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TITLE:

CONCEPT SELECTION REPORT

Otway Development

Granherne

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DOCUMENT INFORMATION			
CDC No: S2000-RG-143039	**DRIMS#:**	**Rev:** 0	**Project Number:** 90901-OTW-RT-A-00003

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☐ Unclassified (Shared without Restrictions)	☐ Review Period 1 Year	☐ By WEL
☒ Restricted (Freely Shared within Woodside and Associated Companies)	☐ Review Period 3 Years	☒ For WEL Under PO/Contract No: 7500030628
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Otway Development

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OTWAY DEVELOPMENT

PHASE 2C CONCEPT FEASIBILITY STUDIES

CONCEPT SELECTION REPORT

DOCUMENT NO	**:**	**90901-OTW-RT-A-00003**
CDC NO	**:**	**S2000-RG-143039**
REVISION	**:**	**0**
DATE	**:**	**April 2003**

Otway Development

DOCUMENT REVISION RECORD

REV	DATE	DESCRIPTION	PREPARED	CHECKED	APPROVED
A	22/04/03	Issued for IDC	G Veroba	P Robson PSR	P Robson PSR
0	23/04/03	Issued for Use	G Veroba	P Robson PSR.	P Robson PSR.

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Title: **OTWAY DEVELOPMENT** **PHASE 2C CONCEPT FEASIBILITY STUDIES** **CONCEPT SELECTION REPORT**	**QA Verified:**
	Date: 24/4/03

CONTENTS

ABBREVIATIONS

A$M	Million Australian Dollars
AC	Assurance Check
AGD	Australia Geodetic Datum
Capex	Capital Expenditure
CO_2	Carbon Dioxide
Cr	Chromium
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
E.L.	Elevation
FID	Final Investment Decision
GDA	Geocentric Datum Australia
G-FAST	Granherne Focused Analysis Screening Tool
GIIP	Gas Initially in Place
GJU	Giant Jack-up
HDD	Horizontal Directional Drilling
HSE	Health Safety and Environment
ICAF	Implied Cost to Avert a Fatality
ID	Internal Diameter
IR	Industrial Relations
JV	Joint Venture
JVP	Joint Venture Partner
km	Kilometre
kV	Kilo Volt
LB	Lower Bound
LPG	Liquefied Petroleum Gas

m	Metre
mD	Milli-Darcy
MEG	Mono-Ethylene Glycol
MLT	Marathon Letourneau
mm	Millimetre
NPV	Net Present Value
OHGP	Open Hole Gravel Pack
Opex	Operating Expenditure
PLL	Potential Loss of Life
RFSU	Ready for Start-up
SEAGAS	South East Australia Gas Pipeline
SS	Stainless Steel
STOS	Shell Todd Oil Service
SWOT	Strengths Weaknesses Opportunities and Threats
T.O.S.	Top of Steel
TVD	Total Vertical Depth
TXU	Texas Utilities (Australia)
UB	Upper Bound
VIR	Value Improvement Ratio
WEL	Woodside Energy Ltd
WGS	World Geodetic System
WHP	Wellhead Platform

HOLDS

1. No Holds.

1.0 EXECUTIVE SUMMARY

Woodside Energy Ltd (WEL) together with its Joint Venture partners, Origin Energy Resources Limited, Cal Energy Gas (Australia) Limited and Benaris International NV, propose to commercially develop the Thylacine and Geographe gas discoveries (Otway Development) located in Licence Blocks VIC/P43 and T/30P. The Geographe and Thylacine reservoirs (containing gas and condensate), are located approximately 55km and 70km respectively offshore Port Campbell, Victoria in 85m and 100m of water respectively. WEL is the Operator of both Licence Blocks.

On behalf of the Joint Venture, WEL has undertaken concept studies to determine feasibility of field development and to select a preferred development option. This work was completed by an integrated engineering team comprising of Woodside, Granherne and JP Kenny personnel. The key objectives were to:

- Evaluate a number of potential development options and select those which provide highest value.
- Complete development concept cost optimisation and overall value enhancement.
- Evaluate technical uncertainties that need to be understood and resolved to support the concept selection decision.

A series of 4 workshops and numerous peer reviews were used during the studies to review work completed and key technical issues, with a view to carrying forward those options which provided the highest value and suitability for further work.

Based on the concept screening work completed, the Thylacine field should be developed initially using a normally unmanned wellhead platform. A Giant Jack-up drilling rig will be used to install the wellhead platform and complete well construction. A 20" multi-phase pipeline will transport production fluids from Thylacine to the onshore gas processing plant located near the Iona gas plant, where sales quality gas, propane, autogas and condensate will be produced. A subsequent drilling campaign will be completed using a semi-submersible drilling rig to develop the Geographe field and further develop the Thylacine field. Geographe subsea facilities will be tied into the pipeline near the Geographe field location, with the Thylacine well tied back to the Thylacine wellhead platform. Total development cost is estimated at 1017 A$M (excluding decommissioning) with an expected RFSU date of July 2006.

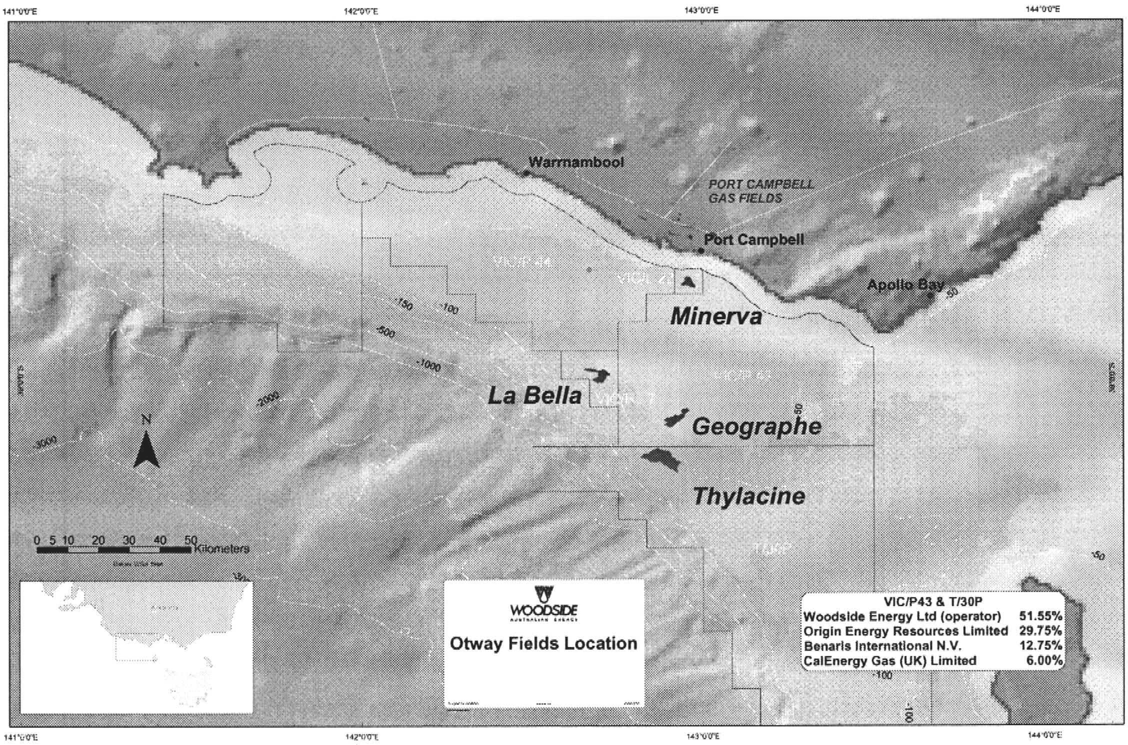
The purpose of this document is to summarise the concept selection decision-making process employed and key issues considered.

2.0 INTRODUCTION

Woodside Energy Ltd (WEL) together with its Joint Venture partners, Origin Energy Resources Limited, Cal Energy Gas (Australia) Limited and Benaris International NV, propose to commercially develop the Thylacine and Geographe gas discoveries (Otway Development), in the offshore Otway Basin. The development is expected to capitalise on a market opportunity in the Victorian and South Australian gas markets expected to materialise in 2004 - 2006.

The Geographe and Thylacine reservoirs (containing gas and condensate), are located approximately 55km and 70km respectively offshore Port Campbell, Victoria in 85m and 100m of water respectively (see Figure 2.1 below). The Development spans two Licence Blocks VIC/P43 and T/30P. WEL is the Operator of both Licence Blocks.

Figure 2.1
Development Location

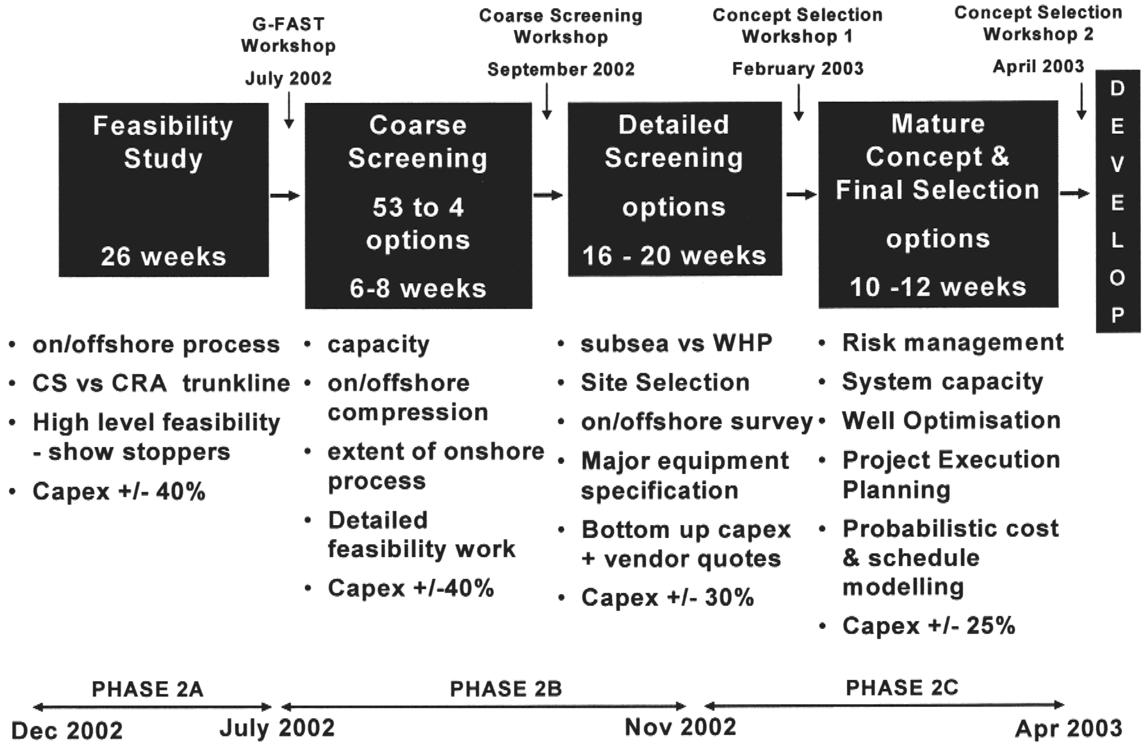


This report summarises the concept selection process and major issues reviewed during the Phase 2B and 2C feasibility studies carried out from July 2002 to April 2003.

3.0 OPTION SCREENING AND SELECTION METHODOLOGY

The work and decision making process utilised in the Otway Phase 2 Concept Feasibility Studies is shown in Figure 3.1.

Figure 3.1
Concept Screening Work Flow



The key objective of the Phase 2B work was to evaluate a number of potential development options and short list to more detailed evaluation in the next phase of the work. This work was completed by an integrated engineering team comprising of Woodside, Granherne and JP Kenny personnel.

The main activities of the Phase 2B and 2C studies focused on:

- Development concept cost optimisation.
- Areas where more value is considered to be added to the overall development economics, not simply cost.
- Areas where work is required to support the cost estimate.
- Technical uncertainties that need to be understood and resolved for concept selection.

A series of workshops were used throughout the conceptual studies to review work completed and key technical issues, with a view to carrying forward those options which provided the highest value and suitability for further work, as summarised below.

3.1 July 2002 G-FAST Workshop

A detailed review of the workshop proceedings can be found in Ref. 1.

A workshop was held on 15 to 17 July 2002 to review project drivers and focus concept screening work on options which were viewed to add the most potential value. This built on a Volumes to Value workshop carried out in June 2002. The Granherne G-FAST workshop format was utilised to complete a focused evaluation process to generate options to be reviewed in the concept screening.

The workshop integrated all development disciplines to optimise the development scenarios generated to date, brainstorm other development scenarios, and generate equipment sizes and costs in the workshop.

Working groups identified 53 development scenarios that were ranked based on project business drivers. The most promising 11 scenarios were carried forward for further technical and cost analysis. The 11 scenarios consisted of options ranging from the current Reference Case (all subsea development with shore umbilical), subsea with various control and processing platform options, Geographe wellhead platform, and all platform development.

Screening level technical and cost analyses were completed on the 11 scenarios. In addition, production profiles were developed to determine field life revenues to evaluate economic metrics. Options were ranked on their ability to meet the project's business drivers, including: HSE, project economics, project cost and schedule, operability, regional growth and technical robustness. A risk ranking was also completed against each business driver to determine the risk to the project driver and the ability to manage the risk. This was used as part of the final options screening.

Based on the results of the options ranking and risk evaluation, it was determined that the following seven scenarios should be carried forward for further concept screening work:

- S1 – full subsea development.
- S2 – full subsea development with control platform.
- S3 – full subsea development with control/bulk water removal platform.
- S5 – full subsea development with control/bulk water removal platform and future offshore compression.
- WS1 – Geographe wellhead platform and Thylacine subsea development.
- WS2 – Geographe wellhead platform with future compression and Thylacine subsea development.
- WW1 - Geographe wellhead platform with future compression and Thylacine wellhead platform.

3.2 September 2002 Coarse Screening Workshop

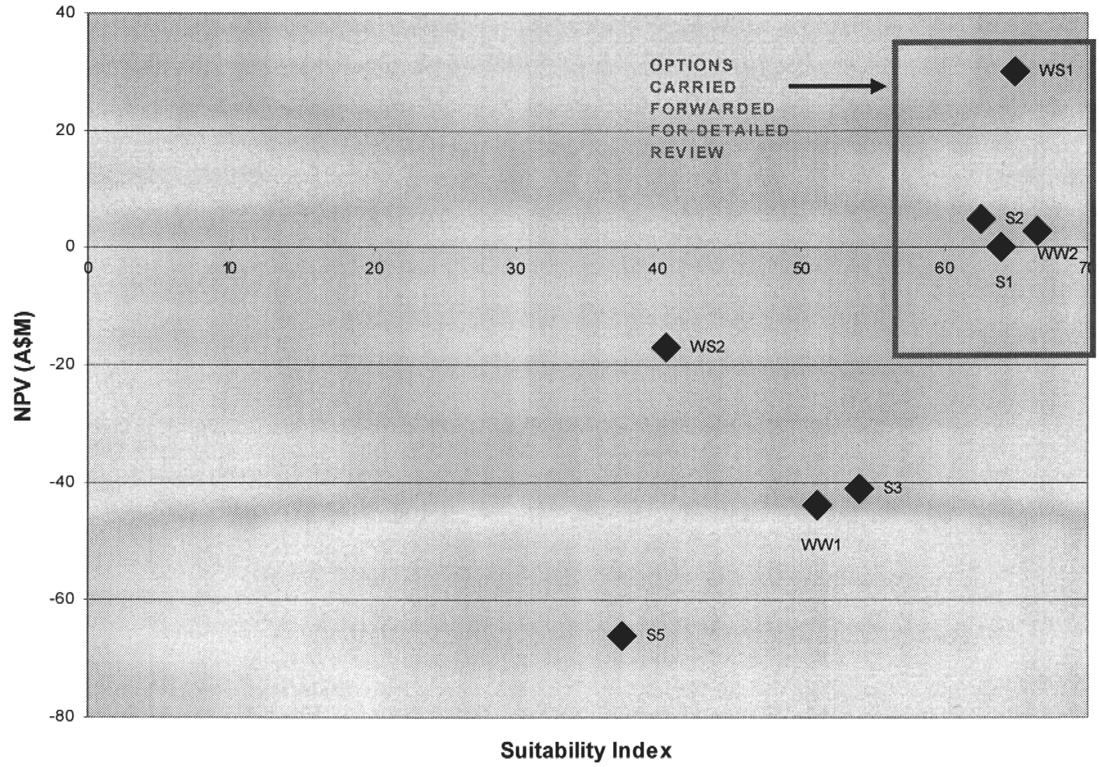
A detailed review of the workshop proceedings can be found in Ref. 2.

A Coarse Screening workshop was held on 12 and 13 September to review and validate work completed to date by the Otway integrated engineering project team. 35 attendees were present over the 2 days representing a broad cross section of Woodside, JV partners, integrated project team and external review personnel. The main objectives of the workshop were to ensure technical risk and uncertainty areas were understood and were being managed/mitigated by the project team, identify any new opportunities not being considered by the project team and identify the highest value development options that should be carried into the detailed screening phase for further definition.

Based on the results of the economic review and options screening process, the following recommendations were made and adopted by the workshop participants:

- Options S1, S2, WS1 and WW2 (a hybrid of WW1 comprising 2 minimum facilities wellhead platforms) were to be carried forward to the detailed screening phase for further review based on the results of the options ranking outlined in Figure 3.2 below.

Figure 3.2
Coarse Screening Workshop Options Ranking



- Detailed screening would focus on onshore compression based on the current production modelling and the Options Ranking results. Integrated production modelling would be completed for offshore compression to validate current modelling results.
- Detailed screening would focus on onshore water handling systems based on the Options Ranking results and technical definition work completed to date. A further review of onshore water disposal options for a range of rate sensitivities would be completed to determine optimal cost-ultimate recovery. In addition, MEG salt handling/disposal required further review for the base case, and a review of the methanol hydrate inhibition processing option would be completed.
- Detailed screening would focus on Giant Jack-up drilling for platform development cases. Platform design would focus on wireline intervention only for detailed screening definition.
- Detailed screening would focus on subsea cluster layout for subsea development cases. Continuing integration with well engineering to optimise drill centre and potential satellite tie-backs to optimise overall cost would be required.
- Detailed screening would focus on LPG recovery as the base case liquids recovery option.
- Further work was required on liquids markets and site selection in the detailed screening phase prior to liquid export option selection being possible. Unrestricted trucking would remain as the base case for liquids export until market options were further explored. In addition, remote storage and shipping options would be reviewed to develop alternate marketing opportunities.
- Future integrated production modelling work would be completed on the following:
  - Phased Geographe, followed by Thylacine development and vice versa, with onshore compression.
  - Concurrent Geographe and Thylacine development with onshore compression.
  - Offshore compression sensitivity on base case.
  - Evaluation of produced formation water rate versus ultimate recovery.

3.3 February 2003 JV Concept Selection Workshop #1

A detailed review of the workshop proceedings can be found in Ref. 3.

The main objectives of the Concept Selection workshop were to:

- Explore key differentiators between remaining concepts.
- Update JVPs on issues raised in the AC-2 review.
- Share experiences.
- Select one/two preferred development concepts for further development.

Five options were reviewed in detail prior to the February 2003 workshop:

- S1 – full subsea development.
- S2 – full subsea development with control platform at Geographe.
- S2T – full subsea development with control platform at Thylacine with capability of pigging.
- WS1 – Geographe subsea development and Thylacine wellhead platform development.
- WW2 - Geographe and Thylacine wellhead platforms.

A number of key technical issues were highlighted by the Phase 2C work as noted in Table 3.1.

Table 3.1
Offshore Concept Key Technical Issues

S1	S2	S2T	WS1	WW2
• Reservoir recovery • Metering • Sand Control • Routine Subsea Pigging • Umbilical Reliability	• Reservoir recovery • Metering • Sand Control • Routine Subsea Pigging • Umbilical Reliability • Geotechnical Risk • Platform Installation Weather Window	• Reservoir recovery • Metering • Sand Control • Umbilical Reliability • Geotechnical Risk • Platform Installation Weather Window	• Metering • Sand Control • Geotechnical Risk • Platform Installation Weather Window	• Geotechnical Risk • Platform Installation Weather Window • Installation Sequence

In addition, a number of key technical issues common to all development options were highlighted, including:

- Offshore pipeline stability/spans.
- HDD/shore crossing location.
- Onshore plant site selection.
- Onshore plant noise.
- Land acquisition.
- Onshore plant power supply.
- LPG optimisation.
- Water disposal.
- Liquid transportation (trucking versus pipeline).

The options screening process that was utilised considered differential NPV between options and concept suitability. The differential NPV values were also normalised to consider full lifecycle cost impacts areas including:

- Project economics.
- Project Schedule – NPV would be adjusted by 3 A$M for every one month change in start-up date relative to the reference case.
- PLL – NPV would be adjusted by -10 A$M per ICAF.
- Availability – NPV would be adjusted by 5 A$M per % availability change relative to the reference case.
- Reservoir monitoring impacts (not addressed in Suitability Index) – the cost of one well side track per subsea field development would be considered for the second drilling campaign due to lack of reservoir monitoring, contributing a -2.3 A$M NPV reduction per subsea field.

Differential NPV for each option were compared to the S1 Reference Case to provide a value differentiator, and Suitability Index to provide a risk differentiator. This allowed options that provided high value and high suitability to be screened for further review prior to AC-3. A summary of normalised economic results, Suitability Index results developed in the workshop and overall Options Selection results are presented in Table 3.2, Table 3.3 and Figure 3.3 respectively.

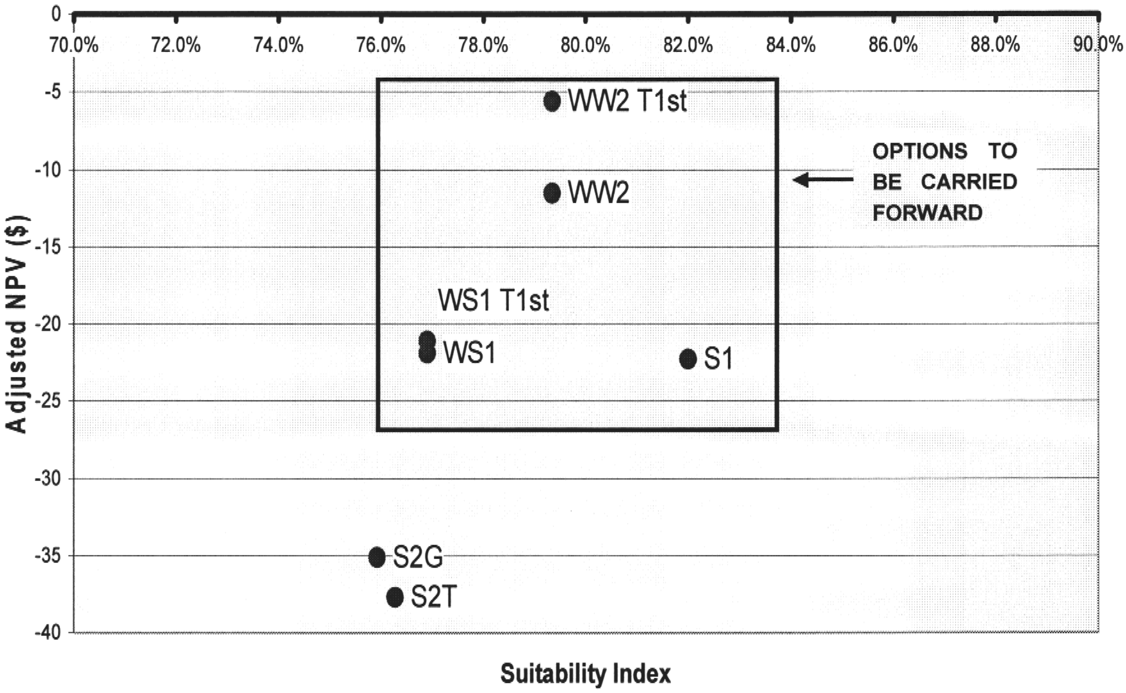
Table 3.2
February 2003 Normalised Lifecycle NPV (Relative to S1)

INPUT/OPTION	S1	S2G	S2T	WS1	WW2	WS1 Thyl 1st	WW2 Thyl 1st
Base NPV relative to S1 (A$M)	0	-13.2	-15.8	-16.2	-8.4	-15.4	-2.5
NPV Adjustments							
Production Profile NPV Loss (A$M)	**-14**	**-14**	**-14**	**0**	**0**	**0**	**0**
Schedule NPV loss (A$M)	0	0	0	0	0	0	0
PLL/ICAF NPV loss (A$M)	-3.7	-3.8	-3.8	-3.9	-4.1	-3.9	-4.1
Availability NPV loss (A$M)	0	0.5	0.5	0.5	1	0.5	1
Res Monitoring NPV loss (A$M)	-4.6	-4.6	-4.6	-2.3	0	-2.3	0
TOTAL ADJUSTED NPV (A$M)	**-22.3**	**-35.1**	**-37.7**	**-21.9**	**-11.5**	**-21.1**	**-5.6**

Table 3.3
February 2003 Suitability Index Summary Results

THEME	SUITABILITY INDEX						
	S1	S2	S2 (Thy)	WS1	WW2	WS1 Thyl 1st	WW2 Thyl 1st
Base Case	82.0%	75.9%	76.3%	76.9%	79.4%	76.9%	79.4%
Min Life Cycle Cost / Capex	76.6%	73.6%	74.4%	79.3%	83.9%	79.3%	83.9%
HSE	85.4%	79.7%	79.6%	78.0%	78.2%	78.0%	78.2%
Technical	75.4%	70.6%	72.0%	79.0%	85.4%	79.0%	85.4%
Unweighted	80.5%	76.0%	76.5%	78.1%	82.1%	78.1%	82.1%

Figure 3.3
Options Screening Process Results



As indicated, WW2 provided the best value and highest suitability when technical and lifecycle cost risk mitigation is given highest weight. S1 provided reasonable overall value, but provides the highest suitability when HSE and schedule/cost risk mitigation is given highest weight.

Considering the above, it was suggested that the WW2 Thylacine first and S1 concurrent development scenarios be considered for further review.

Although WS1 as presented was not recommended to be carried forward for further review in the workshop, subsequent discussions suggested that a WS1 hybrid case would provide both cost reduction and risk mitigation potential. This considered the development of the Thylacine field first using a downsized WHP and Jack-up drilling rig, with the second campaign utilising a semi-submersible drilling rig to develop Geographe and drill the remaining Thylacine wells for subsea tieback to the Thylacine WHP. This resulted in the WS1 also carried forward for further review.

3.4 April 2003 JV Concept Selection Workshop #2

A detailed review of the workshop proceedings is summarised in Ref.4.

Major objectives for this workshop were to:

- Update on key issues arising from the February 2003 workshop.

- Update on cost, economics and Suitability Index results.
- Develop a consensus on the preferred option to be carried forward to AC-3.

A similar process to that used in the February 2003 workshop was employed to assist in concept selection. Absolute NPV for each option was used to provide a value differentiator, and Suitability Index to provide a risk differentiator to determine which option provided the highest value and suitability for further review prior to AC-3. A summary of normalised economic results, Suitability Index results and overall Options Selection results are presented in Table 3.4, Table 3.5 and Figure 3.4 respectively. In addition, the SWOT analysis results validated during the workshop are provided in Appendix I.

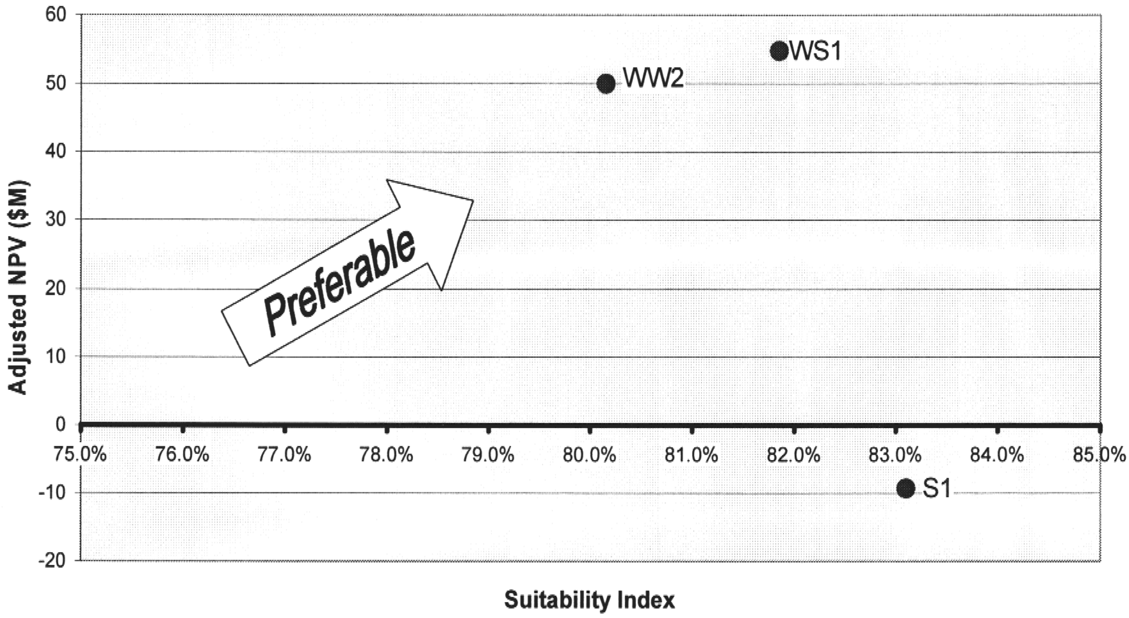
Table 3.4
April 2003 Normalised NPV

Input/Option	S1	WS1 Thyl 1st	WW2 Thyl 1st
Base NPV (A$M)	-1	58.2	53.1
Schedule NPV	0	0	0
PLL/ICAF (NPV loss)	-3.7	-3.9	-4.1
Availability (%)/NPV loss	0	0.5	1
Res Monitoring NPV loss	-4.6	0	0
TOTAL ADJUSTED NPV (A$M)	**-9.3**	**54.8**	**50**

Table 3.5
April 2003 Suitability Index Results

Risk Category	Weight	S1	WS1	WW2
Environmental	10%	88	82	82
Safety	20%	90	76	71
Political	10%	73	89	89
Technical Risk - Surface	10%	81	82	80
Technical Risk - Subsurface	10%	68	86	97
Schedule/ Cost	20%	92	78	72
Operations	15%	74	83	85
Expandability	5%	92	94	80
Base Case Results	**100%**	**83%**	**82%**	**80%**

Figure 3.4
April 2003 Options Screening Results



As indicated in Figure 3.4, although S1 has highest suitability, unacceptably low NPV eliminated this option. NPV reduction occurred with the S1 option relative to other options due to more complex and costly subsea wells to incorporate downhole sand control and SMART well completions, and the associated production impact of sand control and completion design.

WS1 provided the best combination of overall value and suitability, with WW2 providing similar project value. A key feature of WS1 and WW2 was the ability to provide best intervention and reservoir management opportunities for the largest Thylacine reserve, which was viewed by participants as critical to project success. Although GJU drilling and installation was viewed to be feasible, a major differentiator was WW2 reliance on GJU drilling and platform installation for all campaigns, resulting in higher risk for WW2. Selection of highest value WS1 also does not preclude Geographe WHP development in future if required.

It was the view of the participants that the WS1 option should be carried forward as the preferred development option.

Major issues that required further evaluation subsequent to the workshop included:

- Seven year plateau length was viewed as being undesirably short.
- Two year length between initial drilling campaign and second drilling campaign was insufficient to complete reservoir evaluation, second campaign development planning and project execution.

3.5 Peer Assists and Reviews

In addition to the concept selection reviews, the following peer assists and reviews were held to support the concept feasibility analysis and decision-making process:

- AC-10 Subsurface Peer Review (April 2002).
- Stakeholder Intermediate Milestone Review (April l2002).
- Offshore Facilities (August 2002).
- Flow Assurance (September 2002).
- Onshore and Offshore cost challenge (September 2002).
- Process (October 2002).
- AC-12 Cost and Schedule Assurance (October 2002).
- AC-2 Feasibility Review (October 2002).
- Offshore Topsides Layout (December 2002).
- Onshore Plant Layout (December 2002).
- Offshore Pipeline Span and Stability (January 2003).
- Process and Facilities peer assist by STOS Pohokura (March 2003).
- Sand Control (February 2003).
- Structures and Installation (April 2003).
- Well Selection 75% Review (April 2003).
- AC-12 Cost and Schedule Assurance (March/April 2003).
- AC-10 Subsurface Integrity (April 2003).
- AC-8 HSE Audit (April 2003).
- AC-11 Commercial Review (April 2003).
- Various Subsurface discipline reviews.

4.0 OFFSHORE DEVELOPMENT OPTIONS

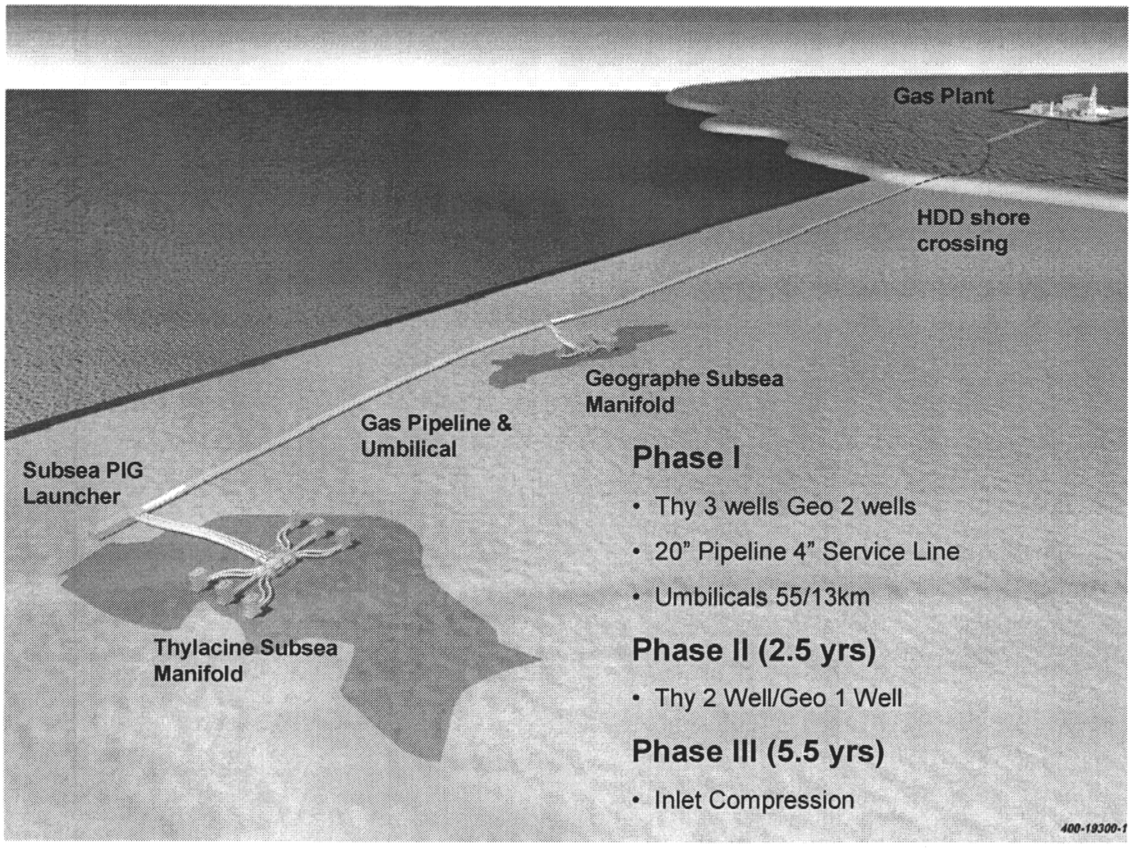
4.1 Option S1

This option is based on full subsea development with subsea cluster manifolds located at each of Geographe and Thylacine locations, controlled from shore via an umbilical as shown in Figure 4.1. Subsea facilities would be developed in a cluster arrangement with manifolds located in approximately 85m of water at Geographe and 100m of water at Thylacine. Provision would be made to accommodate future satellite wells if required. Control and monitoring of the subsea wells would be from shore via a steel tube electro-hydraulic umbilical piggybacked to the gas export pipeline.

The base case S1 option utilises concurrent field development with the following well phasing:

- Phase 1 - Three subsea cluster wells drilled on Thylacine, two subsea cluster wells drilled on Geographe.
- Phase 2 - Two subsea cluster wells drilled on Thylacine and one subsea cluster well on Geographe.

Figure 4.1
Option S1 Development



4.2 Option WS1

This option is based on an unmanned wellhead platform development at the Thylacine location controlling a subsea cluster manifold development at the Geographe location via umbilical and Thylacine subsea tie-back wells drilled in later project life. As shown in Figures 4.2 and 4.3, the base case WS1 option utilises initial Thylacine field development using a minimum facilities tripod wellhead platform and drilling/platform installation using a harsh environment Giant Jack-up drilling rig. Phase 2 field development utilises Geographe development and further development of the Thylacine field using subsea wells drilled using a semi-submersible drilling rig. Well phasing is as follows:

- Phase 1 - Four wells drilled from a Thylacine platform.
- Phase 2 - One subsea tie back well in Thylacine and three subsea cluster wells in Geographe.

Figure 4.2
Option WS1 – Phase 1 Development

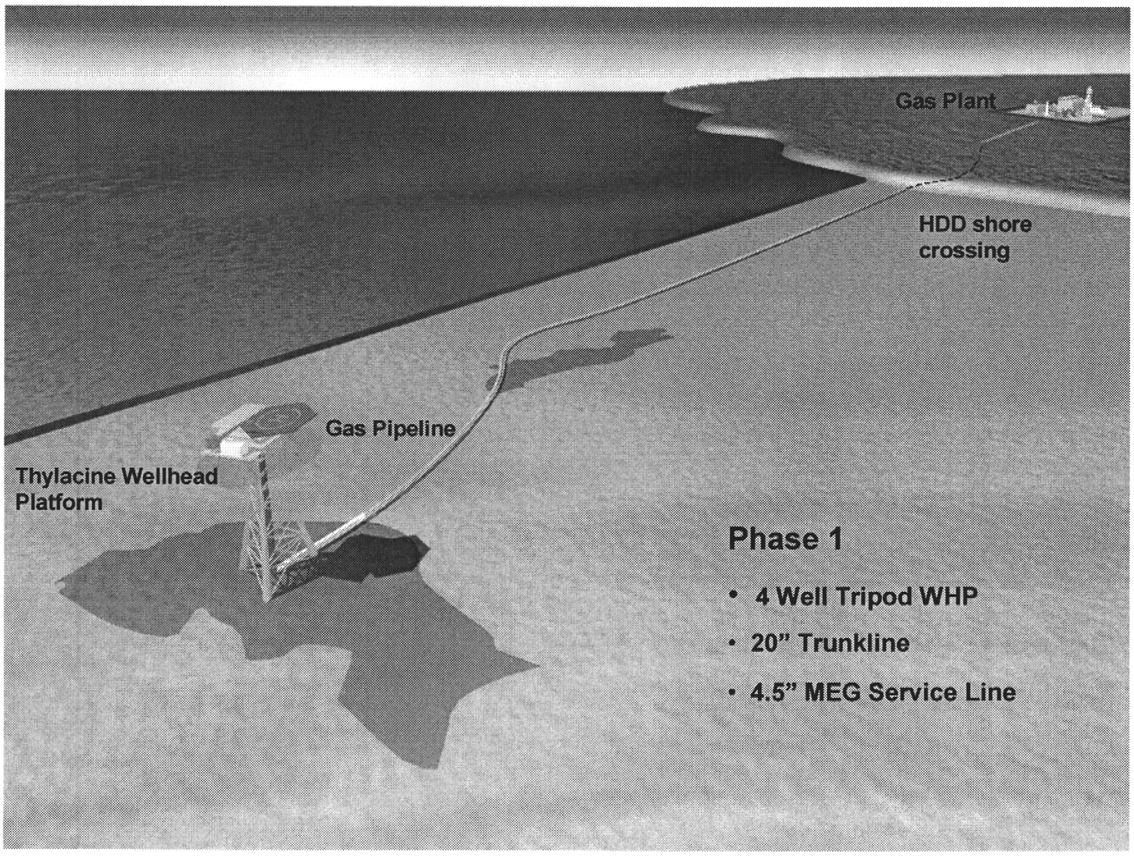
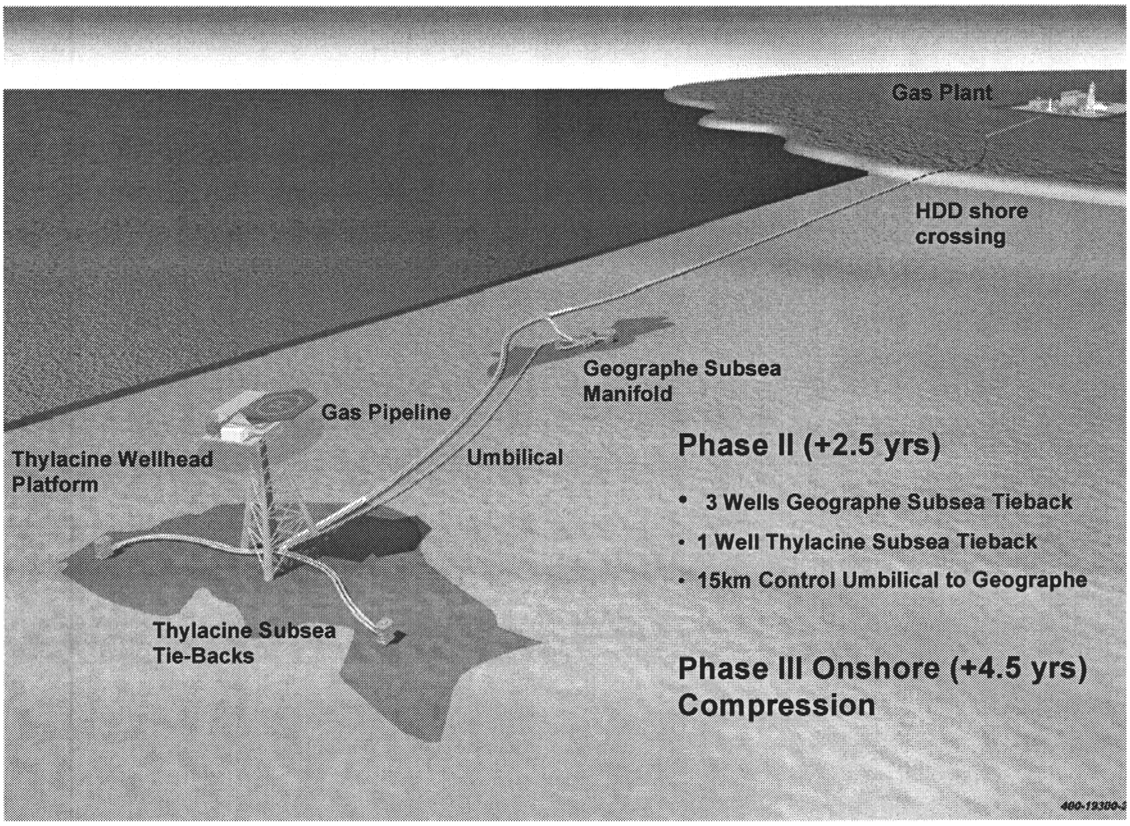


Figure 4.3
Option WS1 – Phase 2 Development

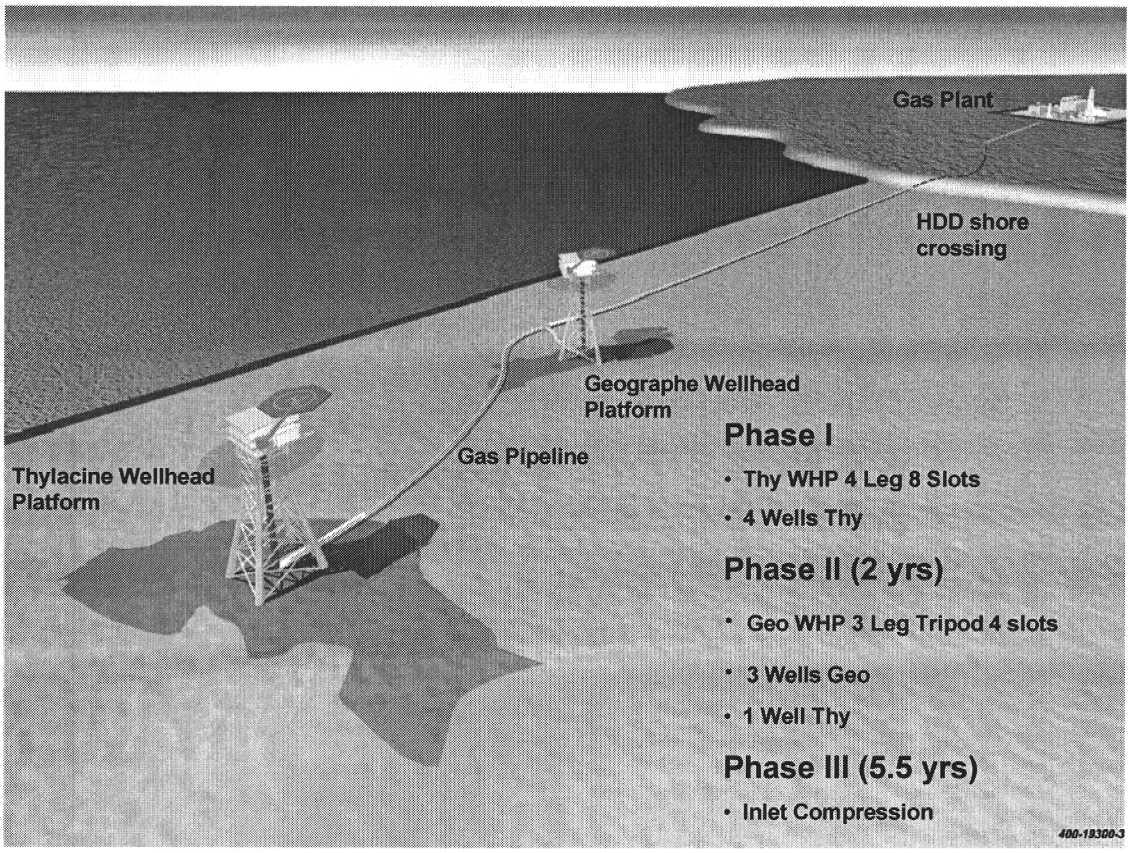


4.3 Option WW2

This option is based on unmanned wellhead platform developments at both the Thylacine and Geographe locations. As shown in Figure 4.4, the base case WW2 option utilises initial Thylacine field development using a minimum facilities four-legged wellhead platform using a harsh environment Giant Jack-up drilling rig for both drilling and platform installation. Phase 2 Geographe development uses a minimum facilities tripod wellhead platform and further development of the Thylacine field using a harsh environment Giant Jack-up drilling rig for both drilling and platform installation. Well phasing is as follows:

- Phase 1 - Four wells drilled from a Thylacine platform.
- Phase 2 - One well drilled from the Thylacine platform and three wells drilled from a Geographe platform.

Figure 4.4
Option WW2 Development



5.0 KEY DECISION REVIEW

A summary of key decisions and reference documentation is attached in Appendix II. Major concept decision areas have been highlighted below.

5.1 Sand Production

Sand prediction work for Thylacine and Geographe is now complete, core samples have been strength tested and the data input into the "FIST" sand prediction program. The FIST program outputs whether a reservoir unit is in one of three sand production regions:

- Safe Region – Only a finite amount of clean up sand is produced.
- Transient Region – The formation around perforation tunnels fails due to increased stress and some sand is produced. It is termed transient as it occurs in bursts for example when a well is brought online.
- Catastrophic Region – The formation fails and either the sand fills the well stopping production or the rate of sand production is a threat to well and facility integrity.

The integrity of the carbon steel flowline to shore drives sand control recommendations, as sand production into the flowline can not be tolerated due to increased corrosion. Sand control can be accomplished using two methods:

- Downhole sand control (eg., using gravel packs or expandable screens).
- For platform cases, topsides sand removal using a desanding cyclone system.

In a subsea case where a reservoir unit has transient or catastrophic failure downhole, sand control is required, as there is no other means to prevent sand entering the flowline. In a platform case, transient sand production can be managed using the topsides desanding system, with catastrophic regions still requiring downhole sand control. The sand control decision process is summarised in Table 5.1 and sand control recommendations for specific production units summarised in Table 5.2.

Table 5.1
Sand Control Decision Process

Field Development	Safe Region	Transient Sand Failure	Catastrophic Sand Failure
Subsea	No Sand Control	Downhole Sand Control	Downhole Sand Control
Platform	No Sand Control	Topsides Desanding	Downhole Sand Control

Table 5.2
Downhole Sand Control Recommendations

Production Unit	Subsea	Platform With Topsides Desander
Geographe 1 Unit 1	No sand control	No sand control
Geographe 1 Unit 2	No sand control	No sand control
Geographe 1 Unit 4	No sand control	No sand control
Thylacine 1 Unit 1	Sand control	No sand control
Thylacine 1 Unit 2	Sand control	No sand control
Thylacine 1 Unit 4A	Sand control	Sand control
Thylacine 1 Unit 4	Sand control	Sand control
Thylacine 1 Unit 5	Sand control	Sand control

The main difference is transient sand production from Thylacine Units 1 and 2, resulting in sand control for the subsea case and no sand control for the hydrocyclone platform case. This has added approximately 24A$M to the Thylacine subsea case and has been a driver for selecting a topsides desander for a Thylacine platform.

5.2 Jack-up Rig Feasibility

A study was conducted by Noble Denton to investigate Jack-up feasibility using Thylacine soil data and metocean conditions. The studies found eight rigs worldwide are capable of drilling over a platform at Thylacine without modification, as summarised in Figure 5.2. An additional five rigs require spudcan modifications or artificial seabed and a further five rigs would require leg strengthening.

It is planned to tender and secure a Jack-up prior to FID to eliminate availability and cost uncertainty and enable detailed engineering work to progress with focus on jacket installation using the Jack-up.

Figure 5.2
Jack-up Rig Feasibility

	Company/Rig Name	Design
1	Maersk Innovator	MSC-CJ70-150-MC
2	Maersk XL2	"
3	Rowan Gorilla V	MLT Super Gorilla
4	Rowan Gorilla VI	"
5	Rowan Gorilla VII	"
6	Rowan Gorilla VIII	"
7	Maersk Gallant	MSC-CJ62-150-MC
8	Smedvig West Epsilon	"

6x Can Install Thylacine Jacket

8x Can Drill at Thylacine Platform

1	SantaFe Galaxy 1	F&G L-780 Mod VI
2	SantaFe Galaxy 2	"
3	SantaFe Galaxy 3	"
4*	Santa Fe Constellation 1	F&G JU-2000
5*	Santa Fe Constellation 2	"
6	Maersk Giant	Hitachi Giant
7	Maersk Guardian	"
8	Rowan Gorilla II	MLT-150-88-C
9	Rowan Gorilla III	"
10	Rowan Gorilla IV	"

5x Require Spudcan Mods or Artificial seabed

5x Require Leg Strengthening + Artificial seabed / Spudcan Mods

* Study Not Complete on this rig

5.3 Wellhead Platform Design

Refer to the Offshore Structures Concept Design Report for further details (Ref. 5).

The substructure configuration comprises an extended base and a vertical tower. Appurtenances such as risers and J-tubes are located between the tower legs. Where possible to minimise the wave and current loads the well conductors are installed through the jacket legs.

The substructure configuration has been developed to provide the flexibility of a two piece installation using a Jack-up drilling rig or smaller installation vessels with limited crane capacity (eg. pipelay barge). Further, the two piece installation provides easy handling, upending and positioning due to limited hook height and reach. On-bottom stability, which generally is a problem for slim-line marginal platform, improves with the extended base and lower structure height during installation.

The topsides are two level open deck structures with an integrated heli-deck for personnel access (refer to Figures 5.3 and 5.4). This is again typical for minimal facilities platforms in the North West Shelf of Australia and in the North Sea. The underside of the cellar deck is set at E.L.+24.5m to clear the 2,000 year return wave for the un-manned platform, resulting in a main deck elevation of E.L.+29.5m T.O.S. Well intervention with wireline is possible with equipment located on the main deck and the lubricator either hung off the platform crane or guyed off. Access to the valves below the well head tree and drains sump is via a sub-cellar deck located at E.L.+20.0m which clears the 100 years wave crest.

Figure 5.3
Topsides Plan View

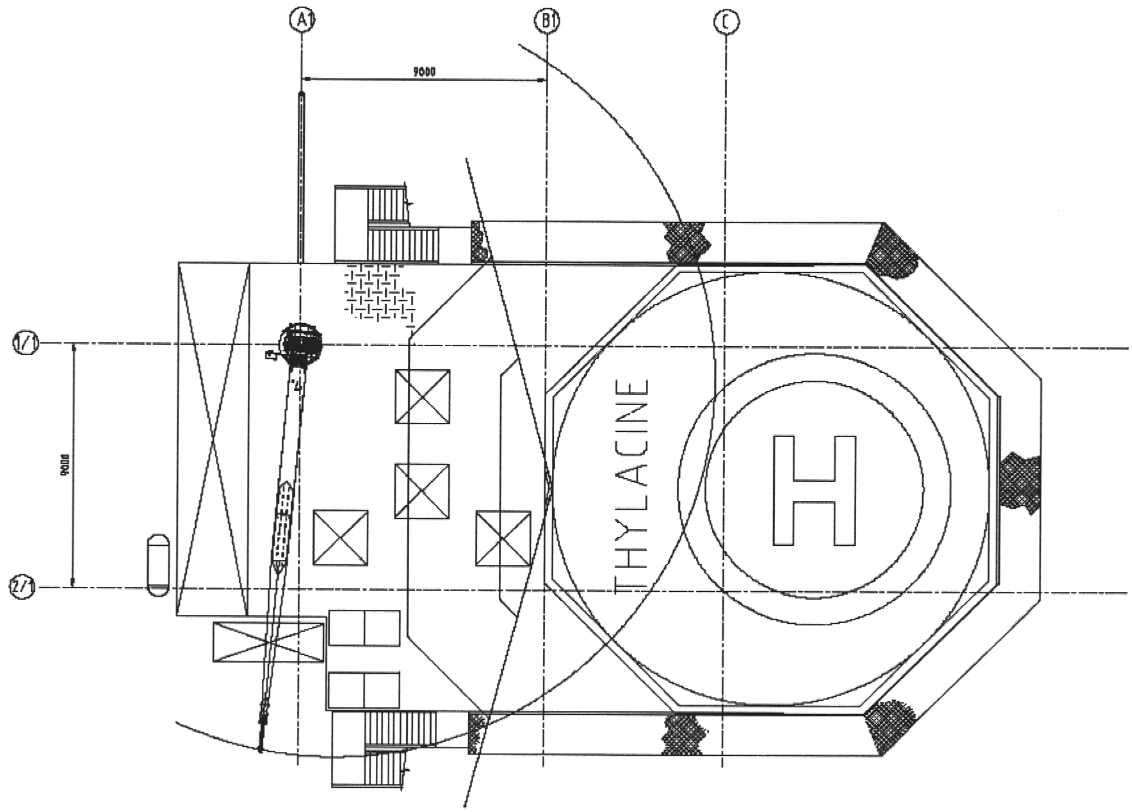
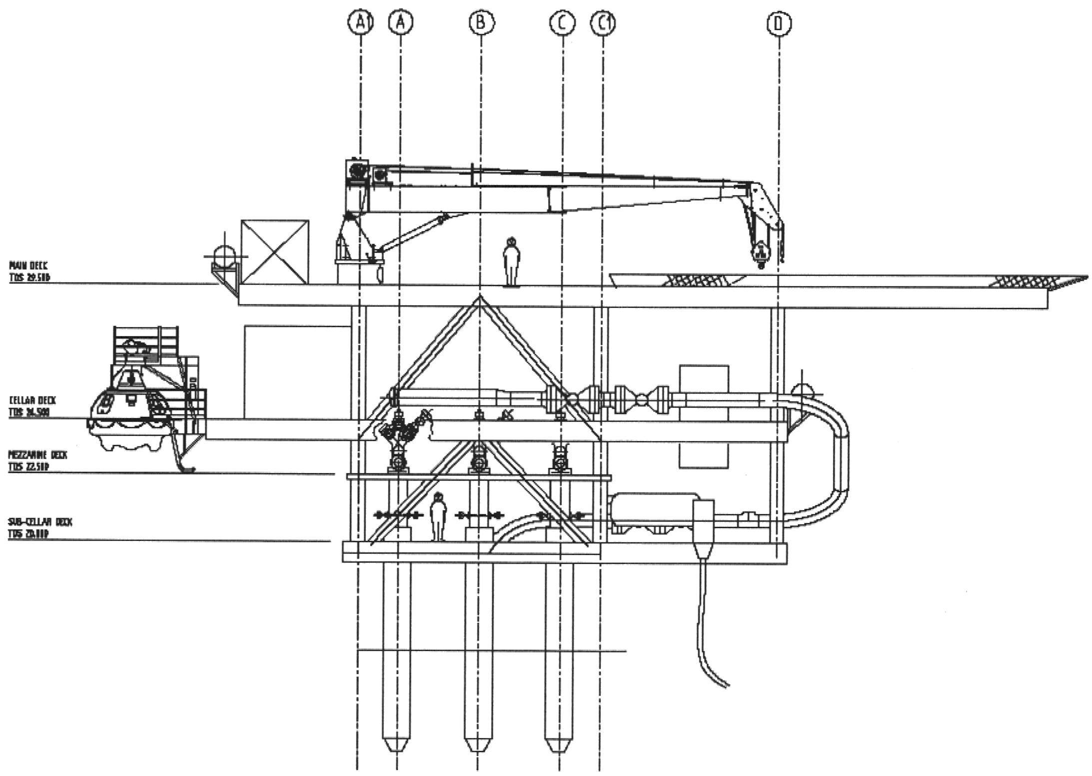


Figure 5.4
Topsides Section View



The minimum facilities platforms with an extended base substructure and drilled and grouted piles are feasible for the Geographe and Thylacine locations, subject to confirmation following completion of site specific soils investigations. Wave and current loads are the primary drivers for the substructures due to the extreme environmental conditions in the Otway region. Hence it is beneficial to utilise slim-line platforms and to shield appurtenances where possible, eg. locating conductors in the substructure legs.

The 4-Leg WW2 Thylacine wellhead platform has an un-factored two-piece substructure lift weight of 1720 tonnes (520 tonnes for the tower and 1200 tonnes for the base) and the topsides has an un-factored lift weight of 390 tonnes. Refer to Figure 5.5.

The tripod wellhead platform for the WS1 case has an un-factored two-piece substructure lift weight of 915 tonnes (225 tonnes for the tower and 690 tonnes for the base) and the topsides has an un-factored lift weight of 295 tonnes. Refer to Figure 5.6.

Figure 5.5
Thylacine 4-Leg Jacket Isometric View

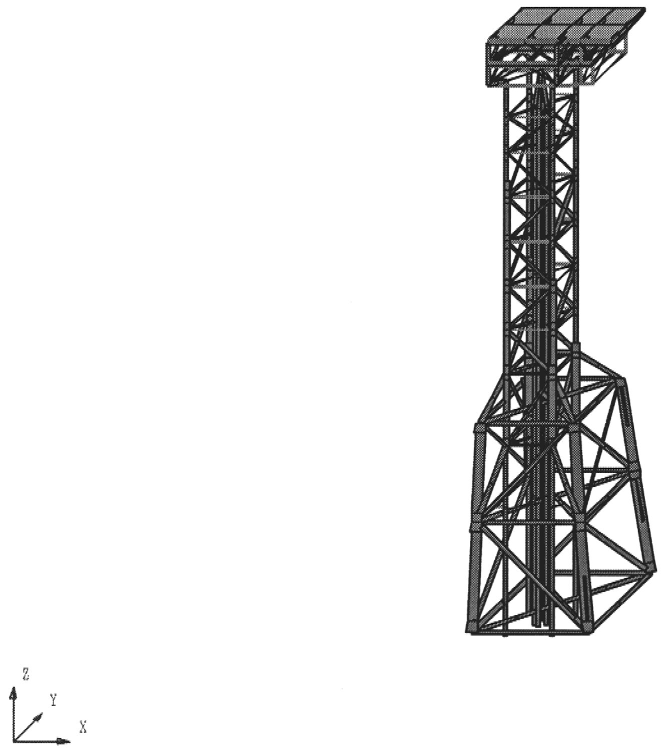
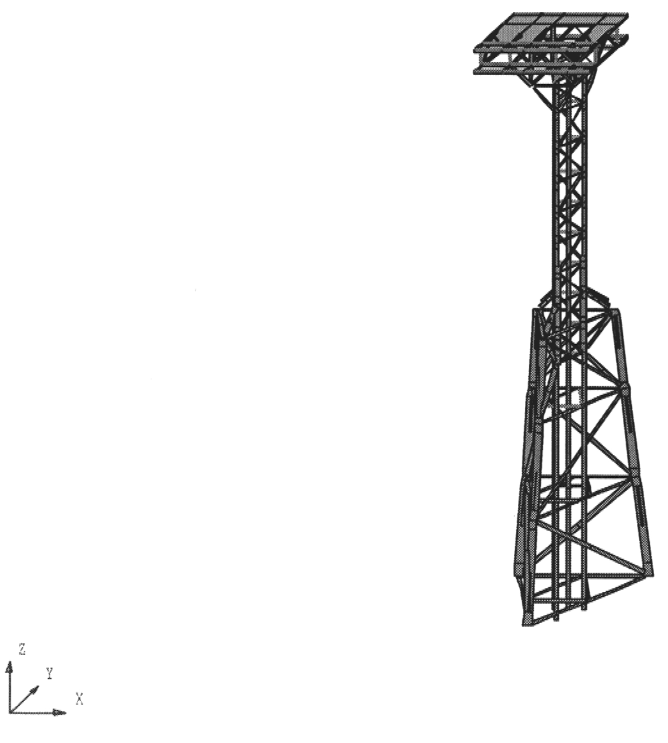


Figure 5.6
Thylacine Tripod Jacket Isometric View



5.4 Platform Installation

Refer to Offshore Installation and Construction Technical Note for further details (Ref. 6).

The drilling programme for the WS1 and WW2 development options is based on using a Giant Jack-up with the 'Base Case' for wellhead platform installation using the GJU draw works/cantilever, as illustrated in Figure 5.7 to 5.9. The substructure will be installed in two sections due its lift weight. To facilitate lifting by the GJU, the substructure components will be transported in a vertical position pre rigged for lifting. The base section would be installed and piled using drilled and grouted insert piles after which the tower section would be lifted, stabbed and a grouted connection made, followed by the lift and setting of the topside.

Figure 5.7

Substructure Lower Section GJU Installation

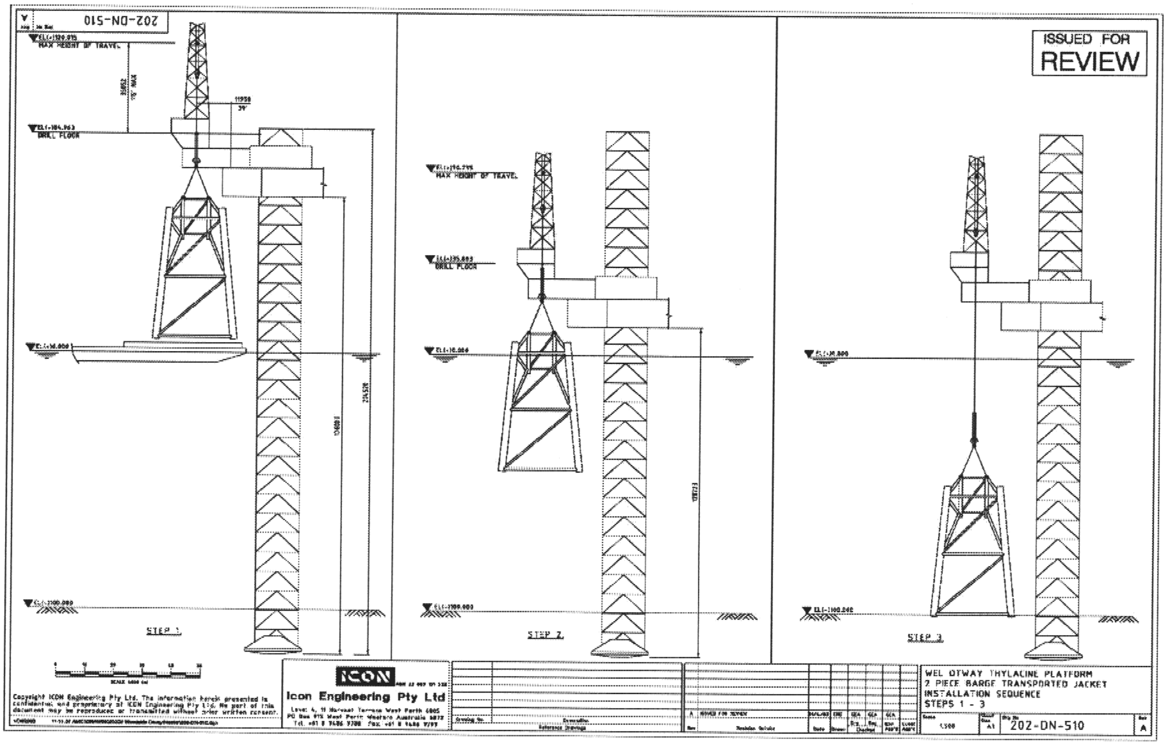


Figure 5.8

Substructure Upper Section GJU Installation

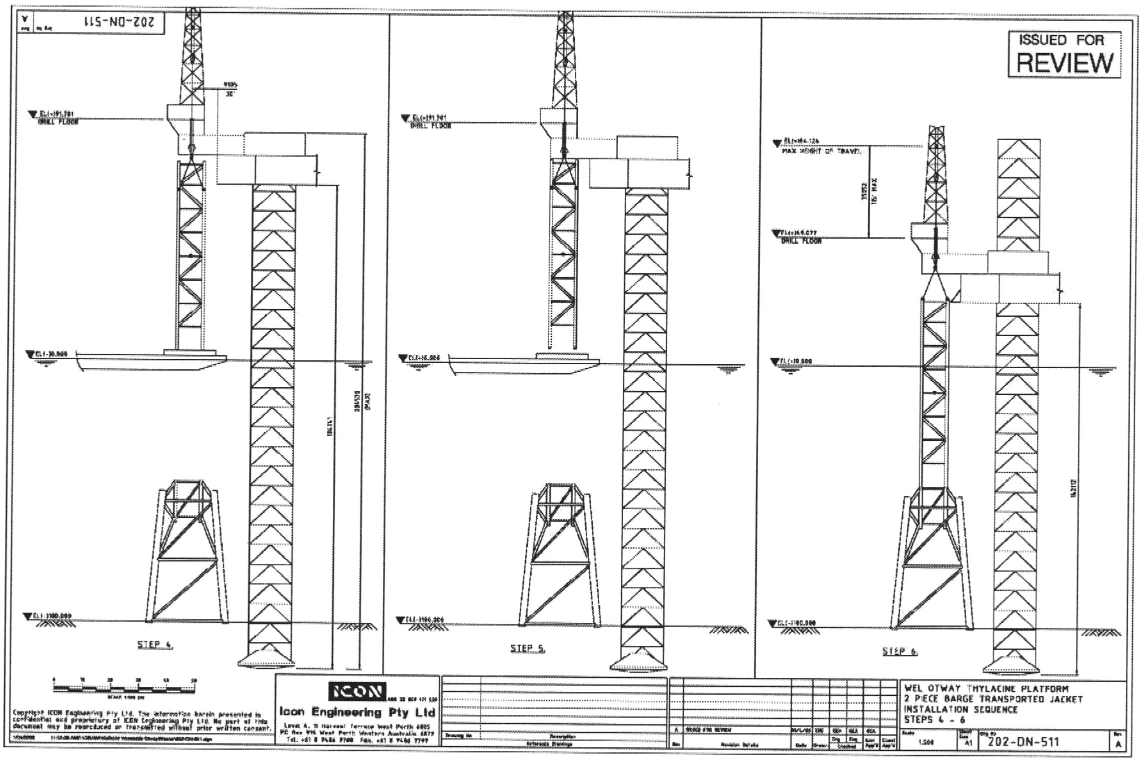
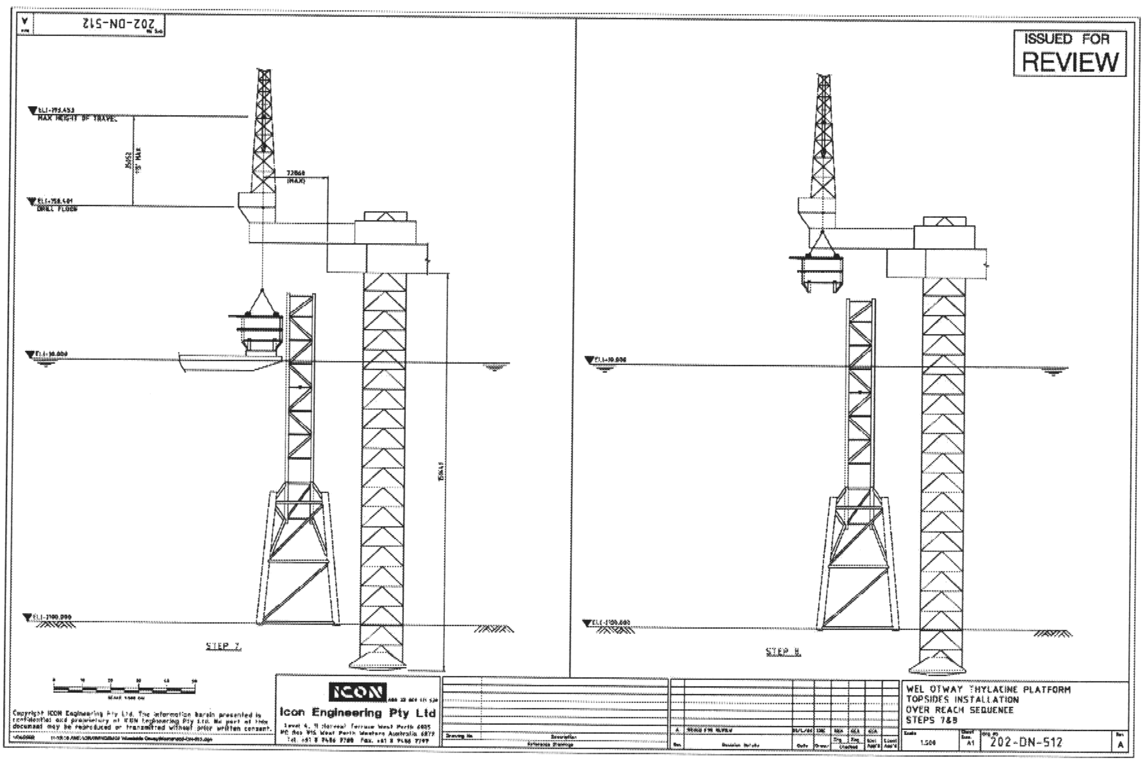


Figure 5.9

Topsides GJU Installation



5.5 Offshore Pipeline Corrosion Management and Material Selection

Refer to the Corrosion Potential and Mitigation report for further details (Ref. 7).

Pipeline corrosivity assessment has indicated that the produced fluids are corrosive and that an acceptable corrosion allowance will only be achieved with a high performance corrosion inhibitor and inhibitor injection facility at a point along the pipeline where the produced fluids have cooled to less than 60°C to reduce the corrosion rate. To achieve this, the offshore pipeline materials selection strategy uses a hybrid material selection philosophy utilising 316 SS-lined CRA sections for the 'hot' pipeline ends and carbon steel with corrosion allowance and corrosion inhibitor injection for the cooler section of the pipeline. 1500 m CRA length at the Thylacine 'hot' end and 800 m CRA length at the Geographe 'hot end' are recommended to achieve the maximum life cycle corrosion allowance of 5 mm for the 35 year offshore pipeline design life.

Corrosion inhibitor will be continuously injected with the MEG hydrate inhibitor to provide an expected inhibitor availability of 99 percent. Provision for batch corrosion inhibition will be available fro the Thylacine wellhead platform if required.

Corrosion inhibition effectiveness will be impacted by the presence of produced water and sand, and therefore effective monitoring must be in place. Corrosion monitoring spools will be installed downstream of each field 'hot end', with well sand monitoring and field wet gas metering installed to detect contaminant breakthrough that would require action.

5.6 Onshore Plant LPG Recovery

Refer to the LPG Recovery Review (Ref. 11) and LPG and Gas Specification Review (Ref. 12) Technical Notes for detailed review.

Evaluation was completed to determine the most economic liquids recovery option. Options reviewed included condensate only, LPG recovery and ethane recovery.

The economic comparison for these cases is summarised in Table 5.4 below.

Table 5.4
Economic Comparison of LPG Recovery Options

Option	Condensate A$M	LPG A$M	Ethane A$M	Gas A$M	Capex A$M	Opex A$M	NPV A$M	ΔVIR A$M
Condensate	0	0	0	0	0	0	**0**	**0**
LPG recovery	27	248	0	-59	74	15	**127**	**1.7**
Ethane recovery	33	270	142	-134	159	30	**122**	**0.8**

The values in this table are pre-tax, discounted at 10% and are relative to Condensate Recovery.

The review indicated:

- Incremental NPV of A$127M (before tax) was achieved for the LPG recovery option. This compares very favourably with the incremental Capex spent (A$74M discounted).
- Ethane recovery provided some additional condensate and LPG revenue, with the NPV remaining essentially the same as for the LPG recovery option i.e. no improvement for the additional Capex spent.

The similar NPV can be attributed to the relative price for LPG and ethane that has been assumed. Similar quantities of each stream are extracted, but the price of ethane is only half that of LPG.

Ongoing optimisation of the LPG process has been completed, including the evaluation of patented LPG recovery and operating parameter review to maximise the value of the LPG product. As a result of this work the LPG revenue has been improved by approximately 10% due to an increase from 95% recovery to 99% recovery, an improvement in propane / autogas split and increased ethane recovery.

5.7 Site Location and Land Acquisition

The site selection process addressed the requirements for both shore crossing and gas plant locations. By November 2002, the selection process had established two potential shore crossing locations and three potential gas plant locations. There was sufficient definition at this stage to allow land access agreements to be negotiated, purchase options to be prepared and survey activities to be executed. The crossing sites and plant locations considered are defined in Table 5.5.

Table 5.5
Site Location Options

Shore Crossing	Gas Plant
• Rifle Range in Two Mile Bay – Port Campbell	• Adjacent to TXU Iona gas plant • Vaughans Road
• Flaxman Hill – West of Peterborough	• Baileys Road

Due to lack of survey data for the both the offshore pipeline routes and the shore crossing locations it was not possible to select a single shore crossing location at this time and hence two options were retained. This strategy also assisted with land acquisition negotiations and allowed stakeholder consultation before selection of the preferred site. The location at the Rifle Range was the preferred shore crossing site due to the minimum distance to the offshore gas fields and the fact that it allowed easier access to the existing gas infrastructure facilities in the region. In addition, recently obtained survey information has indicated that the offshore pipeline route to Flaxman Hill would require significant pipeline span mitigation measures, thereby further increasing the cost differences between the two shore crossing locations.

Survey data collection, environmental impact studies and land acquisition options have been completed for both gas plant locations associated with the Rifle Range crossing. In recent months, work has been focussed on making a final selection between the 'greenfield' site at Vaughans Road and a 'brownfield' co-location at TXU Iona. In this context, the term 'co-location' refers to an independent Otway gas process facility situated adjacent to the existing Iona facility.

Local Government Coastal Management Plan guidelines propose co-location of gas plants in the region wherever practicable. The community (with the exception of neighbours to existing gas plants) has also expressed a preference for co-location.

Investigations into total integration of Otway and Iona concluded that due to significant incompatibility in capacity and process capability, there would be a net negative value to Otway in such a venture. However, study work (Ref. 8) did indicate that there was potential benefit in utilising certain components of the TXU Iona facility to complement the Otway gas plant. Table 5.6 presents expected values that can be associated with this selective utilisation approach. The figures are direct comparisons with an equivalent 'greenfield' gas plant site at Vaughan's Road. The 'Probability of Realisation' column contains subjective figures that were generated within a workshop environment following discussions with TXU.

Table 5.6

TXU Co-location Value Analysis (Iona versus Vaughan's Road)

CAPEX Items	Lower Bound Estimated Value A$M	Upper Bound Estimated Value A$M	Probablility of Realisation	LB Estimated Realised Value A$M	UB Estimated Realised Value A$M
Compression upgrade	$6.90	$6.90	0.80	$5.52	$5.52
Pipeline infrastructure (SEAGAS Tie-in)	**$0.50**	**$3.00**	0.25	$0.13	$0.75
Waste water disposal	**$1.00**	**$1.50**	0.75	$0.75	$1.13
Firewater supply	$1.20	$1.20	0.75	$0.90	$0.90
Civil works and road upgrade costs	**$1.20**	**$1.80**	1.00	$1.20	$1.80
Pipeline costs (Condensate +LPG)	**$3.70**	**$4.80**	1.00	$3.70	$4.80
Noise attenuation & Land Acquisition	**-$3.00**	**$0.60**	1.00	-$3.00	$0.60
Sub Total	$11.50	$19.80		$9.20	$15.50
OPEX Items					
Operational synergies (1.3 A$M pa)	$15.80	$15.80	0.50	$7.90	$7.90
MEG proc essing (0.1 A$M pa)	$0.90	$0.90	0.25	$0.23	$0.23
Sub Total	$16.70	$16.70		$8.13	$8.13
TOTAL	**$28.20**	**$36.50**		**$17.32**	**$23.62**

Based on the preferences of government and the community coupled with the opportunity to realise Capex savings by co-locating with TXU, the Rifle Range crossing location and gas plant location adjacent to TXU were adopted for the Base Case. Specific areas of the co-location that were found to have significant Otway benefit have been included in Base Case, including:

- Use of TXU export compression as back-up. This allowed the down-sizing of Otway export compression from 2 x 80% to 2 x 50% with TXU providing back-up through a tariff arrangement.
- Use of TXU produced water injection well as back-up. This allows the downsizing of Otway injection wells from 2 x 100% to 1 x 100% with TXU providing back-up through a tariff arrangement.
- Upgrade of the existing 22 kV power supply main to TXU as back-up. This allows the downsizing of Otway on-site power generation to from 2 x 100% gas turbine generation to 1 x 100% with mains power supply as back-up. Refer to the Power Supply Options Technical Note (Ref. 9) for further details.
- Fire water storage using existing TXU firewater dam.

6.0 COST AND SCHEDULE

6.1 AC-3 Cost Estimates

At the end of Phase 2C, Capex and Opex estimates were generated to provide an overall +/-25% estimate accuracy. As outlined in the Cost Estimating Methodology Technical Note (Ref. 10), "bottom-up" facility Capex and Opex estimates were generated to support this outcome, with vendor quotes received for key equipment and services.

Base Case cost estimates associated with each Option are summarised in Table 6.1. In addition to Base Case cost estimates, a number of scenario and sensitivity cost estimates were generated for economic evaluation and validation of selection decisions.

Table 6.1
Base Case Cost Summary

Option	S1 Concurrent (A$M)	WS1 Thylacine First A$M	WW2 Thylacine First A$M
PHASE 1			
Drilling	$235.3	$164.3	$164.3
Thylacine Platform Substructure	-	$45.2	$58.9
Thylacine Platform Topsides	-	$20.4	$22.1
Offshore Pipelines & Subsea	$282.3	$174.2	$174.2
Onshore Pipelines	$13.2	$11.4	$11.4
Onshore Plant	$279.7	$279.7	$279.7
Condensate Export Pipeline	$38.5	$38.5	$38.5
TOTAL PHASE 1	**$849.0**	**$733.7**	**$749.1**
PHASE 2			
Drilling	$154.7	$172.9	$183.9
Geographe Platform Substructure	-	-	$43.4
Geographe Platform Topsides	-	-	$15.6
Subsea and Pipelines	$17.4	$61.7	$3.3
TOTAL PHASE 2	**$172.1**	**$234.6**	**$246.2**
PHASE 3			
Inlet Compression	$48.7	$48.7	$48.7
TOTAL PHASE 3	**$48.7**	**$48.7**	**$48.7**
TOTAL CAPEX	**$1,069.8**	**$1,017.0**	**$1,044.0**
Decommissioning	$70.4	$75.0	$79.9
GRAND TOTAL	**$1,140.2**	**$1,092.0**	**$1,123.9**
PV @ 10%	**$724.2**	**$662.4**	**$679.0**
Max Annual OPEX	**$26.0**	**$22.0**	**$19.0**

6.2 Project Schedules

Indicative Level 2 project execution schedules were generated for the three development Options to determine time from Final Investment Decision to first gas. These schedules are shown overleaf in Figures 6.1 to 6.3. For all Options, time from Final Investment Decision (FID) to RFSU is expected to take 27 months, with onshore gas plant major equipment procurement and construction being the critical path activities.

Figure 6.1
Option S1 Project Schedule

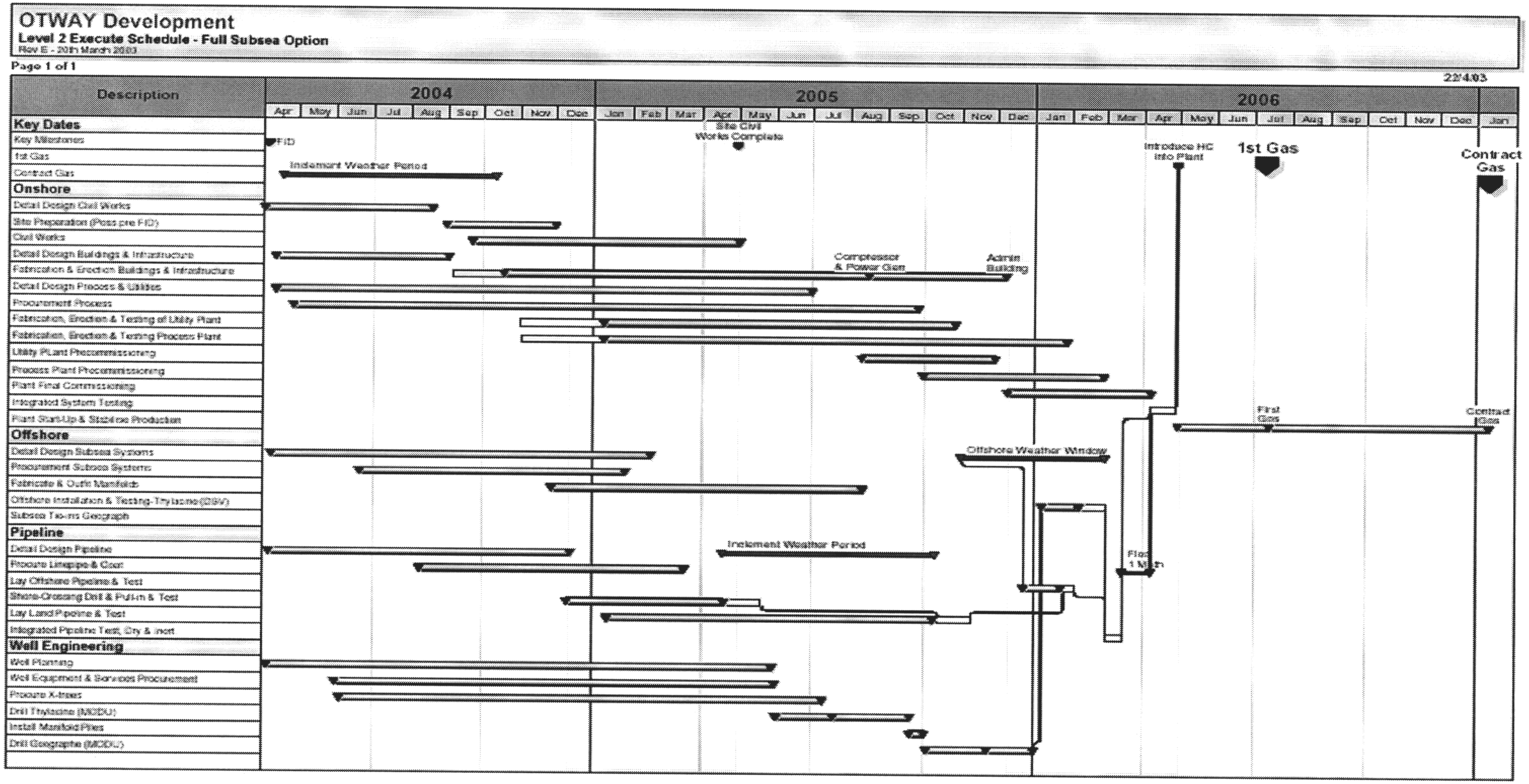


Figure 6.2

Option WS1 Project Schedule

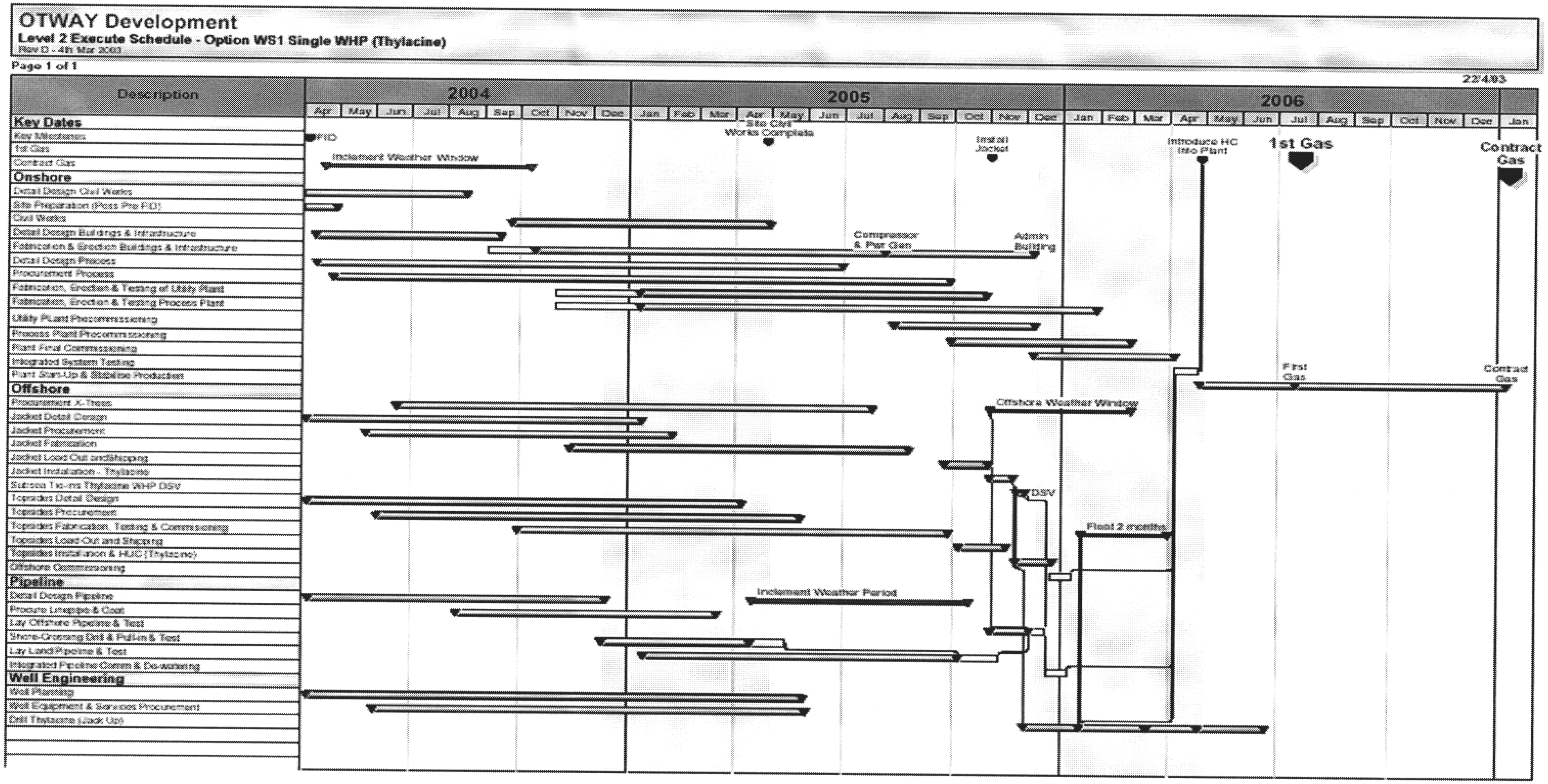
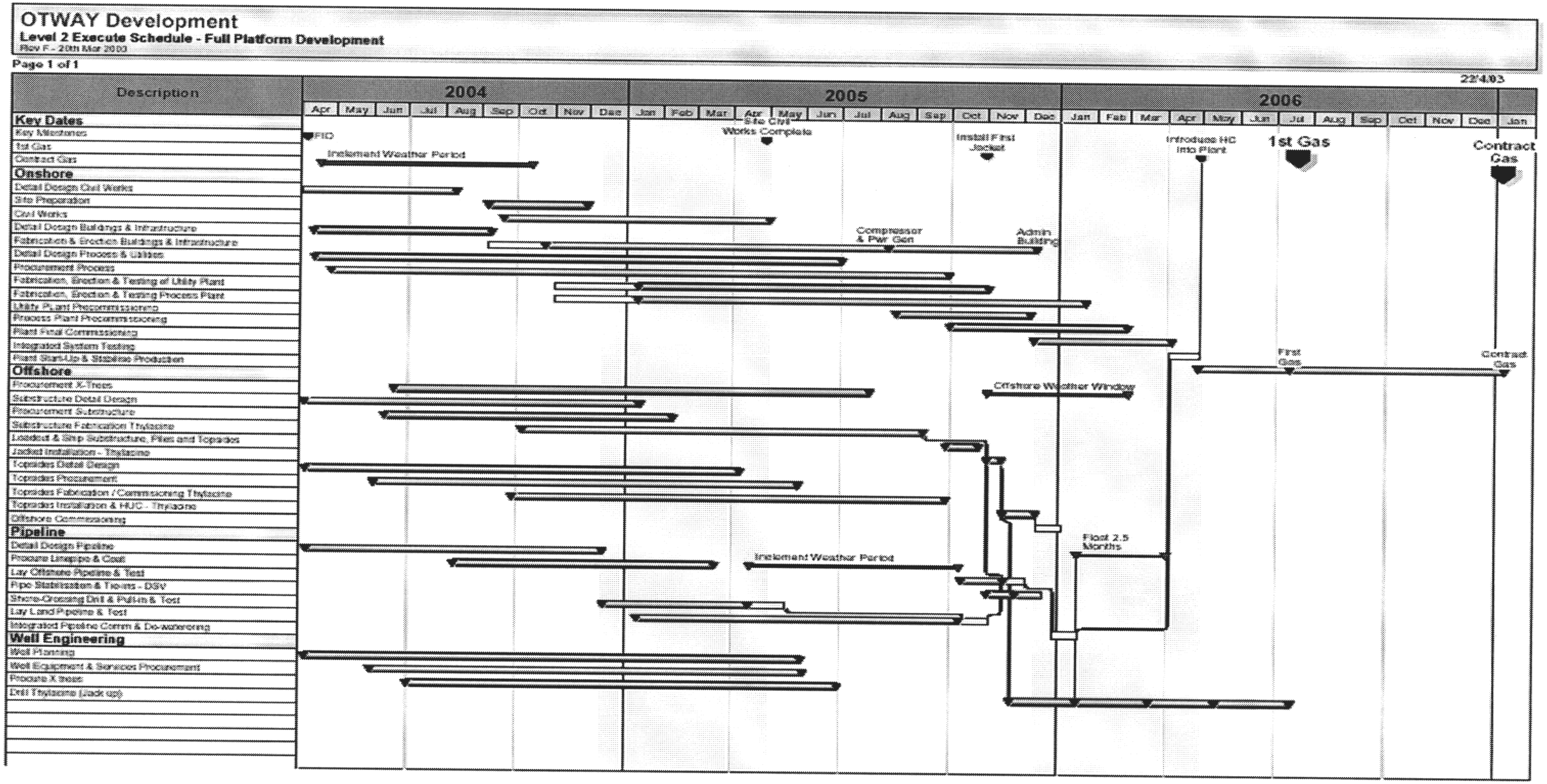


Figure 6.3

Option WW2 Project Schedule



7.0 WS1 RISKS AND UNCERTAINTIES

Several uncertainties and risks are apparent with the WS1 preferred development option that will require further evaluation in Phase 3:

- Poorer than expected reservoir performance (lower than expected GIIP or fault transmissibility) or TM1 well failure could result in acceleration of second drilling campaign. Contingency plans have been developed to minimise production and cost impact and will require further review.
- GJU rig availability, mobilisation/demobilisation and day rate require evaluation.
- WHP installation plans and weather impacts will require further review to mitigate cost and schedule risk.
- Final offshore geotechnical results are required to confirm WHP foundation design.
- Finalisation of WHP substructure transport and offload procedure.
- WHP topsides and substructure weight growth could impact cost and installation feasibility. Impact on installation feasibility has been mitigated by adopting a 2-piece tripod substructure design.
- Lack of regional pipelay vessels capable of installing the offshore pipeline could result in increased cost risk. Further review is required to enhance commercial competitiveness.
- Potential increase in IR impacts and labour rates relative to current assumptions could impact project cost and schedule. Development of an Industrial Relations strategy will be required to reduce risk of IR action and escalating labour rates.
- Noise attenuation and produced water recharge strategies will require approval by the Regulator.
- Delay in Government approvals could impact project schedule.
- Condensate pipeline to the Shell Geelong refinery has not been fully approved and is subject to ongoing marketing and economic analysis.
- Project Operating and Maintenance model requires finalisation.

8.0 REFERENCES

1. Document 90886-OTW-RC-A-00001, Rev. 0, CDC # S2000-RG-138899, "G-FAST Workshop Report", September 2002.
2. Document 90886-OTW-RM-A-00002, Rev. 0, CDC # S2000-RG-138900, "Coarse Screening Workshop Report", November 2002.
3. Document 90901-OTW-RT-A-00001, Rev. 0, CDC # S2000-RG-142551, "Concept Selection Workshop Report", March 2003.
4. Document 90901-OTW-RT-A-00004, Rev. A, CDC # S2000RG144253, "April 2003 JV Workshop #2 Report", April 2003.
5. Document 90901-OTW-RD-S-00001, Rev. A, CDC # S2000-RS-143176, "Offshore Structures Concept Design Report", April 2003.
6. Document 90901-OTW-TN-M-00005, Rev. A, CDC # S2300-RG-138974, "Offshore Installation and Construction Technical Note", April 2003.
7. Document 90901-OTW-RT-M-00001, Rev. A, CDC # S2400-RL-138956, "Corrosion Potential and Mitigation Report", April 2003.
8. Document 90901-OTW-TN-M-00001, Rev. 0, CDC # S2500-RM-142672, "TXU Co-Location Review Technical Note", April 2003.
9. Document 90901-OTW-TN-E-00001, Rev. 0, CDC # S2500-RE-142638, "Gas Plant Electric Power Supply Cost Analysis Technical Note", April 2003.
10. Document 90901-OTW-RT-K-00002, Rev. 0, CDC # S2000-RG-139004, "Cost Estimating Methodology", December 2002.
11. Document 90886-OTW-TN-C-00008, Rev 0, CDC # S2000-RP-138951, "LPG Recovery", March 2003.
12. Document 90901-OTW-TN-C-00002, Rev. 0, CDC # S2500-RP-142667, "LPG & Gas Specification Review", April 2003.

APPENDIX I
APRIL 2003 SWOT ANALYSIS

The points highlighted in green, prefixed with * and red, prefixed with #, are significant strengths and weaknesses respectively.

Table A-I.1

Option S1 – Full Subsea Development

Strengths	Weaknesses
*Simplest concept to project manage, less interfaces – single concept *No ongoing supply vessel & helicopter support requirements (Ops & Safety) Lowest HSE risk Not subject to vessel collision risk Low potential for accidental discharge of service fluids/condensate Least Construction manhours (safety) Negligible risk from fires (safety) Less dependent on geotechnical information Not subject to extreme environmental loading Weight growth not an issue Greater rig (semi sub) availability	#Ability to execute well intervention activity restricted as cost of mobilising rig is prohibitive #Lower ultimate recovery for subsea development #Shorter plateau length Government preference for platform for perceived enhanced recovery Routine regular pigging not cost effective with subsea pig launcher Recovery from hydrate blockage if it occurs will be difficult. Blowdown from well end via service line only Relies on single umbilical for control. Damage to umbilical will result in extended shutdown More complex wells (sand/SMARTs) More dependant on diver operations
Opportunities	**Threats**
Consider sponsoring development programme for wet gas flow meters Greater opportunity to realise early production (assuming onshore plant available for processing)	Base case is currently no intervention for reservoir monitoring purposes, potentially a high reservoir management risk Ability to execute well intervention activity restricted as cost of mobilising rig is prohibitive

Table A-I.2

Option WS1 – Wellhead Platform at Thylacine with Second Campaign Subsea Tiebacks, Subsea at Geographe

Strengths	Weaknesses
*Most economically attractive option, minimal up front CAPEX ($16M) *Subsea development for 2nd phase maximises flexibility *Ability to quickly (cost effective) execute well intervention at critical Thylacine wells (TM1) *Improved data gathering & reservoir management at Thylacine (largest most complex reservoir) Not dependant on reliability of single umbilical to shore Improved access for maintenance Single lift sub structure minimises exposure to met-ocean conditions Less complex well design (no sand control or SMART for Thy wells) Does not rule out use of tripod on Geo for 2nd Phase Ability to better manage hydrate blockage	Safety - Helicopter flights on regular basis, fires, HC releases, dropped objects, vessel collision, pigging activity Limited ability to retrofit Geo sand control Intervention for 2nd Phase wells dependant on mobilising MODU (however semisubs more readily available than GJUs)
Opportunities	**Threats**
Improve ongoing metering reliability due to access to meter Opportunity to maximise HC recovery Use of smaller GJU to secure more cost effective rig rate (analysis to confirm ability to use)	GJU availability could impact 1st Phase (consider securing Jack-up prior to FID) Build sequence dependencies may result in increase costs or delays Poor geotechnical results in cost increase for WHP foundations

Table A-I.3

Option WW2 – Wellhead Platforms at Both Thylacine and Geographe

Strengths	Weaknesses
*Dry trees will increase recovery due to quick/inexpensive intervention *Improved data gathering & reservoir management *No umbilicals, increases control reliability Preferred by DITR as perceived as maximising HC recovery Almost no subsea infrastructure requiring diving activities (safety) Flow assurance - lowest risk for hydrate management & recovery Improved access for maintenance Lowest OPEX Less complex well design (no sand control or SMART for Thy wells) Ability to retrofit Geo sand control (if required)	#Availability of GJU for Phase 1 & 2 and major workovers #Most construction manhours (safety) Increased foundation risk – 2 WHPs Safety - fires, HC releases, dropped objects, vessel collision, pigging activity Frequent helicopter flights required for both WHP attendance Geo WHP close to major shipping lane (collisions) Feasibility of installing 2nd WHP in P90 scenario
Opportunities	**Threats**
Greatest opportunity to maximise HC recovery Use of smaller GJU to secure more cost effective rig rate (analysis to confirm ability to use)	Feasibility of GJU platform Installation with available rigs Poor geotechnical results in cost increase for WHP foundations Build sequence dependencies may result in increase costs or delays Greater transportation and installation risk Unable to source GJU

APPENDIX II
KEY DECISION REGISTER

Attachment

Decision Register, 4 pages

DECISION AREA	RESP	PRIORITY	WORK COMPLETED	DECISION	STATUS	REFERENCE DOCUMENTS
GENERAL						
Options Screening	PR/GV	H	Development screening completed to reduce from 53 concepts in the G-FAST workshop to current 4 concepts. Currently considering full subsea (S1), subsea with Geographe control platform (S2G), subsea with Thylacine control platform and pigging (S2T), subsea/WHP development at Thylacine (WS1T) and two WHPs (WW2). Concept screening workshop held 17/18-Feb, concepts reduced to S1 concurrent and WW2 Thyl 1st, WS1 Thyl 1st with subsea 2nd campaign added subsequent. April JV Workshop held that selected WS1 as preferred Option.	WS1 recommended as preferred option in April JV workshop.	To be validated in AC-3.	90886-OTW-RC-A-00001 (issued) 90886-OTW-RT-A-00002 (issued) 90901-OTW-RT-A-00001 (issued) 90901-OTW-RT-A-00004 90901-OTW-RT-A-00003 Economic runs
Suitability/Risk	DF/CM	H	Suitability Index prepared for Sept 2002 coarse screening workshop. Developed detailed Suitability Index and SWOT Analysis for remaining 5 options for Feb 2003 JV workshop. Action Plan developed for all low suitability ("Pink") areas and SI updated prior to February concept selection workshop. SI reviewed/updated during workshop, with Rev 1 report issued. SI and SWOT updated during April JV workshop and used for concept	Input into Concept Select decision.	Complete	90901-OTW-RT-X-00001 (Rev 2 issued) 90901-OTW-RT-A-00001 (issued) 90901-OTW-RT-A-00004
Availability	DF/FB	M	Completed Availability Analysis to determine option availability for end Phase 2B. Updated with most recent changes in onshore plant, offshore facilities and well configuration. Report issued incorporating Phase 2C equipment configuration.	Input into Concept Select decision.	Complete	90886-OTW-RT-X-00006 (issued) 90901-OTW-RT-X-00006 (issued)
Design Factors and Margin	TV/FdB	M	Creaming curve cost sensitivities and economic evaluation completed. Results presented at Concept Selection workshop. Further screening on 50 and 70 PJ/a completed as part of cost reduction initiative and included in economic sensitivities pre-AC3. Base case is MDQ/ACQ 125% and 100% design margin on all processing equipment. Condensate liquid processing margin changed to 100% design factor for Geographe feed.	Base case is MDQ/ACQ 125% and 100% design margin on all processing equipment. Condensate liquid processing margin based on Geographe feed.	Complete	90901-OTW-RT-A-00001 (issued) 90901-OTW-TN-C-00003 (issued)
System Capacity	FdB/TV	M	Creaming curve cost sensitivities and economic evaluation completed. Economic and forecasting runs considered 50, 70, 75 and 90 PJ/a sensitivities. Results presented at Concept Selection workshop. Further screening on 50 and 70 PJ/a completed as part of cost reduction initiative and included in economic sensitivities pre-AC3. 60 PJ/a as base case.	60 PJ/a as base case.	Complete	90901-OTW-RT-A-00001 (issued) 90886-OTW-TN-C-00004 (Rev B) Economic results
Equipment Sparing	FdB	M	Incorporated into offshore and onshore facilities reviews No sparing on offshore equipment, single onshore plant processing train, major rotating equipment sparing or backup. Use of TXU export compression and water injection well as back-up, 22 kV power supply as power generation back-up to reduce capex.	No sparing except critical rotating equipment, power mains back-up, and export compression/water injection back-up using TXU.	Complete	90886-OTW-TN-C-00003 (issued) 90886-OTW-TN-C-00007 (issued) 90886-OTW-TN-C-00004 (issued) 90901-OTW-TN-C-00003 (issued) 90901-OTW-TN-C-00007 (issued) 90901-OTW-TN-M-00001 (issued)
Pre-investment	PR	M	Spare well slots on Geographe manifold for well expansion, spare WS1 WHP riser, J-tube and 'tee' slots for future subsea tiebacks, deferred inlet compression and MEG regeneration where possible. Pipeline Corrosion Allowance increased to allow 35 year design life. 2 future offshore pipeline tie-in fittings installed. INcorporated into cost estimates and technical work.	Pre-investment for future additional Geographe wells using spare manifold slot/flowbase daisy chain, Thylacine wells using subsea tiebacks. 2 pipeline tie-in fittings to be installed for future field tie-ins.	Complete	90886-OTW-TB-A-00004 (issued) 90886-OTW-TN-C-00003 (issued) 90886-OTW-TN-C-00007(issued) 90901-OTW-TN-C-00003 (issued) 90901-OTW-TN-C-00007 (issued)

DECISION AREA	RESP	PRIORITY	WORK COMPLETED	DECISION	STATUS	REFERENCE DOCUMENTS
Field Phasing	FdB	H	Cost sensitivities and production profiles developed for AC-2 review for Geographe first, Thylacine first and concurrent field phasing. Reviewed again in Concept Selection workshop. Based on economics, concurrent production is chosen for S1 case and Thylacine First for WS1 and WW2 cases. Economic sensitivity run for WS1 concurrent to validate results.	WS1 and WW2 using Thylaince First field phasing, S1 using concurrent field phasing.	Complete	90886-OTW-TN-C-00004 Rev A (issued) 90886-OTW-RT-K-00003 (issued) 90901-OTW-RT-A-00001 (issued) Economic runs
Compression	FdB	M	High level integrated modelling completed pre-AC2 and TN issued which indicated highest value in deferred onshore compression for all field phasing cases. Sensitivities run for larger/smaller inlet compression to validate results.	HFPT modelling complete, sensitivites generated and economics run.	Complete	Economic evaluation
OFFSHORE						
Platform/Drilling Centre Location	BL/SJ/DC	M	Evaluation and TN completed - cluster drilling found to be best value for subsea development. Platform/Drill Centre location chosen above main reservoir blocks for each field, minimises drilling cost for initial wells. Thylacine centre shifted to improve first campaign well planning/cost, with second campaign wells as subsea tiebacks.	Field location shifted in March 2003 to reflect optimised drilling location/cost.	Complete	90886-OTW-RT-U-00002 (issued) CDC# S2000-RG-138683
Rig Type for WHP Drilling	DC/GV	H	Evaluation complete and TN issued on drilling and WHP costs to determine greatest value. GJU provided greatest overall value when considering drilling and WHP costs. Noble Denton study completed to validate GJU capability for Otway.	GJU validated to complete Otway WHP drilling.	Complete	90886-OTW-TE-D-00001 (issued) Noble Denton Review
Sand Management	GN	H	Transient sand production potential evaluated and viewed as potential, with high risk for pipeline corrosion evident (validated by SGS). Sand prediction work completed that determined Geographe units in 'safe' region, Thyl Units 1 and 2 in transient sand production region and Thyl Units 4, 4a and 5 in 'catastrophic' sand productin region. Base case sand control methodology developed using downhole sand control for Thyl Units 4, 4a and 5 for all development options, and Thyl Unit 1 and 2 sand control using downhole control for subsea wells and topsides sand removal for for subsea and topsides desanding for WHP wells.	No Geographe sand control is required. Thylacine Unit 4, 4a, 5 downhole control for all cases, and Thylacine Units 1 and 2 downhole control for S1 and WS1 subsea wells, topsides for WS1 & WW2 dry tree wells.	Complete	90901-OTW-RT-A-00003
Subsea Pigging	BL	H	Pigging study report complete which validates subsea pigging and develops logistics. Incoporated review by FMC and Statoil in decision.	Subsea pigging acceptable for S1 case.	Complete	90901-OTW-TN-L-00001 (issued)
Water Production and Handling	FdB/BM	H	Reservoir modelling completed to develop water production profile. Evaluation completed as part of Phase 2B that reviewed S2 offshore FWKO case, case eliminated in Sept 2002 coarse screening. 1000 bwpd (total) with onshore water removal and injection is current reference case.	1000 bpd water production rate with onshore removal/water injection recharge is base case. MEG injection sized for contingency for 2000 bwpd equivalent. Contingency for offshore water disposal to outfall developed in case recharge not approved by regulator.	Complete	Reservoir modelling/PDC 90886-OTW-RM-A-00002 (issued) 90901-OTW-TN-C-00010 (issued)
Pipeline Corrosion Management and Material Selection	BL/AL	H	Main pipeline to use Carbon steel with continuous corrosion inhibitor blended with MEG injection. CRA cooling sections to be installed downstream of each field manifold or WHP to reduce fluid temperature below 60 C for TOL corrosion mitigation. Reviewed with SGS via telecon 13-Mar-03 that validated Otway inhibitor availability position. Revised report issued.	Carbon steel with CRA cooling sections to be used for offshore pipeline. Continuous corrosion inhibitor to the dosed with MEG injection.	Complete	90886-OTW-RT-M-00001 (issued) 90901-OTW-RT-M-00001 (issued)

DECISION AREA	RESP	PRIORITY	WORK COMPLETED	DECISION	STATUS	REFERENCE DOCUMENTS
Hydrate Management	FdB	H	Hydrate mitigation using MEG injection with onshore regeneration to be used. MeOH reviewed as an alternate, all other options have been eliminated. MEG found to be preferred inhibitor for routine operations. MeOH to be provided for start-up and recovery operations. Require review in Phase 3A on salt deposition.	Offshore dehydration eliminated. MEG injection to be used for ongoing hydrate management.	Complete Salt deposition review in Phase 3A	90886-OTW-RT-C-00005 (issued) 90901-OTW-TN-C-00008 (issued)
Metering	FdB	M	Evaluation completed on metering configuration to meet regulatory and reservoir management requirments. Well venturi meters with single field wet gas meter proposed and found acceptable for requirements. Further work in Phase 3A to review Statoil K-Lab testing results for the Mikkal field to validate decision.	Well venturi meters with single field wet gas meter to be used for all development options.	Complete Phase 3A review of Mikkal testing results.	90901-OTW-TN-J-00001 (issued)
Platform Manning	DW	M	Operations philosophy developed, normally unmanned facilities to be installed for control and WHP cases due to simplicity of equipment and operation. Control and monitoring from onshore plant control centre. Platform operations and maintenance support using onshore plant personnel.	Normally unmanned installation monitored and controlled from onshore plant. Operations intervention using onshore plant personnel.	Complete	90901-OTW-TP-O-00001 (issued) Concept Asset Reference Plan
Communications Control	BL	M	Technical review on umbilical reliability and acceptability for Otway, found to be acceptable. Subsea control by umbilical from shore (S1) or via microwave link from shore to platform (S2, WS1, WW2). Geographe control from Thylacine WHP via umbilical. Platform communication contingency to use satellite link.	Subsea control by umbilical from shore (S1) or via microwave link from shore to platform (S2, WS1, WW2). Geographe control from Thylacine WHP via umbilical.	Complete	90886-OTW-TN-U-00001 (issued) 90901-OTW-TN-U-00001 (issued) 90901-OTW-TN-U-00002 (issued) 90901-OTW-TP-J-00001 (issued)
Foundation Design	JT	H	Borehole investigation using PROD completed. Initial geotechnical information suggests rock layer. Drilled and grouted piles viewed to be acceptable, pending further evaluation. Incorporated into cost estimate.	Single-cased driled and grouted piles as base case.	Pending further evaluation in Phase 3A.	90901-OTW-RD-S-00001
Nearshore Pipeline Stability	BL	L	Geotechnical results received, and stabilisation review completed. Technical work complete, optimisation of concrete thickness completed and selection of rock bolts. Peer review completed to validate. Robust solution for concept selection, incorporated into cost estimate.	Concrete coating for stabilisation used for nearshore and main CS pipeline sections. CRA sections to use gravity anchors or rock bolts.	Complete	90886-OTW-RD-L-00002 (issued) 90901-OTW-RD-L-00002 (issued)
Platform Installation	SJ	M	Installation methodology completed to review a variety of installation options. Work completed by Icon on JU installation plan complete for Phase 2C to validate GJU feasibility. Pipelay "Combi" barge to install control platform (1 piece installation) with WHP to use 2 piece GJU installation. Further work required for Phase 3 to validate installation plan.	WHP installation to use 2 piece GJU installation.	Complete for Phase 2C. Work in Phase 3 to further develop installation plans.	90886-OTW-TN-M-00003 (issued) 90901-OTW-RD-S-00001 90901-OTW-TN-M-00005 (issued) Icon report 202-CS-001 Otway Jackup Installation Study (Rev 0 issued)
Pipeline Pressure	FdB/BL	M	Design MOP is 196 bar to allow full SIWHP, operating pressure initially at 90 bar and through plateau, reducing with inlet compression and through end of field life 'tail'.	Complete	Complete	90886-OTW-TN-C-00004 Rev A (issued)
ONSHORE						
Gas Processing	FdB	H	Condensate stabilisation, onshore dehydration, gas sweetening and LPG recovery/fractionation as reference case.	Complete.	Complete	90886-OTW-TN-C-00003 (issued)
Plant Operating Pressure	FdB	M	Evaluation completed using 70 bar inlet pressure. Sensitivity run using 50 bar for economics.	Awaiting economic results.	Complete	90886-OTW-TN-C-00004 Economic results
Liquids Transport	MJ	M	Evaluation of trucking of condensate vs pipeline to refinery indicates pipeline erodes value. However, pipeline viewed as best decision to reduce risk to public to ALARP. Condensate to be transported by pipeline, propane and Autogas to be transported by truck from the plant.	TN issued to support condensate pipeline. Require economic validation using new condensate discount and risk assessment to validate.	Complete	90886-OTW-TE-C-00002 (issued)

DECISION AREA	RESP	PRIORITY	WORK COMPLETED	DECISION	STATUS	REFERENCE DOCUMENTS
CO2 Disposal	FdB	M	Evaluation completed on CO2 disposal options. Reference case CO2 disposal is to vent via gas turbine exhaust due to best overall value, in line with other Australian facilities. WEL environmental standards and goals do not exclude CO2 venting.	CO2 disposal by venting to gas turbine exhaust	Complete	90886-OTW-TN-C-00002 (issued) DRIMS 216383
Water Treatment & Disposal	FdB	H	Assessment of Onshore vs Offshore indicates Onshore disposal most cost effective . Reference Case based on treatment and in-jection/recharge to onshore Waare aquifer.	Reference Case based on treatment and in-jection/recharge to onshore Waare aquifer. Contingency for offshore water disposal to outfall developed in case recharge not approved by regulator.	Complete for Phase 2C. Follow-on in Phase 3A required to validate subsurface feasibility and to get Regulator approval.	90886-OTW-TN-C-00001 (issued) 90901-OTW-TN-C-00010 (issued)
Onshore Construction	MJ	M	Review completed on on-site "stick build"construction versus PAU fabrication. Modularisation provides value to improve cost effectiveness in addition to reducing IR risk. 11 plant systems targeted for PAU installation, cost estimates revised.	PAUs to be used to maximise value and reduce potential IR risk.	Complete	90901-OTW-TN-M-00004 (issued)
Shared Infrastructure	MJ	H	Site selection options consider TXU co-location, with value opportunities shown with co-location. Base case plant location adjacent to TXU. Shared infrastructure opportunities developed include use of TXU power feed as backup in lieu of Otway power generation,export compression backup using TXU compresion, firewater storage sharing and water injection backup using existing TXU water injection wells.	Infrastructure sharing opportunities with TXU included in base case include export compression, water injection well, firewater storage and main power line.	Complete	90901-OTW-TN-M-00001 (issued)
Power Supply	BS	L	Initial review of power generation options completed. Base case to install 1x4.2MW generators with backup line power from 22 kV line. Load studies on 22 kv line require investigation in Phase 3. Costs included in cost estimate.	1 x 4.2 MW onsite GT generator with 22kv mains power back-up.	Complete for Phase 2C. Follow-on in Phase 3A required.	90901-OTW-TN-E-00001 (issued)
H2S	FdB	M	Potential for trace H2S may require removal to meet ground level concentration requirements. Evaluated installation of H2S scavenger and included as part of base case process design. Incorporated into cost estimate.	Non-regenerable H2S absorber to be included for contingency.	Complete Phase 3A process selection required	90901-OTW-TN-C-00003 (issued)