPB at this initial stage, and instituting changes or limitations to the development cases before the major evaluation is started, avoided the use of field development cases which may potentially have been rejected by the CSNOBP.

Martec met with Mr. Bob Hale of CNSOPB in December 2009. At this time, the full scope and vision of the SOMIT project (Phases 1 and 2) were discussed. This included discussions around operations and proposed developments which did not include helicopter access. The CNSOPB would expect any developer or development to meet all safety and risk requirements set out by the regulations, but does not prescribe the form or how operators choose to meet these requirements. Mr. Hale and CNSOPB are committed to review any development proposal which meets the current regulations.

3.0 DISSEMINATION AND TECHNOLOGY TRANSFER

The work completed for the development of SOMIT includes multiple efforts to make local industry and the general petroleum industry aware of the various methods available to develop Nova Scotia's current offshore resources, including the following.

Offshore Technical Conference (OTC) 2010
A paper was authored and submitted to this international conference held in Houston, Texas, May 3-6, 2010. The paper was presented at the conference via a 20-minute presentation. The paper and presentation have been included in Appendices F & G.

Nova Scotia Energy Research and Development Forum 2010
A biannual event held in Nova Scotia to highlight research and capabilities in energy in Nova Scotia. A 15-minute presentation was prepared and presented during this forum. This can be found in Appendix G.

4.0 CONCLUSIONS AND RECOMMENDATIONS

The main scope and tasks for this project have been completed, and the Sable Offshore Minimal Infrastructure Tool (SOMIT) has been developed and issued to NSDOE. The tool has been designed to evaluate various subsea and standard production type developments simultaneously for a full evaluation of the development of both single- and multiple-SDA developments.

The following main tasks of the original scope of work have been completed:

1. *Trend Analyses of the Proposed Minimal Structures*: Phase 1 work was expanded to include a range of water depths and multiple structures.
2. *Evaluation and Development of Subsea Tie Back Development Concepts*: Working with subsea vendors and engineering contractors, viable subsea development scenarios were developed and included in SOMIT.
3. *Evaluation of a Larger Range of Production Process Scenarios*: Phase 2 included the evaluation of 12 topside (dry) production cases, as well as fully subsea production cases for natural gas, with estimated production rates of between 15MMscfd and 90MMscfd.
4. *Evaluation of Various Field Development Requirements for Offshore Infrastructure:* Phase 1 work was expanded to include field development options for all SDAs. The SOMIT tool has also been expanded to include the option to evaluate the development of multiple SDAs within a single development plan.
5. *Development of the Tool Interface and Output Requirements*: SOMIT has been completed and delivered to NSDOE, complete with default pricing information.
6. *Develop Schedule of Rates for Use in the Tool to Derive Overall Infrastructure Costs:* Data from both local and international sources were evaluated and reported back to NSDOE, and ultimately included in the cost and rate information for SOMIT.
7. *Interface with CNSOPB:* Envisioned development and planning scenarios were vetted with CNSOPB to ensure that the resulting SOMIT evaluations would represent plausible development strategies for the Nova Scotian Offshore.

While SOMIT fills an informational gap with regard to the evaluation of Nova Scotian SDAs, further study is required in the following areas:

Oil Production – to consider oil production, a similar effort would be needed to determine the required equipment and processing for the production types anticipated for Nova Scotia Offshore.

Drilling – this remains the largest portion of the overall development costs, and was not considered in great detail in the current study's scope of work. Therefore, the estimation of this cost is based on high-level analysis only. An evaluation tool should be created to suit SOMIT, which could be based on SDA reservoir and geological information, and present drilling/well production options and costs for the various SDAs. As the most expensive portion of the overall field development cost, drilling represents the largest impediment to development of Nova Scotia's SDAs.

Deep Water – the scope of the current study has focused on the known reserves, and, therefore, has been limited to shallow water development. Much of Nova Scotia resource potential lies in water depths of >500m. Infrastructure required to explore and develop resources at such depths are far different from those used at the shallower depths.

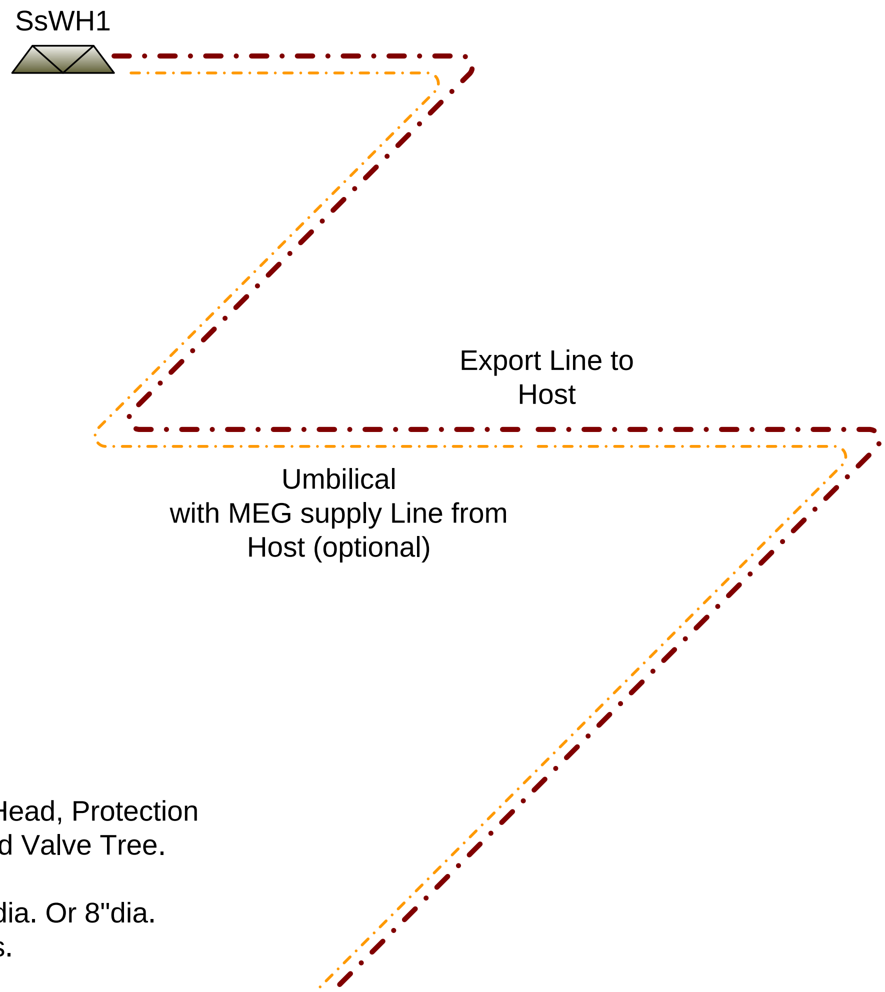
5.0 PUBLICATIONS

The work completed in this scope produced a paper for the Offshore Technical Conference 2010. This paper is reproduced in Appendix F for reference.

APPENDIX A

FIELD LAYOUTS

Option 1a: Full Subsea
Multiple Wells



Option 1a Notes:

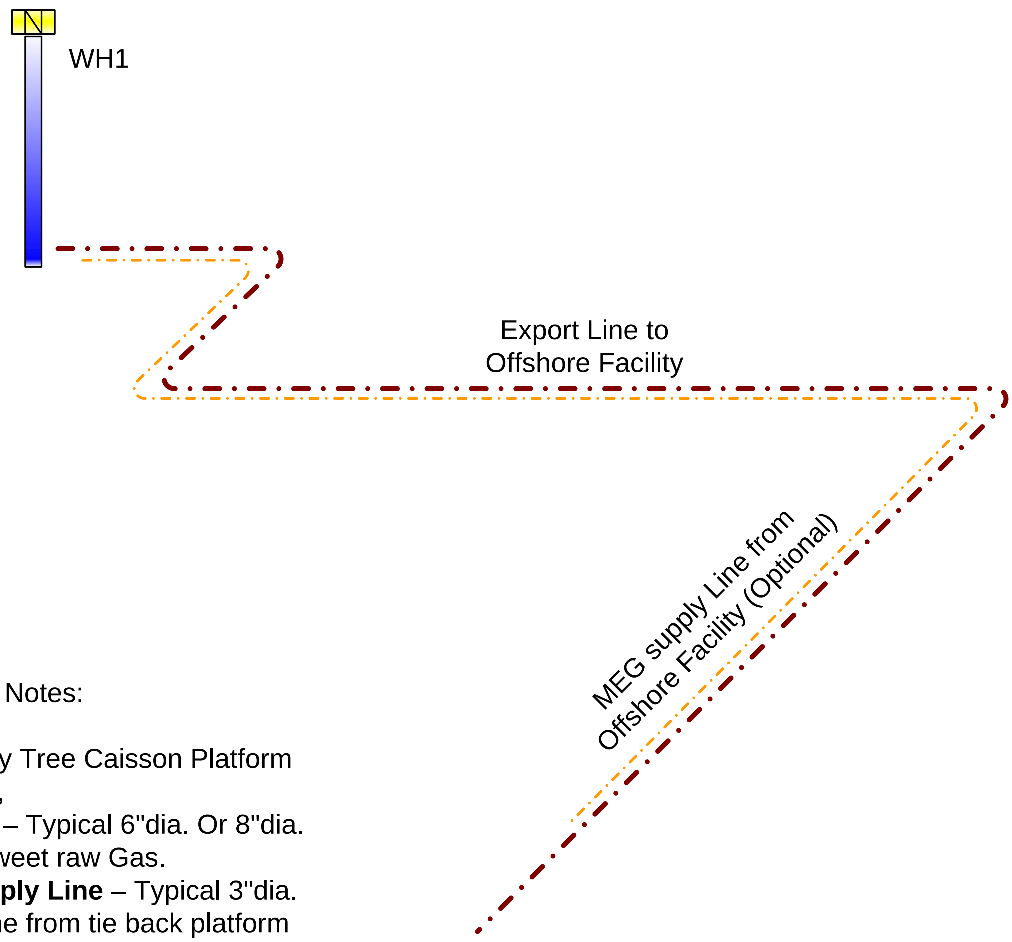
SsWH – Subsea WellHead, Protection Structure, wellhead and Valve Tree. Chemical Injection
Flow line – Typical 6"dia. Or 8"dia. Line for sweet raw Gas.

Umbilical – Wellhead Communications, power / hydraulic, MEG optional.

Export line - 6"dia. To 8" dia. Export line for raw flow.

Check Pressure rielf system, HIPPS or back at Tie Back Host.
SsWH max range to Host: 10km
SsWH max range to Host with MEG: 50km

Option 1b: Single Well – Dry Caisson



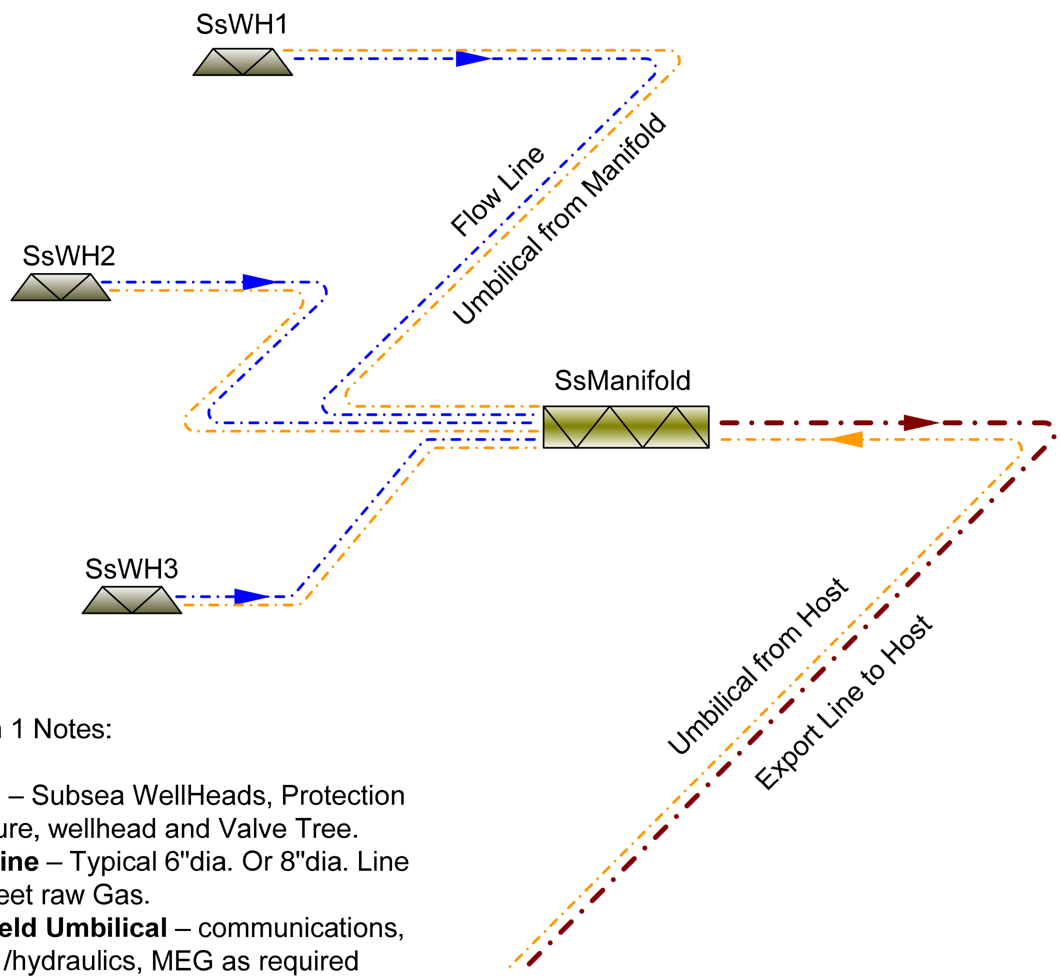
Option 1b Notes:

WH1 – Dry Tree Caisson Platform WellHead,
Flow line – Typical 6"dia. Or 8"dia. Line for sweet raw Gas.
MEG Supply Line – Typical 3"dia. Supplly line from tie back platform (Optional will allow increased range)
Export line - 6"dia. To 8" dia. Export line for raw flow.

Process:
Minimum of Dry Tree and HIPPS
Options for:
MEG Injection
Test Separation

WH max range to Host: 10km
WH max range to Host with MEG: 50km

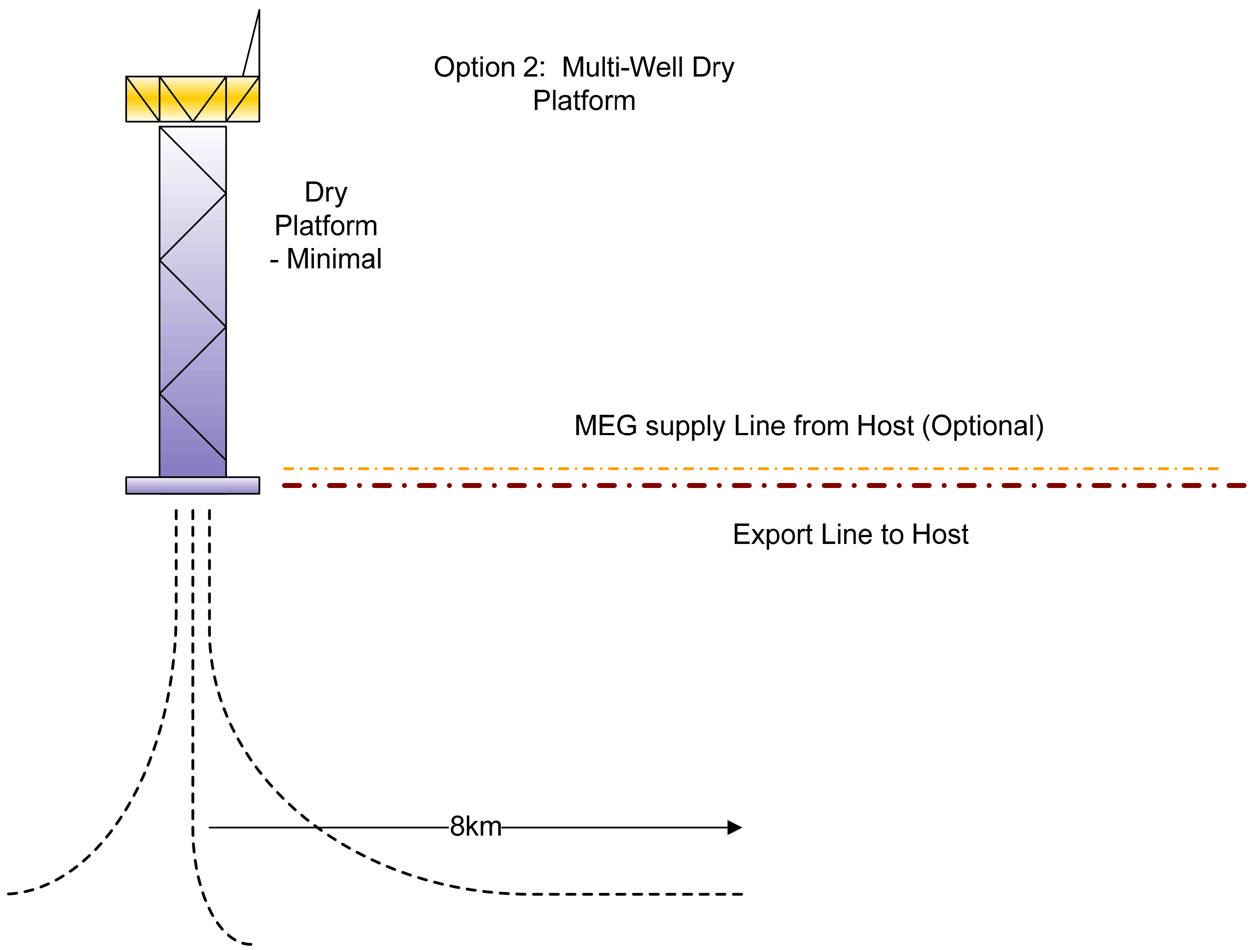
Option 1: Full Subsea
Multiple Wells



Option 1 Notes:

SsWH – Subsea WellHeads, Protection Structure, wellhead and Valve Tree.
Flow line – Typical 6"dia. Or 8"dia. Line for sweet raw Gas.
Interfield Umbilical – communications, power /hydraulics, MEG as required
SS Manifold – Subsea Manifold, complete with MEG injection. Include emergency shut off and pressure relief system, if not available on tie back platform. (HIPPS)
Umbilical – ss communications, power / hydraulics, MEG as required
Export line - 8"dia. To 14" dia. Export line for raw, inhibited flow.

Manifold allows for multiple ssWH to be managed together to produce one export line, instead of each ssWH exporting to Tie-Back Platform. Check Pressure relief system, HIPPS or back at Tie Back Host.
SsWH max range to Manifold: 10km
SsManifold max range to Host: 50km



Option 2 Notes:

Processing - Multi- Well platform would allow for partial or full processing;
Partial Dehydration, water treatment,
Power generation (diesel), Pressure relief (small flare), MEG Injection,
Metering
(Limit is dependant on depth of reservoir and current drilling capabilities)

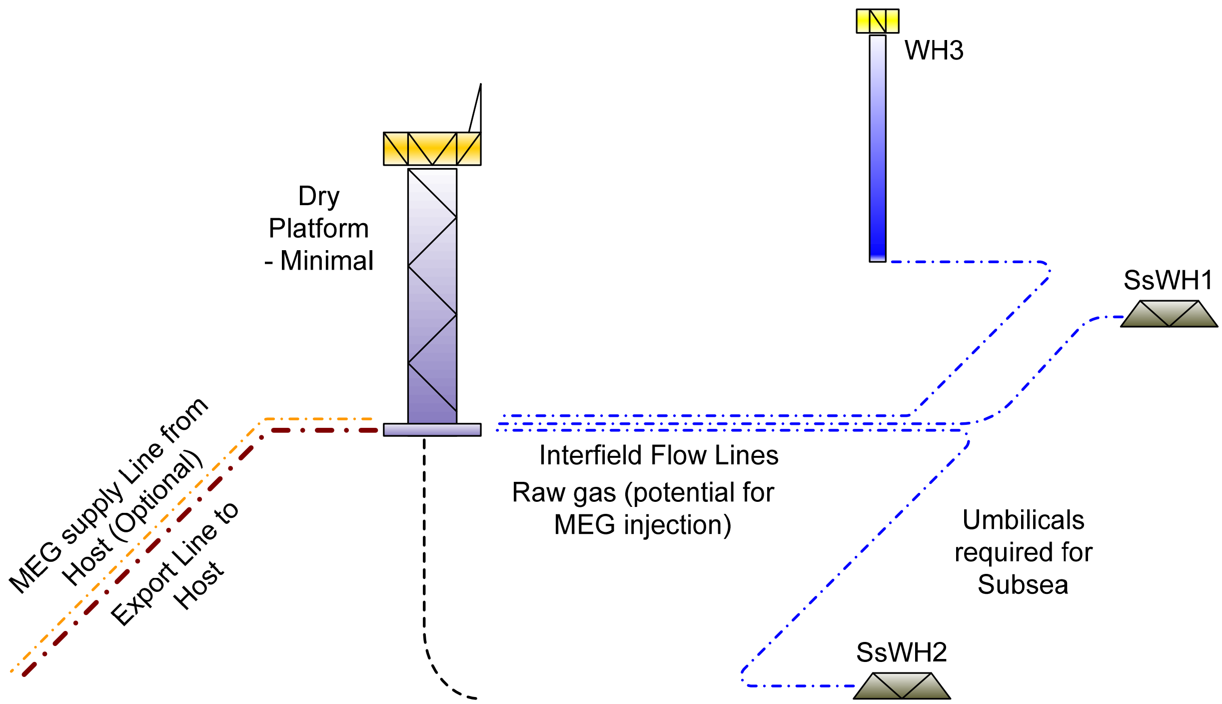
MEG Supply Line – Typical 3"dia. Suppliy line from tie back platform
(option to have reclamation on platform and not require MEG line)

Export line - 8"dia. To 14" dia. Export line for raw, inhibited flow.

Water Depth - limit of 80m
Wells – 1-4 Wells are directionally drilled up to approximately 8km from platform.

Increased processing onboard increases flow assurance and max distance to tie-back Host Facility. Could be as much as 100km (dependant on reservoir contents, pressure and temp).

Option 3: Multi-Well Dry Platform with
Subsea Extension



Option 3 Notes:

This option is an extension of Option 2, with additional wells tied back to the new Dry Hub Platform. This diagram shows both subsea and single caisson type wellheads, as well as, the Hub having a well.

Processing – Dry Hub platform would allow for partial or Full processing;
Partial Dehydration, water treatment,
Power generation (diesel), Pressure relief (small flare), MEG Injection,
Metering
(Limit is dependant on depth of reservoir and current drilling capabilities)

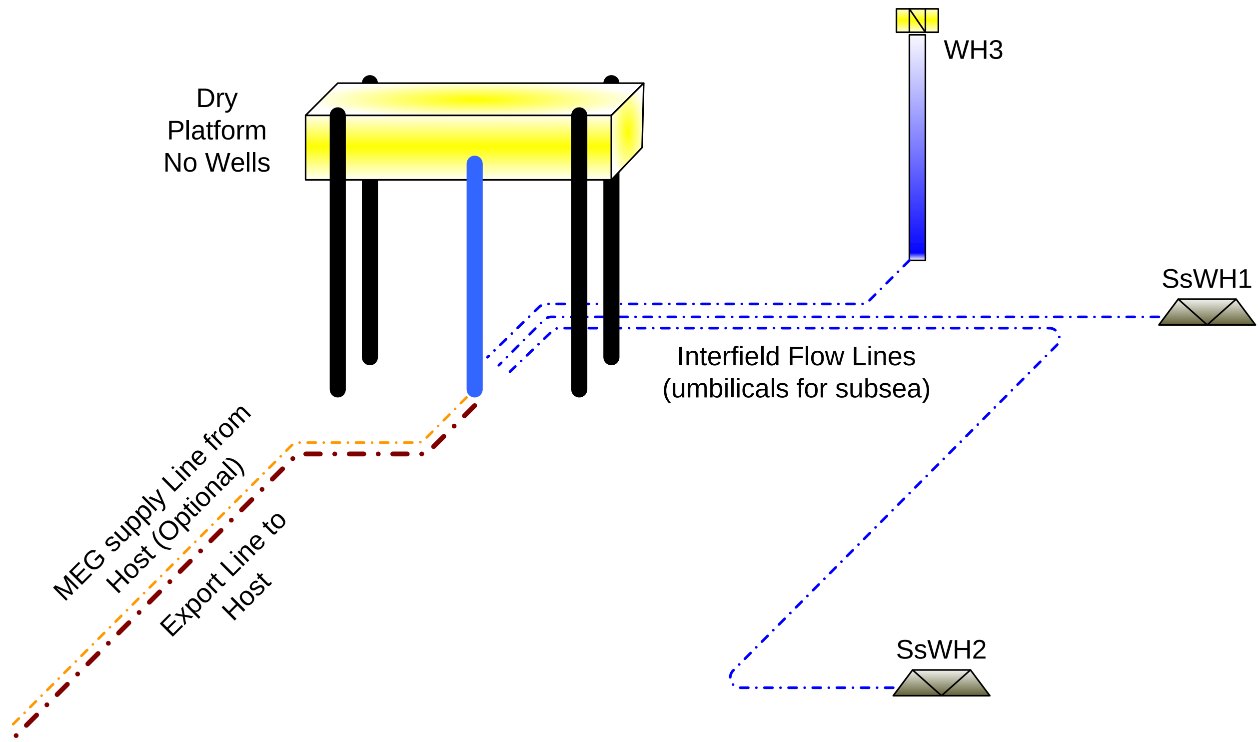
MEG Supply Line – Typical 3"dia. Supplly line from tie back platform. (Reclamation with full processing can eliminate need for MEG line)

Export line - 8"dia. To 14" dia. Export line for partially treated flow.

Water Depth - Dry Hub platform limit of 80m – subsea extension to deeper water
Wells – 1-2 Wells are directionally drilled at Dry Hub up to approximately 8km from platform + well head tie-backs.

Increased processing onboard increases flow assurance and max distance to tie-back Host Facility. Could be as much as 100km.

Option 4: Self Elevating Dry Platform
(no wells) with Tie-Backs



Option 4 Notes:

This option is an extension of Option 3, with all wells tied back to the new Dry Hub Platform.
This diagram shows both subsea and single caisson type wellheads.

Processing – Dry Hub platform would allow for partial or Full processing;
Partial Dehydration, water treatment,
Power generation (diesel), Pressure relief (small flare), MEG Injection,
Metering
(Limit is dependant on depth of reservoir and current drilling capabilities)

MEG Supply Line – Typical 3"dia. Supply line from tie back platform (MEG line is not required if reclamation is provided on the platform)

Export line - 8"dia. To 14" dia. Export line for partially treated flow.

Water Depth - Dry Hub platform limit of 60m (Self Elevating?)– subsea extension to deeper water
Wells – 1-2 Wells are directionally drilled at Dry Hub up to approximately 8km from platform + well head tie-backs.
Increased processing onboard increases flow assurance and max distance to tie-back Host Facility. Could be as much as 100km.

Self Elevating type Platform Hub, would allow for significant processing, No wells at platform.

APPENDIX B

PRODUCTION DESIGN BRIEF

MARTEC
Minimal Topsides Estimating

DESIGN BASIS

0	04 DEC 09	ISSUED FOR DESIGN	RCL		EAW	
A	01 DEC 09	ISSUED FOR REVIEW	RCL			
REV	**DATE**	**DESCRIPTION**	**BY**	**CHK**	**PROJECT APP**	**CLIENT APP**

PREPARED FOR:	PREPARED BY:			
Martec, Limited 1888 Brunswick Street, Suite 400 Halifax, Nova Scotia B3J 3J8 Canada	Mustang Engineering 16001 Park Ten Place Houston, TX 77084			
Document No	**PROJECT**	**DOC TYPE**	**DISCIPLINE**	**SEQ. NO**
	16196	DC	UPE	0001

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1.0 INTRODUCTION

1.1 PURPOSE

The purpose of this Design Basis is to establish the assumptions to be made for Mustang Engineering to prepare a cost and weight estimating tool for various types of Normally Unmanned Installations offshore Nova Scotia. These facilities are premised as tie-backs to an existing Central Production Facility.

1.2 ABBREVIATIONS

CPF	Central Production Facility
CPI	Corrugated Plate Interceptor
FWHP	Flowing Wellhead Pressure
HIPPS	High Integrity Pressure Protection System
MEG	Monoethylene Glycol
NUI	Normally Unmanned Installation
SCADA	Supervisory Control and Data Acquisition
SITP	Shut-In Tubing Pressure

1.3 FACILITY TYPES

The tie-back facilities configuration will be largely based on the flow assurance scheme used to prevent hydrate formation in the flowlines between the wells and the existing facility where full gas, condensate and water treating can be provided. Three different primary configurations will be considered.

1.3.1 Type 1 – No Treating

This configuration will require the least topsides equipment. For this configuration, wells will produce into a production header. MEG supplied by a pipeline from the CPF will be injected into the production header in quantities sufficient to inhibit hydrate formation. As produced water is not removed from the production stream, the MEG will require vacuum distillation type recovery (MEG Reclamation) at the CPF. If quantities of produced water are high, then this option will not be feasible. A topsides HIPPS system may be required to protect the subsea pipeline from overpressure.

1.3.2 Type 2 – Partial treating

For this configuration, partial dehydration of gas and condensate is provided at the production facility. Water is removed via conventional separation and then treated for overboard disposal. Like the Type 1 configuration, glycol provided via pipeline from the CPF is injected into the production stream to inhibit hydrate formation in the flowline; however, since free water is removed, less glycol is required and conventional glycol dehydration at the CPF is able to regenerate the glycol.

1.3.3 Type 3 – Full Treating

This configuration like the partial treating NUI, removes free water. However, this facility includes a glycol contactor and glycol regeneration package and subsequently does not require glycol supply from the CPF.

1.4 CASES

The cases to be analyzed are summarized in Table 1. The number of wells refers to the number of production dry tree wells and/or well slots on the facility. The option for a Helideck and an associated Saferoom will be considered. This option will have one cost and weight that can be associated with any of the cases. The facility Types are described in Section 1.3.

	Type 1	**Type 2**	**Type 3**
1 Well	Case 1		
2 Wells	Case 2		
4 Wells w/ On Board Power	Case 3	Case 5	Case 9
4 Wells w/ Power Cable from CPF		Case 6	Case 10
6 Wells w/ On Board Power	Case 4	Case 7	Case 11
6 Wells w/ Power Cable from CPF		Case 8	Case 12
Helideck / Saferoom	OPTION		

Table 1 – Case Matrix

2.0 PROCESS DATA

2.1 INDIVIDUAL WELL DATA

The data for each producing well is summarized below. For the various cases summarized in Section 1.4, the number of wells is multiplied by the production rates below to obtain the facility design production rate.

Gas Production Rate	17,700 m^3/hr (15 MMscfd)
Condensate Production Rate:	63.8 m^3/day (400 BPD)
Water Production Rate	21.2 m^3/day (135 BPD)
Total Liquids Production Rate	85 m^3/day (535 BPD)
Reservoir SITP	< 400 bar (5800 psi)
FWHP	< 345 bar (5000 psi)
Wellhead Rating	API 5000 or ANSI 2500

2.2 SPECIAL CONSIDERATIONS

Sand Production	Minimal - provide sand probes in flowlines
Condensate Emulsion	Not anticipated
Hydrates	MEG required for inhibition for Cases 1 thru 8 Hydrates not anticipated for Cases 9 thru 12
Paraffin	Nil
CO_2	Nil
H_2S	Nil

3.0 PROCESS SYSTEMS

3.1 PRODUCTION MANIFOLD

Cases 1 and 2	Production Header only No well testing capability
Cases 3 and 4	Production Header and a Test Header Test Header will contain a 3-phase meter to provide well test capability
Cases 5 thru 12	Production Header and a Test Header Each header feeds a Separator

3.2 GAS/LIQUID SEPARATION

Cases 1 thru 4	No gas/liquid separation
Cases 5 thru 12	Test Separator sized for 1 well flow rate Production Separator sized for peak total production rate

3.3 WATER TREATMENT

Cases 1 thru 4	No water treatment.
Cases 5 thru 12	Bulk water removal in the Production Separator Water treated for disposal overboard via hydrocyclones and secondary treatment (skimmer or CPI)

3.4 Gas Treatment

Cases 1 thru 4	MEG from CPF injected into Production Header using Gas/MEG Static Mixer to prevent hydrate formation in departing pipeline. Lean MEG Booster Pumps may be required, but are not preferred.
Cases 5 thru 8	MEG from CPF injected into Production Header using Gas/MEG Static Mixer to prevent hydrate formation in departing pipeline (less MEG injection required due to lack of free water in pipeline). Lean MEG Booster Pumps maybe required.
Cases 9 thru 12	Glycol contactor and glycol regeneration package provided to dehydrate the departing pipeline gas below hydrate formation temperature. This in conjunction with produced water disposal results in the elimination of a need for MEG from the CPF for hydrate inhibition.

3.5 Condensate Handling

Cases 1 thru 4	No condensate treating.
Cases 5 thru 12	Primary separation in the Production Separator, followed by a condensate dehydrator prior to reinjection of condensate into departing pipeline

3.6 Departing Pipeline

Cases 1 thru 4	Carry inhibited (MEG) gas, water and condensate to the CPF. Pipeline size will likely range between 6” and 10”, depending on number of wells.
Cases 5 thru 8	Carry inhibited gas and condensate to the CPF. Pipeline size will likely range between 8” and 10”.
Cases 5 thru 12	Carry dehydrated gas and condensate to the CPF. Pipeline size will likely range between 8” and 10”.

3.7 Pipeline Pig Launcher

Cases 1 thru 4	Provisions (space/weight) provided for Pig Launcher, but not installed
Cases 5 thru 12	Permanently installed Pipeline Pig Launcher

4.0 FLOW MEASUREMENT

Cases 1 and 2	Three-phase meter on Production Header (total flow, not individual well test)
Cases 3 and 4	Three-phase meter on Test Header
Cases 5 thru 12	Gas, condensate and water meters at Test Separator outlets Gas allocation meter prior to commingling with condensate at departing pipeline Condensate allocation meter prior to commingling with gas at departing pipeline

5.0 PROCESS UTILITIES

5.1 VENT AND RELIEF

Cases 1 thru 4	HIPPS used to avoid need for a vent/relief system
Cases 5 thru 12	Full vent/relief system provided. Includes a Relief Scrubber, conventional flare boom, high pressure flare tip and low pressure vent. System will be designed to handle full production rate. Snuffing system

5.2 DRAINS

Cases 1 thru 4	Open Drain Caisson or Tank and Pumps
Cases 5 thru 12	Hazardous Open Drain Tank and Pumps

6.0 POWER

An electrical control room will be provided for all cases. The size will vary depending on the quantity of loads. Power supply/generation for each case is provided below.

Cases 1 thru 4	On board power generation from a remote power generator device such as a solar, wind or thermo-electric generator.
Cases 5, 7, 9 and 11	On board power generation from diesel generators
Cases 6, 8, 10 and 12	Power provided by a cable from the CPF

7.0 CONTROL SYSTEM

A Wellhead Control Panel will be provided for all cases. This panel will house the SCADA components required for communication/control via the CPF supervisory system.

8.0 UTILITY SYSTEMS

8.1 CHEMICAL INJECTION SYSTEM

The chemical injection system shall consist of tote tanks with electric motor driven or hydraulic powered chemical injection pumps. A nominally sized skid will be determined for each case; however, the chemicals required for each case will not be provided.

8.2 CRANES

Number of Cranes:	1
Type:	HOLD
Load Rating:	HOLD

8.3 FIREWATER PUMPS

None

9.0 HELIDECK

A helideck will be considered as an option for each case. The following will be required for a helideck installation.

- Helideck (same size each case)
- Temporary Safety Room
- HVAC unit

10.0 SAFETY AND LIFE SUPPORT EQUIPMENT

Life boats or life rafts will be provided to support

APPENDIX C

PRODUCTION EQUIPMENT LISTS

Equipment List - Type 1 Facilities

Equipment Type	Equipment Description
Well Control Panel	Well control panel with integral SCADA system and Hydraulic Power Unit. The HPU consists of small pumps and an accumulator.
Production Manifold	Production manifold with actuated valves controlled manually from the CPF. Includes Production and Test Manifold for Cases 3 and 4. Case 1 is a simple production line, Case 2 is a small production manifold with no test capability.
Gas Allocation Meter Skid	Multiphase meter on test header used to indicate oil/water/gas flowrates on individual wells. The multiphase meter is not "required" for the 1-well or 2-well cases; however, it is included in the cost estimate.
HIPPS System	High Integrity Pressure Protection System on departing pipeline to protect pipeline from overpressure. System consists of 2 actuated pipeline valves, 3 pressure transmitters, standalone control system
Open Drain Tank and Pumps	Tank provided to catch any hydrocarbon leaks that may occur on the deck. Pumps spike the hydrocarbons into the departing pipeline.
Methanol Injection Skid	Methanol tank and pumps used for pressure equalization and hydrate inhibition prior to startup
NAV Aids	Lights, fog horns, etc.
Escape Capsules	Life Rafts and Survival Craft as required by Client and by Code
Generator	15 to 25 kW diesel generator for lighting and small power users. Outdoor rack with Transformer and Distribution Panel. No MCC Building.
Diesel Storage Tank	Small diesel tank for generator
Crane	2 Te jib crane

Equipment List - Type 2 Facilities

Equipment Type	Equipment Description
Well Control Panel	Well control panel with integral SCADA system and Hydraulic Power Unit. The HPU consists of small pumps and an accumulator.
Production Manifold	Production manifold with actuated valves controlled manually from the CPF. Includes Production and Test Manifold.
Test Separator	Carbon steel 3-phase separator to allow for metering of condensate, water and gas at vessel outlets
Production Separator	Carbon steel 3-phase separator to segregate condensate, water and gas
Condensate Allocation Metering	Meter for condensate after primary separation and prior to combining with gas in the departing pipeline.
Gas Allocation Meter Skid	Meter for gas after primary separation and prior to combining with condensate in the departing pipeline.
Pipeline Pig Launcher	Permanently installed pig launcher for departing pipeline
Produced Water Hydrocyclones and Water Skimmer	Produced water treatment equipment to remove condensate from the produced water to a level acceptable for overboard disposal of produced water.
Flare Scrubber and Pumps	Carbon steel vertical flare scrubber. Liquids from the scrubber would be routed back to the production header. Flare system also includes high volume flare tip, CO2 vent snuffing and ignitor panel.
Open Drain Tank and Pumps	Tank provided to catch any hydrocarbon leaks that may occur on the deck. Pumps spike the hydrocarbons into the departing pipeline.
Methanol Injection Skid	Methanol tank and pumps used for pressure equalization and hydrate inhibition prior to startup
NAV Aids	Lights, fog horns, etc.
Escape Capsules	Life Rafts and Survival Craft as required by Client and by Code
Generator	100 kW Diesel Generator with attached 2.5 m x 2.5 m building to house main breaker and motor control center. HVAC included with building.
Diesel Storage Tank	Diesel tank for generator
Crane	2 Te jib crane

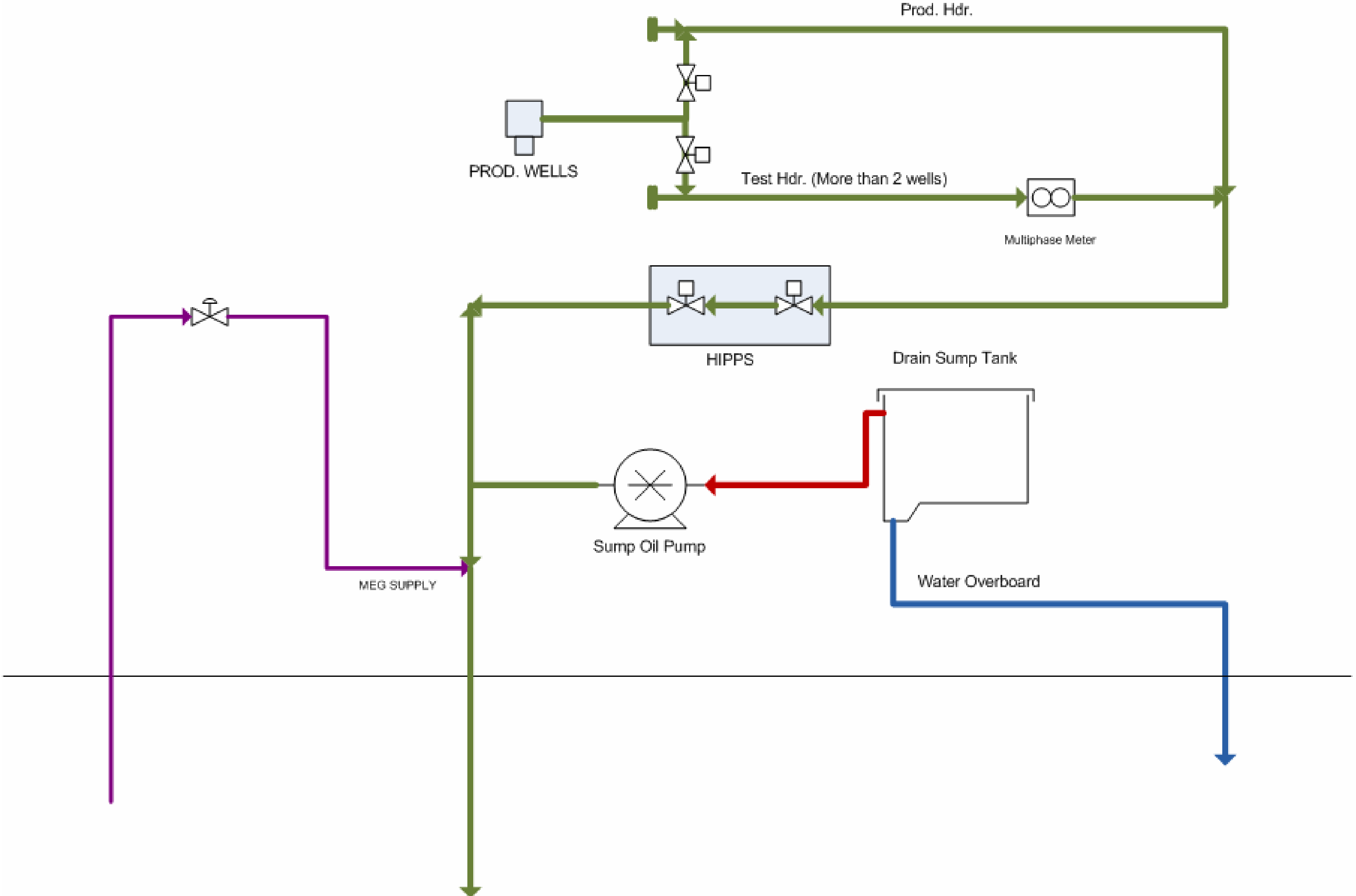
Equipment List - Type 3 Facilities

Equipment Type	Equipment Description
Well Control Panel	Well control panel with integral SCADA system and Hydraulic Power Unit. The HPU consists of small pumps and an accumulator.
Production Manifold	Production manifold with actuated valves controlled manually from the CPF. Includes Production and Test Manifold.
Test Separator	Carbon steel 3-phase separator to allow for metering of condensate, water and gas at vessel outlets
Production Separator	Carbon steel 3-phase separator to segregate condensate, water and gas
Condensate Coalescer and Pumps	Secondary condensate treatment to remove additional produced water from the condensate. The dewatered condensate is then spiked back into the departing pipeline.
Condensate Allocation Metering	Meter for condensate after primary separation and prior to combining with gas in the departing pipeline.
Glycol Dehydration / Regeneration	Glycol dehydration and glycol regeneration package to remove sufficient amount of water vapor from the produced gas stream to avoid hydrates in the departing pipeline. The glycol reboiler will be heated with an electric heating element.
Gas Allocation Meter Skid	Meter for gas after primary separation and prior to combining with condensate in the departing pipeline.
Pipeline Pig Launcher	Permanently installed pig launcher for departing pipeline
Produced Water Hydrocyclones and Water Skimmer	Produced water treatment equipment to remove condensate from the produced water to a level acceptable for overboard disposal of produced water.
Flare Scrubber and Pumps	Carbon steel vertical flare scrubber. Liquids from the scrubber would be routed back to the production header. Flare system also includes high volume flare tip, CO_2 vent snuffing and ignitor panel.
Open Drain Tank and Pumps	Tank provided to catch any hydrocarbon leaks that may occur on the deck. Pumps spike the hydrocarbons into the departing pipeline.
Methanol Injection Skid	Methanol tank and pumps used for pressure equalization and hydrate inhibition prior to startup
NAV Aids	Lights, fog horns, etc.
Escape Capsules	Life Rafts and Survival Craft as required by Client and by Code
Generator	150 kW Diesel Generator with attached 2.5 m x 3 m building to house main breaker and motor control center. HVAC included with building.
Diesel Storage Tank	Diesel tank for generator
Crane	2 Te jib crane

APPENDIX D

PROCESS DIAGRAMS

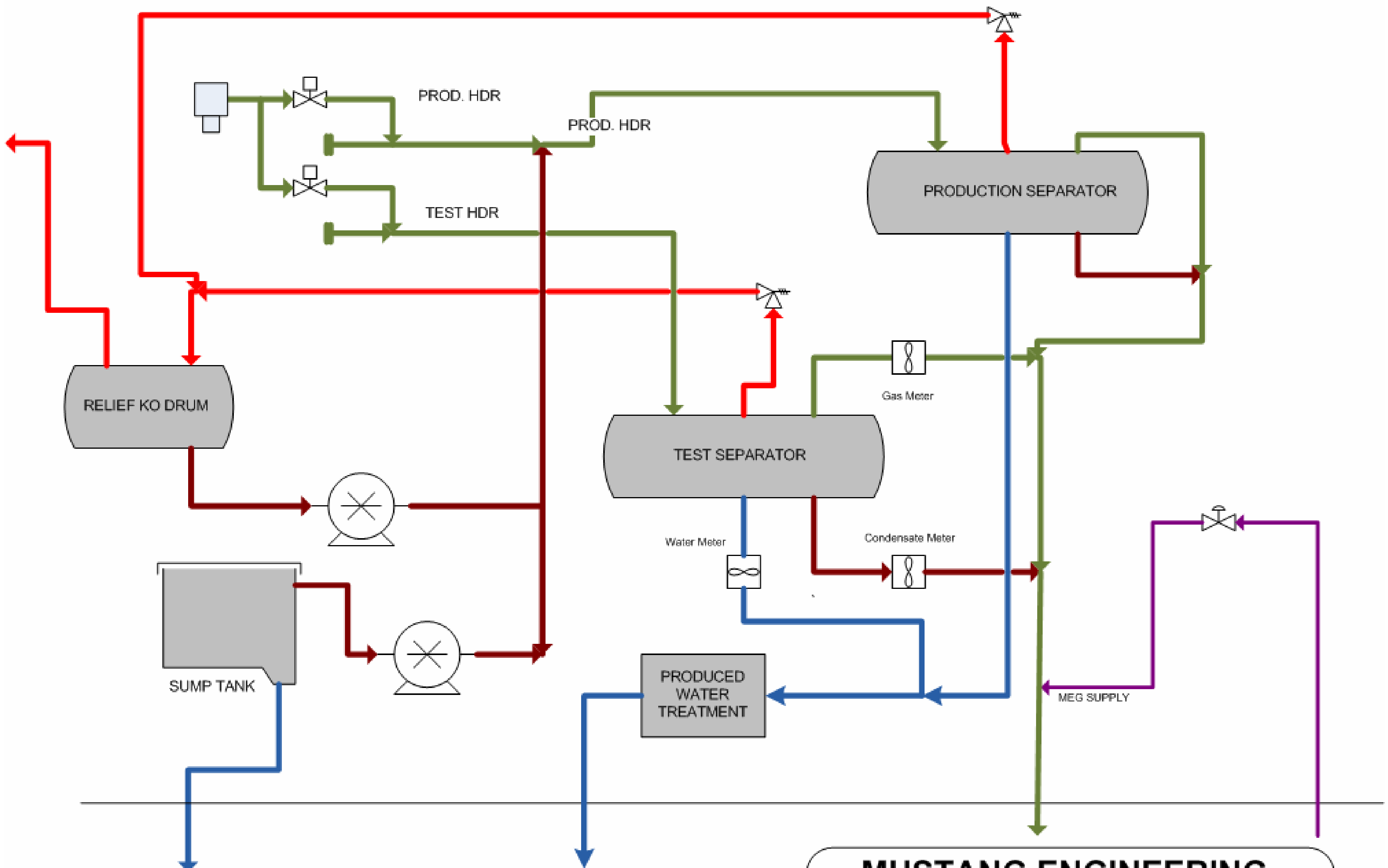
CASES 1 - 4



MARTEC™

MUSTANG ENGINEERING		
BLOCK DIAGRAM	Minimal Process	REV. 0

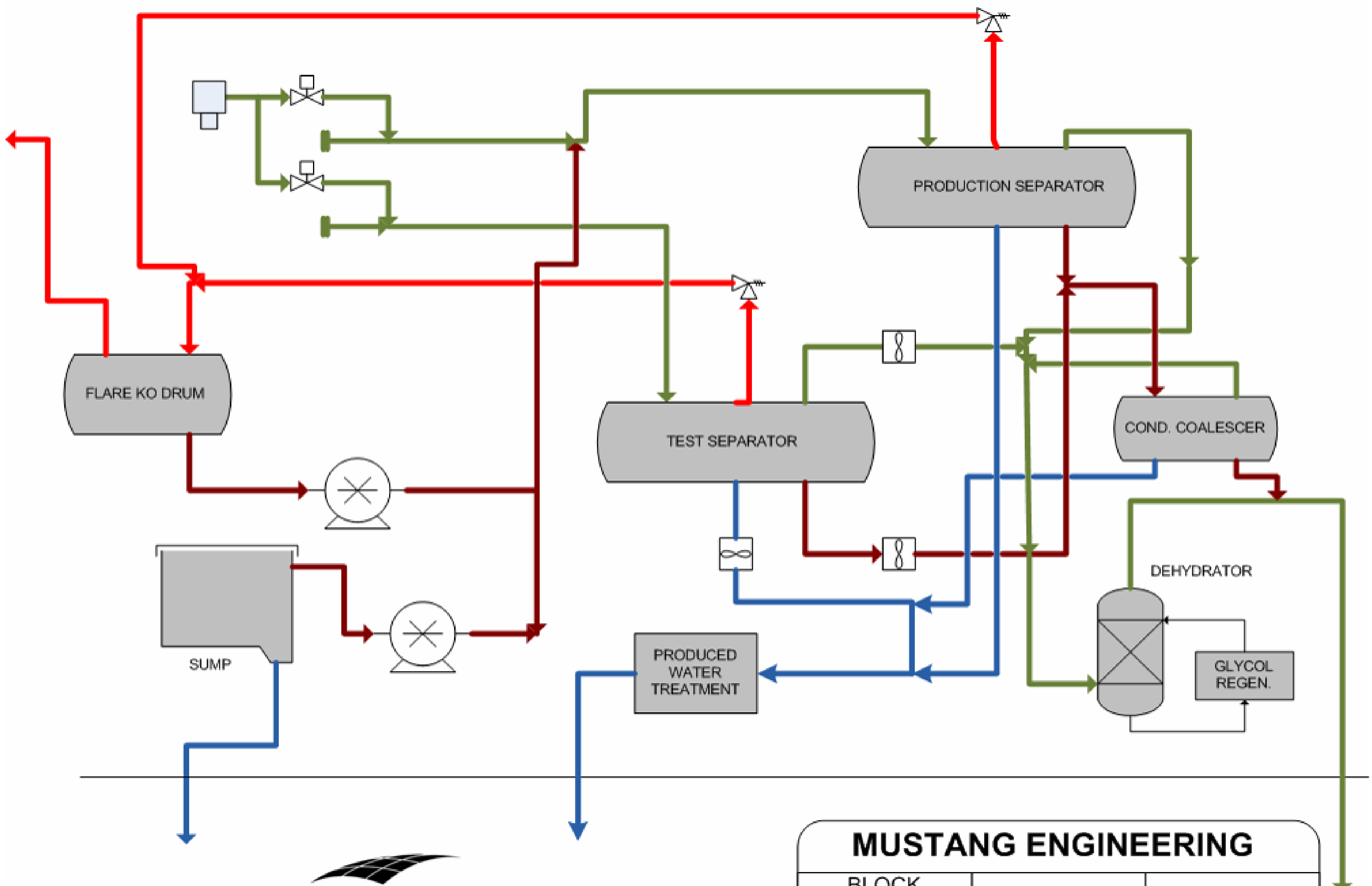
CASES 5 & 7



MUSTANG ENGINEERING		
BLOCK DIAGRAM	Semi-Process	REV. 0

MARTEC™

CASES 9 & 11



MARTEC™

MUSTANG ENGINEERING		
BLOCK DIAGRAM	Full Process	REV. 0

APPENDIX E

COST ESTIMATES

Restore Default Rates & Costs

SYSTEM DESCRIPTION	USER-INPUT COST	NOTES
STRUCTURAL INSTALLATION	**UNIT COST ($CDN)**	
Steel Procurement/Fabrication Including Piles ($CDN/Tonne)	$ 5,000	
Mobilization & Demobilization of Installation Flotilla (One-Time, Fixed)	**NIT COST ($CDN)**	
Drilling Rig	$ 2,500,000	
Onshore Crane & Supporting Equipment	$ 500,000	
Construction/Installation Vessel	$ 1,750,000	For example, 150T heave-compensated w/crane. Including pile-driving capabilities where required.
Support Vessel	$ 750,000	
Small Barge (e.g., Caisson Topsides, WHPS)	$ 50,000	Vessel may be available locally (i.e., mobilization not required)
Large Barge (e.g., Hub Topsides)	$ 100,000	Vessel may be available locally (i.e., mobilization not required)
Small Tug	$ 75,000	Vessel may be available locally (i.e., mobilization not required)
Large Tug	$ 150,000	Vessel may be available locally (i.e., mobilization not required)
Heavy Lift Vessel (Traditional Jacket Only)	$ 30,000,000	Day Rate x 30 days round trip to Sable
Day Rates for Installation Flotilla ($/day)	**UNIT COST ($CDN/DAY)**	
Drilling Rig	$ 500,000	
Onshore Crane & Supporting Equipment	$ 125,000	
Construction/Installation Vessel (Subsea Capable)	$ 400,000	
Support Vessel	$ 150,000	
Small Barge (e.g., Caisson Topsides, WHPS)	$ 20,000	
Large Barge (e.g., Hub Topsides)	$ 50,000	
Small Tug	$ 25,000	
Large Tug	$ 60,000	
Heavy Lift Vessel (Traditional Jacket Only)	$ 1,000,000	
Engineering & Project Management (Fraction of Steel)	0.10	During design and installation (not including topsides kit)
SUBSEA MANIFOLD SYSTEM	**UNIT COST ($CDN) PER**	
4-Slot 6"x10" Production Manifold (Including Procurement, Assembly, Testing, Insulation, Pigging Loop, Suction Pile Material/Fabrication, Protection Structure, Engineering & Project Management)	$ 10,000,000	Price to be scaled based on number of incoming flowlines.
Hookup & Commissioning (4-Slot Manifold)	$ 1,000,000	Hookup/Commissioning Cost (default based on 10%) to be scaled based on number of incoming flowlines.
SUBSEA WELLHEAD/TREE	**UNIT COST ($CDN)**	
Subsea Wellhead & Tree System (Including SIT, Engineering & Project Management)	$ 12,500,000	
Tooling Requirements	$ 4,500,000	
Hookup & Commissioning	$ 1,250,000	Default cost based on 10% of system cost.
PIPELINE/CABLE INSTALLATION	**COST PER KM ($CDN/km)**	
Materials Procurement/Fabrication		
Interfield Flowline	$ 175,000	6"
MEG Injection Line	$ 100,000	3"
Umbilicals	$ 400,000	Data power/hydraulics
Export Line	$ 350,000	
Power Cable Tie-Back	$ -	Included in umbilical price
Mobilization of Pipelay Spread (One-Time, Fixed)	**UNIT COST ($CDN)**	
Pipelay Vessel	$ 5,500,000	
Trenching Vessel	$ 4,500,000	Typically trenching for EXPORT Line ONLY
Survey Vessel	$ 2,500,000	
Pipe Supply Vessel (Incl 10xDayRate in Transit)	$ 625,000	
Day Rates for Pipelay Spread ($/day)	**UNIT COST ($CDN/DAY)**	
Pipelay Vessel	$ 550,000	
Trenching Vessel	$ 200,000	
Survey Vessel	$ 150,000	
Pipe Supply Vessel	$ 50,000	
Estimated Pipe Lay Rate (km/day)	3.50	
Weather Downtime Factor	0.60	The lower the value, the less time lost do to weather.
Export Line Trenching (Fraction of Total Length)	0.80	
Engineering & Project Management (Fraction of Materials)	0.10	Flat rate $137,500 per km also suggested
TOPSIDES ACCESSIBILITY OPTIONS	**UNIT COST ($CDN)**	
Infrastructure for Boat Access Only	$ 100,000	To be confirmed.

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Topsides Cost / Weight Summary

			COST						WEIGHT (Te)				
Type	Case #	Description	Engineering / Inspection	Equipment	Structural Fab	Outfitting	Loadout / Tiedown	TOTAL	Equipment	Structural	Bulks	TOTAL	Deck Area (m^2)
1	1	1 well, no treating	$ 224,248	$ 1,057,558	$ 275,962	$ 702,361	$ 46,184	**$ 2,306,313**	9	26	17	**53**	**101**
	2	2 well, no treating	$ 268,974	$ 1,201,322	$ 336,436	$ 835,525	$ 55,655	**$ 2,697,912**	11	32	21	**64**	**123**
	3	4 wells, no treating	$ 427,561	$ 1,581,259	$ 489,368	$ 1,452,539	$ 89,183	**$ 4,039,910**	19	46	36	**102**	**166**
	4	6 wells, no treating	$ 544,795	$ 1,881,453	$ 616,421	$ 1,876,446	$ 114,014	**$ 5,033,129**	25	58	47	**130**	**209**
2	5	4 wells, partial treating, on board power	$ 1,311,983	$ 3,156,599	$ 1,334,487	$ 5,267,152	$ 276,762	**$ 11,346,983**	76	127	114	**317**	**422**
	7	6 wells, partial treating, on board power	$ 1,629,172	$ 3,788,633	$ 1,635,606	$ 7,000,898	$ 342,520	**$ 14,396,830**	95	155	142	**392**	**517**
3	9	4 wells, full treating, on board power	$ 2,048,640	$ 5,439,587	$ 2,041,740	$ 9,222,559	$ 426,878	**$ 19,179,404**	133	194	161	**488**	**605**
	11	6 wells, full treating, on board power	$ 2,767,868	$ 7,078,598	$ 2,654,212	$ 13,538,739	$ 573,916	**$ 26,613,333**	183	252	222	**657**	**787**
Any	Any	Helideck and Saferoom	$ 130,335	$ 65,454	$ 1,018,000	$ 10,039	$ 40,213	**$ 1,264,041**	6	40	0	**46**	**266**

ITEM	PART NUMBER	DESCRIPTION	QTY	Unit Price	Ext'd Price
1.0		**Wellhead**			
1.1		30" Low pressure housing with 30' of 30" x 1 1/2" conductor pipe welded, Grade X-56. Bottom connection VETCO ALT-2 BOX. With handling lugs.	6	80,905	485,430
1.2		18 3/4" High pressure housing with 20' of 20" x 0.812" casing pipe welded, Grade X-56. Top connection mandrel H4, bottom connection VETCO ALT-2 BOX.	6	120,267	721,602
1.3		13 3/8" Casing hanger bottom BOX, torqued to a 20' PIN - PIN 13 3/8" x 0,580 casing pipe, Grade X-56. PIN - PIN Butress, 72 lbs/ft.	6	43,056	258,336
1.4		ASSY, 18-3/4 X 10-3/4 CASING HANGER, COMPLETE WITH INTERNAL CLAD SEAL AREA, WITH 10-3/4 OD X .450 WALL X 20 FT. LG. PUP JOINT, WITH TENARIS TC II PIN	6	49,840	299,040
1.5		ASSY CASING HANGER STC-10, 18-3/4" X 9-5/8" WITH 9-5/8" OD X 53.5LBS X 20FT. LG PUP JOINT NEW VAM 53.5 LBS/FT PIN X PIN THREADS W/THREAD PROTECTOR.	1	37,590	37,590
1.6		Master Wear bushing 18 3/4" for 6 string housing.	3	14,603	43,809
1.7		Wear bushing 18 3/4" x 13 3/8"	3	20,793	62,379
1.8		Wear bushing 18 3/4" x 10 3/4" ASSEMBLY, 10.75" WEAR BUSHING W/ 9.665 I.D., TO LAND ON HGR. IN MID POS. IN HOUSING	3	18,033	54,099
1.9		Wear bushing 18 3/4" x 9 5/8"	1	15,616	15,616
1.10		Temporary abandonment cap	4	14,277	57,108
1.11		Seal Assembly 18 3/4", 10,000 psi, Standard weight	6	14,661	87,966
1.12		Emergency Seal Assembly 18 3/4", 10,000 psi, Standard weight	2	8,896	17,792
2.0		**Horizontal Spool Tree**			
2.1		SpoolTree, 5 IN X 2 IN 10K, G2, Modular, Integral Valves, H4 Profile Top X H4 Profile DWH Connector, 2 SSV, 1 DHCI AND 1 Tree CI, 1 ELEC PEN, Hydraulic Connector T/C S,T,U,V. Production M/C FF, Annulus M/C EE, PSL 3. WD 0-5000 FT, PR2, 'SANDY' API 6A USV. Control Fluid "TRANSAQUA HT". (SCMMB and Instrumentation Free issue from Controls Scope) With Pigging Loop.	6	3,573,533	21,441,198
2.2		6" CVC Pressure Cap for CVC hub on Tree ASSEMBLY, PRESSURE CAP, 6"-10K FLOWLINE HUB, 5.501 SEAL BORE, W/ 3/8" MP AUTOCLAVE PORTS (PLUG W/ 2X O-RINGS), PMT W/ 6X ANODES; (QP-000162-02); PSL-3	6	46,958	281,748
3.0		**PLET Components**			
3.1		Assembly, hub & Receiver structure, 10"-5K CVC	6	67,257	403,542
3.2		9" GV (manual)	6	248,333	1,489,998
3.3		10" Pressure Cap CVC	6	143,378	860,268
5.0		**Jumper Kits**			

CAMERON

EASTERN CANADA
SUBSEA TIEBACKS
EQUIPMENT

SSP50-7080

ITEM	PART NUMBER	DESCRIPTION	QTY	Unit Price	Ext'd Price
5.1		SUB-ASSEMBLY & WELDMENT, JUMPER KIT, 6" X 10" TREE-PLET, 6"-10K CVC X 10"-5K CVC CONNECTORS, 6.625 OD PIPE X .875 WALL; (FULL CLAD BODY W/ DUPLEX PIPE PUP); WP 5,000 PSI; PSL-3; (QP-000162-02)	6	1,004,227	6,025,364
6.0		**Topsides Controls**			
		Topsides Equipment	1	1,813,209	1,813,209
7.0		**Subsea Distribution Equipment**			
		Subsea Distribution Equipment	1	3,427,494	3,427,494
8.0		**Tree Mounted Controls**			
		Tree Mounteded Controls	1	8,457,920	8,457,920
9.0		**Hydraulic Flying Leads**			
		Hydraulic Flying Leads	1	4,193,767	4,193,767
10.0		**Electrical Flying Leads**			
		Electrical Flying Leads	1	315,616	315,616
11.0		**Controls Subsea Instrumentation**			
		Controls Subsea Instrumentation	1	12,736,272	12,736,272
12.0		**Controls Test Equipment**			
		Controls Test Equipment	1	661,361	661,361
13.0		**Testing**			
13.1		SIT Testing	1	2,167,127	2,167,127
14.0		**Freight & Customs & Duties**			
14.1		International Intercompany Freight for Equipment	1	476,772	476,772
15.0		**Personnel**			
15.1		Project Engineering	1	3,763,894	3,763,894
15.2		Project Manager	1	4,705,749	4,705,749
15.3		Travel	1	1,059,343	1,059,343

TOTALS	**76,421,409**

ITEM	PART NUMBER	DESCRIPTION	QTY	Unit Price	Ext'd Price
1.0		**Wellhead Running Tools**			
1.1		Assembly guidebase retrievable and reinstallable with slotted	1	113,583	113,583
1.2		Assembly Running Tool	1	60,063	60,063
1.3		Assembly 30" Housing Running Tool	1	69,532	69,532
1.4		Assembly 18-3/4" Housing Running and Test tool	1	133,723	133,723
1.5		Assembly Running Tool 18-3/4 CSG HGR	1	213,763	213,763
1.6		Assembly Wear Bushing Running/Retrieval tool	1	52,958	52,958
1.7		18-3/4" Weight Set BOT Test tool	1	44,665	44,665
1.8		Assembly Jetting tool	1	16,449	16,449
1.9		Assembly Mill & Flush tool	1	55,834	55,834
1.10		Seal Assembly Retrieval Tool (SART)	1	44,316	44,316
1.11		Wear Bushing 13 3/8"	1	8,996	8,996
1.12		Assembly 10.75" Wear Bushing	1	7,527	7,527
1.13		Wear Bushing 9 5/8"	1	20,403	20,403
1.14		Boll Weevil Tester	1	24,772	24,772
1.15		18 3/4" Bore Protectors	1	12,925	12,925
1.16		T/A Cap Running/Retrieving Tool	1	6,396	6,396
1.17		Tooling Skid #1	1	55,125	55,125
1.18		Tooling Skid #2	1	55,125	55,125
1.19		Tooling Skid #3	1	75,543	75,543
2.0		**Spool Tree Running Tools**			
2.1		Tree Running Tool (TRT)	1	604,844	604,844
2.2		Tubing Hanger Running Tool (THRT)	1	275,050	275,050
2.3		Bore Protector Run/ Ret Tool	1	32,796	32,796
2.4		Tree Handling Tool	1	42,370	42,370
2.5		BOP Weight Set Test Tool	1	84,276	84,276
2.6		TBG. HGR Retrieval Tool	1	74,426	74,426
2.7		Access Stand for THRT	1	3,920	3,920
2.8		Bore Protector Spool Tree System	1	46,354	46,354
2.9		WireLine Tools (Made up of the items below)	1		
2.9.1		Wireline Centralizer	1	3,410	3,410
2.9.2		Wireline Spacer	1	1,206	1,206
2.9.3		Wireline Plug RT	1	13,358	13,358
2.9.4		Wireline Plug Pulling Tool	1	6,750	6,750
2.9.5		Protection Sleeve Running Pulling Tool	1	15,008	15,008
2.9.6		Isolation Sleeve Running Pulling Tool	1	11,314	11,314
2.9.7		Protection Sleeve (Short)	1	19,530	19,530
2.9.8		Protection Sleeve (Long)	1	20,354	20,354
2.9.9		Wireline Isolation Sleeve	1	17,492	17,492
2.10		Tubing Hanger Handling / Test Tool	1	40,932	40,932
2.11		Tree Test and Shipping Skid	1	166,314	166,314
2.12		Det & Assy Flushing plug, Lower Control Line Port	1	1,890	1,890
2.13		Protection Torque Sleeve	1	8,616	8,616
2.14		THRT Handling & Test Tool	1	46,216	46,216

EASTERN CANADA
SUBSEA TIEBACKS
TOOLING

ITEM	PART NUMBER	DESCRIPTION	QTY	Unit Price	Ext'd Price
2.15		Isolation Sleeve Stand	1	90,694	90,694
2.16		Test Stab Control line	1	1,670	1,670
2.17		Boll Weevil Test Tool	1	21,200	21,200
2.18		Mill and Flush Tool	1	28,250	28,250
2.19		Tubing Hanger Split Bowl	1	8,076	8,076
2.20		Safety Davit	1	26,932	26,932
2.21		Tree Ladder	1	4,102	4,102
2.22		Choke Running Tool	1	137,894	137,894
2.23		Choke Running Tool Shipping Skid	1	37,844	37,844
2.24		Choke Insert Shipping & Test Skid	1	24,154	24,154
2.25		Service Container and Miscellaneous Tools	1	466,668	466,668
2.26		Service Container	1	72,060	72,060
2.27		17H Hot Stab	1	2,380	2,380
2.28		TH Shipping Skid	1	24,420	24,420
2.29		THRT Shipping Skid	1	20,046	20,046
2.30		MITCRIT	1	75,530	75,530
2.31		Tronic Test Equipment	1	8,556	8,556
2.32		Tree Maintenance Stand	1	39,572	39,572
2.33		AX Gasket Installation Tool	1	6,860	6,860
2.34		Tubing Hanger Stand	1	2,730	2,730
2.35		Pressure Test Stand THRT Hyd	1	24,442	24,442
3.0		**CVC Tooling**			
3.1		Spreader Bar for Jumpers w/Slings	2	217,885	435,770
3.2		6" Test Clamp Assy (Blind Hub and Clamp)	4	38,276	153,104
3.3		10" Test Clamp Assy (Blind Hub and Clamp)	2	55,292	110,584
3.4		10" Flooding Cap CVC	2	127,707	255,414
3.5		CVC Running Tool w/Sling	4	496,280	1,985,120
3.6		Shipping Stand for 6" Connector end of Jumper	4	51,660	206,640
3.7		Shipping Stand for 10" Connector end of Jumper	4	54,245	216,980
3.8		Jumper fabrication stand for 6" Connector end of jumper	4	173,145	692,580
3.9		Jumper fabrication stand for 10" Connector end of jumper	4	181,803	727,212
4		10" Seal Removal/Replacement Tool	1	31,094	31,094
4.1		6" Seal Removal/Replacement Tool	1	22,489	22,489
4.2		6" Hub Cleaning Tool	1	5,094	5,094
4.3		10" Hub Cleaning Tool	1	5,149	5,149
4.4		HPU for CVC Equipment	2	72,227	144,454
5.0		**Controls Test Equipment**			
5.1		SCM Test and Flushing Unit	1	570,510	570,510
5.2		Hydraulic Test and Flushing Skid & Hydraulic Power Unit	1	711,357	711,357
5.3		Pre-Charge Intensifier Unit (Booster)	1	37,641	37,641
5.4		PETU (Complete with Test Cables)	3	71,258	213,774
5.5		Sand Detector Simulator	1	14,162	14,162
5.6		Wet Gas Flowmeter Simulator	1	75,959	75,959
5.7		PT Transmitter Simulator (can-bus)	1	8,866	8,866

ITEM	PART NUMBER	DESCRIPTION	QTY	Unit Price	Ext'd Price
6.0		**Controls Tools**			
6.1		MPRT	1	394	394
6.2		SCM Offshore Hanlding and Shipping Skid	1	474	474
6.3		FLDF (for EFL's only)	1	221,507	221,507
7.0		**IWOCS**			
7.1		Hydraulic Power Unit c/w Control Panel	1	1,346,182	1,346,182
7.2		Remote ESD Station	2	31,602	63,204
7.3		Workover Umbilical Reel	1	1,349,048	1,349,048
7.4		Workover Umbilical Sheave	1	35,815	35,815
7.5		Umbilical Clamps - Riser (Strap Type)	25	130	3,250
7.6		Umbilical Clamps Drill Pipe - Strap Type	25	130	3,250
7.7		Portable Electronic Termination Unit (PETU)	1	120,083	120,083
7.8		Electrical Flying Lead (BOP to Tree)	2	14,746	29,492
7.9		Hydraulic Flying Lead (BOP to Tree)	1	280,656	280,656
7.10		Electrical Parking Receptacle (BOP)	2	6,320	12,640
7.11		Hydraulic Parking Plate (BOP)	1	50,562	50,562
7.12		Emergency Disconnect Unit	1	316,006	316,006
7.13		Test and Flushing Plate - Female	2	31,601	63,202
7.14		Test and Flushing Plate - Male	2	27,388	54,776
7.15		Test and Flushing Plate - Subsea HFL	1	105,335	105,335
7.16		Electrical Test Connector - Reeler Umbilical End	1	6,321	6,321
7.17		Electrical Test Connector - Subsea EFL (Tree End)	2	6,321	12,642
7.18		Jumper Basket	1	48,454	48,454
7.19		Uninterruptible Power Supply (UPS)	1	18,960	18,960
7.20		Accumulator Precharge Kit (With Nitrogen Intensifier)	1	13,694	13,694
7.21		Fluid Cleanliness Monitoring System	1	36,868	36,868
7.22		Workover Hydraulic Deck Jumper	1	96,741	96,741
7.23		Electrical Deck Jumper	1	31,602	31,602
7.24		IWOC Umbilical	1	Included in 7.3	
7.25		IWOCS Free Plate - attaches to end of IWOCs umbilical	1	Included in 7.3	
7.26		Electrical Test Connector - Subsea EFL (EDU End)	2	5,164	10,328
7.27		Protective Cap	2	159	318
8.0		**ROV Tooling**			
8.1		Flying Lead Orientation Tool	1	64,160	64,160
8.2		ROV Torque Tool, Class 1-4	1	194,480	194,480
8.3		Remote Control Unit (RCU)	1	173,224	173,224
8.4		ROV Linear Override Tool 2" actuator	1	260,428	260,428
8.5		ROV Linear Override Tool 5" actuator	1	280,428	280,428
8.6		Hydraulic Power Pack	1	155,852	155,852
8.7		Dual Port Hot Stab	1	7,520	7,520
9.0		**Testing**			
9.1		IWOCS Test (one off test)	1	146,048	146,048
10.0		**Freight & Customs & Duties**			

EASTERN CANADA
SUBSEA TIEBACKS
TOOLING

ITEM	PART NUMBER	DESCRIPTION	QTY	Unit Price	Ext'd Price
10.1		International Intercompany Freight for Optional Equipment	1	273,690	273,690
11.0		**Personnel**			
11.1		Project Engineering	1	482,972	482,972
11.2		Project Manager	1	483,234	483,234
11.3		Travel	1	37,150	37,150
		TOTALS			**17,247,147**

APPENDIX F

OTC PAPER

20704 DRY VERSUS WET: AN EVALUATION OF SUBSEA TIE-BACKS AND SURFACE PLATFORM DEVELOPMENT STRATEGIES FOR NOVA SCOTIA

OTC 20704

Dry versus Wet: An evaluation of subsea tie-backs and surface platform Development Strategies for Nova Scotia

C. Dunn and P. Rushton; Martec Limited, member of the Lloyd's Register Group

This paper was prepared for presentation at the 2010 Offshore Technology Conference held in Houston, Texas, USA, 3–6 May 2010.

Abstract

The Nova Scotian Offshore has many discovered fields with low quantities of recoverable resources. These marginal fields will need development plans which require lower capital costs than that of standard development. Other areas of the world have also faced similar issues regarding the economics of developing marginal fields. Some of these fields have become economically viable by reducing the cost of the offshore facility and production used to extract and distribute the gas or oil.

This paper presents the results of the evaluation of a case study of a marginal gas field in the Sable Island area of Nova Scotian Offshore. It provides a comparison of the technologies and strategies that would be used to develop the field for a low production rate, including a direct comparison of an exclusively subsea development with that of a minimal Dry Caisson platform development. The comparison includes costs as well as benefits and disadvantages of each development option.

The evaluation results show that for the case study water depth of 40m, the Dry Caisson platform is suitable for use and provides an option for development with a capital cost far lower than the comparable subsea option. Limitations of access, installation considerations and maintenance of both systems are also compared.

Introduction

Currently the Nova Scotian Offshore (NSO) region has many discoveries which could be defined as marginal fields, as shown in Figure 1. Historically, offshore field development for the NSO has used standard large scale and capital intensive infrastructure which would likely be uneconomical for these marginal fields. Minimal platforms and subsea development may provide more cost effective options for future developments.

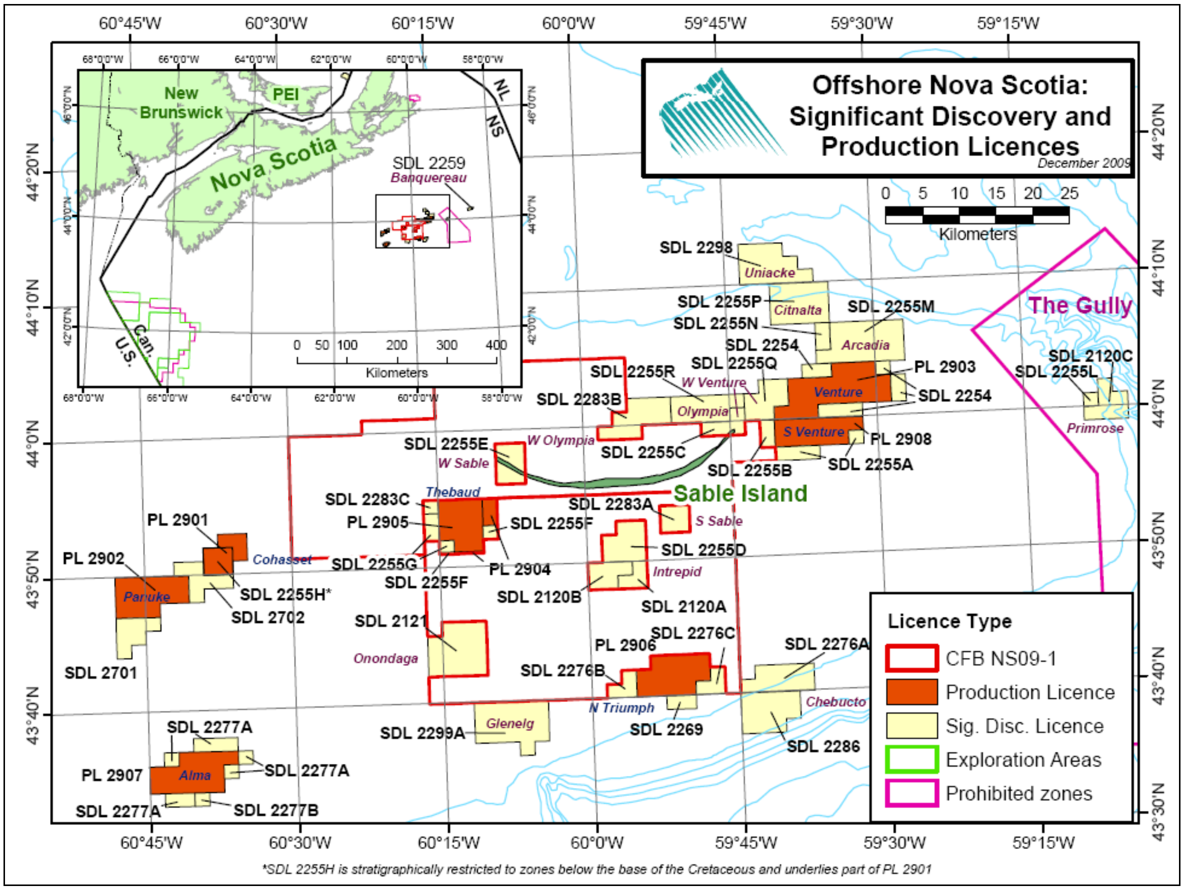

Figure 1: Sable Island Offshore Areas as defined by current Exploration, Discovery and Production Licenses

Minimal platforms typically include a reduction in platform size and weight. These smaller and lighter platforms may eliminate the requirement for extremely expensive offshore heavy lift vessels. The mobilization of these vessels to the remote NSO can have a huge impact on the cost of a marginal field development. Utilization of innovative transport and installation techniques can eliminate the need for these vessels and greatly reduce the installation costs.

However, the NSO seastate is of significant importance in consideration of the use of minimal platforms. The environmental conditions offshore of Eastern Canada are considered severe. Large waves, high tides, strong currents, high winds, spray ice and cold temperatures are some of the factors to be contended with in the design of an offshore facility. These environmental conditions play a significant role in determining the structural robustness of the facility.

Subsea equipment and development also offers the potential for lower development costs and has been used for the first time in 2009 for field development in the NSO. Subsea development typically requires minimal permanent equipment and therefore does not have significant installation requirements. However, as the development is below the water surface, access to the production equipment is very limited.

Significant Discovery Areas (SDAs)

While several major developments have either been operating or are about to start in the NSO, many potential reserves have not been developed. These fields, which have been explored and delineated to varying amounts, have been designated as Significant Discovery Areas (SDAs) by the local regulatory body, the Canada Nova Scotia Offshore Petroleum Board (CNSOPB). To achieve this status, the licensee of the original exploratory license had to have applied for significant discovery designation. The SDAs are presented in Table 1.

The SDAs vary in recoverable assets from 5Bcf to 450Bcf for Gas, and 23MMBbl to 52MMBbl for oil (CNSOPB 2000). The seabed geology is nearly entirely dense sand, with a potential for a clay layer to appear within the first 100m below the seabed. The water depths vary from 0m (West Sable, which initially was drilled from Sable island itself) to 125m. A map of the NSO licenses is provided in Figure 1. It is these locations to which future minimal development will apply.

Table 1: Significant Discovery Areas for NSO

SDA #	Common Name	Current Owner *Sept-08*	General Location		Depth
			Latitude	Longitude	
2255P	Citnalta	ExxonMobil	44-08-45	59-37-30	95m
2286	Chebucto	ExxonMobil	43-38-00	59-41-00	86m
2255D	Intrepid	ExxonMobil	43-52-00	59-53-00	44m
2255Q	West Venture	ExxonMobil	44-02-00	59-40-00	<20m
2255R	Olympia	ExxonMobil	44-03-00	59-48-00	50m
2238B	West Olympia	ExxonMobil	44-02-00	59-53-00	50m
2298	Uniake	Shell Canada	44-11-30	59-41-00	75m
2283A	South Sable	ExxonMobil	43-54-00	59-50-00	<20m
2255N	Arcadia	ExxonMobil	44-05-30	59-35-00	56m
2121	Onondaga	Shell Canada	43-44-30	60-12-30	60m
2299A	Glenelg	ExxonMobil	43-38-00	60-08-00	85m
2255E	West Sable	ExxonMobil	43-57-00	60-07-30	-
2417	Penobscott	Ammonite	44-09-45	60-04-00	125m
2418	Eagle	Ammonite	43-50-00	59-34-00	50m
2255L	Primrose Gas	Shell Canada	44-00-00	59-07-00	100m
2259	Banquereau	ExxonMobil	44-10-08	58-34-00	80m

Case Study

The purpose of the case study is to evaluate the development of a typical marginal field of the NSO, based upon the current information available on the Sable SDAs. The evaluation will focus on the comparison of dry production on a Single Caisson type structure with a development using subsea equipment.

Tie-Back

The Sable Island area of the NSO has several existing offshore structures with varying types of topsides processing. All the current platforms produce natural gas in various forms including market ready and partially dehydrated 2-phase flow. This study compares the dry and subsea development of a gas field in this region as a tie-back development to an existing gas production host. As such, the tie-back facilities will have a minimum of production capabilities, with the majority of required processing provided by the host. This processing by the host can occur on the initial host platform, or further downstream. It is assumed that the host has;

- spare production capacity to accept 2 phase wet gas from the tie-back (no dehydration at wellhead)
- available power if required for the tie-back facility
- available deck space for additional control systems
- available deck space for additional process or metering equipment required (including separation if required)
- source of MEG for tie-back facilities
- available space for required risers, flow lines and umbilicals

Caisson (Braced or Single)

To evaluate the tie-back case using dry equipment, the Single Caisson type structure was used. The Caisson type structure consists of a structural caisson shell which is installed over and around the well conductor casing for the full height of the water column, as shown in Figure 2. The outer caisson shell supports the lateral loading of the wind and wave action. It also supports the topside weight and operational loads. The well conductor is located within the caisson shell and the limited appurtenances are routed on the outside of the shell.

The single caisson design consists of larger diameter tubes at the mudline, with conical transitions to smaller tubes as the structure rises through the water column. The lower sections are designed for maximum bending, whereas the upper portions are reduced to limit wave loading. The caisson shell is driven into seabed as a single pile, after the well conductor casing has been installed by the drilling operations. Within the caisson shell, centralizers ensure that the shell is aligned properly.

The single caisson design is sensitive to soil conditions and particularly to the lateral strength of the soil. For these single caissons, the foundation loading is nearly exclusively lateral loading, as opposed to the typical axial loading of piled foundations. If soil strength is an issue, additional braces can be used to allow for additional piles.

Figure 2: Dry Single Caisson Minimal Platform, 40m of water depth, appurtenances not shown

Subsea

The subsea equipment for this study was chosen to be standard and available from multiple subsea equipment vendors. Figure 3 shows the typical subsea remote wellhead, complete with flow line and umbilical, within the subsea protection structure.

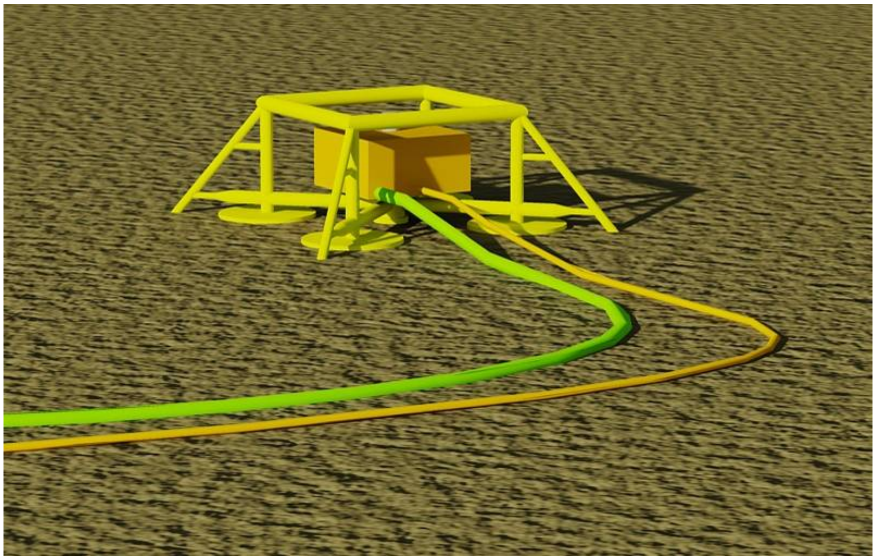

Figure 3: Subsea Wellhead, complete with flow line and umbilical, housed inside subsea wellhead protection structure

Production Case

For the case study, a development of a natural gas field was chosen as this represents the majority of stranded resources in the Nova Scotian offshore (CNSOPB 2000). Table 2 shows the production profile used for the case study. The production rate of 17,700 m3/hr (15 MMscfd) has purposely been set low to allow for the minimal level of facilities to be specified for the development. It is quite likely that increases to production would affect both subsea and dry production in similar fashions. This rate is not indicative of the actual optimal production rate for the Sable SDAs.

The tie-back facilities configuration is based on the flow assurance scheme using MEG to prevent hydrate formation in the flowlines between the well and the host facility where full gas, condensate and water treatment can be provided. The MEG supplied by a pipeline from the host will be injected into the production header in quantities sufficient to inhibit hydrate formation. As produced water is not removed from the production stream, the MEG will require vacuum distillation type recovery (MEG Reclamation) at the host. If quantities of produced water are too high, then in reality this option would not be feasible.

Table 2: Case Study Production Profile	
Gas Production Rate	17,700 m^3/hr (15 MMscfd)
Condensate Production Rate:	63.8 m^3/day (400 BPD)
Water Production Rate	21.2 m^3/day (135 BPD)
Total Liquids Production Rate	85 m^3/day (535 BPD)
Reservoir SITP	< 400 bar (5800 psi)
FWHP	< 345 bar (5000 psi)
Wellhead Rating	API 5000 or ANSI 2500
Sand Production	Minimal - provide sand probes in flowlines
Condensate Emulsion	Not anticipated
Hydrates	MEG required for inhibition
Paraffin	Nil
CO2	Nil
H2S	Nil

NSO Metocean Conditions

While the environmental conditions will be different for every site considered, the Sable region of the NSO has several consistent features. The area has consistent soil of dense sand layers, with a periodic layer of firm clay. For the purposes of this study the soil was assumed to be dense sand, ideal for driven pile performance. Another feature of the Sable region is the accretion of spray ice and severe wave loading. While a common design criterion for spray ice and wave loading is not available for the region, Table 3 shows the spray ice and Table 4 shows the metocean criteria used for this case study, as suggested by Dunn et al. (2009).

Water depth is critical to the loading of the Caisson Structure. For the case study the water depth was chosen as 40m (131ft). This represents a depth of water at many of the Sable SDA locations (CNSOPB 2000).

For the consideration of flowline and umbilicals, the distance between the remote tie-back wellheads was taken as 10km (6.2 miles) to the host platform. At this distance flow assurance should be achievable with hydrate inhibition alone.

Reservoir pressure and temperatures were assumed to be within typical equipment ranges, with no requirement for high pressure/ high temperature considerations.

Table 3: Wave Study Spray Ice	
Elevation	**Thickness (mm)**
25m above MSL	0
10m above MSL	24
8m above MSL	144
5m above MSL	300
4m above MSL	300

Table 4: Case Study Metocean Criteria	
Parameter	**Nova Scotian Offshore**
Marine Growth	100mm: at MSL +2.0m 50mm: at the Mudline
Current (Linear Stretching)	2.0 m/s at Surface 1.7m/s at Mid Depth 1.1 m/s at Mudline
Wave Theory	Stream Function
Hydrodynamics: Cd Cm	0.65 smooth 1.05 rough 1.60 smooth 1.2 rough
Wave Kinematics Factor	0.90
Water Depth (MSL) (m)	Hmax / Associated Period (T)
15	11.0m / 10.1s
20	14.7m / 11.7s
30	20.0m / 14.3s
40	24.0m / 16.5s
50	26.9m / 17.9s
60	28.2m / 19.0
70	28.2m / 19.0
80	28.4m / 19.0
90	28.4m / 19.0
100	28.4m / 19.0
Soil Type	Dense Sand

Results

The production case and metocean criteria were applied to both the dry single caisson tie-back and the single subsea wellhead tie-back with results described as follows:

Single Caisson

The Single Caisson structure was developed including a 7.5m x 7.5m topsides platform, consisting of two deck levels, in Figure 4. The description of the platform structural details is found in Table 5.

Table 5: Single Dry Caisson Results 40m of water depth	
Caisson Structural Shell weight	218 tonnes
Maximum shell diameter	2400mm
Minimum shell diameter	915mm
Topsides Structure weight	26 tonnes
Topsides Equipment Weight	9 tonnes
Topsides Bulks Weight	17 tonnes
Topsides Estimated Deck Area	101 m^2
Topsides deck	7.5m x 7.5m

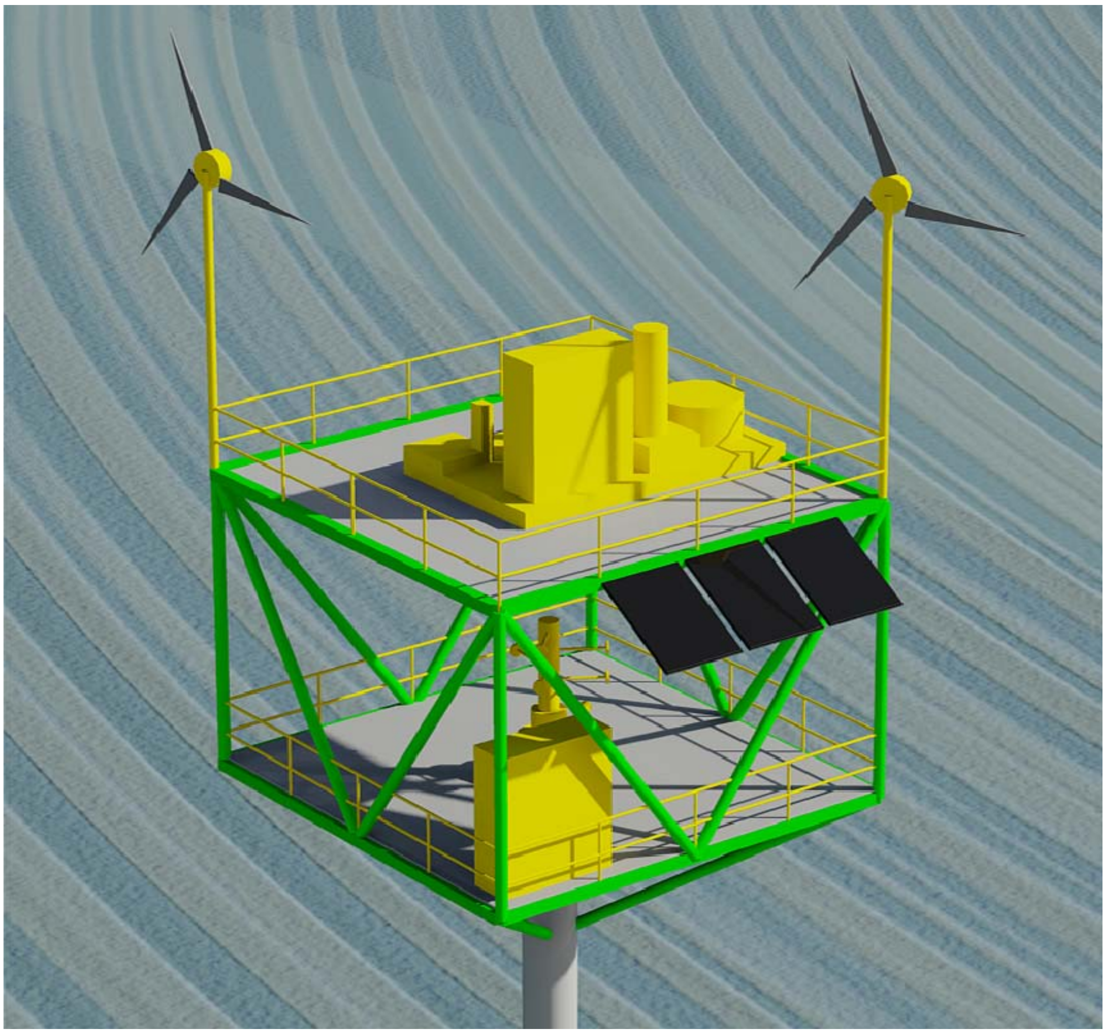

Figure 4: Dry Single Caisson case study topsides, complete with wellhead, control unit, generator, MEG injection, HIPPS, Wind&solar power, 100m² of useable deck space

The topside equipment list and process (Figure 5), allowing the platform to meet the production profile and case study requirements for a remote tie-back are as follows;

Single Caisson Equipment List

Production Well Control Panel

HIPPS systems

Gas Pipe line Pig Launcher (allowed space only)

Open Drains Tank

Open Drains Pumps

Methanol Injection Skid

Nav Aids

Escape Capsule

15 to 25 kW Generator (or Wind, solar, battery)

Small Diesel tank

Process Control System

Well control panel

Emergency Shut Down System

Telecommunications System (Microwave)

Offskid Valves and Instruments

Crane (2 tonne)

Piping

Piping Supports

Cable Tray

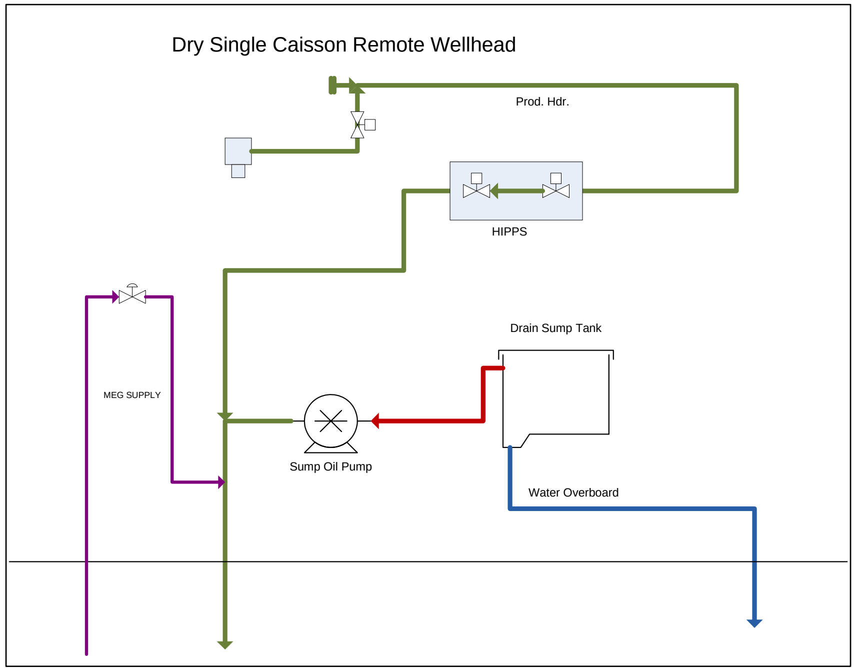

Figure 5: Dry Single Caisson process diagram

The equipment provides the minimal process and flow assurance required to meet the case study requirements and results in a topside deck requirement which can be met by the Single Caisson platform. The topsides offshore lift weight of less than 60 tonnes will be low enough to allow for standard construction vessels to install the topsides without need of specialized installation equipment or vessels.

The Single Caisson platform does not include helicopter access nor does it have temporary facilities for personnel. This is unlike current unmanned platforms in the Sable Island area which use helicopter access as the main means for maintenance and inspection. Boat would be the main form of access to the Single Caisson topsides, either though man basket type transfer or specialized heave compensated access gangways. The topsides can also be accessed by workover or construction vessels during more intensive maintenance or workover campaigns.

Subsea

The subsea system and equipment chosen to meet the case study requirements are shown below, and shown in Figure 6:

Wellhead

30" Low pressure housing

18 3/4" High pressure housing

13 3/8" Casing hanger bottom BOX

Master Wear bushing

Wear bushings

Temporary abandonment cap

Seal Assembly 10,000 psi, Standard weight

Emergency Seal Assembly 10,000 psi, Standard weight

Horizontal Spool Tree

SpoolTree, 10,000psi, With Pigging Loop.

6" CVC Pressure Cap for CVC hub on Tree ASSEMBLY

PLET Components

Assembly, hub & Receiver structure,

9" GV (manual)

10" Pressure Cap CVC

Jumper Kits

Topsides Equipment / Topsides Controls (ss only, does not include power / hydraulic supply or brownfield to accept product)

Subsea Distribution Equipment

Tree Mounteded Controls

Hydraulic Flying Leads

Electrical Flying Leads

Controls Subsea Instrumentation

Controls Test Equipment

SIT Testing

Flow assurance is provided in a similar fashion to the Dry Caisson option, with MEG being supplied by the host facility and injected into the flow at the wellhead. The subsea system does not have HIPPS specified, and therefore the host would have to ensure direct access to Venting system to provide pressure relief. The equipment list also does not include specialized tooling equipment. For the completions of the wellhead, and the installation of the tree and subsea commissioning, specialized tooling is required by the drilling contractor. In most cases this is supplied by the subsea equipment vender. However, it is also possible for drilling contractors to meet some of the tooling requirements through pre-owned tools or rental.

Unlike the Dry Caisson, the subsea wellhead system does not need open drains, pumps or power generation for operation, and therefore the system is much simpler. It consists only of a subsea wellhead completion, subsea valve tree and injection into the production flow line. The subsea system will require an umbilical which will carry, in this case, hydraulic fluids to operate the valves and controls on the subsea equipment, data transmission, power and MEG fluids.

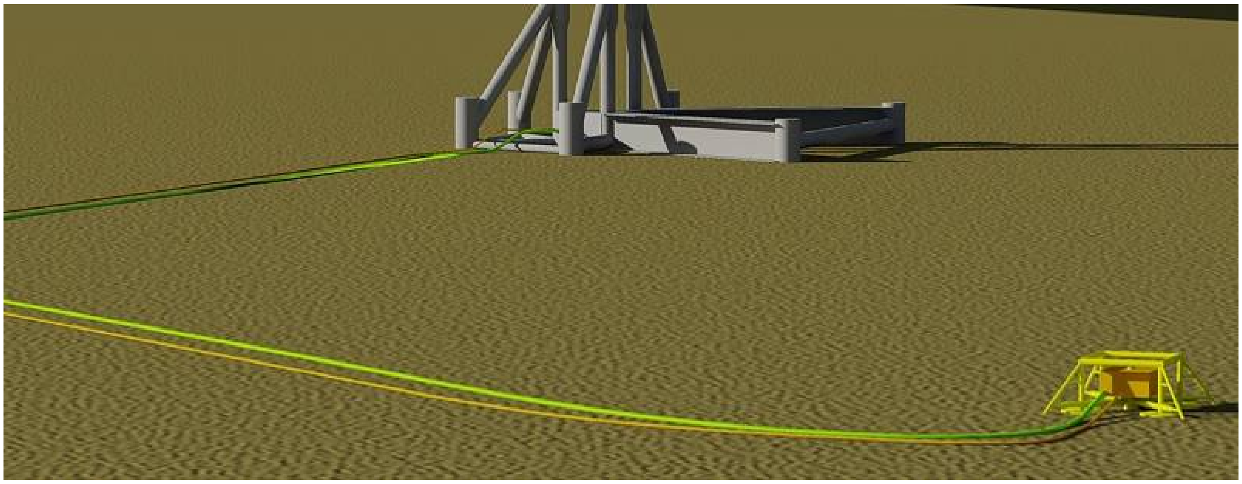

Figure 6: Subsea Wellhead, complete with flow line and umbilical, tied back to fixed platform.

Cost Comparison

A detailed cost comparison was completed on both the Dry Caisson and the subsea system based on the equipment as specified above. The high level results are shown in Table 6 below:

Table 6: Case Study Cost Evaluation		
	Single Caisson	Subsea Wellhead
Caisson Shell and substructure, Wellhead protection	$1,100,000	$200,000
Topsides equipment and structure	$2,925,000	-
Boat Access Provision	$100,000	-
Subsea Equipment (no tooling)	-	$12,500,000
Total	**$4,125,000**	**$12,700,000**

The costing does not include;

- Subsea tooling
- Installation costs for pipeline, subsea, caisson installation, caisson topsides installation
- Commissioning and hookup
- Brownfield costs at the host platform
- Flow Line, MEG line or umbilical

For this very simplified process case, which includes effectively no processing, the cost of the subsea equipment was found to be far greater than the combined costs of the dry equipment and platform structure. However, with the requirement of additional equipment and systems for the dry caisson, it can be assumed that increased maintenance will be required in comparison to the subsea option. The amount and effort required for the maintenance of the dry caisson would be difficult to estimate and would depend greatly on the composition of the raw gas and the reservoir behavior and production plan.

A key additional capital cost for both development methods is the provision of the Flow lines, MEG line or umbilical. The cost of this essential infrastructure is dependant upon the options for installation and seabed conditions. The fact that the subsea option would use some form of umbilical makes a cost comparison difficult. This is due to the fact that umbilicals are typically custom designed and manufactured for the specific application. However, the cost of installation of the lines by far exceeds the cost of the procurement of the lines. Therefore, the installation of one expensive umbilical could be as cost effective as the installation of two inexpensive standard rigid lines. In general terms, it is estimated that the cost to procure and install the flow lines required for the 10km tie-backs would be in the order of $10-$15 million.

Both the subsea and dry caisson will require equipment and hookup at the host facility. The costs of such work are not included herein, as they are not possible to estimate without acute knowledge of the host and the precise requirements of the remote wellhead. For comparative purposes, both systems would have similar requirements on a host. Both would require control units, power, access to pigging systems, access to production systems and MEG supply. The subsea system would require venting access and hydraulic control unit. Both would require the host to install MEG Reclamation.

Operational /Installation Considerations

Installation

While installation costs have not been included, it is anticipated that the costs would be similar for both. A drilling platform can install both systems with minimal specialized equipment, with the exception of the subsea tooling. For the specified subsea equipment above, the tooling costs were estimated at $16 million to acquire the entirety of the tooling requirements from the vender.

In many cases however, the drilling contractor can provide some or all of the tooling as part of the drilling and well completion fees.

Installation of the flowlines, MEG line and umbilical would be completed by similar vessels, with the lines likely being installed at the same time as a bundle. It could also be that the umbilical for the subsea option would contain all required lines, including flow line, MEG, hydraulic, and data, simplifying the installation process.

Maintenance and Access

As indicated above, it is anticipated that the Dry Caisson will require more maintenance than the subsea system. In fact, many subsea systems are being installed with the design intent of having no major maintenance or intervention for the duration of the production life. This is logical, as access to the subsea system is naturally very limited.

Access to the Dry Caisson platform here-in, however, is also limited to boat access only. In consideration of seasonal weather of the NSO, it would be expected that access to the platform would be limited to the summer season only, as wave conditions would be significant during the remainder of the year. Therefore, the systems on board will have to be robust enough to operate with little to no maintenance for up to one year. The power requirements for the Dry Caisson systems specified for the case study are quite low, and therefore renewable power generation (wind and solar) are expected to be able to support the operations indefinitely. An emergency generator has been specified, but the supply of fuel would depend on supply vessel access. A remote refueling system has not been included, but could be considered as these are in use in the NSO area currently for the unmanned platforms.

Annual Inspection for the Dry Caisson would likely be required and would allow for personnel to access the platform for this purpose. The subsea system could also have regular inspection by ROV, provided by the standard support vessels.

Metering

With respect to the host and Brownfield cost, it can be expected that some form of metering will be required (Livingston et al. 2003). Also, as the product being delivered to the host is both gas and condensate, it could also be considered that separation would be required to capture the quantities of both commercial streams of product. While there are meters and systems that can be used without separation, it may be difficult to establish contractual agreement on the consistent quantities of gas versus condensate from the tie-back. Therefore separation should be considered, and could have impact on the Brownfield costs. Separation will require deck space on the host, which could be difficult to provide.

Adding deck space to a host facility, while fairly typical practice, is very expensive due to the amount of construction activities offshore. Therefore, the provision of separation for metering must be considered carefully.

Conclusions

The case study development and cost analysis has shown that the Dry Caisson Platform has a lower capital cost than a comparable subsea system. However, the Dry Caisson platform has additional mechanical processes on board which will require increased maintenance in comparison to the Subsea development option. Therefore, operational costs between the systems should be compared.

Conclusions of the study suggest that in considering minimal developments for stranded or marginal fields in shallow water depths, developers should consider both the Dry caisson Platform and subsea wellhead as viable development options.

Acknowledgments

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Nomenclature

CNSOPB	*Canada Nova Scotian Offshore Petroleum Board*
dia	*diameter*
GoM	*Gulf of Mexico*
HLV	*Heavy Lift Vessel*
LNG	*Liquid Natural Gas*
MEG	*Methylethylene Glycol*
MSL	*Mean Sea Level*
NSO	*Nova Scotian Offshore*
NUI	*Not Usually manned Installation*

SDA	*Significant Discovery License*
SOEP	*Sable Offshore Energy Project*
tonne	*metric ton = 1000kg*

References

CNSOPB, *Technical Summaries of Scotian Shelf Significant and Commercial Discoveries*, Canada-Nova Scotia Offshore Petroleum Board, Halifax, 2000

Dunn, C., DesRochers, C., and MacDonald, G.: Martec Limited, 2009, Minimal Structures for Marginal Fields, OTC 20241, Houston, May 2009

Livingston, R., Tong, D., Wensel, E. and Whitworth, M.: Mustang Engineering, 2003, Topsides Lessons Learned from Subsea Tie-Back Projects, OTC 15112, Houston, May 2003

APPENDIX G

OTC POWER POINT PRESENTATION
20704 DRY VERSUS WET: AN EVALUATION OF SUBSEA TIE-BACKS AND SURFACE PLATFORM DEVELOPMENT STRATEGIES FOR NOVA SCOTIA

Similar Presentation used for
NS ENERGY RESEARCH FORUM 2010 POWER POINT PRESENTATION

MARTEC

20704 - Dry versus Wet:
An Evaluation of subsea tie-backs and surface platform Development Strategies for Nova Scotia

OFFSHORE TECHNOLOGY CONFERENCE

Lloyd's Register

Minimals Project

NOVA SCOTIA Department of Energy CANADA

NSDOE working to make the Nova Scotia Offshore (NSO) more attractive for development

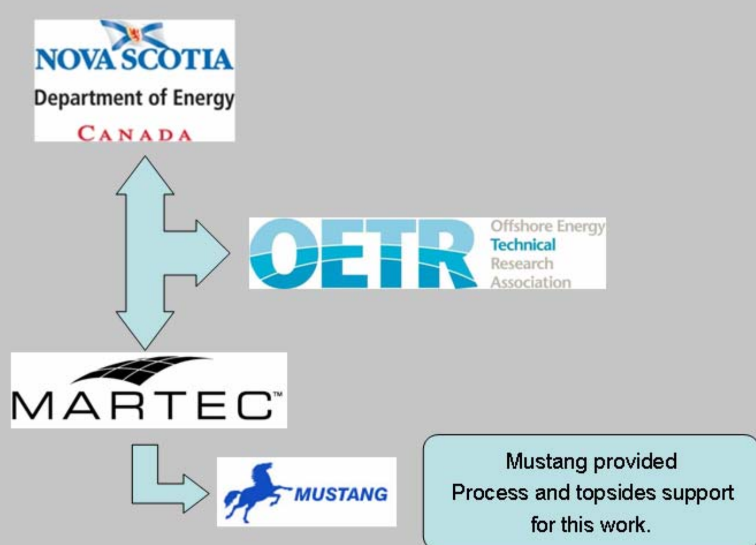
How? – By decreasing risk and providing lower cost development options.

MARTEC

Martec to investigate the use of Minimal Platforms, Local fabrication and Marginal Field Development.

Minimals Project

- Phase 1: Minimal Structures Research
  - Research Structures
  - Conceptual Field Development Cases
  - Production Process Cases
  - Local Fabrication Assessment
- Phase 2: Economics Model
  - Structures Trending
  - Refining of Structures, Concept Field Developments, Production cases
  - Estimator for Physical Facilities



20704 -Dry versus Wet: Subsea tie-backs and surface platform Development Strategies for Nova Scotia Offshore.

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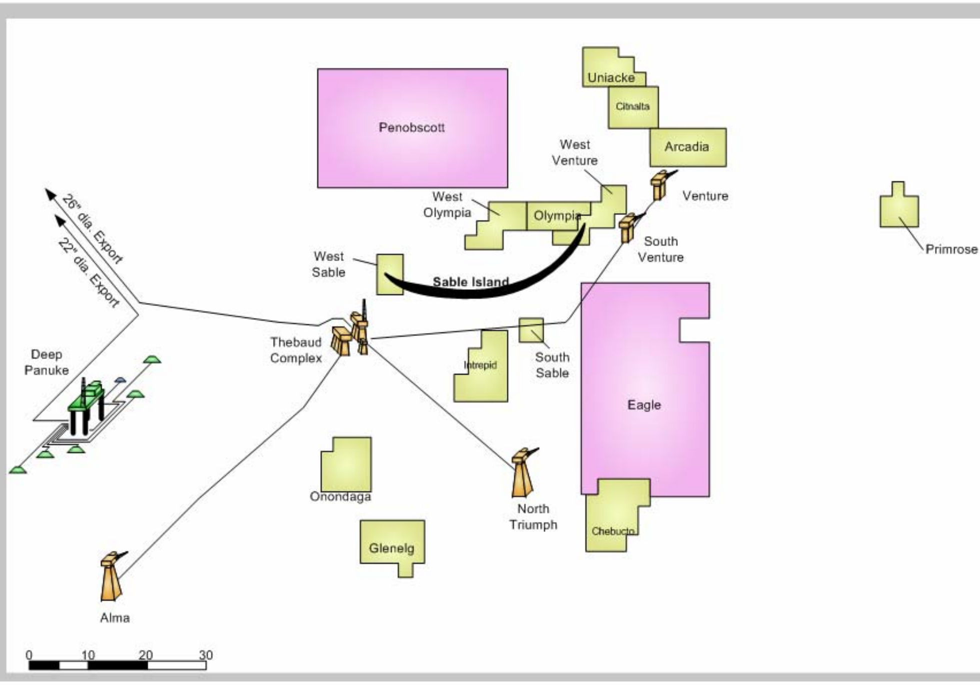
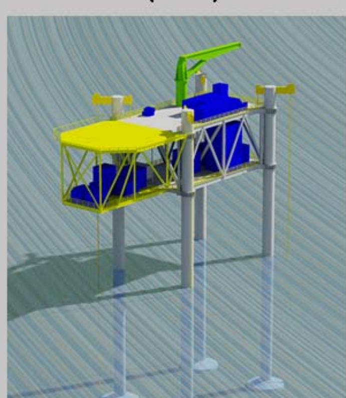
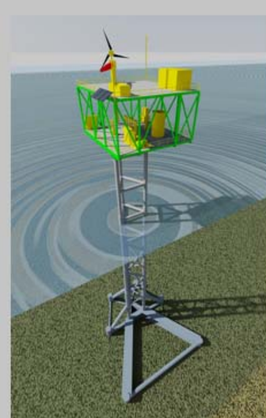


Phase One: an Investigation

- Martec and NSDOE teamed up to investigate Minimal Platforms and their role in the Nova Scotia Offshore (NSO)

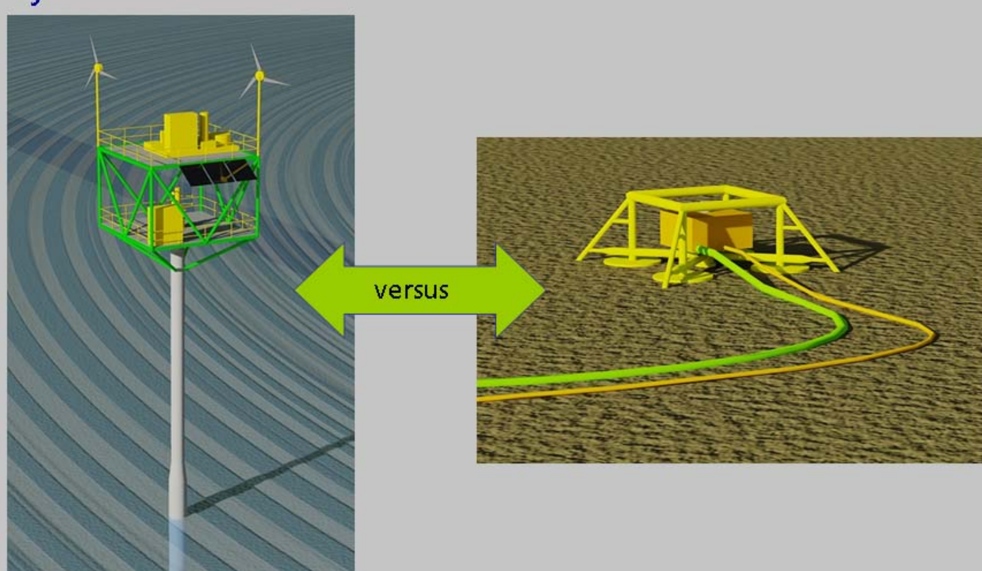




Phase Two: Economic evaluation

- Develop estimates to compare various Marginal field development options
- A portion of the work has resulted in the comparison of complete subsea tie-back of a single, with that of a single caisson platform tie-back.

Dry versus Wet



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Dry versus Wet

- Development of a marginal natural gas field.
- Tie-back facilities configuration based on flow assurance scheme using hydrate inhibition (MEG)
- Host facility will provide full gas, condensate and water treatment, including deck space and MEG supply
- Tie-back wellheads **10km (6.2miles)** to host platform

- Water Depth of **40m (131ft)**
- Spray ice and severe wave loading (Nova Scotian Shelf Conditions)
- Dense sand

Production Case Study

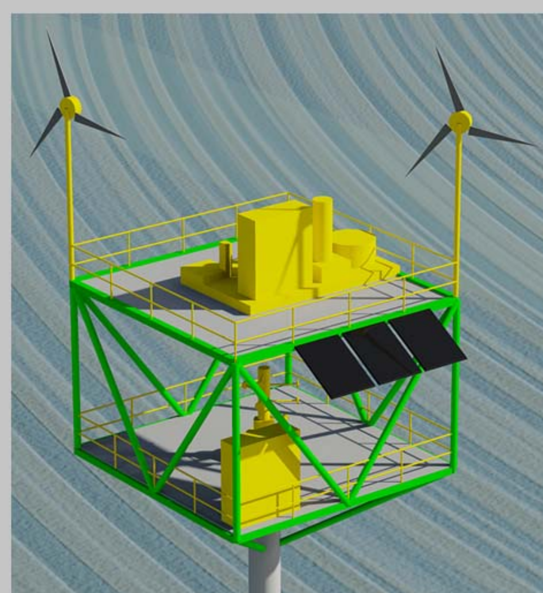
Gas Production Rate	**17,700 m^3/hr (15 MMscfd)**
Condensate Production Rate:	**63.8 m^3/day (400 BPD)**
Water Production Rate	21.2 m^3/day (135 BPD)
Total Liquids Production Rate	85 m^3/day (535 BPD)
Reservoir SITP	< 400 bar (5800 psi)
FWHP	< 345 bar (5000 psi)
Wellhead Rating	API 5000 or ANSI 2500
Sand Production	Minimal - provide sand probes in flowlines
Condensate Emulsion	Not anticipated
Hydrates	**MEG required for inhibition**
Paraffin	Nil
CO2	Nil
H2S	Nil

Single Caisson

- Installed over and around the well conductor casing.
- The Caisson shell supports the lateral wind and wave load as well as the topside weight and operational loads.
- Sensitive to Soil Conditions
- Installed by Drilling Rig (caisson and topsides)

Single Caisson

- 7.5m x 7.5m – 2 level topsides
- 52 tonnes topsides weight
- Caisson – 218 tonnes
- Equipment includes:
  Well control panel
  Valve tree
  HIPPS
  Open Drains Tank
  MEG injection skid
  25kw Generator (wind, solar, battery)
  Small Diesel Supply
  Communications (Microwave)
- Boat Access



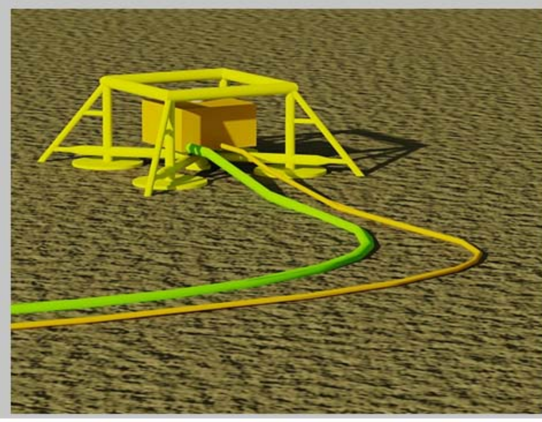
Subsea

- Standard equipment available from multiple subsea equipment vendors.
- Wellhead:

  Hydraulic Operation

  Umbilical includes: Hydraulic, Power, Data, MEG

  Flow line separate



- Installed by Drill Rig

Cost Comparison

	Single Caisson	Subsea Wellhead
Caisson Shell and substructure, Wellhead protection	$1,100,000	$200,000
Topsides equipment and structure	$2,925,000	-
Boat Access Provision	$100,000	-
Subsea Equipment (no tooling)	-	$12,500,000
Total	**$4,125,000**	**$12,700,000**

- Considers initial capex costs only

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Extended Cost Comparison

	Single Caisson	Subsea Wellhead
Caisson / Subsea	$ 4,125,000	$ 12,700,000
Well Infrastructure (pipelines / umbilical procurement)	$ 3,025,000	$ 4,400,000
Pipelay Mobilization	$ 13,125,000	$ 13,125,000
Pipelay (2 lines for both)	$ 7,500,000	$ 7,500,000
Installation Mobilization	$ 2,500,000	$ 2,500,000
Installation and Hook Up	$ 16,250,000 27 days	$ 15,850,000 Incl 4.5M in tooling
	$ 46,525,000	**$ 56,075,000**

Comparison

- Anticipated that the Single Caisson will have higher maintenance costs, due to increased equipment.
    - Easier access to platform
- Umbilical costs higher risk
- Brownfield costs are **not** included in the comparison, could be very significant;
    - Metering should be considered
    - Separation prior to metering could be considered (may require additional deck space on host)

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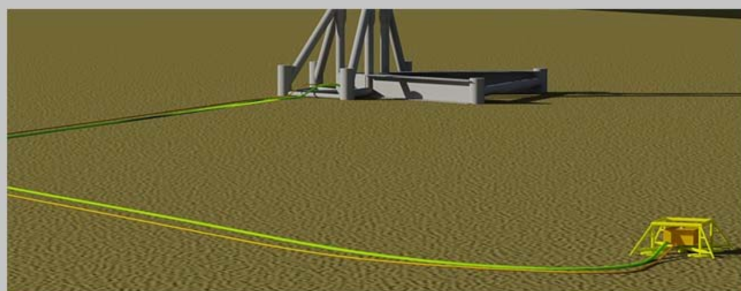
Conclusion

In consideration of minimal developments for marginal fields, single caissons should be considered as well as subsea.



Acknowledgments

- **John Dickie** of the Nova Scotia Department of Energy
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- **Pete Thompson** of Cameron Subsea
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