YOLLA DEVELOPMENT STUDY

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Submitted to

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REVISION RECORD

Revisions may comprise a complete issue of the report or issue of individual pages, as noted in the table below.

B	10 February 1999	General Revision	All	MWM	NJP	DTC
A	21 December 1998	Issued for Comment	All	NJP	DTC	DTC
Rev	**Date**	**Description**	**Revised Pages**	**By**	**Chk'd**	**App**

TABLE OF CONTENTS

TABLES AND FIGURES

TABLES AND FIGURES (cont)

SUMMARY

In October 1998 Premier Oil Australasia Pty Ltd (Premier) requested Woodhill Thornton to examine possible development options for the Yolla and White Ibis gas condensate fields in the Bass Strait. Previous Bass Strait basin development studies performed during 1995 had indicated that economic development of the fields was unlikely to be feasible, or at best marginal.

This study was instigated to determine if recent engineering innovations could be applied along with updated reservoir appraisal data to allow economic development of these gas condensate fields. The possibility of co-producing oil from a separate oil reservoir overlying the Yolla gas field was also to be examined as a potential means of enhancing possible development economics.

Field development is complicated by the relatively low recoverable reserves (335bcf, Yolla plus White Ibis), the extended distances offshore (135-210km), the severe Bass Strait environment, water depths of 60-80m, high carbon dioxide levels (up to 20%) and the high pour point (ca. 15°C) of the Yolla crude.

Several development concepts were evaluated including manned and unmanned fixed platforms, converted jack-ups, novel self-installing concepts such as Arup's ACE 90, and totally subsea developments including oil storage and multiphase pumping options. CAPEX, OPEX and abandonment cost estimates to +/- 30% accuracy were developed for a range of processing options covering several Tasmanian and Victorian landfalls and points of sale, DCQ and swing quantities, sales gas quality options, and oil export rates. Overall case-by-case CAPEX and abandonment costs are compared in Figure 4-1.

Preliminary economic screening of the 22 cases evaluated on the basis of relative CAPEX and product flow indicates that Yolla gas should be developed via Tasmania with a manned offshore facility including gas dehydration and compression facilities – see Figure 3.5-1. Similarly, White Ibis (and Trefoil), if required, should be developed via subsea tie-backs to Yolla. A 30 PJ/a development on this basis is expected to cost ca. A$410M. A comparable Victorian alternative is expected to be at least A$100M more expensive due to the additional offshore pipeline distances and the need to remove CO_2 to meet Victorian gas specifications.

Additional marginal costs to include development of the Yolla oil reservoir range from A$65-150M for recoverable oil quantities of 9-18 MMbbls depending on whether a leased FSU or a subsea oil storage tank is used. The Arup ACE 90 concept appears to offer a low cost (ca. A$ 475M) subsea oil storage option. Removal of oil topside facilities after depletion may provide a timely opportunity for expanding gas processing capabilities if additional gas reserves can be proved up in the Yolla area.

Further work is recommended to confirm the technical feasibility of subsea storage of a high pour point crude. The issue of CO_2 disposal also needs to be addressed and the environmental consequences assessed. Relative development phasing of Yolla, White Ibis and Trefoil reservoirs, yearly production profiles, and assumed condensate yields should also be confirmed.

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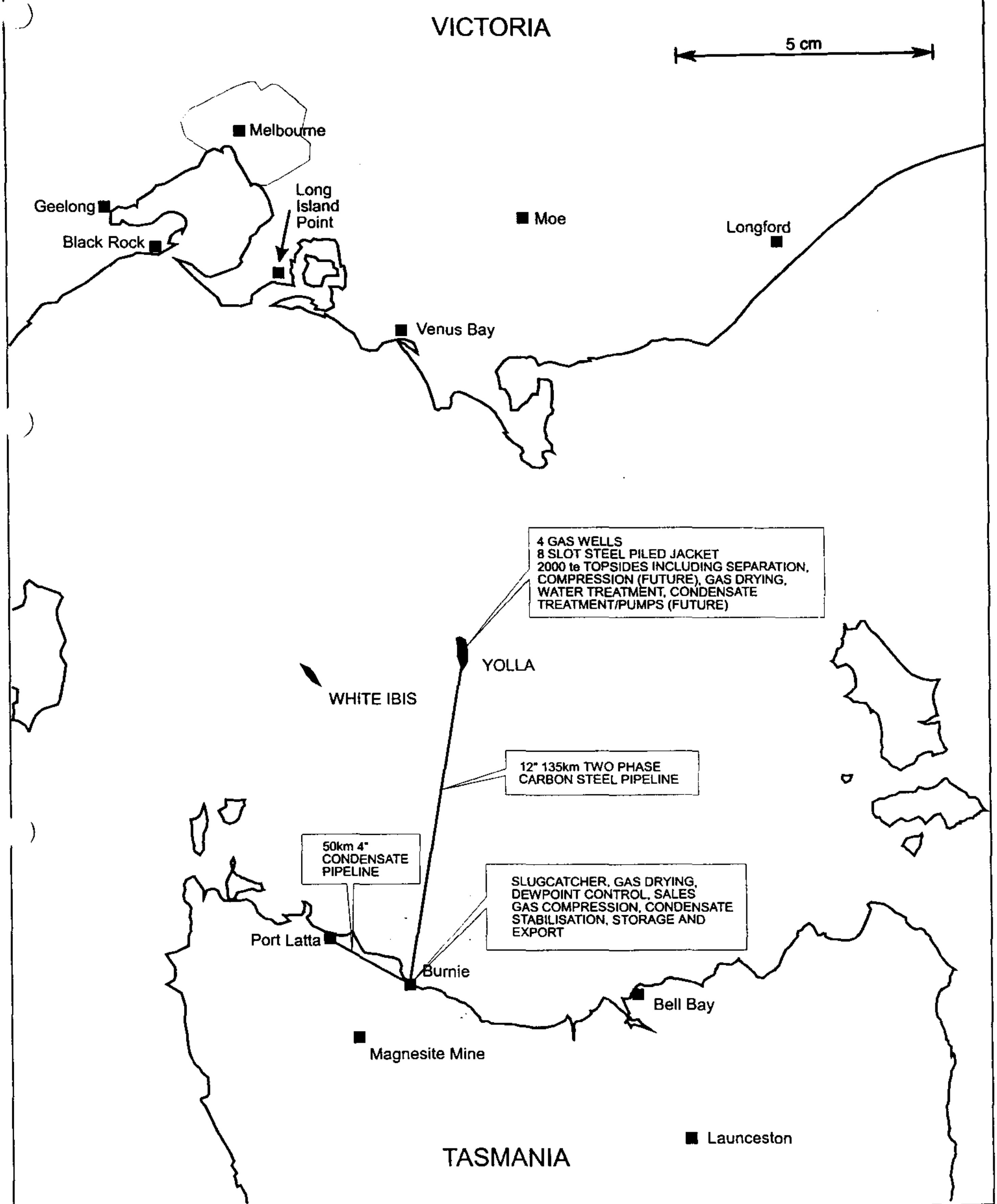
Figure 3.5-1



WOODHILL THORNTON					CASE 1A - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA (BURNIE)
	C	28 Jan 99	MPG	DAF	
	B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	16 Dec 98	MWM	NJP	
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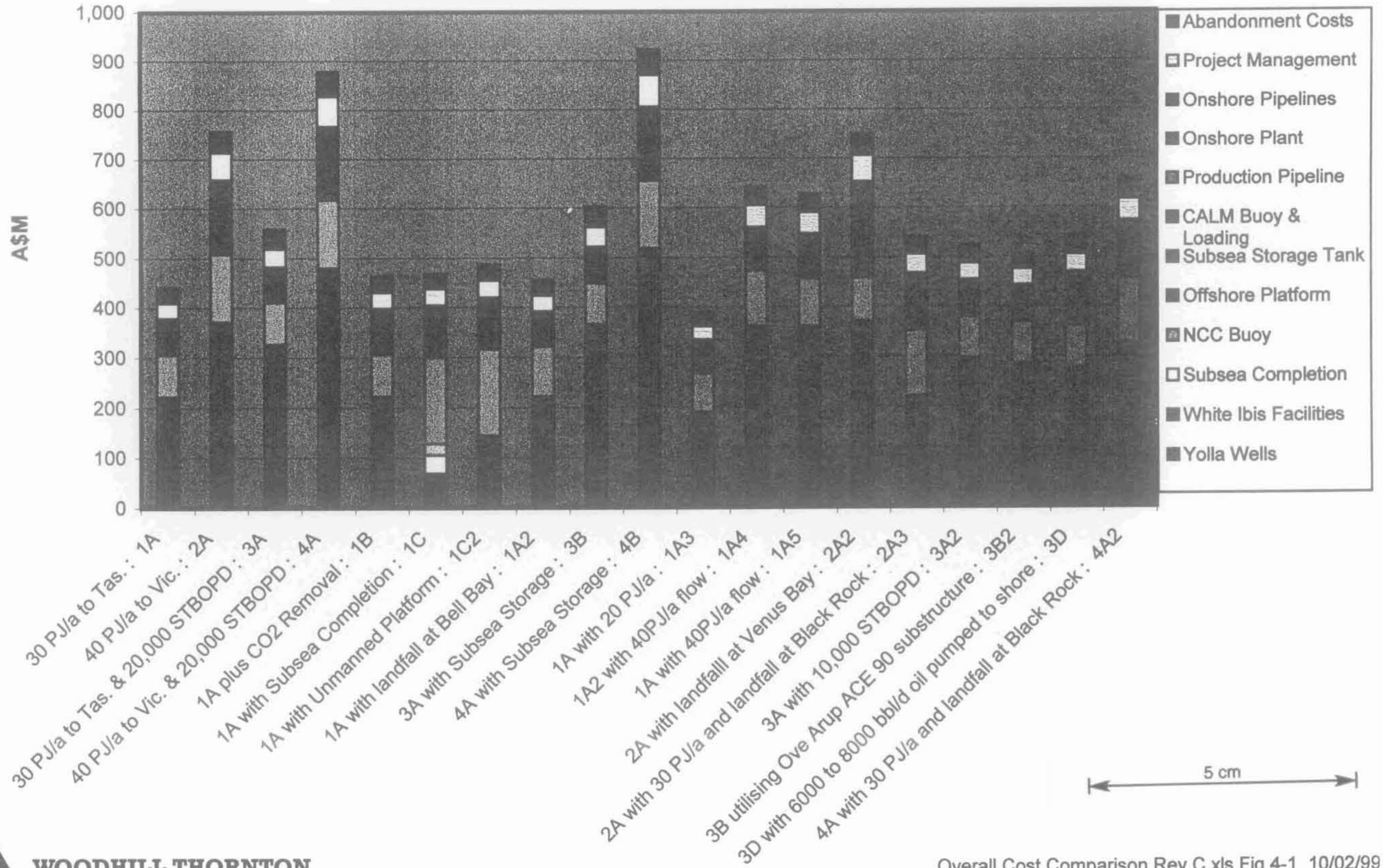
Figure 4-1: Case-by-Case CAPEX and Abandonment Cost Comparison



WOODHILL THORNTON

1 INTRODUCTION

In October 1998 Premier Oil Australasia Pty Ltd (Premier), on behalf of the T/RLI and T/18P Joint Ventures, requested Woodhill Thornton to examine possible development options for the Yolla and White Ibis fields in the Bass Strait between mainland Australia and Tasmania. Previous Bass Strait basin development studies (Ref 1, 2) performed during 1995 had indicated that economic development of the fields was unlikely to be feasible, or at best marginal.

This study was instigated to determine if recent engineering innovations could be applied along with updated reservoir appraisal data to allow economic development of these gas condensate fields. The possibility of co-producing oil from a separate oil reservoir in the Upper Eastern View Coal Measures (UEVCM) was also to be examined as a potential means of enhancing possible development economics.

The study was kicked off in mid October at Woodhill's UK offices with an in-depth brainstorming session. Potential offshore development concepts were identified for feasibility screening and development cost estimation in Woodhill Thornton's Perth offices. The dual office approach was devised to combine access to the latest international oil and gas field development technology with detailed knowledge of Bass Strait and Australian resources and conditions. This report outlines the results of the brainstorming process, details the field development concepts identified, and provides ±30% cost estimates of the more favourable options. Some supplementary cases were costed to an accuracy of ±40%.

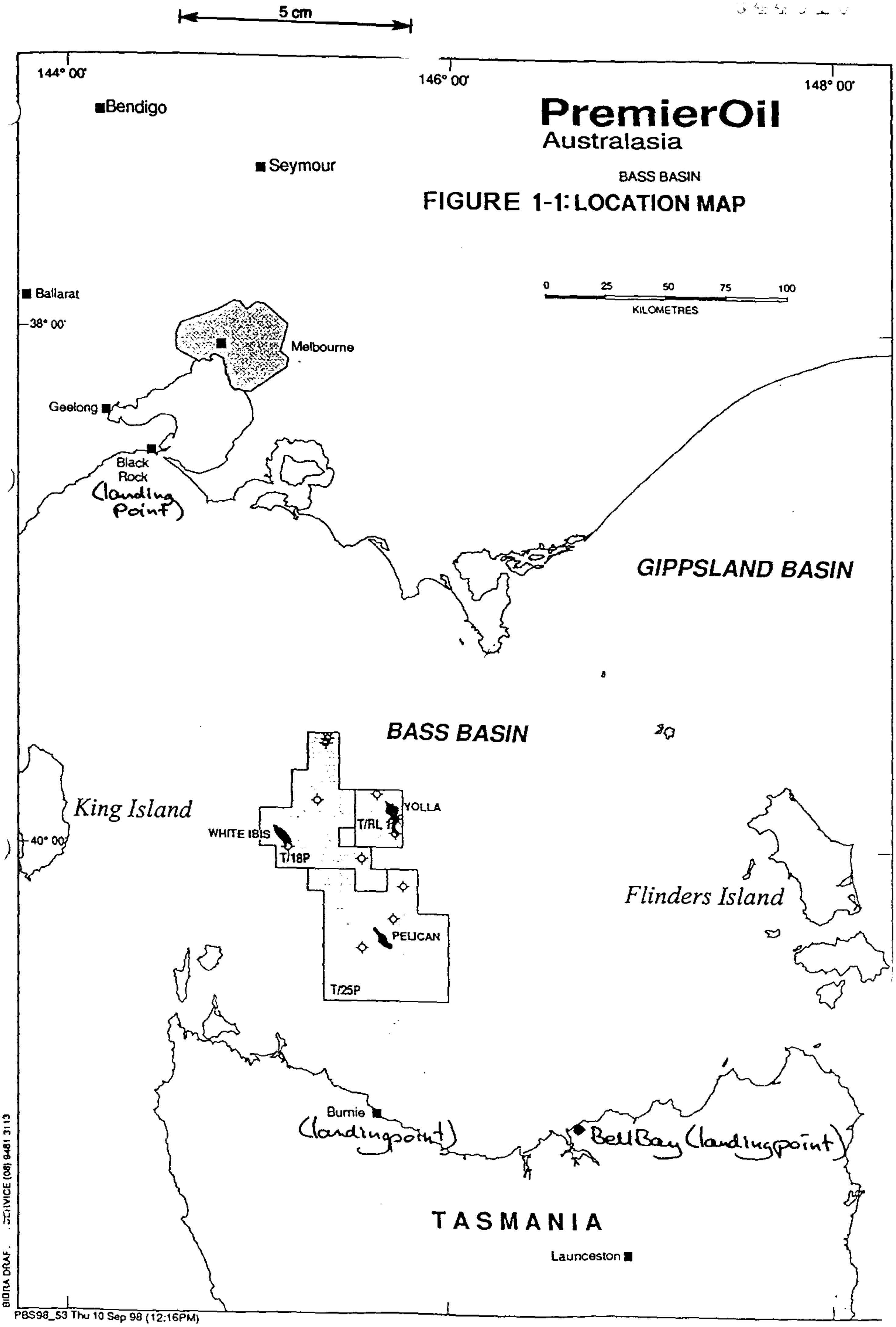
(After issue of Revision A of this report, Ove Arup reduced its ACE 90 concept cost estimate by ca. 30%, and Yolla and White Ibis reserves were revised substantially downwards. The impacts of these changes are captured in this revision.)

1.1 Background

Yolla and White Ibis are rich gas condensate fields (ca. 40bbl/MMscf and 60bbl/MMscf respectively) located in the Bass Strait approximately 135km due north of Burnie on Tasmania's northern coastline and ca. 210km southwest of Black Rock on Victoria's southern coastline, near Melbourne. White Ibis is located ca. 40km west of Yolla.

Water depths in the region range from ca. 60m at White Ibis to ca. 80m at Yolla.

Field development is complicated by the relatively low reserve levels (270 bcf and 65 bcf recoverable from Yolla and White Ibis respectively), the extended distances offshore (135-210 km), high carbon dioxide (CO_2) levels (ca. 20% Yolla and ca. 8% White Ibis) and the high pour point (ca. 15°C) of the Yolla crude oil.



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2 SCOPE OF WORK AND BASE DATA

2.1 Scope of Work

A formal detailed scope of work was not prepared for this study. Premier's requirements were determined through a series of informal meetings and emails, and the Bass Basin Data Pack - included as Appendix 1. The development study work completed included the following key activities:

(i) Concept Development Brainstorming
(ii) Identification of feasible development concepts
(iii) Estimation of CAPEX, OPEX and Abandonment costs to ±30% accuracy of four base cases:

CASE	1A	30 PJ/a (nil swing) Industrial Tasmania (Burnie)
CASE	2A	40 PJ/a (+25% swing) Sales Gas to Victoria (Black Rock)
CASE	3A	30 PJ/a (nil swing) Industrial Gas to Tas plus 20,000 STBOPD export via FSU
CASE	4A	40 PJ/a (+25% swing) Sales Gas to Vic plus 20,000 STBOPD export via FSU

(iv) Estimation of CAPEX, OPEX and Abandonment costs to ±30% accuracy of nine alternative cases (where practical):

CASE	1B	as per Case 1A but with onshore CO_2 removal (Sales Gas)
CASE	1C	Case 1A developed subsea
CASE	1C2	as per Case 1C but with an unmanned wellhead platform
CASE	1D	as per Case 1A but with offshore CO_2 removal
CASE	1A2	as per Case 1A but a Bell Bay landfall / Sales Gas destination
CASE	2B	Case 2A developed subsea
CASE	3B	as per Case 3A but with a subsea oil storage tank
CASE	3C	Case 3A developed subsea via multiphase pumping
CASE	4B	as per 4A but with a subsea oil storage tank

(v) Woodhill Thornton participation in Adelaide Joint Venture Marketing and Development Study Workshops (09/10 November 1998)
(vi) Estimation of CAPEX costs to ±40% accuracy of the following additional sensitivity cases:

CASE	1A3	as per Case 1A but with a 20 PJ/a Sales Gas flow
CASE	1A4	as per case 1A but with 40 PJ/a Sales Gas flow to Bell Bay
CASE	1A5	as per case 1A but with 40 PJ/a Sales Gas flow to Burnie
CASE	2A2	as per Case 2A but with an east of Melbourne landfall (Venus Bay)
CASE	2A3	as per Case 2A but with a 30 PJ/a Sales Gas flow (nil swing)
CASE	3A2	as per Case 3A but with 10,000 STBOPD export (via FSU)
CASE	3B2	As per Case 3A but with up to 10,000 STBOPD stored in Arup's ACE 90
CASE	3D	As per Case 3A but with up to 10,000 STBOPD pumped to shore with gas.
CASE	4A2	as per Case 4A but with 30 PJ/a Sales Gas flow (nil swing)

(vii) Preliminary evaluation of Trefoil development cost options (±40% accuracy)

(viii) Cost Reduction Review (to identify potential cost reduction options).

2.2 Base Data

The study was based on the following data:

Yolla Gas Field

Location:	Refer to Figure 1-1
Water Depth:	80 m
Reservoir Depth:	2900 m
Recoverable Reserves:	270 bcf
Field Life:	6 – 12 years (depending on sales contract)
CGR of Gas:	ca. 40 bbl/MMscf initially
Number of wells:	4 – 5 (depending on sales contract)
WHFP / WHFT:	150 - 50 Barg / 70 – 80 °C
Reservoir BHP / Temperature	ca. 260 Barg / 100 - 110 °C, approximately at dew point conditions
Reservoir composition	see Appendix 3

White Ibis Gas Field

Location:	Refer to Figure 1-1
Water Depth:	60m
Reservoir Depth:	2200 m
Recoverable Reserves:	65bcf
Field Life:	1.5 - 3 years (depending on sales contract)
CGR of Gas:	ca. 60 bbl/MMscf initially
Number of wells:	2
WHFP / WHFT:	150 - 50 Barg / 70 – 80 °C
Reservoir BHP / Temperature	ca. 260 Barg / 100 - 110 °C
Reservoir composition	see Appendix 3

Yolla Upper EVCM Oil Reservoir

Reservoir Depth:	1850 m
Recoverable Reserves:	15 - 30 MMbbl oil
Production Rate:	10 – 20,000 STBOPD initially; 20,000 bbl/d total fluids
Field Life:	5 Years
GOR of Oil:	1175 scf/bbl at 10 Barg, 50 °C (first stage separator conditions)
Pour Point:	15 °C
Wax Content:	1.3%

Water Cut:	nil initially, rising to 95% after 5 years
Artificial Lift Requirements:	Lift Gas (3 MMscfd per well)
Number of wells:	2 –3 (Multi laterals)
WHFP / WHFT:	10 – 65 Barg / 50 – 60°C
Reservoir composition	see Appendix 3

Environmental

Ambient Seabed Temp:	10 – 15°C
Ambient Air Temp.:	25°C (design)
Winds:	10 – 20 knots average
Waves:	6.0m and 6.8 m 1-year and 10-year wave return periods respectively
Storm Conditions:	The region experiences exatropical cyclones, thunderstorms, and pressure gradient intensification storms.

Pipelines

Material:	Offshore API 5L X65 (mechanically bonded CRA pipe specified where appropriate) Onshore API 5L X52
Design Temperature:	100°C
Design Pressure:	MAWP of specified standard flange at Design Temperature
Inlet Pressure:	Offshore: 130barg (ANSI Class 900) Onshore: As required for salesgas specification
Coatings:	Offshore: 50mm concrete stabilisation, 400µm FBE internal
Burial:	Offshore: Approximately half to fully buried Onshore: burial at 0.9m minimum
Thermal Conductivities:	Pipeline material: 60W/m.K Concrete coating: 1.0W/m.K Soil: 0.5W/m.K
Wall Thickness:	As per material, design pressure, and corrosion allowance
Corrosion Allowances	Nominally 3mm (7mm for wet inhibited CS pipelines)
Pipeline roughness:	0.0254mm

Pipeline route distances:	Yolla	- Burnie	135 km
		- Bell Bay	170 km
		- Black Rock	210 km
		- Venus Bay	122 km
		- White Ibis	40 km
	Burnie	- Port Latta	50 km
	Black Rock	- Geelong	35 km
	Venus Bay	- Moe	100 km

Cost Estimate Assumptions

Exchange Rates taken as A$1.00 = US$0.65, and A$1.00 = UK£0.38

Well Costs

Well costs were as advised by Premier.

3 TECHNICAL ANALYSIS

3.1 Brainstorming

A three day brainstorming session was held in Woodhill's UK offices between 8 October and 13 October 1998. Full details of the process and offshore development concepts considered are included in Appendix 2.

Four offshore development concepts were identified as potentially favourable:

- a conventional fixed platform with floatover deck
- a converted jack-up
- Ove Arup's ACE 90 concept (see Appendix 5)
- a subsea development

Use of a strand-jacked barge is not ruled out, however it is expected to have similar costs to a conventional platform and hence it was not investigated separately.

FPSO's were considered but deemed unsuitable for a gas development due to their low level of availability. In addition, FPSO mooring system designs are likely to prove problematic in water depths of 80m under Bass Strait environmental conditions.

Similarly, barge-based and Spar development concepts were also considered but ruled out due to the severe marine environment.

3.2 Concept Evaluation

Individual concepts were evaluated on a case-by-case basis using the following stepwise approach:

(i) Base Cases (Cases 1A, 2A, 3A & 4A) and Alternative Cases were evaluated from first principles:
- process simulations were developed for each case using HYSIM to confirm concept feasibility and to allow estimation of equipment requirements and investigation of product quantities and qualities.
- offshore production gathering and onshore sales gas pipeline models were developed via PIPESIM to allow reasonably accurate pipeline and slugcatcher size estimates to be produced.
- offshore, onshore and pipeline equipment lists were developed based on the above simulations.

- offshore facility footprints were estimated to allow alternative offshore development concept costs to be estimated.
- costs for each base case were developed via a "building block" approach (further details are provided in Section 4 below).

(The Alternative Cases (1A2, 1B, 1C, 1C2, 1D, 3B, 3C & 4B) were devised to investigate potential CAPEX reductions for Case 1A. It was intended to apply any such reductions discovered to other Base Cases as appropriate.)

(ii) Sensitivity Cases (1A3, 1A4, 1A5, 2A2, 2A3, 3A2, 3B2, 3D, 4A3) were evaluated making maximum use of existing base and alternative case data. Equipment lists were not produced for these cases. (HYSIM and PIPESIM models were developed to allow preliminary assessment of production pipeline capacity in Case 3D.)

Preliminary design calculations for all cases are listed in Appendix 13.

3.3 Carbon Dioxide (CO_2) Levels

As noted above Yolla gas contains approximately 20%mol CO_2. As such under expected production conditions it will be highly corrosive in the presence of free water. Preliminary investigations predict corrosion rates of ca. 5mm / year at 120 Barg and 15 °C with no corrosion inhibition, and ca 0.5mm / year at 120 Barg and 15 °C with 90% effective corrosion inhibitor. (With well-managed facilities inhibitor efficiencies of up to 95% are achievable.) Hence provided the gas is cooled to below 15 °C (maximum expected seabed temperature) carbon steel pipework with a 6-7 mm corrosion allowance can be utilised.

This option has been explored in Cases 1C1 and 1C2 (see below). Where temperatures are in excess of 15 °C in these two cases corrosion resistant alloys (CRA) as mechanically bonded CRA pipe have been specified. In all other cases, offshore gas dehydration has been included to remove the water and allow use of carbon steel piping.

Subsea heat exchangers were considered as an alternative to the use of CRA pipe, but were not found to have any significant advantages.

3.4 Offshore Structure

As noted in 3.1 above, four offshore development concepts were identified initially as potentially favourable.

- a conventional fixed platform with floatover deck
- a converted jack-up

- Ove Arup's ACE 90 concept (see Appendix 5)
- a subsea development

OPS International Inc (OPS) and Production Testers Australia Pty Ltd (PT) were requested to provide budget costs for either leased or purchased converted jack-ups based on preliminary topsides weight and layout estimates for each of the four base cases.

PT declined to respond. OPS responded stating that a heavy duty 300 ft WD rated jack-up would be required and that a new-build vessel would cost between A$215-250M. OPS suggested that a converted jack-up would possibly be less expensive, however no suitable deep water vessels were currently available and in OPS's view were unlikely to become available in the near future given typical rig market conditions. (That is, in a soft rig market the heavy duty deep water rigs tend to push the smaller units out of operation). Whilst market conditions are prone to change, at this stage we can see no reason to disagree with OPS's view.

Ove Arup & Partners (Arup) initially advised (Ref 7) that the self-installing ACE 90 concept could be installed for ca. A$77M including substructure and barge deck but excluding topsides facilities.

Conventional fixed platform and subsea development concept costs were developed in-house (Section 4). Preliminary jacket costings indicated that a suitable facility could be installed for ca. A$60M that is, ca. 30% less than Arup's ACE 90. Hence Base Case development concepts were pursued based on installation of a conventional offshore platform. Subsea alternatives were also investigated.

Subsequently Arup advised (Ref 9) that its initial A$ 77M estimate was overly conservative and that an ACE 90 concept including ca. 250,000bbl of wet storage could be provided for ca. A$ 55M. This option hence became more attractive than a conventional platform for all cases, and significantly more attractive for the oil production cases. It was therefore revisited via a Sensitivity Case (Section 3.7).

3.5 Base Case Concepts

Outline concept summaries of the four Base Cases (1A, 2A, 3A, 4A) development option are included at the end of this section (Figures 3.5-1 to 3.5-4). Block Flow Diagrams for all options (where appropriate) are included in Appendix 2. Process Schematics are included in Appendix 6. Further details of each Base Case are provided below.

Case 1A - 30 PJ/a Sales Gas to Tasmania (Figure 3.5-1)
Case 1A is based on delivery of 30 PJ/a DCQ of Sales Gas to Burnie on the Tasmanian coast. (Ex-plant gas sales have been assumed with gas transmission to purchaser via a third party pipeline operator.)

The facilities required include a manned offshore platform, a 135 km two phase gas condensate production pipeline to shore, an onshore gas processing plant and a 50 km condensate export line to Port Latta.

Four pre-drilled Yolla gas wells are assumed tied back to an eight slot four leg jacket. A barge launch is assumed with jacket piling via a derrick lay barge. A floatover integrated deck type topsides (2000te) is proposed to minimise offshore commissioning costs. Well tie back and completion with a platform based hydraulic work over unit has been assumed. (Alternatively, a Gorilla type jack-up could be utilised to post-drill and complete the wells. Similar well costs are envisaged.)

Topside facilities include production cooling, three phase condensate, water and gas separation, gas dehydration (TEG), water treatment, and condensate filter coalescers. Initially, wellhead flowing pressures are sufficient to free flow production to shore. It is assumed that, from Year 3 onwards gas compression and condensate pumping facilities are required to maintain production at a pipeline inlet pressure of ca. 130 Barg. The CAPEX phasing is based on this assumption. Information provided by Premier regarding reservoir modelling indicates that this timing may vary between Years 3 and 5. Two 50% gas turbine driven compressors are envisaged to provide suitable onshore sales gas availability. Class 900 offshore piping was selected to minimise pipeline size and hence CAPEX. Produced water is discharged overboard after condensate removal via hydrocyclones and degassing.

A 12" gas condensate production pipeline to shore is required to ensure an onshore plant arrival pressure of ca. 50 Barg. This arrival pressure was selected to ensure efficient onshore gas drying and to minimise onshore sales gas compression costs. A carbon steel production pipeline is sufficient (despite the high gas CO_2 levels) as over-dehydration of the gas offshore will absorb any small amounts of free water produced due to ambient cooling or pressure changes en route to shore. Pipeline installation is assumed via a S.E Asian laybarge.

Onshore facilities are assumed to be located within 2 km of landfall. Facilities required include slugcatcher, gas dehydration (TEG – to remove water extracted from the condensate), gas dewpoint control, sales gas compression, condensate stabilisation and storage. LPG extraction is not required. Two 50% 800 bbl slugcatchers were selected based on review of expected pipeline liquid hold-up. Dewpoint control is envisaged via a turbo expander unit.

(A potentially less expensive Joule Thomson valve alternative was investigated, however it was considered insufficiently flexible to ensure that both sales gas dewpoint (-2°C) and condensate product RVP (10 Psi) specifications could be met under all expected conditions. This option should be re-visited if and when a development option is selected.)

Gas export is proposed via two 100% gas turbine driven sales gas compressors at a pressure of 80 Barg. The combination of a large offshore pipeline (and hence significant line pack), two 50%

offshore compressors and two 100% onshore sales gas compressors should provide sufficient sales gas availability for a dedicated purchaser.

Conventional onshore condensate stabilisation is proposed. Condensate export is assumed via two new storage tanks located in the vicinity of Port Latta fuel oil import depot. A 50 km 4" condensate pipeline with pumping and metering skid will be required to transfer product to the tanks.

Full details of all proposed offshore and onshore equipment items are included in the Case 1A equipment list - Appendix 7.

Industrial quality sales gas will be available at 30 Barg, ambient temperature, with a -14°C dewpoint and with a higher heating value (HHV) of 34.2 MJ/sm^3, marginally below the Victoria sales gas HHV specification limit of 36 MJ/sm^3 (Appendix 4) despite its higher CO_2 content (ca. 20%mol.) Full details of expected Case 1A sales gas quality is included in Appendix 8 along with expected condensate product makes. Scope exists for sales gas quality optimisation should Case 1A be approved for further development.

Case 2A - 40 PJ/a Sales Gas to Victoria (Figure 3.5-2)
Case 2A is based on delivery of 40 PJ/a DCQ with 25% swing to a Victorian "Gascorette" assuming a Geelong point of sale and a Black Rock landfall.

The facilities required include a manned offshore platform located over Yolla, subsea development of White Ibis, a 210 km two phase gas condensate production pipeline to shore, an onshore processing plant including CO_2 removal and LPG fractionation, and 35 km sales gas and condensate pipelines to Geelong.

Four pre-drilled Yolla gas wells are assumed. Two subsea White Ibis wells will be installed following partial depletion of Yolla expected after 4-5 years of Yolla production. (Clearly, in practice White Ibis installation timing will be set by Yolla reservoir performance and sales gas demand.) The White Ibis wells will be completed subsea and tied back via a 12" 40 km flowline to an eight slot four leg Yolla jacket. Each sub sea well is assumed to be connected to a three slot subsea manifold via flexible flowlines and umbilicals. Two multiphase flowmeters, one per well, are provided on the manifold for well testing and reservoir management. A 2" piggy-back line is proposed on the White Ibis flowline to allow continuous injection of hydrate (ca. 40-100 bbl/d of MEG) and corrosion inhibitors. MEG will be recovered and stored on the Yolla platform along with the corrosion inhibitor.

A White Ibis flowline pressure drop of ca. 15-25 Bar is predicted at the design flow of 60-100 MMscfd. Flowline fluid temperatures are expected to fall to seabed levels (ca. 10 - 15 °C) within

15 km of the subsea manifold due to ambient cooling. Hence, mechanically bonded CRA pipe is assumed for the first 20 km of the flowline to prevent CO_2 induced corrosion.

As in Case 1A, a barge launched jacket is assumed with piles installed via a derrick lay barge. A floatover integrated deck type topsides (2600 te) is proposed to minimise commissioning costs. Yolla well completion using a hydraulic work over rig has been assumed for tying back the predrilled wells. (Alternatively, a Gorilla type jack-up could be utilised to post-drill and complete the wells. Similar well costs are envisaged.)

Topsides facilities are as per Case 1A but with additional separation capacity (22m^3) to accommodate White Ibis flowline slugs, a hydrate inhibitor recovery unit, and gas compression and condensate pumps installed from Day 1 to boost White Ibis arrival pressures of ca. 120 Barg to the required platform export pressure of 130 Barg. A 16" carbon steel gas condensate production pipeline to shore is required to ensure an onshore plant pressure of 50 Barg.

Onshore facilities are assumed to be located within 2 km of landfall. Facilities required include slugcatchers, CO_2 removal (Amine plant), gas dehydration (TEG), gas dewpoint control, sales gas compression, LPG fractionation, storage and truck loading facilities, and condensate stabilisation and storage.

Three 33% 2100 bbl slugcatchers were selected based on review of expected pipeline liquid hold-ups. As in Case 1A, dewpoint control is via a turbo expander unit and gas export is via two 100% gas turbine driven compressors. Unlike Case 1A, Case 2A requires CO_2 and LPG removal to meet Victorian gas specification requirements (Appendix 4).

CO_2 removal via a conventional amine system is proposed. (Previous studies (Ref 1) have indicated that membrane-based CO_2 removal systems offer little, if any CAPEX advantages over amine systems.) Due to the large amounts of CO_2 to be removed (up to 30 MMscfd), major amine facilities are required leading to significant plot and CAPEX requirements.

LPG removal is via a conventional fractionation plant comprising de-ethaniser, de-propaniser and de-butaniser columns, with separate propane and butane overhead products. Four Horton spheres are envisaged to provide five days LPG storage: two propane and two butane. LPG export via truck loading has been assumed. Metering skid facilities have been incorporated.

Condensate export is assumed via a 4" pipeline to Shell's Geelong refinery.

Full details of Case 2A offshore, onshore and pipeline requirements are included in the Case 2A equipment list - Appendix 7.

Case 2A Sales Gas will be supplied to the gas transmission line in the Geelong area at a pressure of ca. 38 Barg, via a 35 km buried onshore gas pipeline. A hydrocarbon dewpoint of ca. -37°C is anticipated, with HHV and Wobbie indices of 40.1 MJ/sm³ and 50 MJ/sm³ respectively and a CO_2 content of 2.5%mol., comfortably within Victorian Sales Gas specification limits (Appendix 4).

Scope exists for sales gas quality optimisation should Case 2A be approved for further development. Full details of expected Case 2A product quantities and qualities are provided in Appendix 8.

Case 3A - 30 PJ/a Sales Gas to Tasmania with 20000 BOPD oil production (Figure 3.5-3)
Case 3A is based on delivery of 30 PJ/a DCQ of sales gas to Burnie on the Tasmania coast, plus offshore export via a Floating Storage Unit (FSU) for oil production of up to 20,000 STBOPD. That is, it is identical to Case 1A except that in addition it incorporates sufficient offshore facilities to allow production of up to 20000 STBOPD from the Yolla upper EVCM oil reservoir.

The additional offshore facilities required include three multilateral oil production wells, a twelve slot four leg jacket (that is, four slots more than Case 1A), oil stabilisation, associated gas compression, lift gas supply, oil export and (oily) produced water treatment, and an offshore loading line, CALM buoy and FSU. A 2700 te integrated deck is envisaged. Installation methods are as per Case 1A.

A separate (that is, oil and Yolla gas condensate are not co-mingled) two stage oil stabilisation train is proposed with first and second stage oil separators operating at 10 Barg and 1 Barg respectively. Associated gas (up to 40 MMscfd) is recovered and compressed up to 50 Barg before co-mingling with Yolla separator gas production. It should be noted that the additional oil facilities require installation of offshore gas booster compression facilities from day 1 to allow associated gas recovery. Oil lift gas requirements of 3 MMscfd/well (15 MMscfd total) at a pressure of ca. 130 Barg have been assumed.

Oil heating and circulation pumps are required on both the topsides and the FSU to allow for the relatively high oil pour point of 15°C. (Operational experience may demonstrate satisfactory performance via pour point suppressants or via condensate blending, however insufficient data is available at this stage to justify such optimistic assumptions. Hence the more conservative and costly heating option has been selected.)

Oil production is expected to decline rapidly over five years, after which time the oil facilities can be mothballed or removed. The platform deck space could be utilised for expanding the gas production facilities to handle the increased gas flowrates eg from White Ibis.

Increasing water production is expected with the decline in oil flow. Separate 20000 BWPD water handling facilities (hydrocyclones and degasser) are proposed. (Separation of the oil de-watering facilities from those of the Yolla gas allows their removal after oil depletion when they are no longer required, thus providing additional topsides area.)

No additional onshore facilities are required for Case 3A over and above those provided for Case 1A. An equipment list for Case 3A is included in Appendix 7.

During production of the Yolla upper EVCM oil reservoir, onshore sales gas becomes marginally richer due to recovery of the associated gas. Initially sales gas will be delivered with a -12°C dewpoint, a HHV of ca. 36 MJ/sm^3, a Wobble Index of 40 MJ/sm^3 and a CO_2 context of ca. 16%mol. Over five years industrial quality sales gas will gradually become leaner until Case 1A qualities are achieved when oil production ceases. Full details of Case 3A product quantities and qualities are provided in Appendix 8.

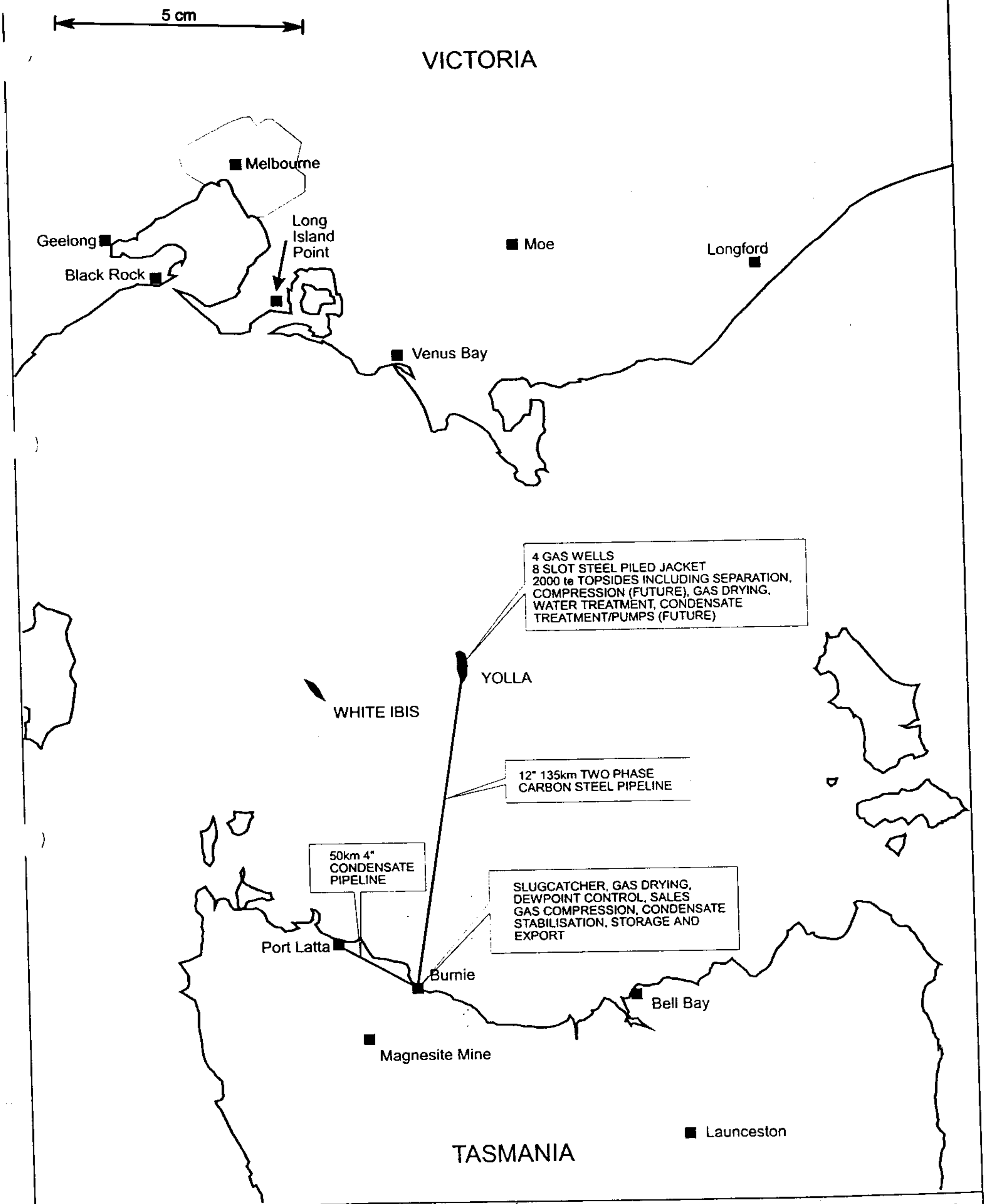
Case 4A - 40 PJ/a Sales Gas to Victoria with 20 000 STBOPD Oil Production (Figure 3.5-4)
Case 4A is based on delivery of 40 PJ/a DCQ with 25% swing to a Victorian Gascorette assuming a Geelong point of sale and a Black Rock landfall, with offshore export via a FSU of up to 20000 STBOPD. That is, it is identical to Case 2A except that in addition it incorporates sufficient offshore facilities to allow production of up to 20000 STBOPD from the Yolla upper EVCM reservoir.

The additional offshore facilities required in this case are almost identical to those additional facilities required in Case 3A above. That is, additional multilateral oil wells, a larger jacket, a two stage oil stabilisation train with interstage heating and oil circulation, associated gas recovery and compression, lift gas supply, oil produced water treatment, oil export facilities including pumps, loading line, CALM buoy and FSU. A 3300 te integrated deck is envisaged. Installation methods are as per Case 2A.

No additional onshore facilities are required for Case 4A over and above those provided for Case 2A. A Case 4A equipment list is included in Appendix 7.

As in Case 3A (above), during production of the oil reservoir, onshore sales gas becomes marginally richer due to recovery of the associated gas. However in this case the impacts on gas quality are much less noticeable due to the proportionally lower amount of associated gas (30% in this case versus 50% in Case 3A) and the more rigorous onshore gas processing, that is, including CO_2 and LPG removal. Full details of expected Case 4A product quantities and qualities are provided in Appendix 8.

Figure 3.5-1



WOODHILL THORNTON

REV	DATE	BY	CKD
C	28 Jan 99	MPG	DAF
B	14 Jan 99	MWM	DAF
A	16 Dec 98	MWM	NJP

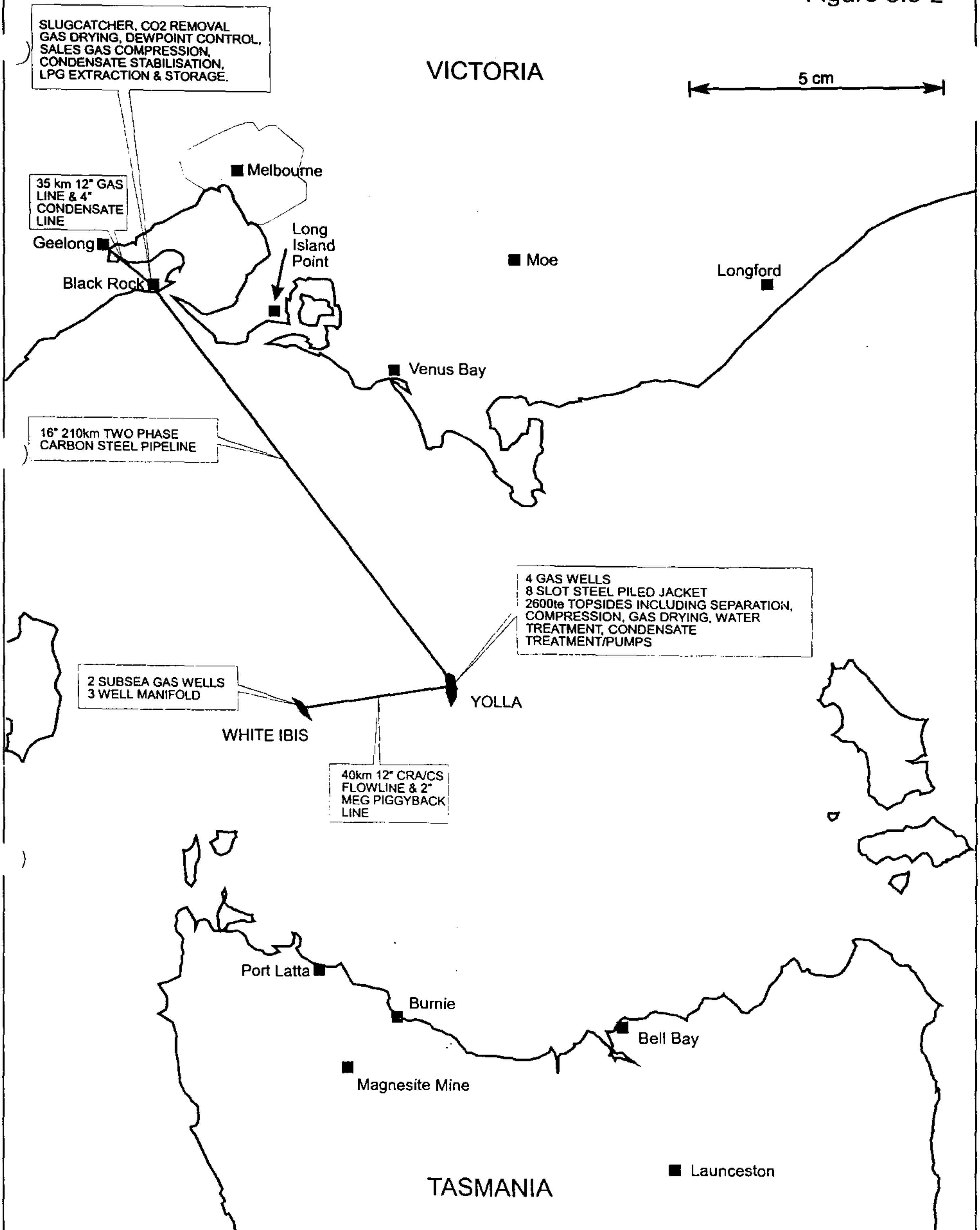
CASE 1A - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA (BURNIE)

YOLLA DEVELOPMENT STUDY
PREMIEROIL

Doc No: 9843-SK-11 | Rev C

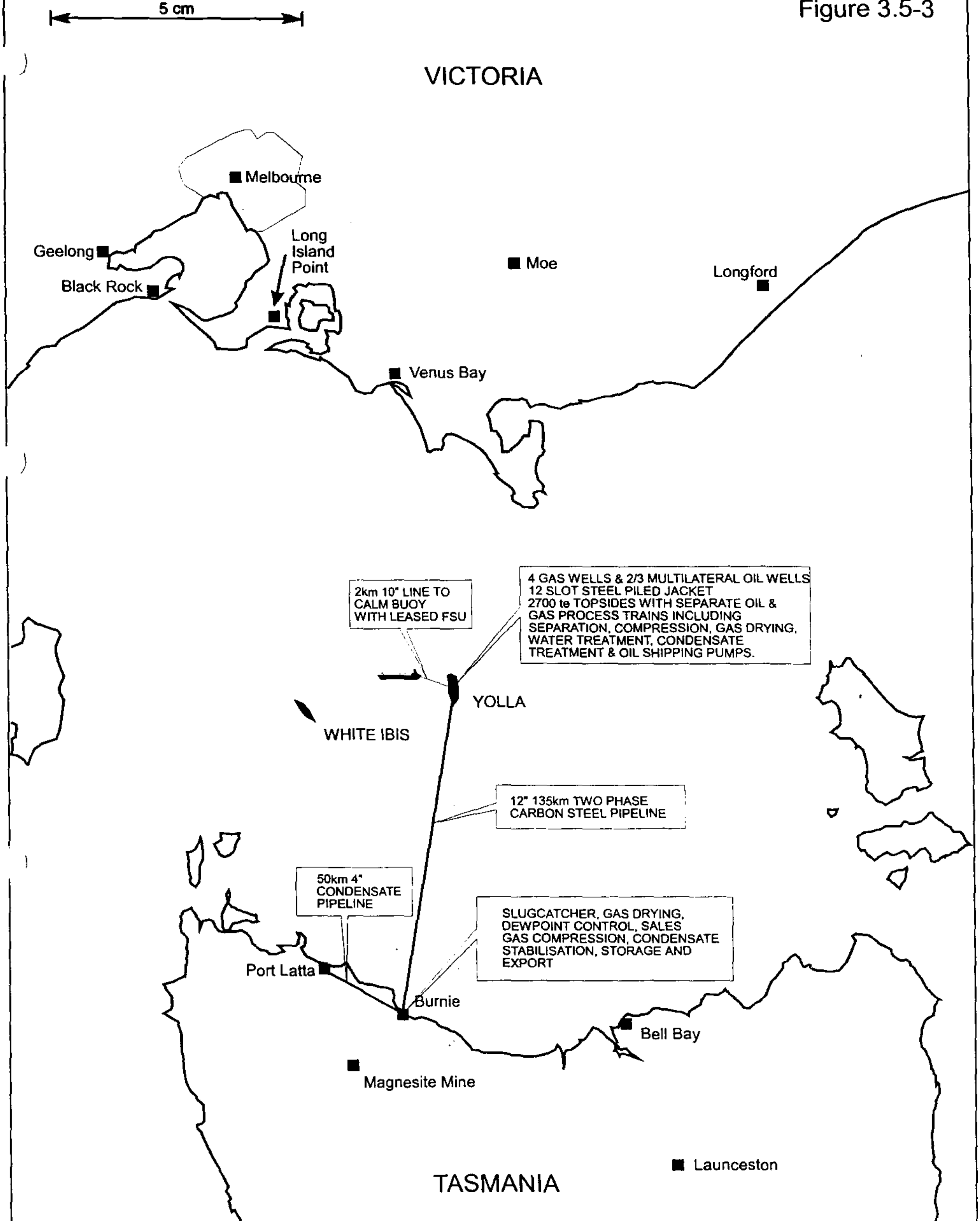
644024

Figure 3.5-2



WOODHILL THORNTON					
	C	28 Jan 99	MPG	DAF	CASE 2A - 40 PJ/YR SALES GAS TO VICTORIA (BLACK ROCK)
	B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	16 Dec 98	MWM	NJP	
	REV	DATE	BY	CKD	Doc No: 9843-SK-12 — Rev C

Figure 3.5-3

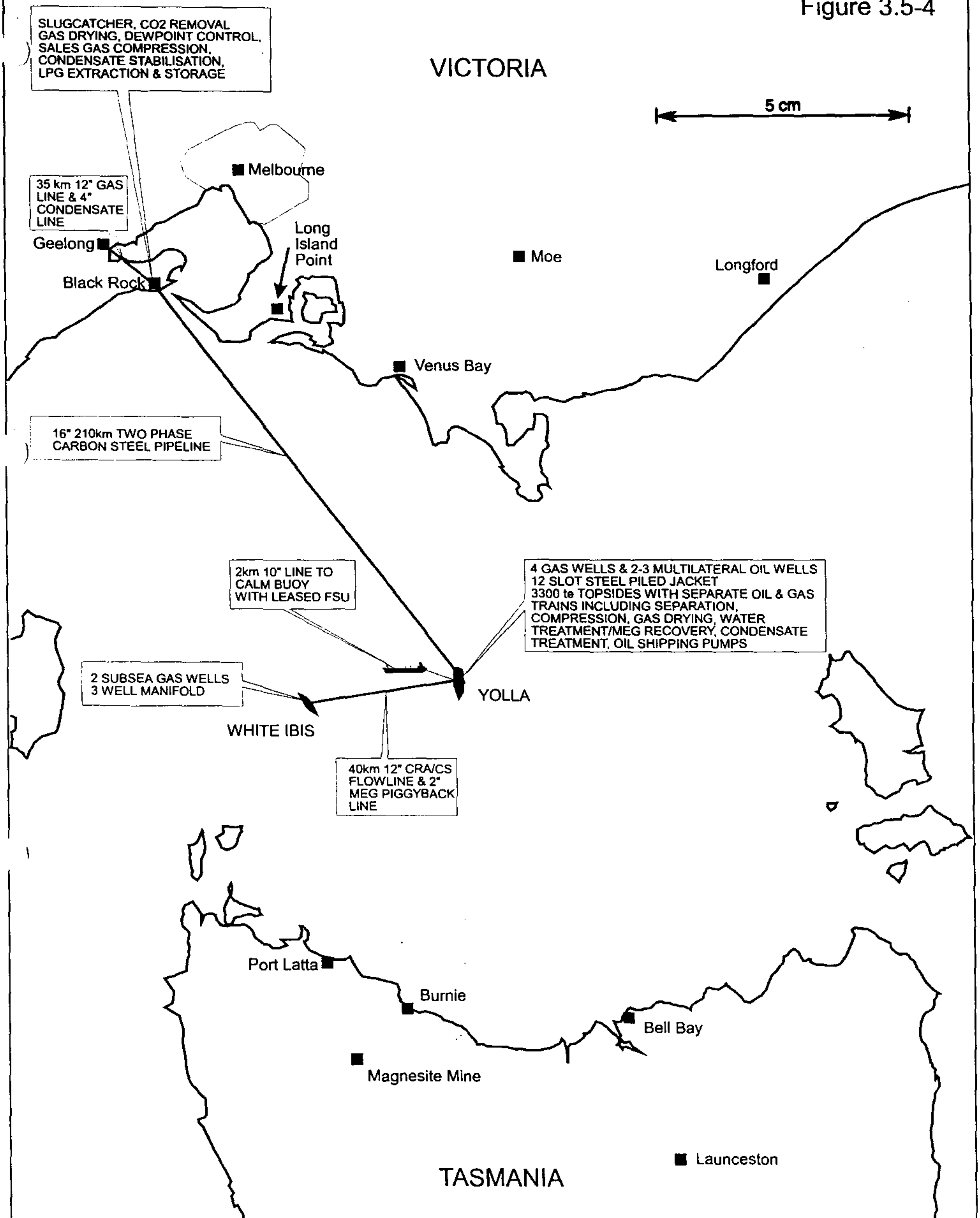


C	28 Jan 99	MPG	DAF	CASE 3A - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA & 20,000 STBOPD EXPORT
B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
A	16 Dec 98	MWM	NJP	
REV	DATE	BY	CKD	Doc No: 9843-SK-13 / Rev C

WOODHILL THORNTON

ATTACHMENT 3

Figure 3.5-4



WOODHILL THORNTON					
	C	28 Jan 99	MPG	DAF	CASE 4A - 40 PJ/YR SALES GAS TO VICTORIA & 20,000 STBOPD EXPORT
	B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	16 Dec 98	MWM	NJP	
	REV	DATE	BY	CKD	Doc No: 9843-SK-14 — Rev C

3.6 Alternative Case Concepts

The nine Alternative Cases described below were devised in an attempt to reduce Base Case CAPEX costs. Alternative Case installation methods are only discussed where they differ markedly from those assumed for the Base Cases. Outline concept summaries of feasible Alternative Cases 1B, 1C, 1C2, 1A2, 3B & 4A are included at the end of this section (Figures 3.6-1 to 3.6-6). Block Flow Diagrams and Process Schematics (where applicable) are included in Appendices 2 & 6 respectively.

Case 1B (Figure 3.6-1)

Case 1B is identical to Case 1A (above) with the addition that it incorporates onshore CO_2 removal facilities with a view to supply sales gas quality gas to the Tasmanian market.

It is interesting in that it indicates that provided at least 3%mol CO_2 is left in the sales gas then Victorian specifications for HHV and Wobbe Indices can be achieved. That is, it indicates that apart from the CO_2 speeification, Victorian specification sales gas can be achieved without a LPG fractionation plant. Thus significant savings in Case 2A may be achievable by deletion of the LPG removal and export facilities. This potential CAPEX reduction option has yet to be investigated in detail although a corresponding order-of-magnitude cost reduction is identified in Section 4.3 below.

A Case 1B equipment list in included in Appendix 7. Case 1B product quality and quantity data is included in Appendix 8.

Case 1C (Figure 3.6-2)

Case 1C is a subsea completion alternative of Case 1A. The wells are completed subsea and the wet three phase fluid mixture piped directly to shore. A six slot subsea manifold is assumed at Yolla with the four individual wells connecting to it via flexible flowlines and control/chemical injection umbilicals. Wellhead control is provided through a surface Control Buoy linked to the subsea manifold via a dynamic umbilical. Corrosion inhibitor is supplied to each wellhead and the subsea manifold via storage tanks and injection pumps located in the buoy. Hydrate inhibitor (MEG) supply is via a 2" piggy-back line from shore to the subsea manifold and to each individual wellhead.

To minimise CO_2 induced corrosion, CRA lined flowlines and a CRA subsea manifold are proposed. In addition the first 30 km of the production pipeline to shore will consist of mechanically bonded CRA piping. (Pipeline fluid contents are expected to cool to 15 °C within 15 km - see Section 3.3 above.) The remainder of the pipeline will be constructed of carbon steel with a 7 mm corrosion allowance.

An 18" offshore production pipeline was selected. This line size allows deferment of onshore compression until approximately half way through the field life - Year 4. By Year 8 the predicted slugcatcher pressure has fallen to ca. 20 Barg. This is considered the minimum practical suction pressure to ensure that only one stage of onshore compression is required prior to onshore gas processing.

The required onshore slugcatcher size is almost double that required in Case 1A (3100 bbls versus 1600 bbls), due to the increased pipeline size, different flow regime (wavy stratified as opposed to annular in Case 1A), and increased liquid hold-up.

Clearly an optimum economic balance exists between pipeline/slugcatcher sizes and onshore compression requirements. Whilst this optimum has not been investigated in detail at this stage, significant changes from the selected compressor / pipeline configurations are not anticipated.

Onshore water treatment (hydrocyclones and degasser) and MEG recovery facilities are also required in this case. Full details of Case 1C equipment requirements are listed in Appendix 7.

Case 1C product qualities and quantities are almost identical to those of Case 1A - see Appendix 8.

(It is technically feasible to develop White Ibis in conjunction with this case - however detailed review of system hydraulics will be required to confirm onshore compression phasing and the optimum White Ibis flowline size.)

Case 1C2 (Figure 3.6-3)
Case 1C2 is identical to Case 1C except that it incorporates an unmanned minimal facilities offshore wellhead platform instead of a subsea development. Platform installation and well tie-back methods are as per Case 1A. The minimal facilities include multiphase flowmeters for well testing and reservoir management, corrosion and hydrate inhibitor injection facilities (MEG will be supplied via 2" piggy-back line from shore as per case 1C), power generation, life support utilities, temporary accommodation and helideck.

Onshore facilities and product qualities and quantities are as per Case 1C.

(It is technically feasible to develop White Ibis in conjunction with this case - however detailed review of system hydraulics will be required to confirm onshore compression phasing and the optimum White Ibis flowline size.)

Case 1D
Case 1D is identical to Case 1A except that it incorporates offshore CO_2 removal. This case was explored as a means of reducing offshore production pipeline CAPEX via minimisation of its required volumetric throughput. Offshore CO_2 removal reduces the raw gas to shore quantity by ca. 20%. Unfortunately, hydraulic analyses indicted that despite the flow reduction a 12" pipeline

was still required. In addition, topsides weight and space requirements will increase dramatically to support a 15-20 MMscfd CO_2 removal unit requiring an approximate footprint of 400 m^2 and weighing ca. 700 te. Hence offshore CO_2 removal was not considered further.

Case 1A2 (Figure 3.6-4)
Case 1A2 is the same as Case 1A except that it incorporates a Bell Bay landfall with local consumption of industrial quality sales gas, and local condensate export. Case 1A2 equipment requirements are detailed in Appendix 7.

A 170 km production pipeline to shore is required in this case, however its diameter remains at 12" NB as per Case 1A. Due to the increased pipeline hold-up predicted the required onshore slugcatcher size increases by approximately 70% to 2800 bbls. Onshore plant CAPEX costs will increase accordingly. Onshore condensate pipeline CAPEX is however eliminated with this option. Full CAPEX details are provided in Section 4 below.

Case 2B
Case 2B is a subsea completion alternative of Case 2A. Work on this option was halted when hydraulic studies indicated that a 22" offshore production pipeline would be required. It was considered that the additional pipeline, slugcatcher and onshore compression CAPEX due to the larger pipeline would significantly outweigh any offshore CAPEX reductions achieved via use of subsea facilities.

Case 3B (Figure 3.6-5)
Case 3B is identical to Case 3A in all aspects apart from oil export facilities. In Case 3A a leased FSU is proposed. For Case 3B a subsea oil storage tank was investigated.

Additional offshore facilities required include high capacity (25000 bbl/h) oil shipping pumps and a 400,000 bbl subsea oil storage tank. Periodic shuttle tanker loading is expected to be monthly initially, falling to once every three to four months by the end of oil reservoir life.

The cost estimate for this case was developed based on Case 3A building block estimates and on CALM Buoy / loading line costs derived from a similar recent NWS project. A specific Case 3B equipment list was not developed.

Case 3C
Case 3C is a subsea alternative of Case 3A based on multiphase pumps. Initial work on this option indicated that it was unlikely to be feasible or economic.

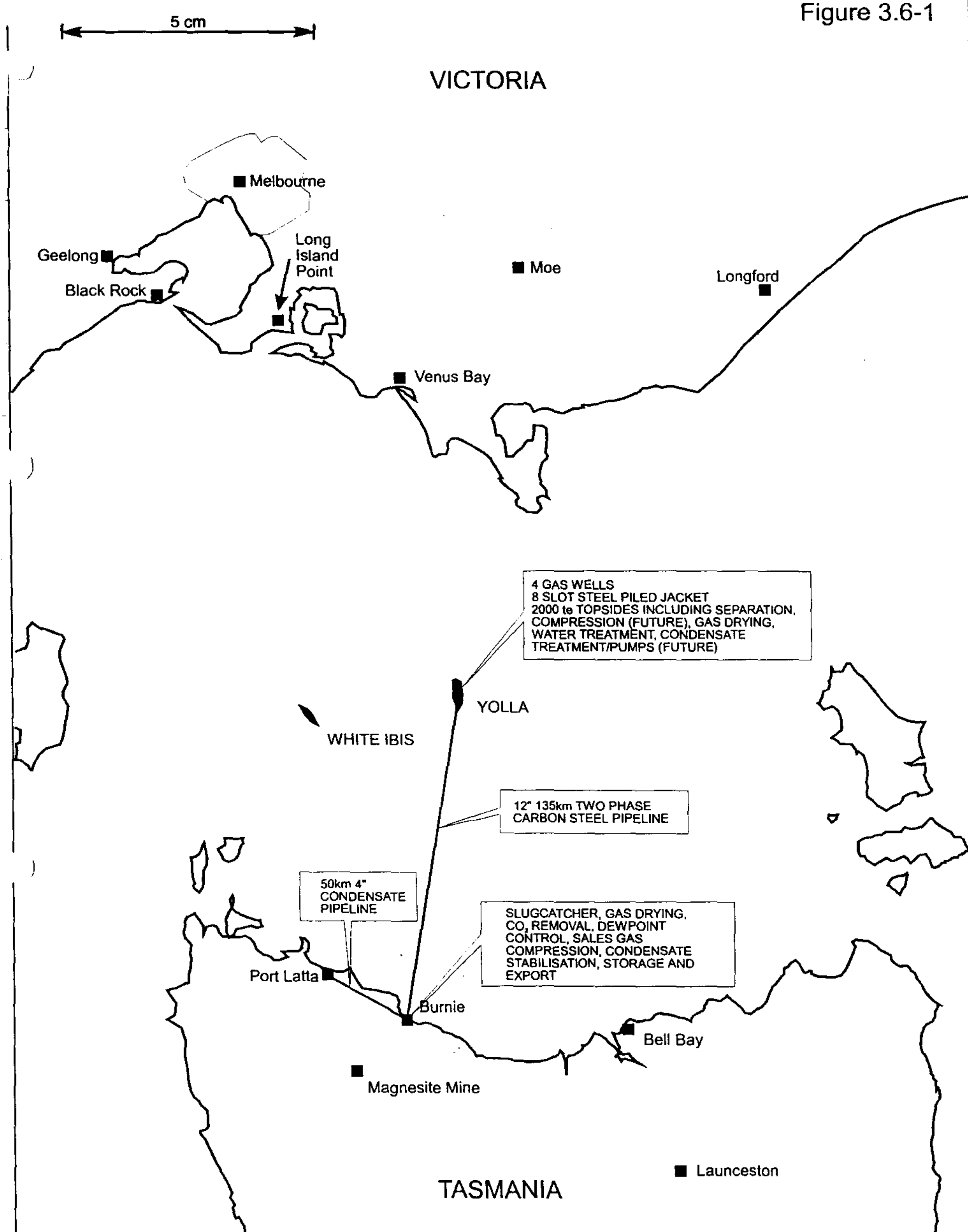
Four 2000m^3/h multiphase pumps would be required to raise the oil flow of ca. 140 m^3/h with a gas volume fraction (GVF) of 95% from 10 Barg to 80 Barg. Such pumps are on the limit of currently available multiphase pumping technology (maximum head and flow) and hence their proposed utilisation poses significant technical risk.

Transfer of the three phase oil, associated gas, Yolla gas, condensate and water to shore is expected to require a 20"-24" production pipeline. It was considered that the additional pipeline, slugcatcher, multiphase pumps, and onshore booster compression CAPEX would significantly outweigh any offshore CAPEX reductions achieved via use of subsea facilities.

Case 4B (Figure 3.6-6)
Case 4B is identical to Case 4A in all aspects except for oil export facilities. As in Case 3B above, Case 4B utilises a subsea oil storage tank with periodic shuttle tankers rather than a leased FSU. Additional facilities and cost estimate basis are as per those detailed in Case 3B above.

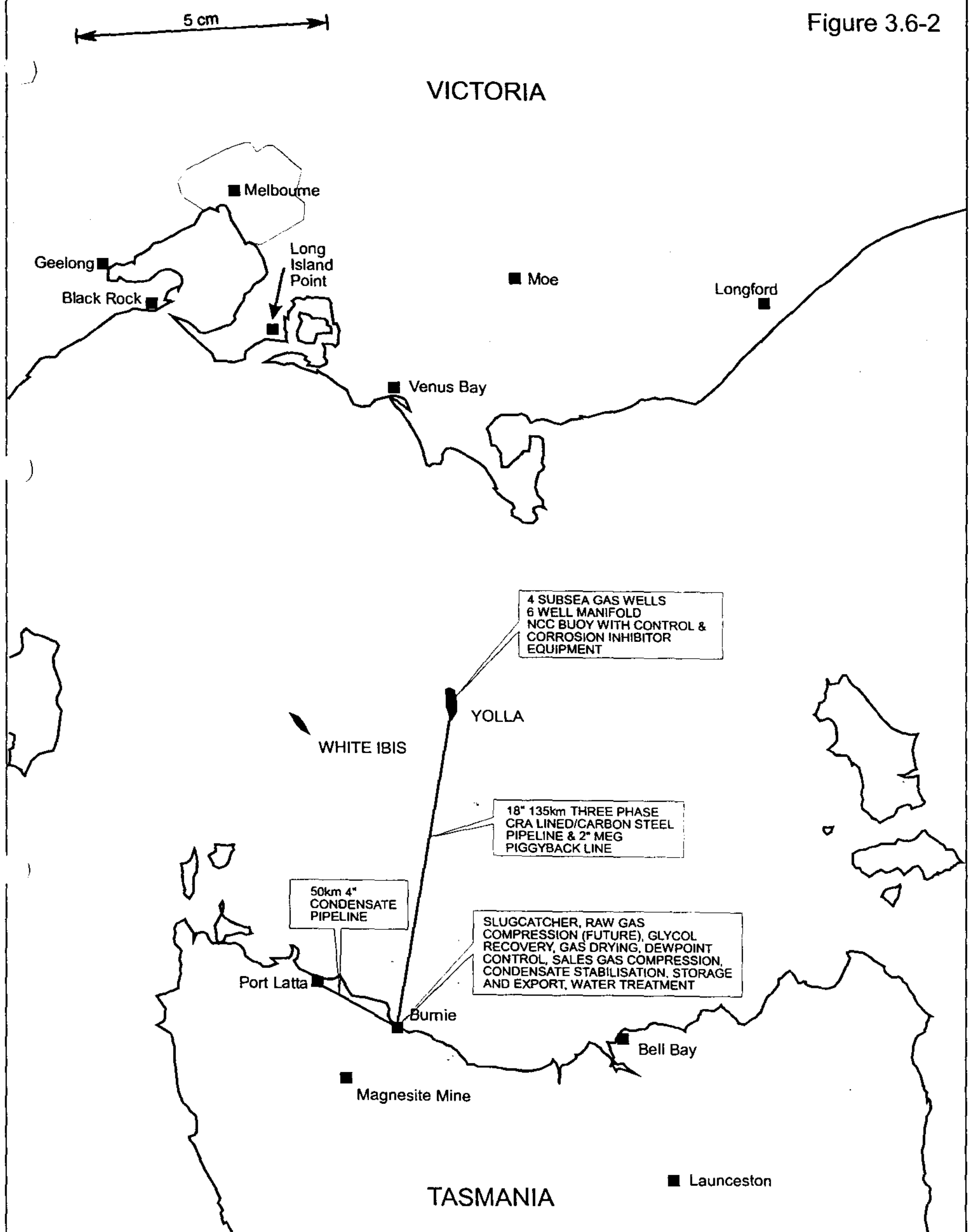
644031

Figure 3.6-1



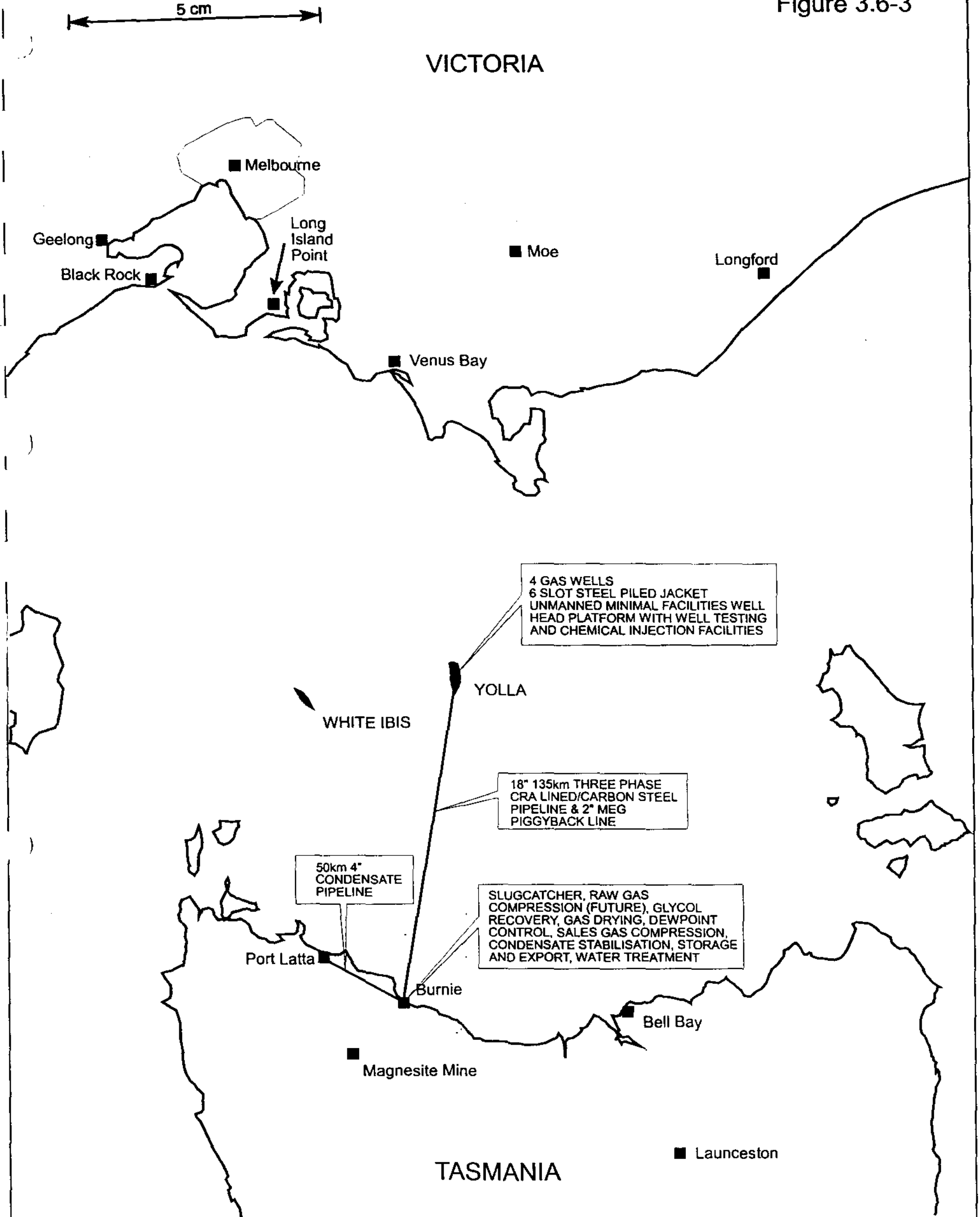
WOODHILL THORNTON					CASE 1B - 30 PJ/YR SALES GAS TO TASMANIA (BURNIE) WITH CO_2 REMOVAL
	C	28 Jan 99	MPG	DAF	
	B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	16 Dec 98	MWM	NJP	
	REV	DATE	BY	CKD	Doc No: 9843-SK-16 — Rev C

Figure 3.6-2



WOODHILL THORNTON					CASE 1C - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA (BURNIE): SUBSEA
	C	28 Jan 99	MPG	DAF	
	B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	16 Dec 98	MWM	NJP	
	REV	DATE	BY	CKD	Doc No: 9843-SK-17 — Rev C

Figure 3.6-3



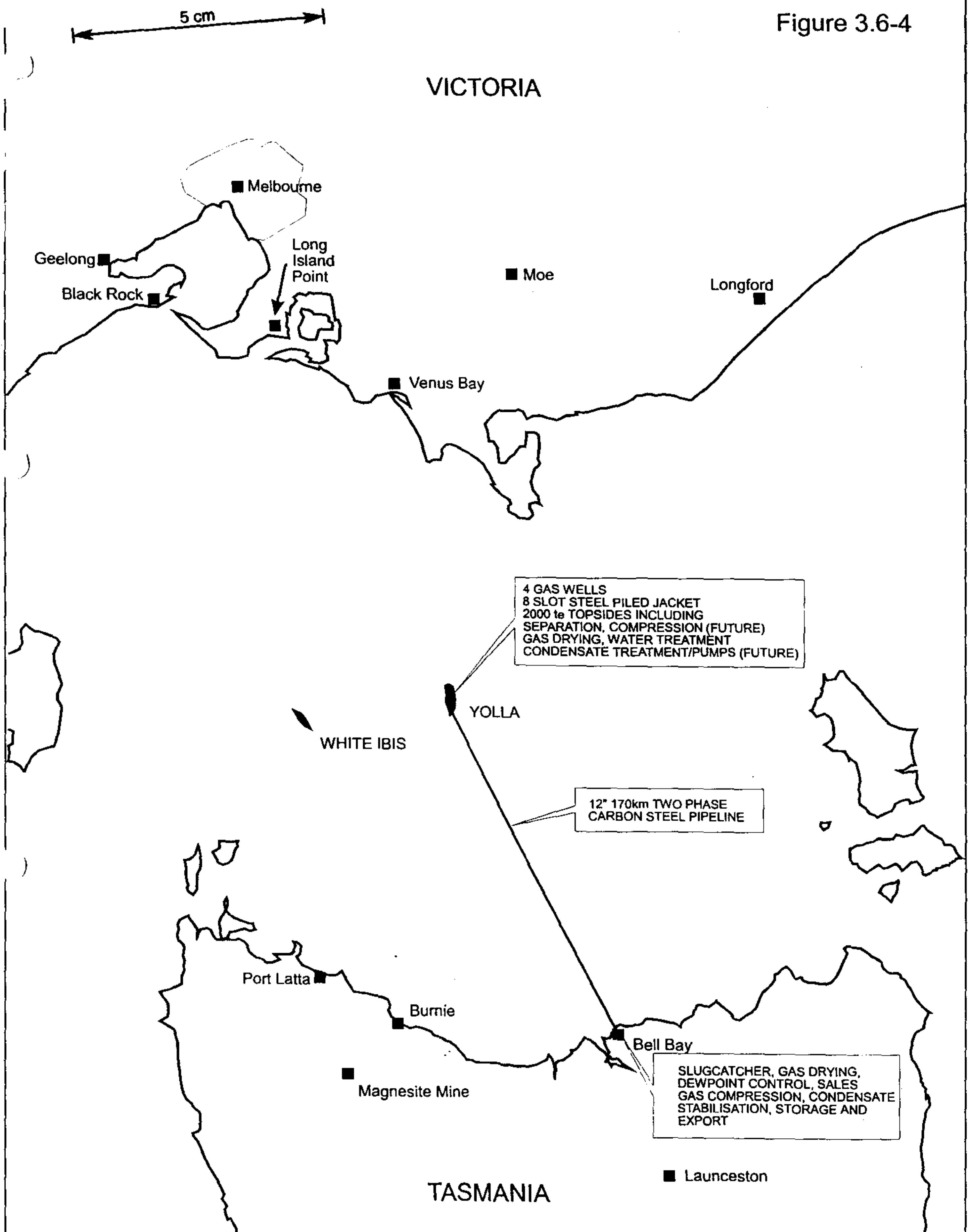
WOODHILL THORNTON				
	C	28 Jan 99	MPG	DAF
	B	14 Jan 99	MWM	DAF
	A	16 Dec 98	MWM	NJP
	REV	DATE	BY	CKD

CASE 1C2 - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA : UNMANNED PLATFORM

YOLLA DEVELOPMENT STUDY PREMIEROIL

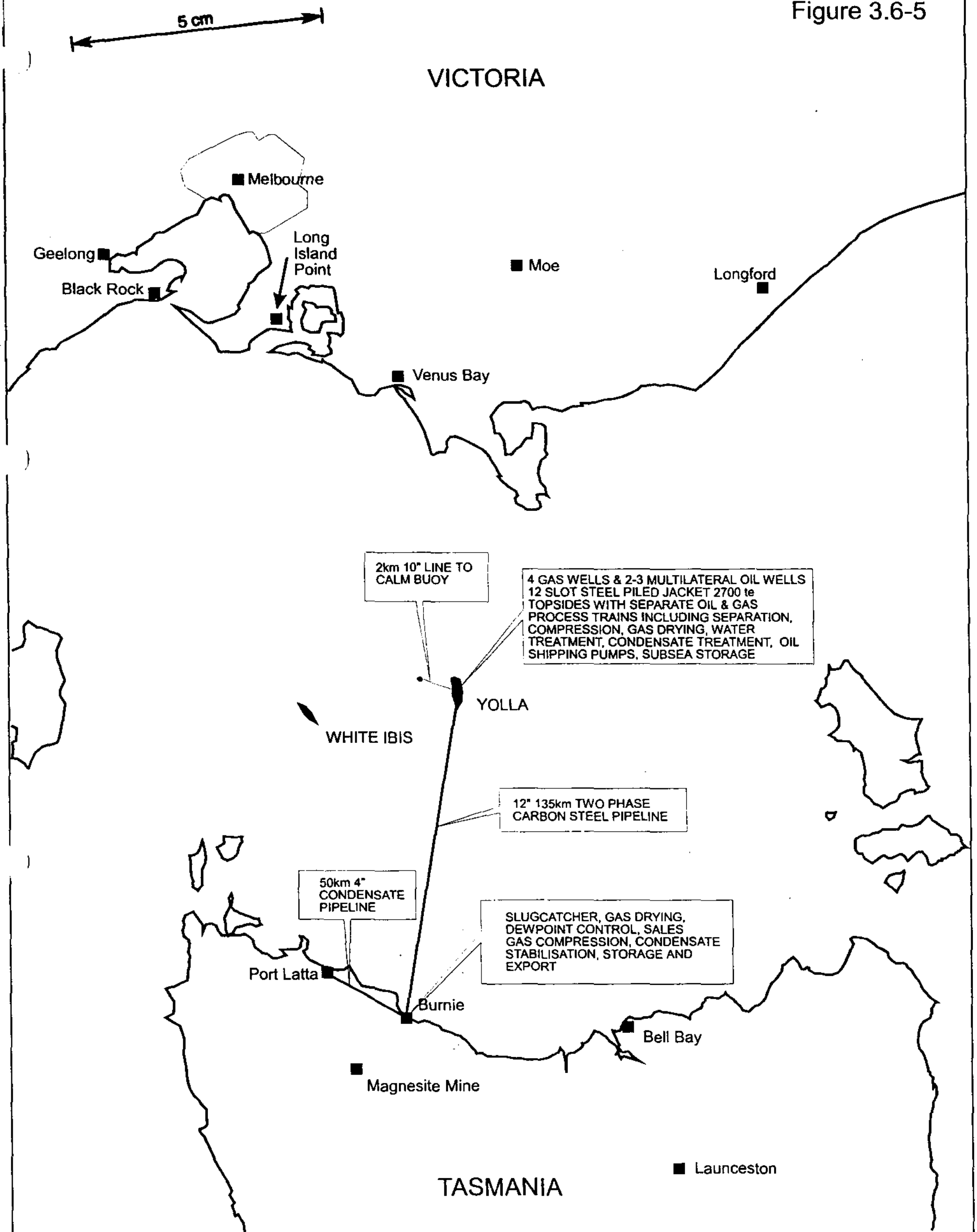
Doc No: 9843-SK-18 | Rev C

Figure 3.6-4

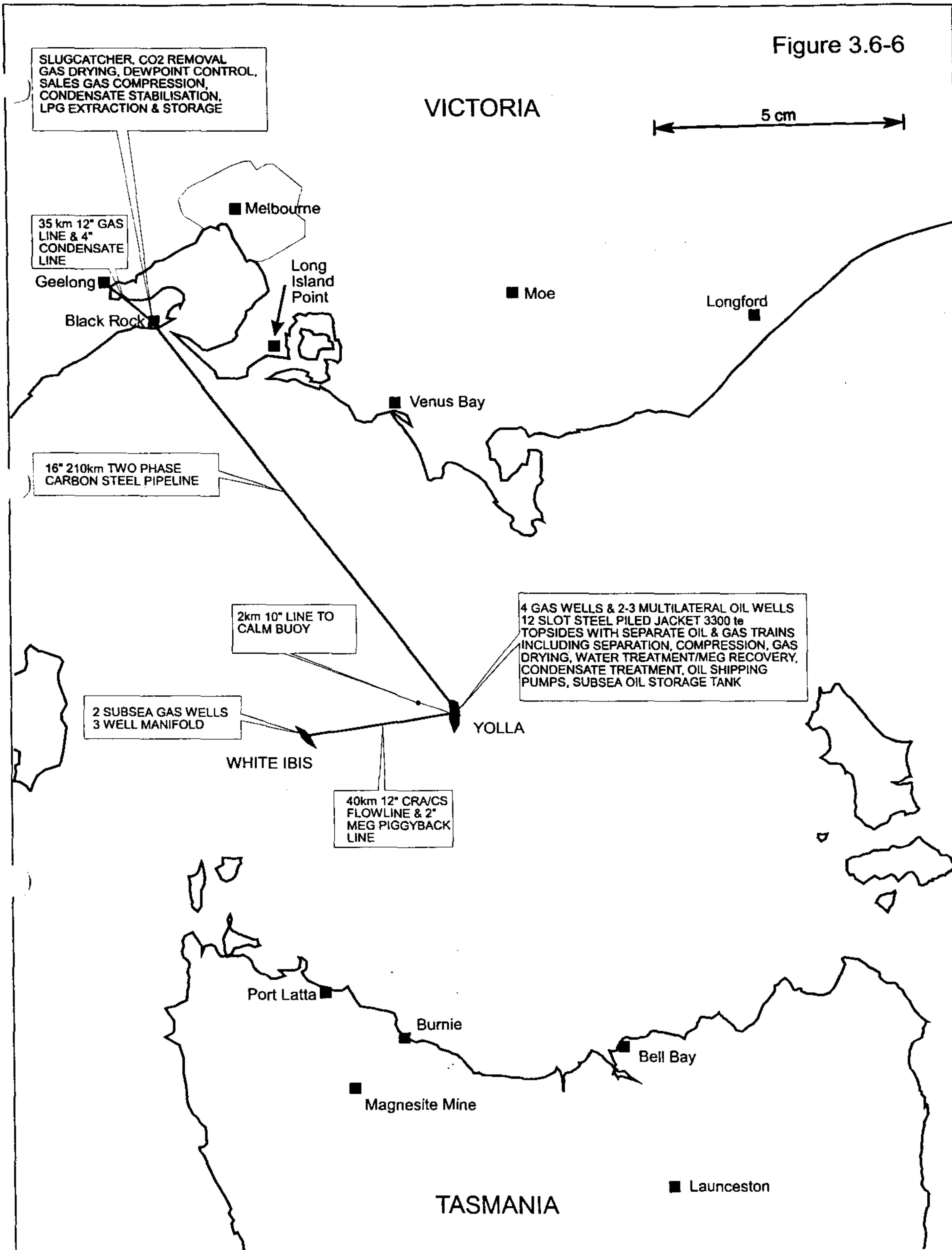


WOODHILL THORNTON					CASE 1A2 - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA (BELL BAY)
	B	28 Jan 99	MPG	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	16 Dec 98	MWM	NJP	
	REV	DATE	BY	CKD	Doc No: 9843-SK-15 — Rev B

Figure 3.6-5



WOODHILL THORNTON					
C	28 Jan 99	MPG	DAF	CASE 3B - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA & 20,000 STBOPD EXPORT
B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
A	16 Dec 98	MWM	NJP	
REV	DATE	BY	CKD	Doc No: 9843-SK-21 — Rev C



WOODHILL THORNTON					CASE 4B - 40 PJ/YR SALES GAS TO VICTORIA & 20,000 STBOPD EXPORT
	C	28 Jan 99	MPG	DAF	
	B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	16 Dec 98	MWM	NJP	
	REV	DATE	BY	CKD	Doc No: 9843-SK-23 Rev C

3.7 Sensitivity Cases

Nine sensitivity cases were evaluated:

CASE	1A3	as per Case 1A but with a 20 PJ/a Sales Gas flow
CASE	2A2	as per Case 2A but with an east of Melbourne landfall (Venus Bay)
CASE	2A3	as per Case 2A but with a 30 PJ/a Sales Gas flow (nil swing)
CASE	3A2	as per Case 3A but with 10,000 STBOPD export
CASE	4A2	as per Case 4A but with 30 PJ/a Sales Gas flow (nil swing)
CASE	1A4	as per case 1A but with 40 PJ/a Sales Gas flow to Bell Bay
CASE	1A5	as per case 1A but with 40 PJ/a Sales Gas flow to Burnie
CASE	3D	as per Case 3A but with up to 10,000 BOPD pumped to shore with the gas.
CASE	3B2	as per Case 3A but with up to 10,000 STBOPD stored in Arup's ACE 90

Outline concept summaries for each case are included at the end of this section (Figures 3.7-1 to 3.7-9). With the exception of Cases 2A2, 3B2 and 3D, all the above cases are based on variations of Base Cases 1A, 2A, 3A and 4A. Cost estimates for these cases (1A3, 1A4, 1A5, 2A3, 3A2 and 4A2) were developed based on cost building blocks extracted from the Base Cases. Separate sensitivity case equipment lists were not developed as the required cost estimate accuracy for these cases was reduced to ±40%. CAPEX details are provided in Section 4 below.

Cases 2A2, 3B2 and 3D are discussed further below.

Case 2A2 (Figure 3.7-2)
Case 2A2 is an east of Melbourne alternative to Case 2A. A Venus Bay landfall (see Figure 3.7.2) is assumed with sales gas and condensate export via tie-ins to the existing BHP/ESSO product pipelines at Moe.

A 122 km 14" production pipeline to shore is required in this case, one pipeline size down from Case 2A. A corresponding reduction in slugcatcher size may also be achieved however this effect is expected to be marginal given the large CAPEX associated with this case - see Section 4. (Preliminary examination indicates that onshore plant CAPEX could be reduced by ca. 2% if the reduced slugcatcher size was incorporated into the cost estimate.)

100 km, 16" sales gas and 6" condensate production pipelines are required to transfer gas and condensate products to Moe. LPG export is assumed via truck loading as per Case 2A.

Case 3D (Figure 3.7-8)
This is an oil production case based on producing the UEVCM oil reserves in the same way as case 3A. However instead of providing offshore storage and loading facilities for the crude oil, the oil is pumped into the gas pipeline and flows to shore with the gas and condensate.

A notional GOR of 2,000 SCF/Bbl was assumed to reflect the production of the UEVCM gas cap with the oil.

It was estimated that up to 8,000 STBOPD of oil could be transported down the pipeline. A cost estimate was prepared based on 10,000 STBOPD of oil being flowed to shore. It is estimated that to achieve 20,000 STBOPD a 14" line would be required.

Two technical issues need to be resolved before the feasibility of this case can be confirmed. These issues are:

- Crude oil pour point
- Pipeline Corrosion

The pour point of the crude oil is reportedly ca. 15°C. Minimum sea bed temperature in the Bass Strait is 10°C. The pour point of the crude/condensate mix must be below 10°C or pour point depressants will be required. Detailed laboratory work will be required to assess the impact of Yolla gas condensate on the UEVCM crude pour point.
The base cases assume offshore dehydration to prevent wet CO_2 pipeline corrosion. Offshore dehydration is based on over drying the gas to compensate for residual moisture in the liquids. The gas/liquid ratio in the pipeline will change substantially with inclusion of up to 8000 STBOPD. Condensate can typically be dewatered to 300-500 ppm by separation and filtration. It will be difficult to achieve this level of dehydration with a crude oil. A second stage of oil separation has been assumed together with oil heating in order to maximise crude oil dewatering. A further improvement may be possible using electrostatic coalescing. However it is unlikely that the crude oil could be dehydrated sufficiently to achieve a dry pipeline system. Therefore the issue of wet CO_2 corrosion in the pipeline must be addressed. The presence of crude oil is known to reduce wet CO_2 corrosion rates. However a thorough review of this issue would be required to confirm that the crude pumping scheme is technically feasible. The solution may require CRA cladding of the pipeline for the initial part of the route.

Onshore Case 3D liquids handling facilities were assumed as per Case 3A but scaled up to allow for the increased liquids throughput (12000 bbl/d v 3500bbl/d). The onshore liquids pipeline for Burnie to Port Latta was assumed to increase in size from 4" to 8".

Case 3B2 (Figure 3.7-9)

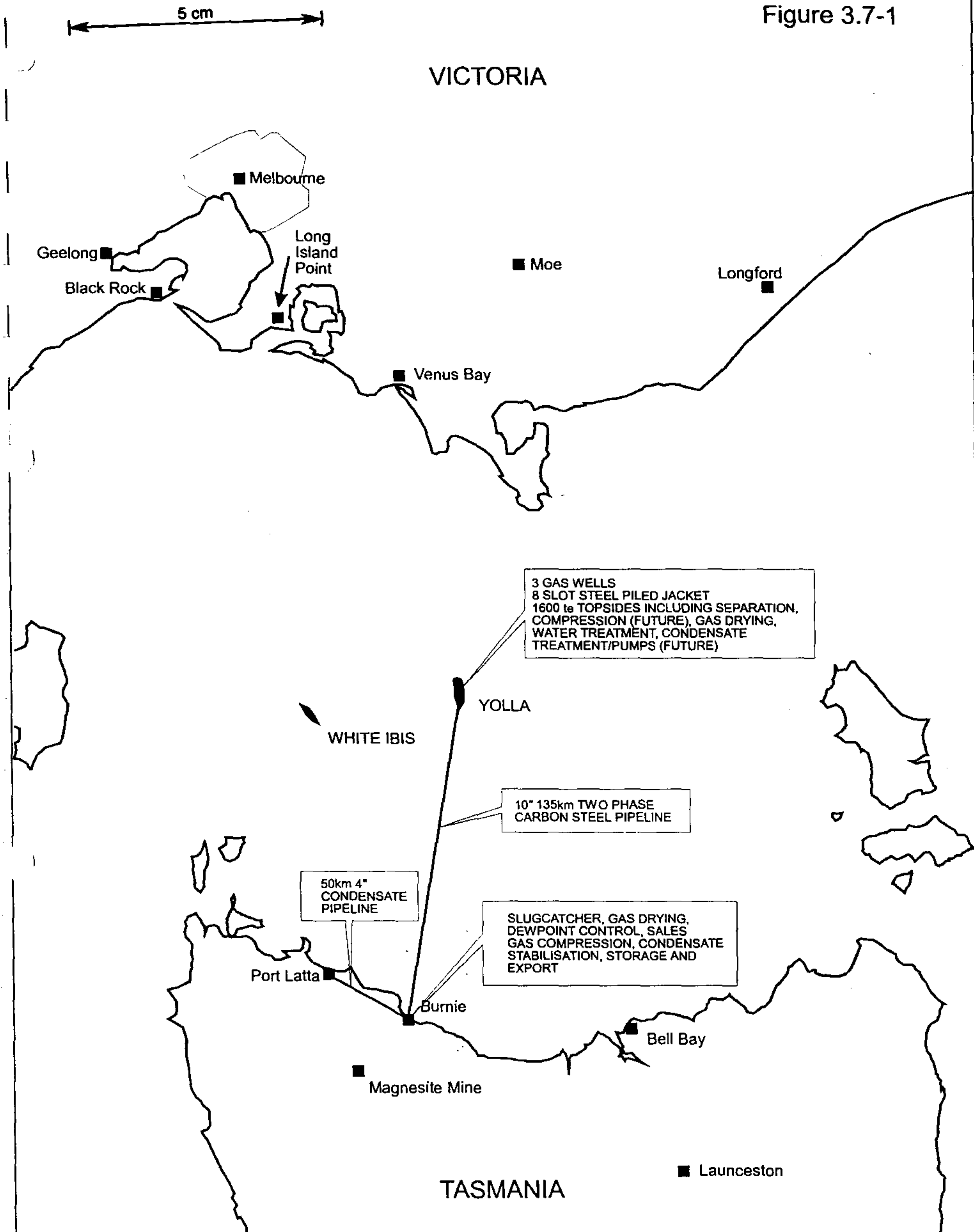
Case 3B2 is identical to Case 3B in all aspects apart from the offshore structure. In Case 3B a conventional jacket was assumed located above a subsea storage tank. In Case 3B2 Arup's ACE 90 concept is utilised (Appendix 5).

The ACE 90 is a self installing jack-up with a concrete gravity base structure (CGS) incorporating up to 250,000 bbl of wet oil storage. Topsides are mounted on a barge deck onshore, mated with the CGS, and floated/towed to the field. The CGS is then jacked down to the seabed and the deck up to provide the desired air gap.

The cost estimate for this case was developed using an Arup budget quotation (Ref 9) and Case 3D building blocks.

Technical risks exist with this case due to the unproven nature of the concept and the high pour point of the crude. (A high reliability oil pump around/heating system will be required to maintain the oil above its 15°C pour point. Whilst such a system is considered technically feasible it has yet to be investigated in any detail.)

Figure 3.7-1



REV	DATE	BY	CKD
C	28 Jan 99	MPG	DAF
B	14 Jan 99	MWM	DAF
A	16 Dec 98	MWM	NJP

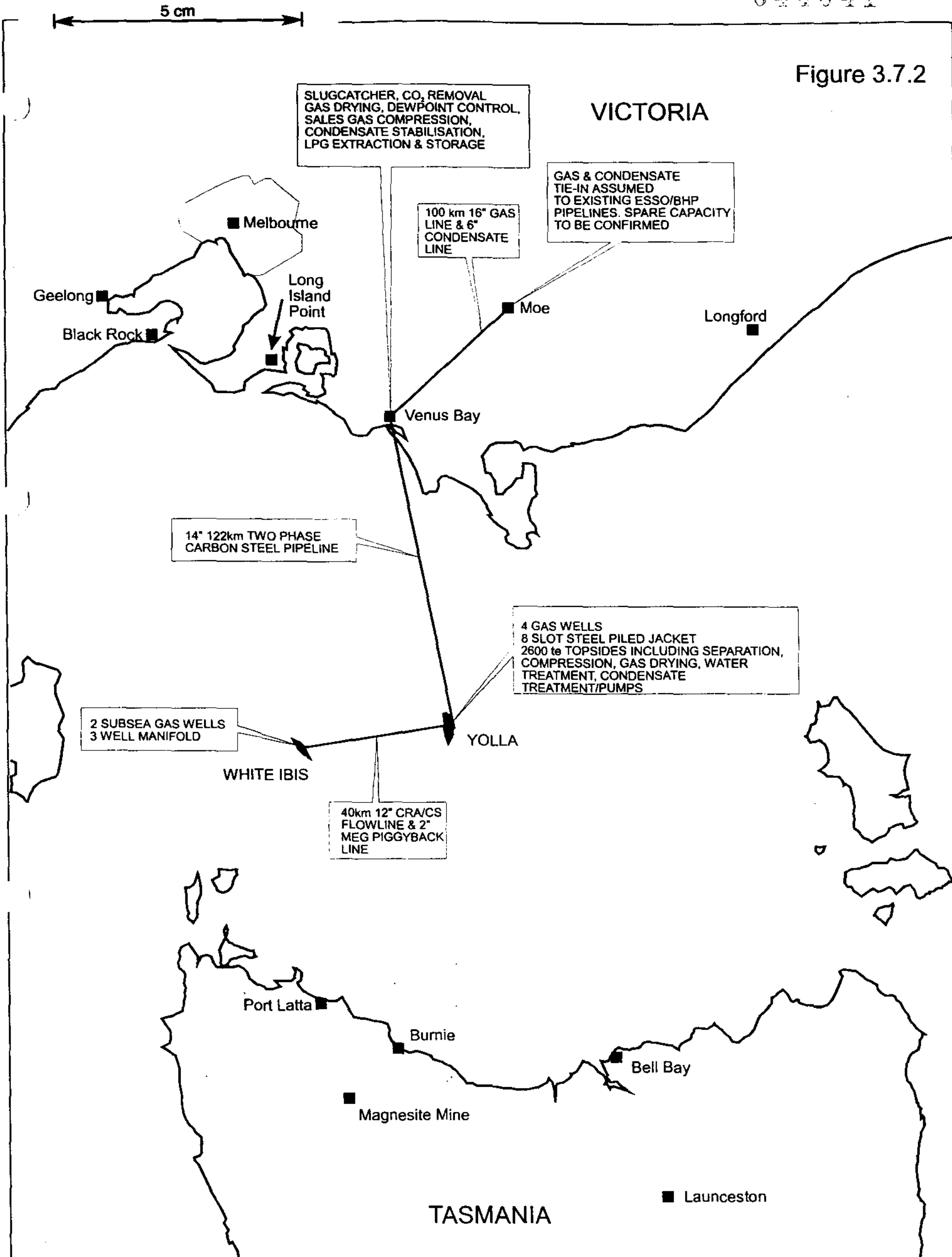
WOODHILL THORNTON

CASE 1A3 - 20 PJ/YR INDUSTRIAL GAS TO TASMANIA (BURNIE)

YOLLA DEVELOPMENT STUDY PREMIEROIL

Doc No: 9843-SK-24 | Rev C

644041

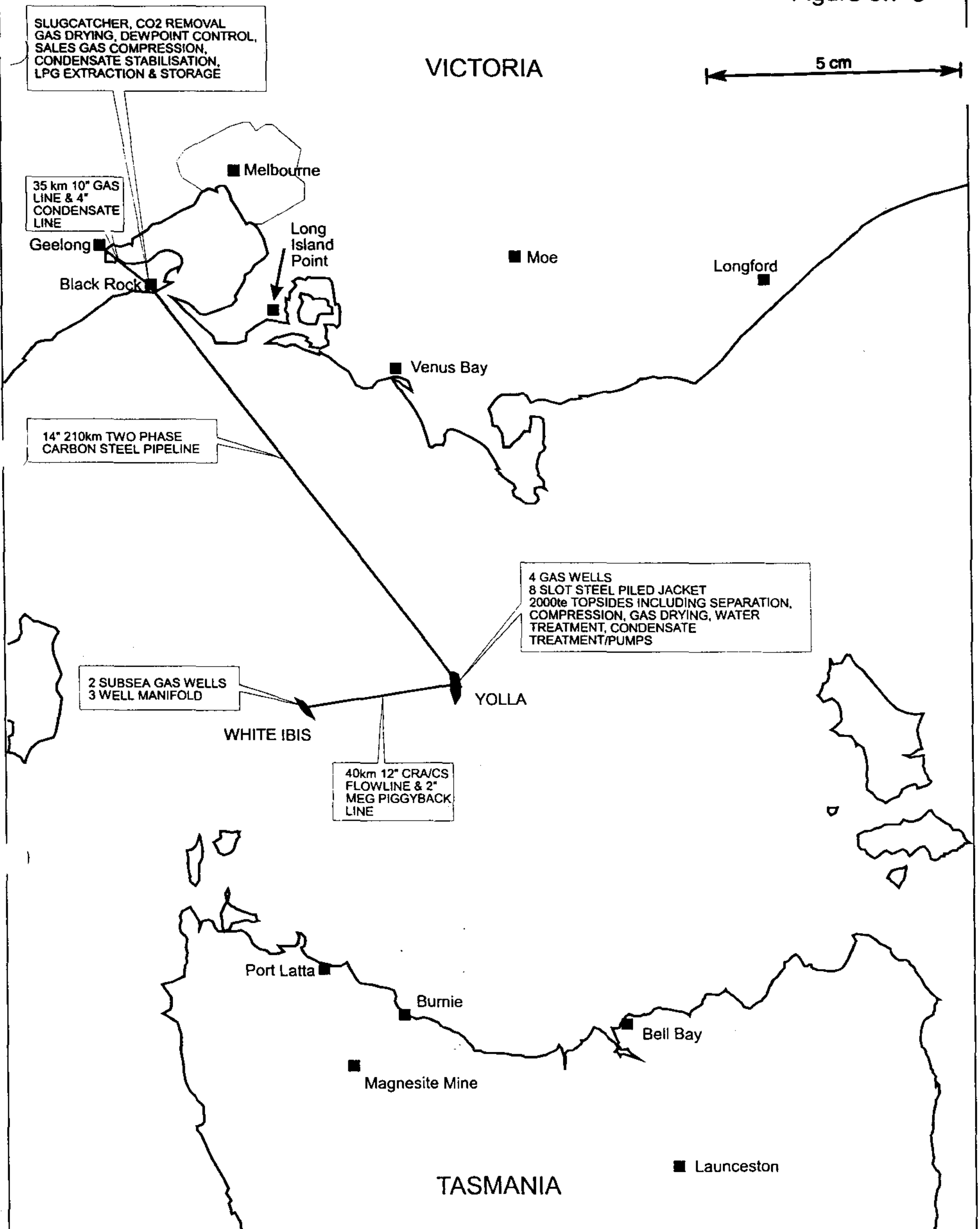


WOODHILL THORNTON				CASE 2A2- 40 PJ/YR SALES GAS TO VICTORIA (VENUS BAY)
	B	28 Jan 99	MPG	DAF
	A	16 Dec 98	MWM	NJP
	REV	DATE	BY	CKD

YOLLA DEVELOPMENT STUDY
PREMIEROIL

Doc No: 9843-SK-25 | Rev B

Figure 3.7-3



WOODHILL THORNTON

REV	DATE	BY	CKD
C	28 Jan 99	MPG	DAF
B	14 Jan 99	MWM	DAF
A	16 Dec 98	MWM	NJP

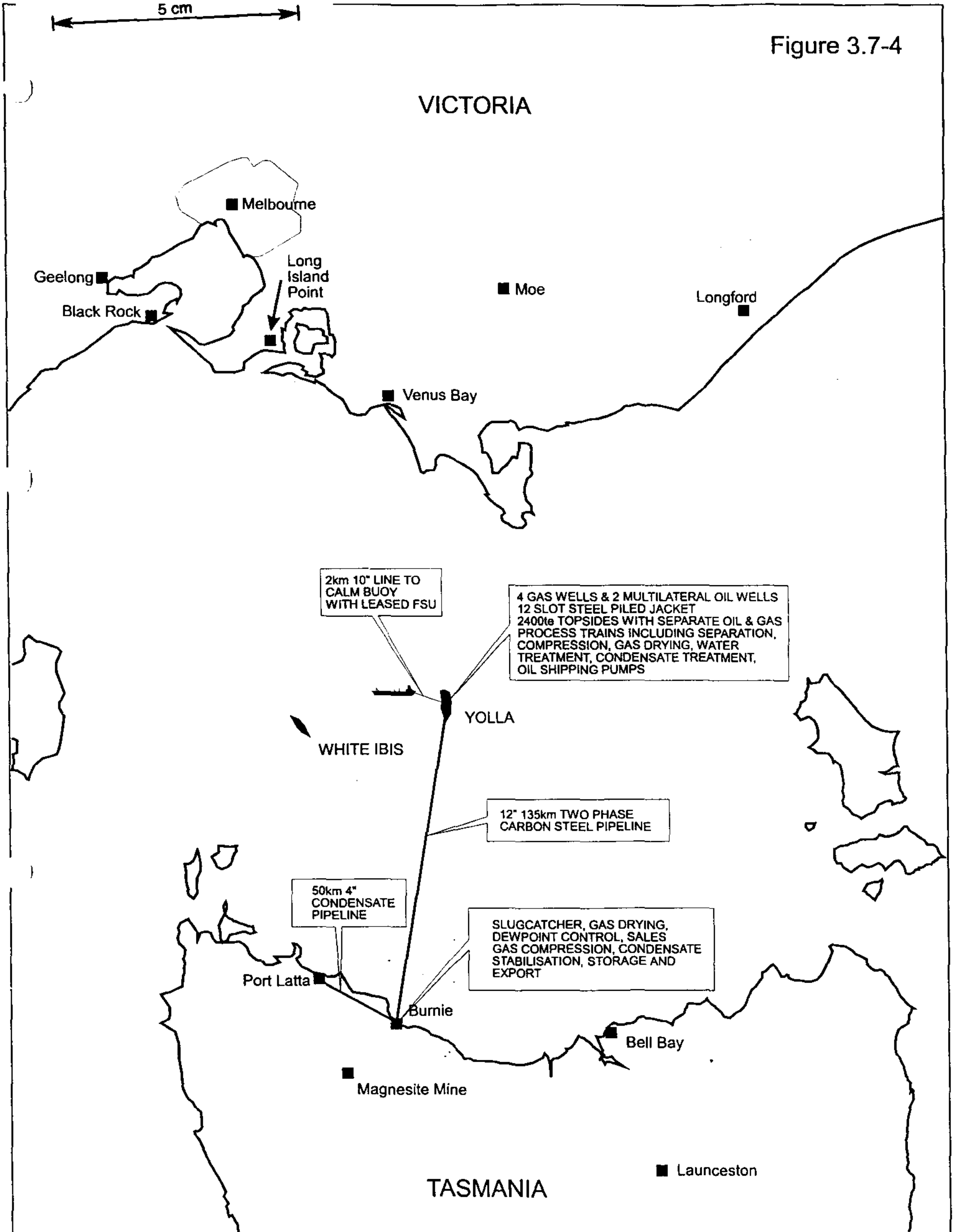
CASE 2A3 - 30 PJ/YR SALES GAS TO VICTORIA (BLACK ROCK)

YOLLA DEVELOPMENT STUDY
PREMIEROIL

Doc No: 9843-SK-26 | Rev C

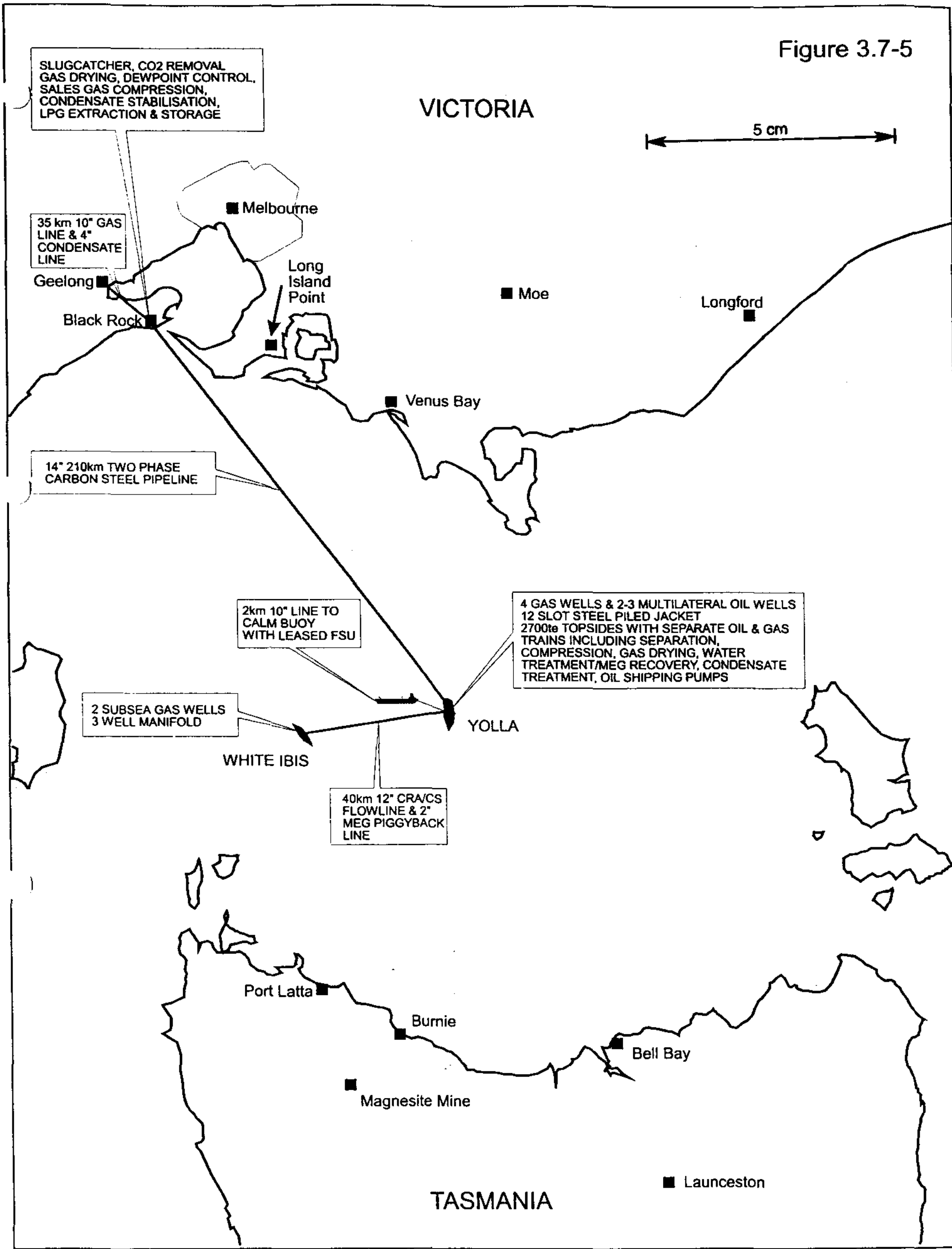
644043

Figure 3.7-4



WOODHILL THORNTON					CASE 3A2 - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA & 10,000 STBOPD EXPORT
	C	28 Jan 99	MPG	DAF	
	B	14 Jan 99	MWM	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	16 Dec 98	MWM	NJP	
	REV	DATE	BY	CKD	Doc No: 9843-SK-27 — Rev C

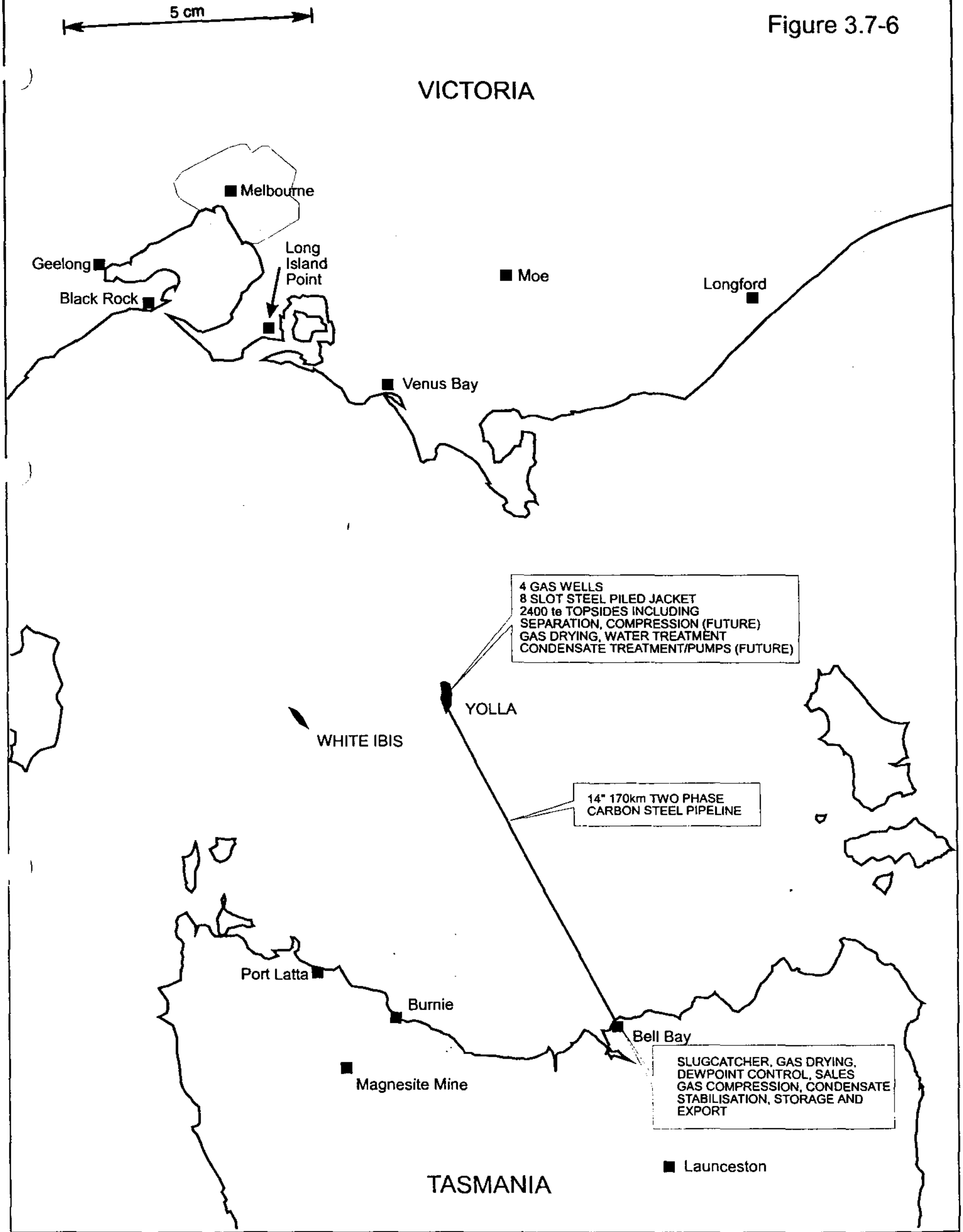
Figure 3.7-5



WOODHILL THORNTON					CASE 4A2 - 30 PJ/YR SALES GAS TO VICTORIA & 20,000 STBOPD EXPORT	
	C	28 Jan 99	MPG	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL	
	B	14 Jan 99	MWM	DAF		
	A	16 Dec 98	MWM	NJP		
	REV	DATE	BY	CKD	Doc No: 9843-SK-28	Rev C

644045

Figure 3.7-6



WOODHILL THORNTON

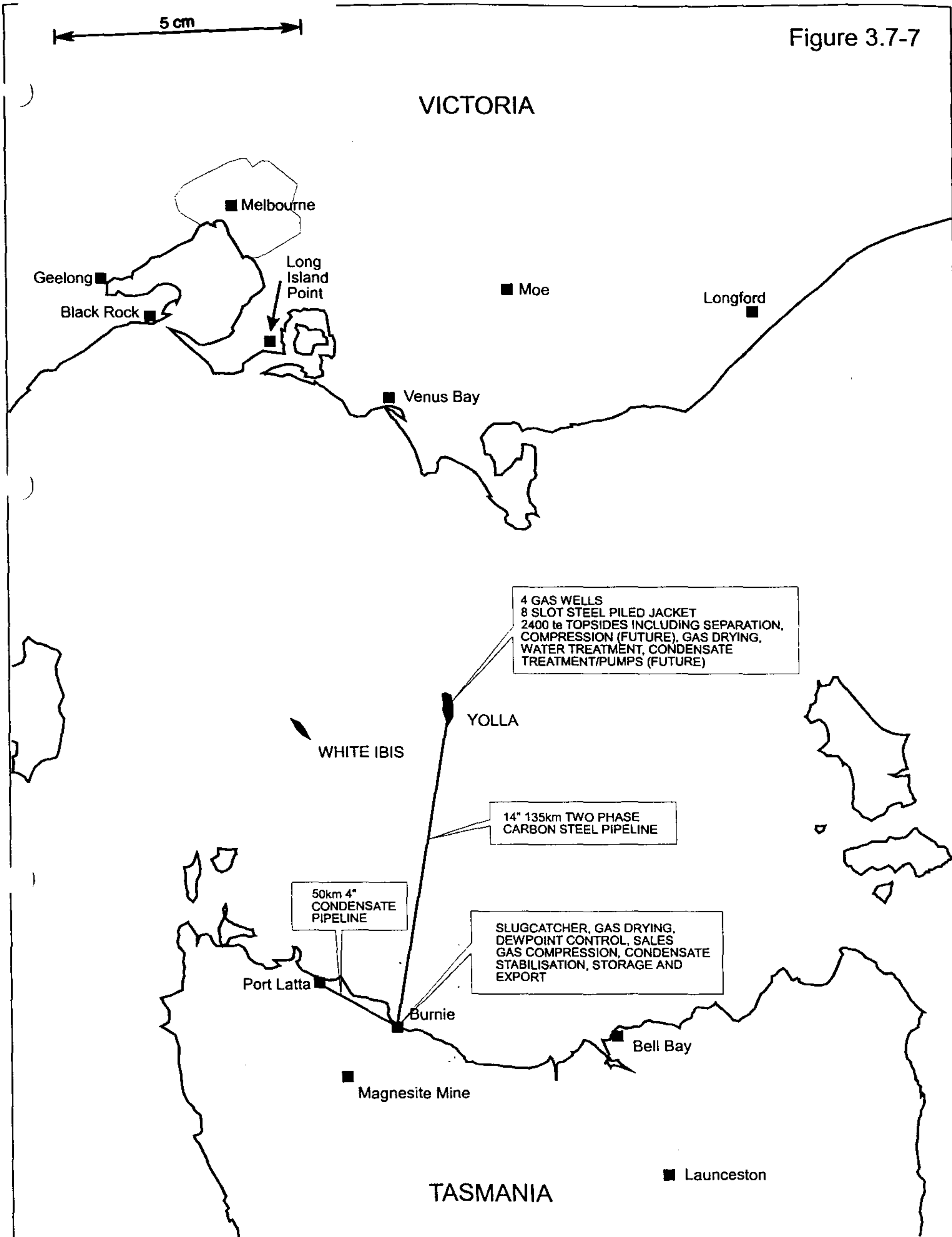
REV	DATE	BY	CKD
B	28 Jan 99	MPG	DAF
A	19 Jan 99	DAF	DTC

CASE 1A4 - 40 PJ/YR INDUSTRIAL GAS TO TASMANIA (BELL BAY)

YOLLA DEVELOPMENT STUDY PREMIEROIL

Doc No: 9843-SK-29 | Rev B

Figure 3.7-7



WOODHILL THORNTON

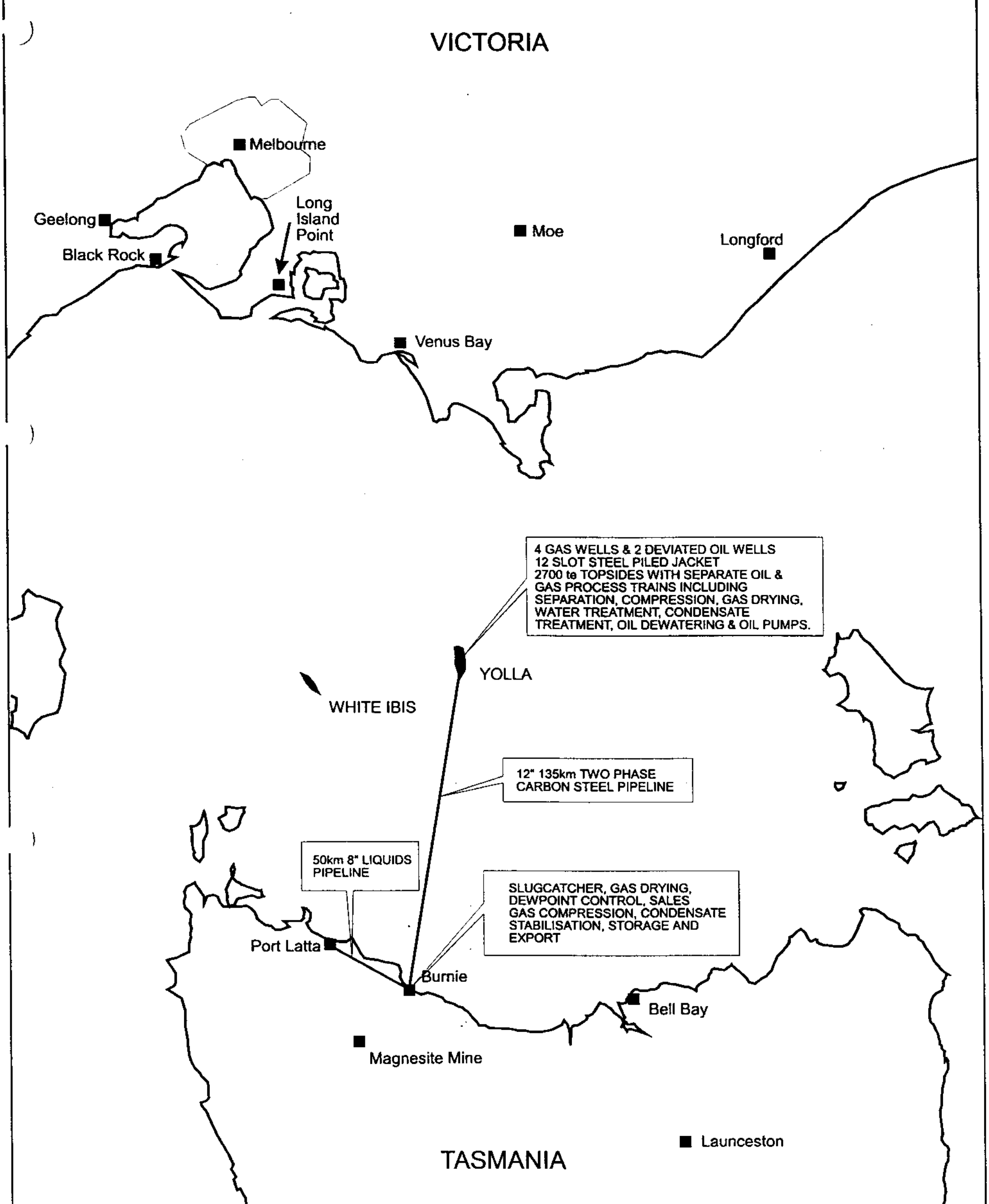
REV	DATE	BY	CKD	
				CASE 1A5 - 40PJ/YR INDUSTRIAL GAS TO TASMANIA (BURNIE)
B	28 Jan 99	MPG	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
A	19 Jan 99	DAF	DTC	

Doc No: 9843-SK-30 — Rev B

644047

5 cm

Figure 3.7-8



WOODHILL THORNTON					CASE 3D - 30 PJ/YR INDUSTRIAL GAS TO TAS. & UP TO 10,000 STBOPD VIA 2-PHASE LINE
	B	28 Jan 98	MPG	DAF	YOLLA DEVELOPMENT STUDY PREMIEROIL
	A	19 Jan 98	DAF	DTC	
	REV	DATE	BY	CKD	Doc No: 9843-SK-31 — Rev B

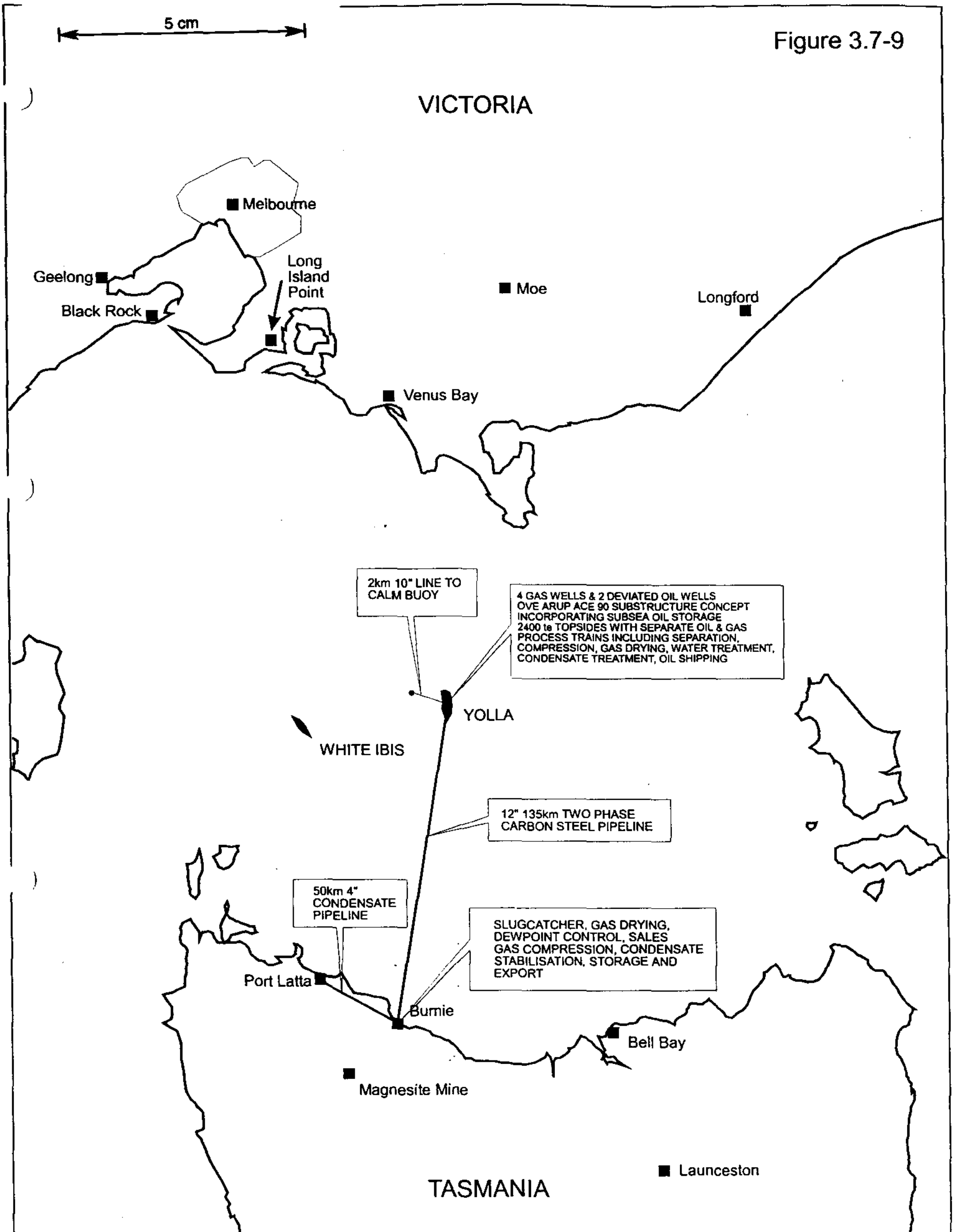


Figure 3.7-9

WOODHILL THORNTON				CASE 3B2 - 30 PJ/YR INDUSTRIAL GAS TO TASMANIA & 10,000 STBOPD EXPORT
	A	28 Jan 99	DAF	NJP	YOLLA DEVELOPMENT STUDY PREMIEROIL
	REV	DATE	BY	CKD	Doc No: 9843-SK-32 Rev A

3.8 Cost Reduction Review

A brainstorming session similar to the initial conceptual brainstorming review was carried out after the bulk of the study was completed to identify the major cost drivers having potential scope for further significant reductions in capital cost. The review concluded that CAPEX reductions may be achievable in the following areas:

Offshore Facility Costs

The Base Cases assume normally manned platforms with dehydration and compression. Options for lowering the cost include:

- Capability to operate a dehydration and compression platform on a not normally manned basis. North Sea technology is continually developing the scope and complexity of not normally manned production. The potential cost saving would be A$20 - 30M.
- Lower installation costs from sharing vessel mob/demob costs with another project in the Bass Strait. This could apply to both the platform and the pipeline. Vessel costs are quite sensitive to market conditions. The potential cost reduction is in the order of A$5M.
- SE Asia fabrication of jacket and topsides may reduce fabrication cost in the order of A$5 - 10M.

Pipeline costs

The main cost drivers for the pipeline are pipeline materials and vessel costs. The installed cost of the pipeline might possibly be reduced by:

- Installing twin flowlines in place of a single pipeline. The flowlines would not require concrete weight coating and trenching/ploughing and hence the overall pipeline installed cost would potentially be lower. The estimated potential cost saving is A$5 - 10M.
- Use of lower cost Corrosion Resistant alloys (such as 13Cr). This would reduce costs on White Ibis/Trefoil and also on the Yolla wellhead platform concept (Case 1C2). Potential cost savings based on Case 1C2 are of the order of A$20M. and Case 1C.

Onshore plant

A locally constructed onshore plant has been assumed. Lower costs in the order of A$10M might be achieved by constructing the plant from large modules or pre-assembled units (PAU). The potential for this option would depend on the available sites for fabrication and the size/weight of the module that could be transported to the plant site. The availability of local infrastructure is critical to this issue.

Contracting Strategy

Use of novel contracting strategies may allow further cost savings of up to 5%.

4 COST ESTIMATE

Base Case, Alternative Case and Sensitivity Case high level cost estimate summaries are compared in Tables 4-1, 4-2 and 4-3 below. Base Case and Alternative Case costs were estimated to a target accuracy of ±30%, which is broadly consistent with the level of engineering undertaken to date. Similarly, Sensitivity Case costs were estimated to ±40% accuracy.

Table 4-1: Base Case Cost Estimate Comparison

Building Block	Development Option / Case Number (Cost in A$M)			
	1A 30PJ/y to Tasmania	2A 40PJ/y to Victoria	3A Per 1A + 20,000bbl/d oil	4A Per 2A + 20,000bbl/d oil
Yolla Wells	71(3)	71(3)	123(4)	123(4)
White Ibis Facilities(2)	N/A	124	N/A	124
Offshore Platform	150	175	188	217
CALM Buoy & Loading	N/A	N/A	15	15
Production Pipeline	84	137	84	137
Onshore Plant	68	138	68	138
Onshore Pipelines	5	13	5	13
Project Management	31	55	36	61
Total CAPEX (1)	**409**	**713**	**519**	**828**
Annual OPEX	**16**	**25**	**45**	**55**
Abandonment Costs	**32**	**43**	**39**	**51**

Notes
(1) See detailed cost summary for CAPEX phasing
(2) White Ibis cost is nominally independent of the option considered
(3) Assumes 4 gas wells
(4) Assumes 4 gas wells and 3 multilateral oil wells

Cost estimate summaries for each Base Case including expected CAPEX phasing requirements are detailed in Appendix 9. Similar Alternative Case and Sensitivity Case summaries are included in Appendices 10 & 11 respectively. Further details (cost estimate building blocks) are included in Appendix 12. An overall case-by-case comparison of CAPEX and abandonment costs is provided in Figure 4-1.

It should be noted that all cost estimates incorporate a 10% contingency (Appendix 12).

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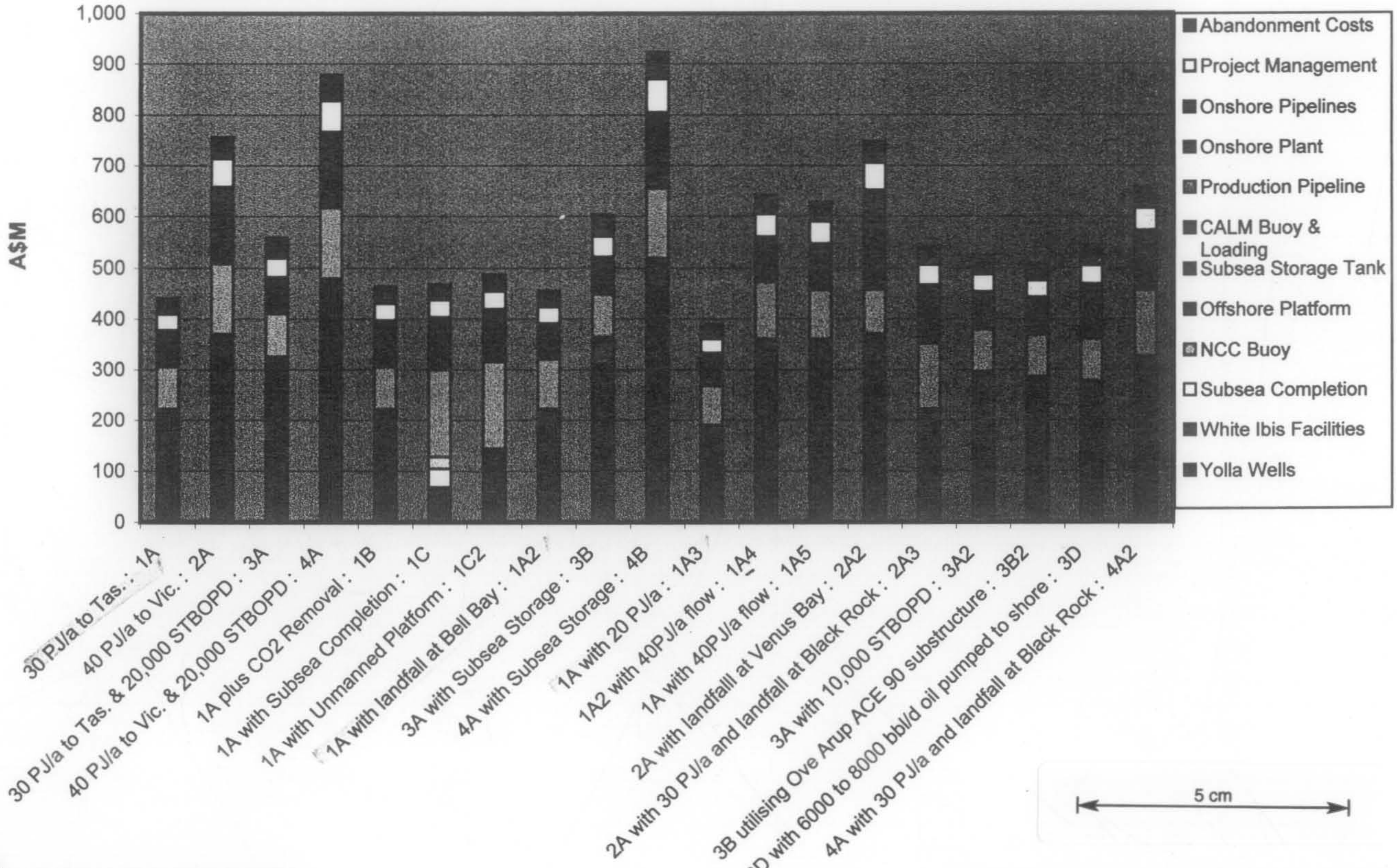
Figure 4-1: Case-by-Case CAPEX and Abandonment Cost Comparison



WOODHILL THORNTON

Table 4-2: Alternative Case Cost Estimate Comparison

Building Block	Development Option / Case Number (Cost in A$M)					
	1B 1A + Onshore CO_2 removal	1C 1A w/ subsea completion	1C2	1A2	3B	4B
Yolla Wells	71(2)	69(2)	71(2)	71(2)	123(3)	123(3)
White Ibis Facilities	N/A	N/A	N/A	N/A	N/A	124
Subsea Completion	N/A	36	N/A	N/A	N/A	N/A
NCC Buoy	N/A	23	N/A	N/A	N/A	N/A
Offshore Platform	150	N/A	72	150	188	217
Subsea Storage Tank	N/A	N/A	N/A	N/A	38	38
CALM Buoy & Loading	N/A	N/A	N/A	N/A	15	15
Production Pipeline	84	172	172	99	84	137
Onshore Plant	87	99	99	70	68	138
Onshore Pipelines	5	5	5	N/A	5	13
Project Management	33	33	35	33	40	65
Total CAPEX (1)	**430**	**437**	**454**	**423**	**561**	**870**
Annual OPEX	**17**	**11**	**10**	**16**	**22**	**32**
Abandonment Costs	**33**	**31**	**33**	**32**	**41**	**53**

Notes
(1) See detailed cost summary for CAPEX phasing.
(2) Assumes 4 gas wells
(3) Assumes 4 gas wells and 3 multilateral oil wells

Table 4-3: Sensitivity Case Cost Estimate Comparison

Building Block	Development Option / Case Number (Cost in A$M)								
	1A3	1A4	1A5	2A2	2A3	3A2	3B2	3D	4A2
Yolla Wells	54(2)	71(3)	71(3)	71(3)	71(3)	105(4)	101(5)	101(5)	123(6)
White Ibis Facilities	N/A	124	124	124	N/A	N/A	N/A	N/A	N/A
Offshore Platform	136	164	164	175	150	176	169	176	188
CALM Buoy & Loading	N/A	N/A	N/A	N/A	N/A	15	15	N/A	15
Production Pipeline	78	113	97	87	130	84	84	84	130
Onshore Plant	60	86	84	138	102	68	68	98	102
Onshore Pipelines	5	N/A	5	55	13	5	5	10	13
Project Management	28	46	45	55	40	34	34	36	45
Total CAPEX (1)	**361**	**604**	**590**	**705**	**506**	**487**	**476**	**505**	**616**
Annual OPEX	**14**	**20**	**20**	**25**	**18**	**44**	**19**	**20**	**48**
Abandonment Costs	**29**	**38**	**38**	**43**	**35**	**37**	**32**	**39**	**43**

Notes
(1) See detailed cost summary for CAPEX phasing
(2) Assumes 3 gas wells
(3) Assumes 4 gas wells
(4) Assumes 4 gas wells and 2 multilateral oil wells
(5) Assumes 4 gas wells and 2 deviated oil/gas wells
(6) Assumes 4 gas wells and 3 multilateral oil wells

4.1 Cost Estimate Methodology

Capital cost estimates for each Base case were broken down into "discipline areas" consistent with how the development may be controlled from an organisational and cost aspect should it be approved. The "discipline areas" were:

- Engineering
- Equipment & Materials Procurement
- Fabrication
- Installation
- Commissioning
- Contractor & Premier/Joint Venture Indirects

Individual estimates or 'building blocks' for each item of equipment, offshore facility, onshore plant units, and pipelines were developed and cost estimates produced for each based on the following methodology and assumptions:

- Engineering and fabrication manhour estimates are based on in-house norms derived from projects within the region with current local rates based upon a build up by discipline and manhours.
- Equipment estimates are based upon factored equipment costs from direct vendor quotations.
- Factors for the individual cost elements are based upon recent in-house project cost data from similar NorthWest Shelf projects.
- Bulk material estimates are based upon in-house cost data for materials by weight.
- Installation mob/demob estimates are based upon a first principle build up from published data.
- Installation and Commissioning estimates are based on a build up of direct manning, equipment, hours and rates.
- Indirect costs are based upon a build up from first principle rules and in-house cost data based upon a variety of developments carried out within the region.
- The "Contingency Cost" is defined as +10%.

Each case cost estimate was then derived via suitable combinations of building block costs.

4.2 Cost Estimate Assumptions

The following assumptions are based upon engineering input, previous project experience, current market conditions, fabrication capabilities and 1998 installation rates.

Wells

- Costs for Yolla gas and oil wells are as provided by Premier (refer Section 2.2 of this report).
- White Ibis wells are assumed to be drilled by a semi submersible drilling rig with subsea completions.
- White Ibis well costs are based upon information received from Premier and benchmarked to recent Australian developments.
- CAPEX phasing assumed one year prior to Ready for Start Up (RFSU). Two rigs are assumed for cases with 10 or more wells.
- Abandonment costs of A$2M per well were assumed.

Subsea Equipment

- A Diving Support Vessel (DSV) mobilised from SE Asia is assumed to install the facilities. Where required support for manifold piling operations will be provided by the Jack-up drilling rig.
- Costs are based upon in house cost data from similar Australian projects and vendor quotations for equipment and installation.
- A two year 60/40 CAPEX phasing was assumed prior to RFSU.
- A$0.5M was assumed to cover disconnection, flooding and capping of pipelines and umbilicals on abandonment.

Offshore Jacket

- Jackets are assumed to be of a steel piled design with both primary and insert piles.
- Jackets are assumed fabricated at Sale (Barry Beach), Victoria and barge launched. Piling operations are assumed via a DLB mobilised from SE Asia.
- An in-house software program has been used to generate the jacket weights and thus material costs.
- Mobilisation and installation day rates are based upon recent budget quotations from Installation contractors. Installation durations are based upon published data for the Bass Strait.
- Engineering and Geotechnical survey costs are based upon in house cost data and norms from other developments within the region.
- A A$13M abandonment cost (of which A$10M is vessel mobilisation cost) was assumed to cover jacket removal by a heavy lift vessel, (HLV) and scrapping.
- A two year 30/70 CAPEX phasing prior to RFSU was assumed in all cases except for Case 1C2 were a one year construction period is expected.

Offshore Topsides

- Individual topside concepts cost estimates were derived from equipment weights listed in Appendix 7. Individual equipment items costs have been estimated using I of E cost curves.
- Bulk weights have been determined by factoring bare equipment weights according to the relevant discipline. Final material costs have been calculated on a cost per unit weight basis. Bulk factors and cost per tonne values are taken from in house data.
- Installation costs and durations are based upon published public domain items and costs from vendors on recent projects.
- Engineering norms are based upon in house data from recent projects.
- A two year 50/x/y CAPEX phasing prior to RFSU was assumed with "y" representing future equipment costs and "x" being equal to (100 - y).
- Topsides removal on abandonment is assumed to cost A$1.5M. The same HLV is assumed to remove the jacket.
- Installation of compression for cases including White Ibis have assumed that compression is installed initially.

Control Buoy

Control Buoy costs are based on a similar recent NWS project. Buoy removal at abandonment is expected to cost A$11.5M utilising a HLV, of whichA$10M is vessel mobilisation cost.

Offshore Pipelines

- Offshore pipelines are assumed manufactured in API 5L X65 ERW material.
- Stabilisation of offshore pipelines was assumed via a combination of concrete weight coating and in the absence of any route survey data a 30km long ploughed section.
- Where appropriate CRA bonded pipeline has been included. CRA pipe costs assumed are based on European mill vendor quotations. CRA pipe lay rates are assumed to be two thirds those of carbon steel.
- A two year 35/65 CAPEX phasing prior to RFSU was assumed.
- On abandonment, production pipelines will be flooded, capped and left in situ for a cost of A$0.5M.

CALM Buoy / Loading Line

- The costs for the procurement installation, and abandonment are based upon a recent budget price for a similar facility.

Subsea Oil Storage

The subsea oil storage tank option cost is derived from a first principle estimate using weights from a similar recent in-house cost estimate. Abandonment costs are estimated at A$2.4M assuming "float-away" and "scrap".

Onshore Plant

Costs have been derived from I of E cost curves and vendor quotations based on equipment weights and duties. Additional bulks and indirect costs have been added based on factors derived from similar NWS developments. A two year construction schedule was assumed for 50/50 CAPEX phasing. Abandonment costs are assumed to be 10% of total CAPEX.

Onshore Pipelines

- Onshore pipelines are assumed manufactured in API 5L X52 material.
- The estimates for the liquids lines are based upon historical estimating norms of A$25,000 per km/inch.
- A one year construction schedule was assumed in all cases.
- Onshore pipelines are assumed left in situ on abandonment.

Project Management

Project Management costs are based on a percentage of the development capital costs consistent with similar developments in the area. These include personnel (other than engineering), office fit-out, office rental and running costs, computer software and hardware, travel and accommodation, and contract works insurances. Costs are assumed phased 10/45/45 over three years prior to RFSU, with further allocation (if required) based on the proportion of capital expended in the relevant year with years -2 & -1 RFSU reduced as appropriate.

Contingency

As noted above, total development costs for each option include a 10% contingency factor based upon a benchmarking exercise of recent and ongoing in-house cost estimate data.

4.3 Additional Building Blocks

The following additional order of magnitude (±40%) cost "building blocks" were evaluated to assist in development economic analyses:

(1) **CO_2 Removal** - onshore CO_2 removal facilities are expected to cost ca. A$20M based on a sales gas flow of 30 PJ/a.

(2) **CO_2 Disposal** – onshore disposal of ca. 20 MMscfd of CO_2 via injection into a suitable reservoir (if available) is expected to cost ca. A$120M based on an estimated compression requirement of 60 MW.

(3) **LPG Plant** - LPG fractionation, storage and export CAPEX is expected to be approximately A$20-25M for the Victorian and Tasmanian development cases considered.

(4) **Offshore Oil Associated Gas** compression CAPEX for recovering 20,000 bbl/d of oil is expected to be ca. A$23M.

(5) **Development of the Trefoil Reservoir** is expected to require CAPEX of ca. A$145M assuming a three well subsea development (with similar reservoir properties to those of White Ibis) tied back to a Yolla platform. This cost estimate increases to ca. A$152M if a minimal facilities wellhead platform Trefoil development is assumed.

5 CONCLUSIONS & RECOMMENDATIONS

5.1 Conclusions

(1) A conventional fixed offshore platform or Arup's ACE 90 concept appear at this stage to be the most cost effective means of developing the Yolla reservoir. Similarly, the White Ibis (and Trefoil) reservoirs, if required, should be developed via subsea tie-backs to Yolla.

(2) Subsea and minimal facility wellhead platforms are predicted to be 7 - 11% more expensive than a conventional platform installed at the Yolla field due to the larger pipeline and onshore slugcatcher sizes required.

(3) Subsea White Ibis (and Trefoil) developments are expected to be approximately 5% less expensive than similar concepts developed using minimal facility wellhead platforms.

(4) CO_2 induced corrosion (due to the high CO_2 levels in the Yolla gas) is controllable via either offshore gas dehydration or through use of mechanically bonded CRA clad pipelines and corrosion inhibitor. Offshore CO_2 removal is not recommended due to the expensive large scale plants required.

(5) The major CAPEX areas in all cases are platform, offshore production pipeline, wells, and onshore gas plant. Onshore product pipeline costs are relatively insignificant (less than 3% of the total) in all cases except the east of Melbourne Victorian option (Case 2A2).

(6) Victorian development options are in general ca. A$100M more costly than similar Tasmanian options due to the additional offshore pipeline lengths and diameter sizes required and the need to remove CO_2 and LPG to meet Victorian gas specifications. (The A$100M cost differential can be broken down into approximate pipeline, CO_2 removal, LPG removal and onshore pipeline cost differentials of A$50M, A$20M, A$20M and A$10M respectively.)

(7) Additional marginal costs to include development of the UEVCM Yolla oil reservoir range from A$110M to A$150M depending on whether a leased FSU or a subsea oil storage tank is used. If projected oil capacity is reduced from 20000 STBOPD initially, to 10000 STBOPD initially, these marginal costs can be reduced to ca. A$65M through use of Arup's ACE 90 concept. Since this option includes up to 250,000 bbl of "free" subsea oil storage it avoids costly FSU leasing fees. Hence its OPEX costs of ca. A$19M are only ca. 20% above those of comparable gas only options. Expected cumulative oil revenues based on a US$10/bbl oil price range from A$135M to A$250M assuming recoverable oil quantities of 9-18 MMbbls. Hence Yolla development options including oil production may be economically attractive.

(8) Tasmanian option development costs can be reduced by approximately A$48M (ca. 12%) by reducing the design sales gas DCQ from 30 PJ/a to 20 PJ/a. Such CAPEX savings (based on capacity reductions) are unlikely to improve overall project economics.

(9) Victorian option development costs can be reduced by approximately A$207M (ca. 30%) by reducing the design sales gas quantities from 40 PJ/a plus 25% swing to 30 PJ/a nil swing. Such CAPEX savings (based on a combination of base capacity and swing reductions) may provide marginal economic benefits to Victorian options.

(10) Further marginal Victorian option costs reductions of up to A$25M (3-4%) are achievable through relaxation of the sales gas specification to allow CO_2 levels of up to 4%mol. Such relaxation should allow Victorian gas specification HHV and Wobbe Indices constraints to be met without an onshore LPG plant.

(11) Utilisation of a Bell Bay landfall in Tasmania is expected to result in a CAPEX increase of ca. A$14M. Cost reduction achieved in this case through deletion of the condensate product pipelines (A$5M) is outweighed by the additional offshore production pipeline (A$16M) and slugcatcher (A$3M) CAPEX required. Clearly such cost differentials (ca. 3%) are marginal and well within the accuracy of the cost estimate (±30%). Hence the optimal Tasmanian landfall is likely to be set by proximity to the eventual gas point-of-sale.

(12) Utilisation of an east of Melbourne landfall in Victoria (Venus Bay) is expected to result in negligible CAPEX decreases (A$8M) over the west of Melbourne Black Rock landfall option. Offshore pipeline CAPEX savings (A$50M) are approximately balanced by increases in onshore pipeline CAPEX costs (A$42M). It should be noted however that realisation of this option relies on spare capacity being available in a competitor's pipelines, and access to that capacity being granted at a reasonable tariff.

(13) Sales Gas and LPG product quantities and qualities are expected to remain approximately constant in each case over the 15 year field life envisaged. Condensate product rates are however expected to decline by ca. 60-70% over the field life in accordance with falling reservoir pressure.

(14) Although this study has not addressed the environmental aspects of the Yolla CO_2 balance, it is likely that onshore disposal of CO_2 via its retention in the sales gas (and subsequent venting within a flue gas mixture) will lead to a satisfactory compromise between project economics and long term environmental concerns.

5.2 Recommendations

(1) The issue of CO_2 disposal needs to be addressed in all cases and the environmental consequences assessed.

(2) Economic assessment of 30 PJ/a Gas plus Oil cases should note that removal of the offshore oil facilities in Year 5 may provide an ideal opportunity for expanding the gas processing facilities for additional gas sales, if additional reserves are proved up in the Yolla area.

(3) Further work is recommended to confirm the technical feasibility of Arup's ACE 90 concept regarding subsea oil storage of a high pour point crude.

(4) Further work is recommended to confirm yearly production profiles and reservoir (both Yolla and White Ibis) behaviour especially in regard to assumed condensate yields.

(5) Further engineering effort to optimise onshore gas processes is also recommended on selection of a favourable development concept.

(6) Marginal oil case export facility cost reductions should be possible through downsizing of the FSU loading lines. Whilst the impact of this on overall project economics is likely to be negligible at this stage, it should be noted for further reference.

6 REFERENCES

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8. Fax, To: Production Testers Australia (N. Jackson), From Woodhill Thornton (N. Patton), "Yolla Development – Offshore Budget Costs", 18 November 1998.

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7 APPENDICES

1. **Bass Basin Data Pack**
2. **Brainstorming Technical Note**
3. **Reservoir Compositions**
4. **Assumed Victorian Gas Specification**
5. **Ove Arup ACE 90 information**
6. **Process Schematics**
7. **Equipment Lists**
8. **Sales Gas, LPG and Condensate Quantity and Quality Data**
9. **Base Case - Cost Estimate Summaries**
10. **Alternative Case - Cost Estimate Summaries**
11. **Sensitivity Case - Cost Estimate Summaries**
12. **Cost Estimation Building Blocks**
13. **Calculation List**

APPENDIX 1

Bass Basin Data Pack

Premier Oil Australia Pty Limited
(ACN 075 609 728)
3rd Floor, 31 Ventnor Avenue (P.O. Box 1649)
West Perth WA 6872

Telephone 61 8 9480 4100
Facsimile 61 8 9324 1212

PremierOil
Australasia

FACSIMILE

REF: G3/KS0908/G3.15/MP/sc
CIRC:

DATE: 6 October 1998

TO: Woodhill Thornton **Attn:** Nick Patton 9486 7244

FROM: Mark Pogson NO. OF PAGES: 2 (including this page)

SUBJECT: **BASS BASIN DATA PACK**

Nick

Before work on the Bass Development starts we need to have an agreed set of data and assumptions to work from. Premier have provided you with copies of the 1995 Yolla development engineering studies sponsored by Boral and Sagasco, these should provide a useful starting point, however, we should be clear on a range of critical parameters outlined below.

1) Field locations and production landing points.

   A number of maps and schematic diagrams have been provided showing the relative position of the various discoveries and the proposed landing points. For Tasmania, *Burnie* should be used as the base case landing point, for Victoria, *Black Rock*.

2) Fluid compositions

   Find attached both White Ibis and Yolla raw gas compositions. It is probably reasonable to assume other gas discoveries have a similar composition to White Ibis.

3) Production profiles and field life

   Gas Capacity – ~80 MMscfd / 55 MMscfd / 110 MMscfd

   Tasmania Most Likely 30 PJ/yr Minimum 20 PJ/yr Maximum 40 PJ/yr
   Victoria Most Likely 40 PJ/yr ~ MMscfd
   Victoria should be considered for a Swing factor of 150%

   Field life for gas to Tasmania is minimum 15 years, for Victoria, 10 years.

   Oil Capacity – currently, there is a significant chance that oil and gas (from a separate reservoir) will be produced through the Yolla facility. These liquids will be in addition to any condensate from Yolla or White Ibis gas. The production and reserves potential of "Yolla oil" is being studied in parallel with the development scenario work, therefore as a first pass, an initial peak liquids rate of 20,000 barrels per day should be used. Additionally, gas and water injection should be accounted for:

- Gas injection volumes 20 mmscf/d (probable).
- Water injection volumes 25,000 b/d (contingent).

4) Well numbers are the subject of current reservoir engineering studies. For a first pass estimate, the following should apply:

Yolla Gas reservoir	20 PJ/yr	Three wells
	30 PJ/yr	Four wells × 15 = 450 P50 Case
	40 PJ/yr	Five wells
White Ibis		Two wells
"Another" gas reservoir		Two wells
Yolla Oil reservoir		Five oil producers One gas injectors Three water injectors

5) Water depth

The water depth in the Bass area varies from 62 metres at White Ibis to approximately 80 metres at Yolla. Currently, any processing facility is likely to be positioned over Yolla.

6) Weather data

A summary of weather related data is provided. The data was commissioned in response to a Drillship mooring analysis, but it may prove useful when estimating FPSO performance.

7) Wellhead Pressure, Delivery pressures and product specifications

245 Bara

Flowing wellhead pressures for Yolla Wells will be approximately 3550 psia at initial conditions and declining to approximately 700 psia at abandonment.

~48 Bara 162 Bara

For White Ibis and "Another" we should assume Flowing wellhead pressures of 2350 psia initial and 600 psia at abandonment.

41 Bara

Tasmania: It can be assumed that we run the process facility plant and can allow gas delivery pressure to drop to say 100 psia. Gas can then be compressed to the required pressure for power generation, feed stock or domestic gas usage. The gas specification can be raw, raw minus condensate or processed.

~70 Bar

Victoria: The Victorian transmission system requires gas at approximately 1000 psia on the eastern side of Melbourne and approximately 500 psia on the western side (Black Rock – base case). The gas must be processed with CO_2 quantities of < 2.0 %.

35 Bar

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I hope this data pack can get things moving, clearly, you will require further information so feel free to contact me asap.

Yours sincerely

MARK POGSON
Bass Basin Team Leader

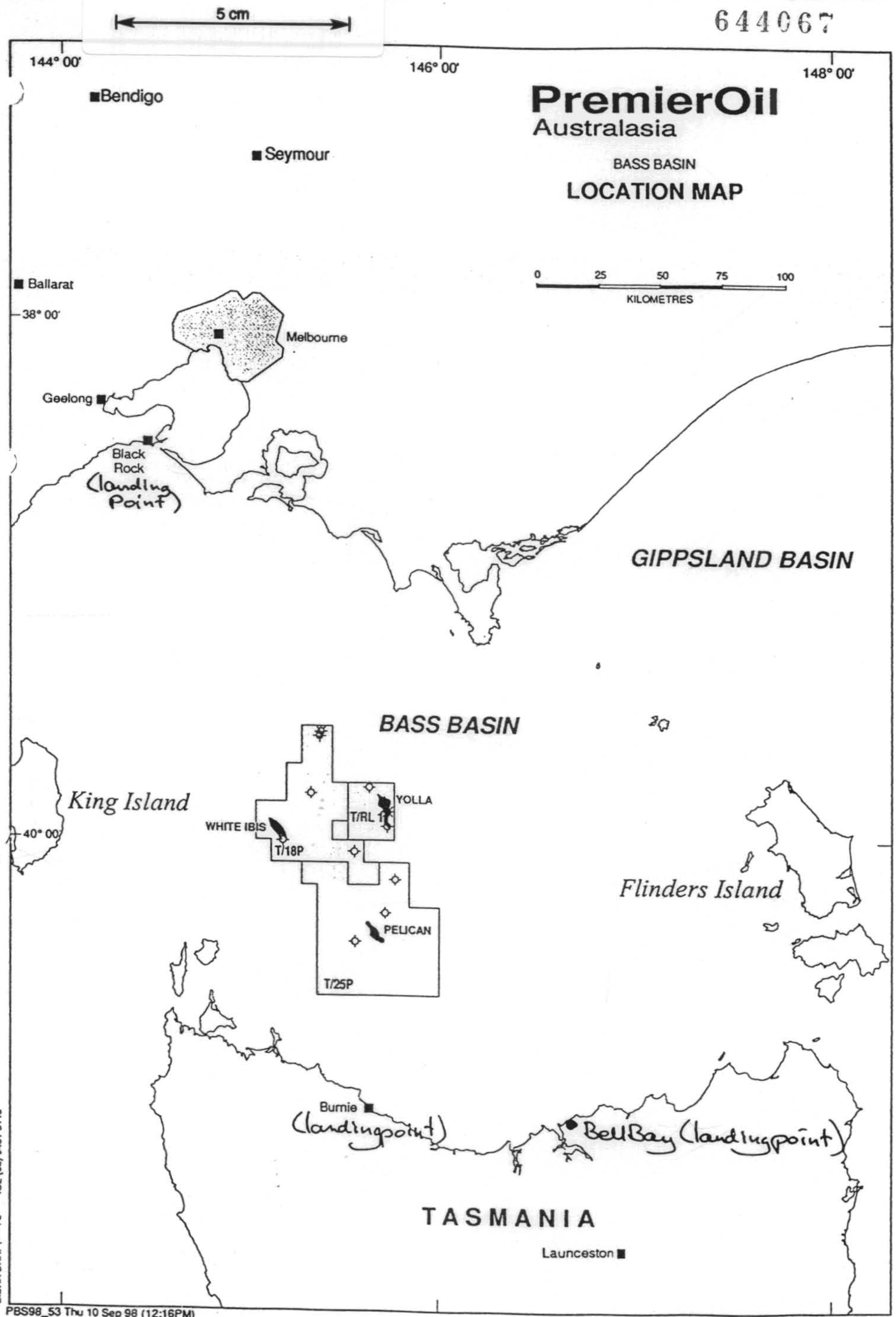
5 cm
144° 00'
146° 00'
148° 00'
PremierOil
Australasia
BASS BASIN
LOCATION MAP
0 25 50 75 100
KILOMETRES
Bendigo
Seymour
Ballarat
38° 00'
Melbourne
Geelong
Black Rock
(landing Point)
GIPPSLAND BASIN
BASS BASIN
King Island
40° 00'
WHITE IBIS
T/18P
T/RL 1
YOLLA
PELICAN
T/25P
Flinders Island
Burnie
(landingpoint)
BellBay (landingpoint)
TASMANIA
Launceston
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FIGURE 1

The Bass Project - Development Planning/Budget

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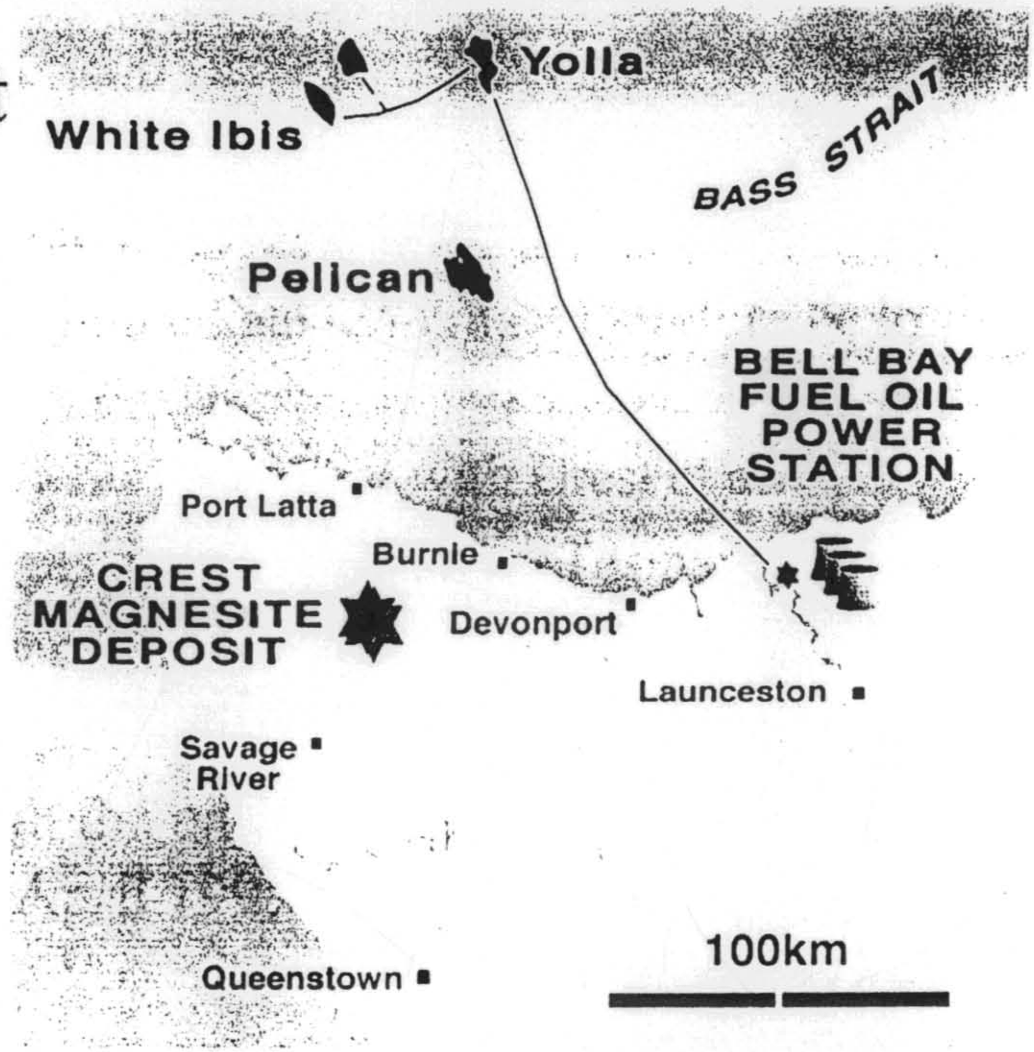
Tasmanian Market Development Concept



- *Yolla plus White Ibis plus exploration success*

5 cm

PremierOil
Australasia

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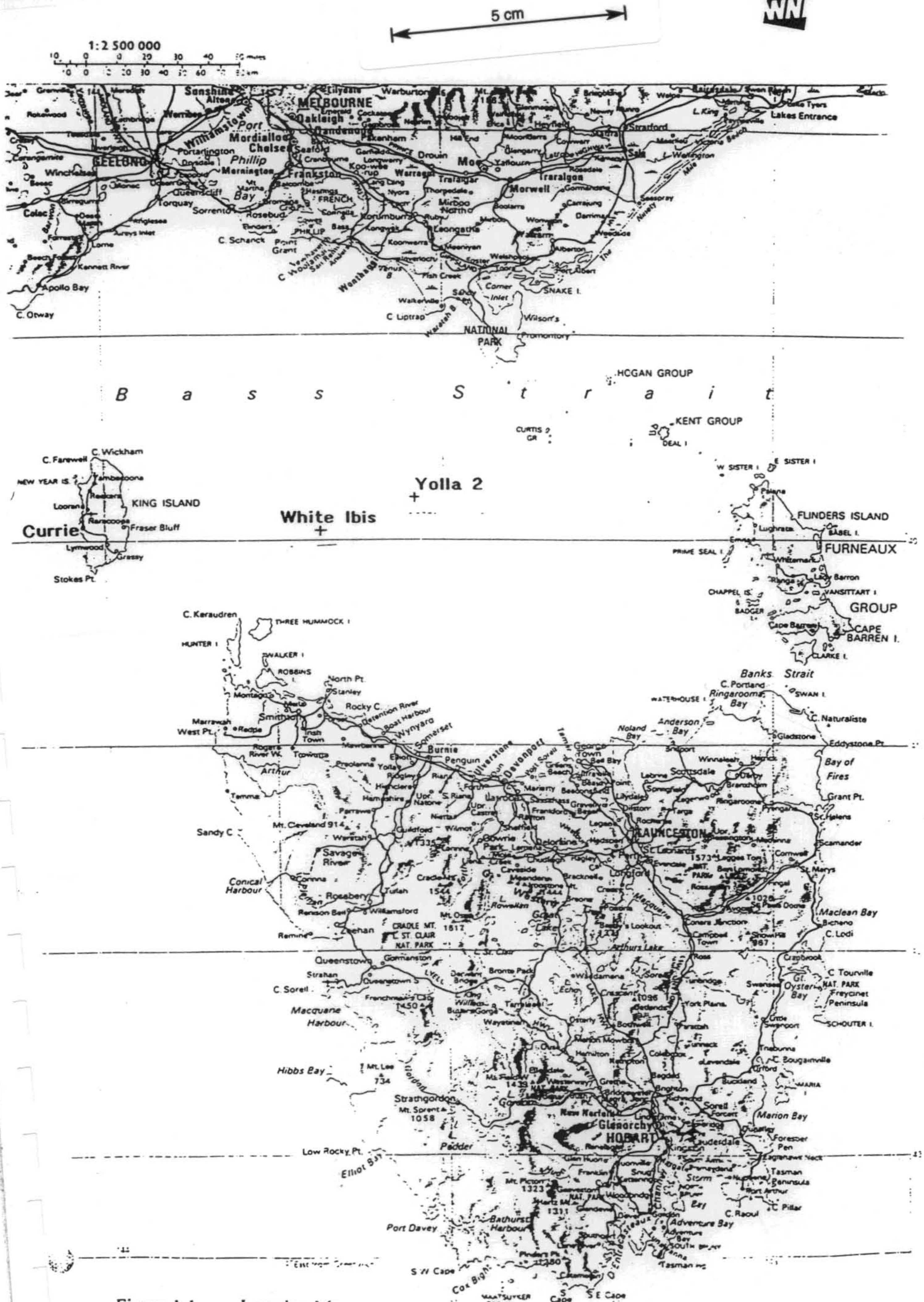

Figure 1.1 Location Map

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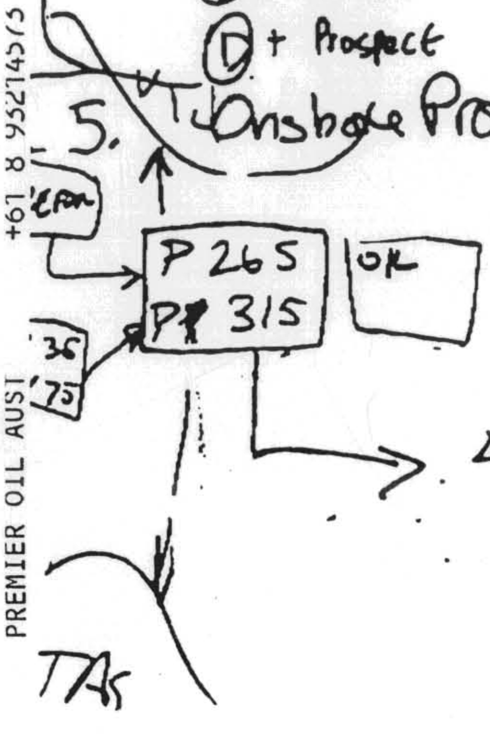
VICTORIA

	SS tie back to Onshore Plant	Unmanned Platform	CPP	FPSO leased/purchased	FPSO + SS	FPSO + UMP	Kav-Opt?	Well Numbers gas	Well Numbers oil
1. Yolla Gas	✓	✓	✓?	✗	✗	✗	✗	4+1	0
2. Yolla Gas + Yolla Oil	✗	?	✓	✓	✓	✓	✓	(4+1)	+ (5+1)
3. Yolla Gas + White Ibis Gas	✓	✓+ss or UMP	✓+ss or UMP	✗	✗	✗	✗	(4+1)+2	0
4. Yolla Gas + Yolla Oil + White Ibis Gas	✗	?	✓	✓	✓	✓	✓	(4+1)+2	+ (5+1)

Ⓐ + Prospect
Ⓑ + Prospect
Ⓒ + Prospect
Ⓓ + Prospect

} 2-4 for Prospect Could increase DCQ.

5. Onshore Processing { Multiphase / Single phase } + Pipeline ✗ ✓ ✓ ✓ ?



40 PJ/YR - 7.5 YRS w/ 300 BCF 100 MMCFD

1. CO_2/H_2O/P/L.
2. Compression
3. Multi vs Single Phase
4. Well numbers/redundancy
5. Minimum Prospect Size
6. Onshore
7. Swing

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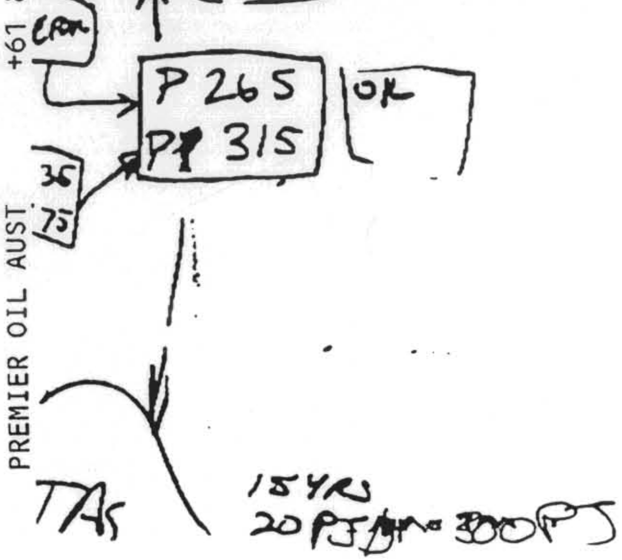
TASMANIA

	SS tie back to Onshore Plant	Unmanned Platform	CPF	FSO leased/purchased	TPSO + SS	FPSO + Unm. P/F	Kav. Opt'n	Well Numbers gas	Well Numbers oil
1. Yolla Gas	✓	✓	✓?	✗	✗	✗	✗	2+1	0
2. Yolla Gas + Yolla Oil	✗	?	✓	✓	✓	✓	✓	(2+1)	+(5+1)
3. Yolla Gas + White Ibis Gas	✓	✓ + ss comp	✓ + ss comp	✗	✗	✗	✗	(2+1)+2	0
4. Yolla Gas + Yolla Oil + White Ibis Gas	✗	?	✓	✓	✓	✓	✓	(2+1)+2	+(5+1)
(A) + Prospect								+2 for Prospect	
(B) + Prospect									
(C) + Prospect									
(D) + Prospect									
5. Onshore Processing	Multiphase / Single phase	+ Pipeline ✗	✓	✓	✓	?			



1. CO_2 / H_2O / P/L.
2. Compression
3. Multi vs Single Phase
4. Well numbers/redundancy
5. Minimum Prospect Size
6. Onshore

PETROLAB

TRANSFER DETAILS

Chamber MPSR-BA # 0160, from 2802 m opened at 2000 psig, was compressed to 6000 psig into single phase with 210 ccs of water behind piston and transferred into Petrolab cylinder # 453

Chamber MPSR-BA # 0185, from 2810 m opened at 0 psig and was found to be empty

Chamber MPSR-BA # 0156, from 2815 m opened at 1700 psig, was compressed to 6000 psig into single phase with 100 ccs of water behind piston and transferred into Petrolab cylinder # 395

Chamber MPSR-BA # 0122, from 2860.4 m opened at 1800 psig, contained water and was transferred into bottle

SUMMARY OF RESULTS

RESERVOIR FLUID FROM 2802 m IN CYLINDER # L-453, Ex MPSR-BA # 0160

SATURATED VAPOUR:

Reservoir Temperature (°F)	:	253
Dew Point Pressure (psig)	:	4788
Gas Formation Volume Factor (Bg)	:	0.00402
Gas Expansion Factor (E)	:	248.76
Gas Deviation Factor (Z)	:	0.958
Specific Volume (CFT/LB)	:	0.05717
Density (gm/cc)	:	0.2802
Viscosity (centipoise)	:	0.0341
Molecular Weight	:	26.70
Gas Gravity (Air = 1.000)	:	0.919
Gross Heating Value (BTU/ft3)	:	1086

Total Plant Products in Dew Point Fluid (GPMM):

RESERVOIR FLUID FROM 2802 m IN CYLINDER # L-453, Ex MPSR-BA # 0160

Dew Point	:	4788 psig @ 253 ° C
Ethane	:	4.298
Propane	:	2.599
Butanes	:	1.857
Pentanes Plus	:	1.427

RESERVOIR FLUID FROM 2815 m IN CYLINDER # L-395, Ex MPSR-BA # 0156

Dew Point		3660 psig @ 253 ° C
Ethane	:	4.294
Propane	:	2.720
Butanes	:	2.185
Pentanes Plus	:	1.729

PETROLAB

Company : Premier Oil Australia Pty. Ltd.
Well : Yolla # 2

COMPOSITIONAL ANALYSIS OF BOTTOM HOLE SAMPLE
Cylinder number L-453, Ex MPSR-BA # 0160, Depth 2802.0 m

Component		Stock Tank Liquid Mol %	Stock Tank Gas Mol %	Reservoir Fluid Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.30	19.66	19.46
Nitrogen	N2	0.00	0.18	0.18
Methane	C1	0.40	67.66	66.96
Ethane	C2	0.23	6.41	6.35
Propane	C3	0.36	2.71	2.69
Iso-Butane	iC4	0.18	0.53	0.53
N-Butane	nC4	0.40	0.81	0.81
Iso-Pentane	iC5	0.35	0.27	0.27
N-Pentane	nC5	0.47	0.28	0.28
Hexanes	C6	2.31	0.41	0.43
Heptanes	C7	9.07	0.56	0.65
Octanes	C8	10.34	0.29	0.39
Nonanes	C9	16.53	0.19	0.36
Decanes	C10	10.91	0.04	0.15
Undecanes	C11	7.06	0.00	0.07
Dodecanes Plus	C12+	41.09	0.00	0.42
TOTAL		100.00	100.00	100.00
Ratios				
Molar Ratio	:	0.0103	0.9897	1.0000
Mass Ratio	:	0.0630	0.9370	1.0000
Liquid Ratio (bbl/bbl)	:	1.0000 @ SC	–	–
Gas Liquid Ratio	:	1.0000 bbl @ SC	62830 SCF	–
Stream Properties				
Molecular Weight	:	163.0	25.33	26.7
Density obs. (gm/cc)	:	0.8044 @ 60 °F	–	–
Gravity (AIR = 1.000)	:	44.2 °API @ 60 °F	0.878	0.919
GHV (BTU/scf)	:	–	1018	1086
Hexanes Plus Properties				
Mol %	:	97.31	1.49	2.47
Molecular Weight	:	166.1	99.0	126.79
Density (gm/cc @ 60 °F)	:	0.8073	0.6878	0.75
Gravity (°API @ 60 °F)	:	43.6	74.0	57.79
Heptanes Plus Properties				
Mol %	:	95.00	1.08	2.04
Molecular Weight	:	168.1	104.8	135.09
Density (gm/cc @ 60 °F)	:	0.8091	0.6953	0.76
Gravity (°API @ 60 °F)	:	43.2	71.6	54.79
Decanes Plus Properties				0.00
Mol %	:	59.06	0.04	0.64
Molecular Weight	:	203.1	84.0	190.69
Density (gm/cc @ 60 °F)	:	0.8311	0.6661	0.8311
Gravity (°API @ 60 °F)	:	38.6	80.7	38.6
Undecanes Plus Properties				
Mol %	:	48.15	0.00	0.49
Molecular Weight	:	218.7	–	218.7
Density (gm/cc @ 60 °F)	:	0.8390	–	0.8390
Gravity (°API @ 60 °F)	:	37.0	–	37.0
Dodecanes Plus Properties				
Mol %	:	41.09	0.00	0.42
Molecular Weight	:	231.0	–	231.0
Density (gm/cc @ 60 °F)	:	0.8449	–	0.8449
Gravity (°API @ 60 °F)	:	35.8	–	35.8

* (P)ressure : 4788 psig * (T)emperature : 253 °F

COMPOSITIONAL ANALYSIS OF BOTTOM HOLE SAMPLE
L-013 Depth 2015.2 m From MRSC-BB-139

omponent		Stock Tank Liquid Mol %	Stock Tank Gas Mol %	Reservoir Fluid Mol %
ydrogen Sulph	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.13	8.16	8.00
itrogen	N2	0.00	1.97	1.93
ethane	C1	0.44	72.33	70.92
thane	C2	0.23	5.96	5.85
Propane	C3	0.51	3.61	3.55
so-Butane	iC4	0.59	1.63	1.61
-Butane	nC4	0.73	1.38	1.37
Iso-Pentane	iC5	1.40	0.97	0.98
N-Pentane	nC5	1.29	0.69	0.70
exanes	C6	5.78	1.32	1.41
eptanes	C7	20.63	1.29	1.67
Octanes	C8	17.63	0.43	0.77
onanes	C9	15.81	0.18	0.49
nes	C10	12.29	0.07	0.31
decanes	C11	7.42	0.01	0.16
Dodecanes Plus	C12+	15.13	0.00	0.28
TOTAL		100.00	100.00	100.00

Ratios

Molar Ratio :	0.0196	0.9804	1.0000
Mass Ratio :	0.0881	0.9119	1.0000
Liquid Ratio (bbl/:	1.0000 @ SC	--	--
Gas Liquid Ratio:	1.0000 bbl @ SC	41551 SCF	--

Stream Properties

Molecular Weigh:	122.0	25.21	27.11
Density obs. (gm	0.7610 @ 60 °F	--	--
Gravity (AIR = 1.:	54.3 °API @ 60 °F	0.874	--
GHV (BTU/scf) :	--	1272	--

Hexanes Plus Properties

Mol % :	94.69	3.30	5.09
Molecular Weigh:	125.5	95.0	106.1
Density (gm/cc @	0.7672	0.6823	0.7164
Gravity (°API @ :	52.8	75.7	65.8

ptanes Plus Properties

% :	88.91	1.98	3.68
olecular Weigh:	128.2	102.3	114.5
Density (gm/cc @	0.7711	0.6921	0.7318
Gravity (°API @ :	51.8	72.8	61.7

Decanes Plus Properties

Mol % :	34.83	0.08	0.75
Molecular Weigh:	161.4	84.0	144.7
Density (gm/cc @	0.8023	0.6661	0.8023
Gravity (°API @ :	44.7	80.7	44.7

Undecanes Plus Properties

Mol % :	22.55	0.01	0.44
Molecular Weigh:	176.3	147.0	172.5
Density (gm/cc @	0.8128	0.7400	0.8128
Gravity (°API @ :	42.4	59.5	42.4

Dodecanes Plus Properties

Mol % :	15.13	0.00	0.28
Molecular Weigh:	190.7	--	190.7
Density (gm/cc @	0.8222	--	0.8222
Gravity (°API @ :	40.4	--	40.4

* (P)ressure : 3827 psig * (T)emperature : 226 °F

1 INTRODUCTION

1.1 Background

Drilling operations in the central Bass Strait region have in the past experienced difficulties due to unexpected oceanographic conditions. Consequently, WNI Science & Engineering (WNI) were contracted by Premier Oil Australia Pty Ltd (Premier Oil) to provide information on extreme and ambient wind, wave and current conditions over a typical five year period at the following locations (Figure 1.1):

Yolla-2:	Latitude	39° 51' S
	Longitude	145° 49' E
White Ibis:	Latitude	39° 58' S
	Longitude	145° 16' E

1.2 Site Characteristics

The two study sites are located in the central Bass Strait area (Figure 1.1). The approximate water depth at both sites is 70 m (± 4 m). Waves and currents in this region are influenced by the surrounding landmasses, islands and reefs and by the variable bathymetry in the area. The study sites are surrounded by the mainland to the north, King Island to the west, Tasmania to the south and Flinders and Cape Barren Islands to the east. A review of the regional meteorology may be found in Section 2.

1.3 Study Approach

1.3.1 Winds

Wind data were obtained from the National Meteorological Center (NMC) (Appendix A). A summary of monthly and annual wind speed and direction based on five years of these data has been provided (Appendix E). The required information is presented in wind roses and wind speed vs wind direction joint frequency tables.

1.3.2 Waves

A comprehensive wave data set was generated by running the spectral ocean wave model WISWAVE over a five year period. The wave data were then analysed to provide monthly and annual summaries of significant wave height (H_s), mean wave period (T_m) and wave direction (Theta-M). Wave roses, exceedence persistence matrices, as well as the following joint frequency tables are presented:

2 REGIONAL METEOROLOGY

2.1 Ambient Conditions

The meteorology of the Bass Strait region is determined chiefly by the location of the sub-tropical high pressure ridge and the migratory low pressure systems which exist on the polar side of the ridge. These low pressure systems are also known as extratropical cyclones and they travel from west to east around Antarctica.

The high pressure ridge is a product of the general circulation of the earth's atmosphere. It consists of a series of cells of high pressure which encircle both hemispheres of the globe at latitudes which, in the mean, vary between 25° and 40° north and south latitude. Seasonal variations occur, the high pressure ridge being displaced towards more poleward latitudes in the local summer and towards more equatorial latitudes in the local winter. Orographic effects, particularly those relating to the distribution of land and ocean and the elevation of the land surface, are also important at or near coastal locations.

In the discussion that follows, the portion of the hemisphere being referred is the Australian region and the seasons are the local (Southern Hemisphere) seasons.

During summer (December-February) the high pressure ridge is usually located between 30°S and 35°S. However, the Great Australian Bight and the Tasman Sea are preferred locations for the migratory high pressure cells which exist within the high pressure ridge belt. This results in a more southward displacement of the high pressure ridge in Australian longitudes than occurs farther west in the Indian Ocean or east in the South Pacific Ocean. The passage of high pressure cells through the Great Australian Bight frequently takes several days. However. as the cell reaches the eastern part of the Great Australian Bight (near approximately 140°E longitude) it usually moves very quickly to the western part of the Tasman Sea, seeming almost to jump the Bass Strait area. Winds associated with these systems are usually between 10 to 20 knots. The winds at the location of interest are often consistently from the south or southeast as the high approaches from the west, and they back through east to northeast as the high passes into the Tasman Sea.

Separations between successive high pressure cells are called troughs. These are highly significant if a cold front, associated with a southern low pressure system (in which winds blow in a clockwise direction) and its upper low pressure trough, extends sufficiently far northwards into the high pressure ridge, so that the general system moves through the Great Australian Bight and over Tasmania and southeastern Australia. As a low pressure system approaches the region under these circumstances, winds at the Yolla-2 and White Ibis locations are usually northerly or northwesterly. As the system passes just to the south of the area, winds back through west to southwest. The wind speed is variable, depending on the proximity and intensity of the centre of the low pressure cell, but usually ranges between 10 and 20 knots. Similar events are common throughout the year.

In winter (June to September) the high pressure ridge is generally more northward than during the summer. Its mean location is east-west across the Australian continent between latitudes 25°S and 30°S. Consequently, the migrating low pressure systems which exist to the south of the high pressure belt also move further northward thereby bringing a westerly wind regime to the eastern part of the Great Australian Bight and western Bass Strait waters. This westerly regime is the northernmost zone of the "Roaring Forties". The low pressure systems may pass from west to east well south of the continent or they may originate more northward in the Indian Ocean between 30° and 35° and then move eastward or southeastward towards the location of interest. The strength of the westerlies is largely dependent on the intensity and location of the low pressure system but the mean wind is mostly between 10 and 20 knots. In circumstances discussed below, in the section on strong wind conditions, the winds are considerably higher.

While this westerly regime is a common winter feature, the influence of high pressure cells, which may be slow moving over the Australian Alps and other high terrain of southeastern Australia, cannot be overlooked. In these circumstances, the winds at the Yolla-2 and White Ibis locations would be northerly and light (less than 10 knots). A southern low pressure system eventually displaces the high pressure system and the westerly regime resumes.

The remaining months, March, April/May and October/November are transition periods during which either the summer or winter regime may predominate. More likely occurrences are conditions which vary between the two.

2.2 Strong Wind and Storm Conditions

There are several storm types which affect the area. These are:

- extratropical cyclones;
- thunderstorms; and
- pressure gradient intensification storms.

Of most importance are the winter extratropical cyclones (low pressure systems in which the winds travel in a clockwise direction). The storms result in the highest sustained winds and generate the largest and most frequently occurring waves affecting the offshore region. Of lesser importance are summer and extratropical cyclones, lines of thunderstorms in all seasons, and strong southeast to easterly winds circulating about intense high pressure systems located in the Great Australian Bight and the Tasman Sea, also in all seasons. Tropical cyclones do not affect the area.

Extratropical cyclones: Extratropical cyclones are the low pressure cold-cored cells existing outside the tropics. The winds about them rotate clockwise (Southern Hemisphere) and the systems can be of the order of 500 to 1000 miles diameter. They are the cause of the common summer and winter gales that occur in the

Southern Ocean. In the Australian area they are frequently referred to as southern depressions.

During winter, extratropical cyclones occur on average once every three to five days and pass from west to east to the south of the Australian continent. In Bass Strait region, they frequently cause northwesterly winds with a mean speed of 25 to 35 knots with individual systems occasionally causing winds to 45 knots, (perhaps once or twice per winter season). As the low pressure system and its associated cold front (relatively sharp boundary between warm northerly air and cooler southerly air) pass to the east of the location, the winds back from the northwest through west to the southwest. Depending on the relationship of the low pressure system to the high pressure ridge, the post-frontal winds may be weaker than the pre-frontal northwesterlies. More frequently, however, the southwesterlies are the stronger. On infrequent occasions, depressions move towards the western part of Tasmania or Bass Strait. This usually occurs when strong ridging (intensification of the high pressure ridge), develops to the south of the low. In these circumstances, the winds may continue to back to the south while maintaining speeds of about 20 knots.

Extratropical cyclones and their cold fronts also affect the area during summer in a manner similar to that of the winter systems. However, their frequency is less, usually about three to five occurrences per month.

Thunderstorms: Lines of thunderstorms can affect the area during any season. In winter they may be associated with a pre-frontal trough, a cold front itself or, most likely, they form in the cold air to the west and southwest of the cold front. During summer, thunderstorms may develop in the deep southerly incursions of warm tropical air that are known as "tropical dips". Whether or not thunderstorms develop in these situations is dependent on the stability of the atmosphere.

In the down-draughts associated with thunderstorms gusts may reach 80 knots or more from a direction dependent on the relative location of the thunderstorm cell to the site.

Pressure Gradient Intensification Storms: Pressure gradients between an intense high pressure ridge extending from the Great Australian Bight to the Tasman Sea and a low pressure trough over inland New South Wales and northern Victoria may cause east to southeast winds at the site to increase to 20 to 30 knots for periods of 24 to 48 hours. Such conditions would probably occur on average about two to three times per summer season, but similar, shorter events with lighter winds, 10 to 20 knots are more frequent.

7 EXTREME ANALYSIS

The results of the wind, wave and current modelling were subjected to extreme analysis using the Conditional Weibull technique. The tabular results and plots can be found in Appendix M and are summarised in Tables 7.1 and 7.2. As only 5 years of data were analysed, return period values beyond 10 years should be used with caution.

7.1 Extreme Winds

A total of 37 peak wind events were selected from the 5 years of NMC wind data. The extreme analysis performed on these peak values yields a 10-year return period wind speed of 22.8 m/s or 44.5 knots (Table 7.1 and Appendix M). It should be remembered that squall winds are not accounted for in this analysis (Section 1.5).

7.2 Extreme Waves

A total of 31 extreme wave events were selected from the 5 years of modelled wave data. The 1-year and 10-year return period significant wave heights are 6.0 m and 6.8 m respectively (Table 7.1 and Appendix M).

7.3 Storm Currents

39 peak wind events were selected from the 8.67 years of data. These were then modelled to generate currents at four levels in the water column (5, 25, 45 and 65 metres below the surface).

7.3.1 Design Currents and Vertical Profile

Estimates of the wind-driven storm currents at four depths in the water column (near-surface to near-bottom) were derived using the following general formula, recommended for use when constant steady winds are expected to be the dominant current generating mechanism (as is the case in Bass Strait).

8 VALIDATION OF RESULTS

The modelled results show lower waves than experienced oceanographers and meteorologists expected in this area of the Bass Strait. It is also known that Amoco experienced significant downtime due to wave action during operations in the mid 1980's. A few individual events were examined to ensure the results from this study were consistent with available reports of waves in the area. Available satellite data and ship observations were also examined for validation purposes.

8.1 Previous Reports

Winds and waves in Bass Strait (Gibbs 1972)

This study reported hindcast waves west off King Island. A few events of about 10-11 m were hindcast mainly in the 1951 to 1954 period. Outside this period (1954-1971) wave maximum significant waves to 8.23 m were hindcast.

Preliminary climatic and oceanographic report for Central Bass Strait (McCormack 1985)

This report was produced for Amoco and the main source of this data was ship observations. These observations showed occasional waves of 7.0-10.0 m, but the data included a large area of the Bass Strait including the Eastern Bass Strait where large southsoutheasterly waves are known to occur. This report indicates waves exceed 2.0 m for about 36.0% of the time while the hindcast in the present report indicates 33.4% of the time.

8.2 Individual Events

Westerly event of 21 June 1993

In the present study, the maximum modelled waves in open ocean off western Tasmania (1992 -1996) were 12.2 m from 275° and were produced during the event of 21 June 1993. This is consistent with the 10.85 m waves modelled in deep waters west of King island by Gibbs (1972) and the 7-10 m waves in the Amoco report (McCormack 1985). During this westerly event the waves were reduced to 4.1 m at the White Ibis location, probably due to the influence of King Island. However, no measurements are available near the location and while the fine-resolution modelling is expected to produce reliable results, such a large reduction may be excessive.

Southwesterly event of 19 September 1994

The most severe event at White Ibis within the 5 years of hindcast was 6.8 m at 2000 GMT, 19 September 1994. The mean wave direction was 254°. The waves

	Wind Speed (m/s)				Direction*	
Month	Mean	Min	Max	S Dev	Mode 1	Mode 2
Jan	6.5	0.5	19.0	3.4	W	SW
Feb	6.2	0.5	17.0	2.9	SW	NE
Mar	6.3	0.5	21.6	3.0	W	WSW
Apr	6.9	0.5	17.0	3.4	W	SW
May	7.5	0.5	20.6	3.8	W	NW
Jun	7.9	0.5	18.5	3.5	W	NW
Jul	8.2	0.5	20.1	3.3	WNW	W
Aug	8.9	0.5	21.6	3.6	NW	W
Sep	8.2	0.5	20.6	3.8	W	SW
Oct	7.1	0.5	17.0	3.4	W	WSW
Nov	7.7	0.5	18.5	3.5	W	WSW
Dec	6.6	0.5	18.5	3.3	W	SW
Annual	7.3	0.5	21.6	3.5	W	WSW

*Note: Mode 1 = most common wind direction; Mode 2 = second most common wind direction.

Table 4.2 Summary of winds over the period January 1992 - December 1996.

644082

	Significant wave height (m)				Mean wave period (s)			
Month	Mean	Min	Max	S Dev	Mean	Min	Max	S Dev
Jan	1.6	0.5	6.5	0.8	6.5	3.8	9.4	1.0
Feb	1.4	0.5	4.8	0.6	6.2	4.3	8.5	0.9
Mar	1.5	0.5	5.4	0.7	6.4	4.0	9.4	0.9
Apr	1.7	0.6	4.4	0.8	6.4	4.2	8.8	0.9
May	1.9	0.5	6.2	1.0	6.7	4.0	11.0	1.0
Jun	1.9	0.5	5.2	0.9	6.5	4.2	13.3	1.1
Jul	2.0	0.7	6.0	0.9	6.3	4.3	9.1	0.8
Aug	2.3	0.6	6.2	1.0	6.6	4.0	8.8	0.8
Sep	2.0	0.6	6.8	1.0	6.6	4.3	9.8	0.9
Oct	1.8	0.6	4.6	0.8	6.6	4.4	9.0	0.9
Nov	1.8	0.5	5.8	1.0	6.3	4.1	8.9	0.9
Dec	1.6	0.4	4.8	0.7	6.4	3.8	9.5	1.0
Annual	1.8	0.4	6.8	0.9	6.4	3.8	13.3	0.9

Table 5.1 Summary of waves over the period January 1992 - December 1996.

	Mean Current (m/s)	Peak Currents (m/s)
Summer	0.31	1.10
Autumn	0.31	1.05
Winter	0.31	1.15
Spring	0.31	1.10
Annual	0.31	1.10

Table 6.1 Annual and seasonal estimated mean and peak surface currents.

	Return Period (Years)			
	1	2	5	10
Wind Speed - Theta M (m/s)	19.9	20.8	22.0	22.8
Significant Wave Height - H_s (m)	6.0	6.3	6.6	6.8

Table 7.1 Summary of extreme wind and wave conditions.

	Return Period (years)						
	1	2	5	10	25	50	100
Wind-Driven Storm Current (m/s)							
5 m below	0.68	0.81	1.00	1.15	1.36	1.52	1.70
25 m below	0.30	0.35	0.44	0.52	0.63	0.73	0.84
45 m below	0.14	0.16	0.20	0.24	0.28	0.33	0.37
65 m below	0.06	0.08	0.09	0.11	0.13	0.14	0.16
Total Steady Storm Current (m/s)							
5 m below	0.98	1.11	1.30	1.45	1.66	1.82	2.00
25 m below	0.60	0.65	0.74	0.82	0.93	1.03	1.14
45 m below	0.44	0.46	0.50	0.54	0.58	0.63	0.67
65 m below	0.36	0.38	0.39	0.41	0.43	0.44	0.46

Table 7.2 Summary of extreme currents.

GEOSAT Waves in Bass Strait

Percentage Occurrence of Significant Total Wave Height (m) vs Wind Speed (m/s)

Wind Speed (m/s)

Significant Total Wave Height (m)	< 0.0	0.0 to 2.5	2.5 to 5.0	5.0 to 7.5	7.5 to 10.0	10.0 to 12.5	12.5 to 15.0	15.0 to 17.5	17.5 to 20.0	20.0 to 22.5	22.5 to 25.0	>= 25.0	Total %
< 0.0	.	.	.	.	.	.	.	.	.	.	.	.	0.00
0.0 - 0.5	.	1.19	4.76	3.17	0.40	.	.	.	.	.	.	.	9.52
0.5 - 1.0	.	3.57	4.76	5.16	2.78	.	.	.	.	.	.	.	16.27
1.0 - 1.5	.	0.40	3.57	7.14	5.95	0.40	.	.	.	.	.	.	17.46
1.5 - 2.0	.	0.79	2.38	9.92	11.11	3.17	.	.	.	.	.	.	27.38
2.0 - 2.5	.	.	0.40	2.78	6.75	3.97	1.59	.	.	0.40	.	.	15.87
2.5 - 3.0	.	.	.	.	2.38	2.78	1.59	0.40	.	.	.	.	7.14
3.0 - 3.5	.	.	.	0.40	.	1.19	0.79	.	.	.	.	.	2.38
3.5 - 4.0	.	.	.	.	.	0.40	0.79	.	.	.	.	.	1.19
4.0 - 4.5	.	.	.	.	.	.	.	1.19	.	.	.	.	1.19
4.5 - 5.0	.	.	.	.	.	0.40	0.40	0.40	.	.	.	.	1.19
5.0 - 5.5	.	.	.	.	.	.	.	.	.	.	.	.	0.00
5.5 - 6.0	.	.	.	.	.	.	.	.	.	.	.	.	0.00
>= 6.0	.	.	.	.	.	.	.	0.40	.	.	.	.	0.40
Total %	0.00	5.95	15.87	28.57	29.37	12.30	5.16	2.38	0.00	0.40	0.00	0.00	

. signifies 0.0 %
* signifies < 0.01 %

Data description : GEOSAT wind/waves
Record period : April 85 to Aug 88
Total records read : 252
Recs with missing data : 0

	Min	Max	Mean	S.Dev
Wind Speed (m/s)	0.01	22.33	7.57	3.50
Significant Total Wave Height (m)	0.05	6.15	1.63	0.93

WNI Science & Engineering - 15:53 Jan 5 1998 (WST)
Program: occmat Source: all.bin1 Output: jft.out

Table 8.1 Joint frequency distribution of wind speed vs wave height derived from GEOSAT data.

Wind Speed (m/s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean	6.8	6.2	6.3	6.9	6.9	7.1	7.4	7.2	7.6	6.6	6.8	6.7
Std Dev	4.1	3.7	4.1	4.6	4.5	4.8	4.7	4.4	4.9	4.3	4.5	4.1
2*Std Dev	15.0	13.6	14.5	16.1	15.9	16.7	16.8	16.0	17.4	15.2	15.8	14.9
3*Std Dev	19.1	17.3	18.6	20.7	20.4	21.5	21.5	20.4	22.3	19.5	20.3	19.0

Significant Wave Height (m)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean	1.7	1.8	1.4	1.9	1.8	1.7	1.8	1.8	1.8	1.6	1.8	1.8
Std Dev	1.1	1.2	0.9	1.3	1.2	1.1	1.0	1.1	1.2	1.0	1.1	1.0
2*Std Dev	3.9	4.2	3.2	4.5	4.2	3.9	3.8	4.0	4.2	3.6	4.0	3.8
3*Std Dev	5.0	5.4	4.1	5.8	5.4	5.0	4.8	5.1	5.4	4.6	5.1	4.8

Note: The 2*std deviation and 3*std deviation would give the approximate 95th and 99th percentile value IF the data was normally distributed. This is NOT the case for wind speed and wave height.

Table 8.2 Monthly ship reports of winds and waves for the area 40°S-41°S, 145°E-146°E.

APPENDIX 2

Brainstorming Technical Note

644089

WOODHILL THORNTON

TECHNICAL NOTE

YOLLA BRAINSTORMING 13 OCTOBER 1998

A	27OCT98	Issued for review	NH	DC	
Rev.	Date	Description	Prepared	Checked	Approved

Premier Oil	Document Number
Bass Strait Commercialisation	[9843tn003.doc]
	Revision
	A

PREMIER OIL, YOLLA BRAINSTORMING – 13OCT98

General Principles

Having reviewed the documentation there are several principles that should be stated/restated prior to thinking about options, they are:

- As a **general** rule onshore processing is cheaper than offshore processing.
- Heavy lift vessels are expensive to hire and unlikely to be readily available in Australia.
- FPSOs in the last five to six years have proved expensive with large over-runs in time and money - treat with caution. Additionally, experienced availabilities are unlikely to be adequate for single source gas sales. However, if lease costs for the FPSO can be laid off against tax then they should be considered. (Same could be applied to semi-subs & Jack-Ups).
- Solutions that are based on large sub sea storage tanks are not likely to be economic due to the relatively small amount of oil. With a pour point of 15°C long-term storage of oil waiting for a monthly tanker seems less favourable than a shuttle tanker option. Two-phase flow may be a better option.
- Solutions that have short lead times giving early cash flow will be attractive.
- Own on-platform drilling with so few wells envisaged is unlikely to be cost effective.
- Do not totally negate the B&R work (confirmed by MAI), learn from the work they have done. Relative comments are:-
    - Subsea options may be expensive compared to a wellhead platform. However, stand-alone subsea options could be feasible even with the long distances from shore e.g. with a control buoy & corrosion resistant alloy (CRA) pipelines. (Cost reductions may be achievable through use of CRA clad CS pipelines.)
    - Three-phase pipeline options are high in capex due to the cost of the pipeline and large slug catcher. (CRAs for these long pipelines can be very expensive - however, some protection is offered by the oil coating the steel reducing the corrosion rate).
    - Onshore storage and onshore gas plant costs are relatively constant and small compared to the total. Only obvious variation to this is the difference between on and offshore compression. Onshore compression used in ARCO Pickerill (& West Sole) and was the base case for Conoco CMS. (Onshore compression can however lead to larger pipelines/ slugcatchers.)

- Membranes offshore may be problematical (blinding) and need much space to achieve acceptable CO_2 levels. Unlikely to be not normally manned (NNM) with membranes.
- CO_2 may have to be injected unless the gas is used directly for say power generation. Venting may raise environmental concerns. Re-injection into another part of the reservoir could be problematical as it could be in the dense phase. Offshore CO_2 removal will minimise pipeline to shore sizes.
- Generally any floating option, jack up or extensive processing (all oil & gas options) will have to be fully manned. Fixed structures with less processing can be NNM.
- 20,000 BOPD of oil requiring gas lift and injection water may be difficult to make economic.

The approach could be to prove the economics of a gas case first and then add the oil reservoir with gas lift only to see the impact on the economics. Water injection costs are likely to be significant.

- Foundation costs for piled structures in the Yolla area need checking. Geotechnical data will also be required.

Process Options

Fundamentally, Premier require four separate processing options to be considered:

(1) - 80 MMscfd sales gas to Tasmania
(2) - 110 MMscfd sales gas to Victoria
(3) - 20,000 BOPD plus 80 MMscfd Gas to Tasmania
(4) - 20,000 BOPD plus 110 MMscfd Gas to Victoria

It should be noted that Victorian gas will have to be produced to pipeline specification; Tasmanian gas may only require minimal processing to allow it to be used as Magnesite mine fuel gas.

Block flow diagrams for each of the above basecase options (Cases 1A, 2A, 3A & 4A) are attached along with several potential alternatives (Case 1B, 1C, 2B etc.).

CASE 1A
Manned offshore facility with bulk water separation, gas drying & later compression. Five Yolla gas wells envisaged. Production cooling provided to allow effective gas dehydration. Two phase CS pipeline to shore (Burnie, Tasmania). CO2 remains in sales gas. Minimal gas dew pointing. 30PJ/yr (ca. 80 MMscfd) gas sales to Magnesite mine. Condensate export via existing Tasmanian oil products import route?

CASE 1B
As per Case 1A but with CO2 Removal onshore.

CASE 1C
Subsea alternative of Case 1A. Control Buoy used to provide corrosion inhibitor to subsea wells. Hydrate inhibitor supplied via piggy back line from shore. Two phase CS pipeline to shore lined with CRA for first ca. 10 km until seabed temperatures achieved (significantly lower corrosion rates predicted). Onshore compression installed to maintain dew point plant inlet pressures. Glycol recovery & water treatment required onshore.

CASE 1D
As per Case 1A but with CO2 Removal offshore. Will result in lower pipeline to shore throughput & hence possibly reduce cost.

CASE 2A
Manned offshore facility with bulk water separation, hydrate inhibitor supply/recovery, gas drying & later compression. Five Yolla & 2 subsea satellite White Ibis gas wells envisaged. Production cooling provided to allow effective gas dehydration. Two phase CS pipeline to shore (Black Rock, Vic.). Onshore facilities include CO2 removal, gas treating to Victorian pipeline spec, condensate stabilisation & LPG fractionation. 40PJ/yr (ca. 110 MMscfd) gas sales. Liquids export to Geelong refinery?

CASE 2B
Will be developed to examine offshore CO_2 removal if Case 1D indicates this alternative is beneficial. (Case 1D offshore CO_2 removal may allow a line size reduction from 10/12" to 8/10" leading to pipeline cost savings of ca. 20%.)

CASE 3A
As per Case 1A but with the addition of Yolla oil production (5 wells assumed). Additional offshore facilities include 2 stage oil separation train with interstage heating, associated gas booster & gas recovery compression, oily water treatment. Oil export assumed via FSU with heated tanks for 5 years. Gas facilities required for 15 years. Onshore gas treatment facilities flexibility required to deal with varying proportions of associated gas & Yolla Gas in feed gas pipeline.

CASE 3B
As per Case 3A but with heated (pumparound) subsea oil storage & oil export via shuttle tankers.

CASE 4A
As per Case 2A but with the addition of Yolla oil production (5 wells assumed). Additional offshore facilities include 2 stage oil separation train with interstage heating, associated gas booster & gas recovery compression, oily water treatment. Oil export assumed via FSU with heated tanks for 5 years. Gas facilities required for 15 years. Onshore gas treatment facilities flexibility required to deal with varying proportions of associated gas & Yolla Gas in feed gas pipeline.

CASE 4B
As per Case 4A but with heated (pumparound) subsea oil storage & oil export via shuttle tankers.

Offshore Development Options

(a) Base Case: Steel jacket with integrated deck

Advantages:-
Simple proven concept.

Disadvantages:-
Abandonment cost of fixed structures is high.

(b) As in a) above but with a second-hand SS or Jack-Up
This was generally disregarded in the B&R report due to the high cost of the SS & Jack Ups. This is probably no longer a factor as the extent of exploration drilling is down due to the current oil price. (Look to see if tax breaks can be had against lease costs)

Advantages:-
Lead times should be low assuming we are just placing process equipment on the deck and not having to modify the vessel. Abandonment costs low. No heavy lift vessel required. No offshore HU costs unless to shorten schedule, long lead equipment (compressors) can be added on location.

Disadvantages:-
Could be space limitations especially for future expansion. Would have to be fully manned.

(c) **As a) but with a wellhead platform and a floating concrete barge deck**

Advantages:-
The concrete barge deck is cheap to build, equipment can be laid out simply like an onshore plant. Abandonment costs low. Lead times low as there is more room to install equipment hence construction time reduced. Wells can be drilled and completed on the simple wellhead platform while the deck is being fitted out. The wellhead platform can be of a simple 4 leg design or **mono tower or Sea Harvester**.

Disadvantages:-
Would need to be manned. Needs to be utilised in non-too hostile waters - this would rule out Bass Straits. This was a recommendation for the Exxon West Natuna

c1) **Concrete barge decks have also been designed with steel support legs in each corner which allows the deck to be jacked up out of the water on these legs on location**

Advantages:-
This obviates the need for a well head platform or sub sea completions as drilling can be done directly off the deck. Could be Not Normally Manned. Abandonment costs lower than above.

Disadvantages: -
Drilling can not really start until deck is in location.

(d) **Float over using a steel jacket and concrete barge**

Advantages:-
Concrete barge has advantages of c) above.

Disadvantages:-
Abandonment expensive, steel jacket more expensive than wellhead jacket. Drilling has to wait until installation of facilities. Barge deck is more complicated because of ballasting sections.

(e) **Ove Arup ACE(90) Platform - GBS with steel supports - self-installing with a ship coded design steel deck integral with GBS on float out. Ballasting of GBS and jacking of deck on location**

Advantages:-
No heavy lift vessel - self-installing GBS. Quick to manufacture. Barge deck can be made to ship standards which are cheaper than offshore. Relatively simple abandonment.

Disadvantages:-
Drilling can not start until installation.

(f) Three-phase flow using either a **wellhead platform or subsea completions**. The subsea will need a buoy for power and communication links.

Advantages:-
No offshore processing.

Disadvantages:-
Pipeline could be expensive and requires significant chemical injection.

(g) Wellhead platform with FPSO (if tax regime supports) but with oil storage and shuttle tanker

Advantages:-
Allows shuttling of a dead crude.

Disadvantages:-
FPSO will have excessive oil storage capacity and is likely to be expensive & insufficiently reliable for a standard gas sales contract.

Note: Consider a simple tanker with limited modular processing equipment placed on the deck. Some suppliers have simple mooring systems that could be applicable. Together this may cheapen the cost of an FPSO option.

(h) Production Spar (or other proprietary floating system)

This is like two concrete barge decks one supported above the other by steel tubulars one at each corner. Both decks are buoyant and the total facility is catenary moored. It is possible to have some **limited** storage in the bottom deck which is underwater.

Advantages:-
Very simple and cheap construction. No heavy lift vessel required, in-shore fit out, some oil storage if required. More stable in hostile waters than a flat barge.

Disadvantages:-
Requires subsea completions. Conditions in the Bass Straits may be too severe.

(i) AMEC Strand Jacked Barge Deck

Either a concrete or steel GBS with four steel shafts. The GBS is floated into location flooded and located. The fully equipped barge deck again steel or concrete is floated in between the four shafts and by the means of Strand Jacks elevated out of the water. This was one of the preferred options for Shell South Arne which had similar duties and water depths.

Advantages:-
Very simple construction, schedule short depending more on long lead process equipment. Drilling from structure. Oil storage allowing a dead crude to be shuttled away and a single phase gas line to

shore. Abandonment costs low.

Disadvantages :
Cost?

(j) Subsea Processing

Many organisations have attempted subsea processing and eventually these will prove economic. Currently Hardy Oil & Gas are spending a lot of effort on a concept and they in particular would be worth talking to in Perth.

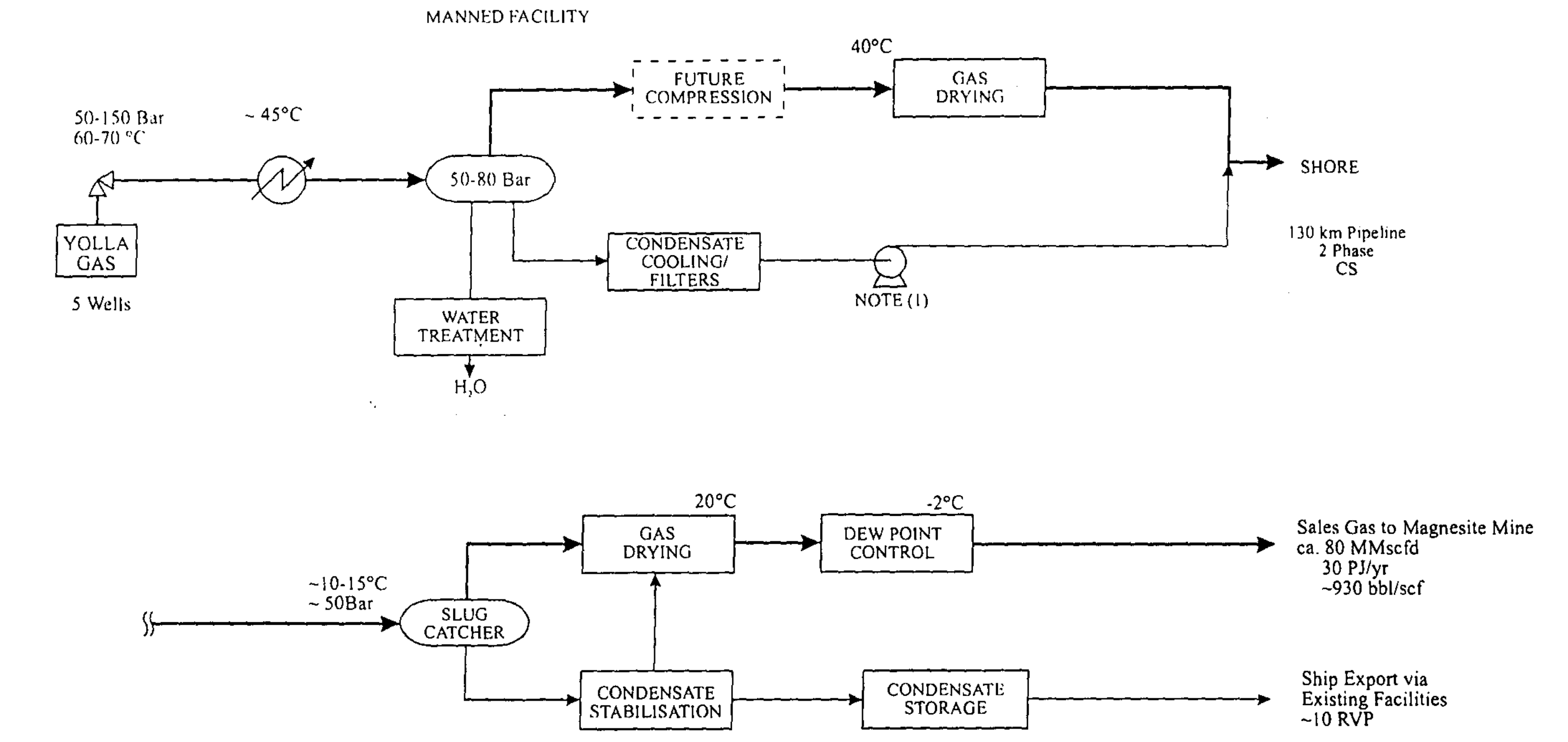
Advantages:-
Eventually should prove very attractive financially.

Disadvantages:-
Currently unproven - frontier technology.

Way Forward

Confirmation of Basecase process options feasibility via preliminary process simulations.
Development of preliminary topside facility weight & space requirements.
Selection & cost estimation of offshore development options.
Cost estimation of favourable process / offshore development option combinations.
Identification of potentially viable field development concepts for further evaluation.

644096



(1) PUMP ONLY REQUIRED WHEN
BOOSTER COMPRESSION INSTALLED

WOODHILL
THORNTON

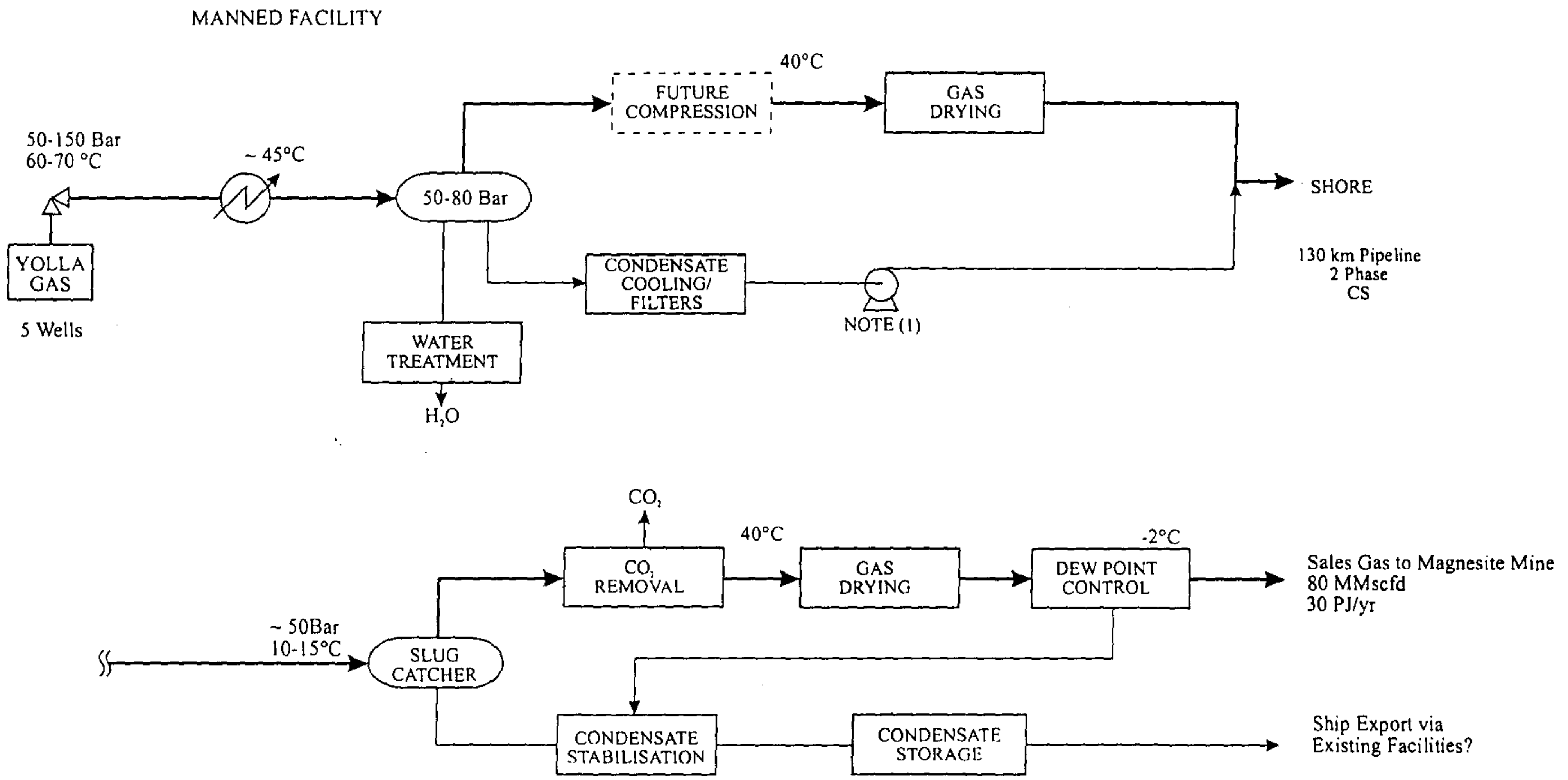
REV	DATE	BY	CKD
A	22/10/98		

Figure 1: Case 1A

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-01 | Rev A

644097



(1) PUMP ONLY REQUIRED WHEN
BOOSTER COMPRESSION INSTALLED

WOODHILL
THORNTON

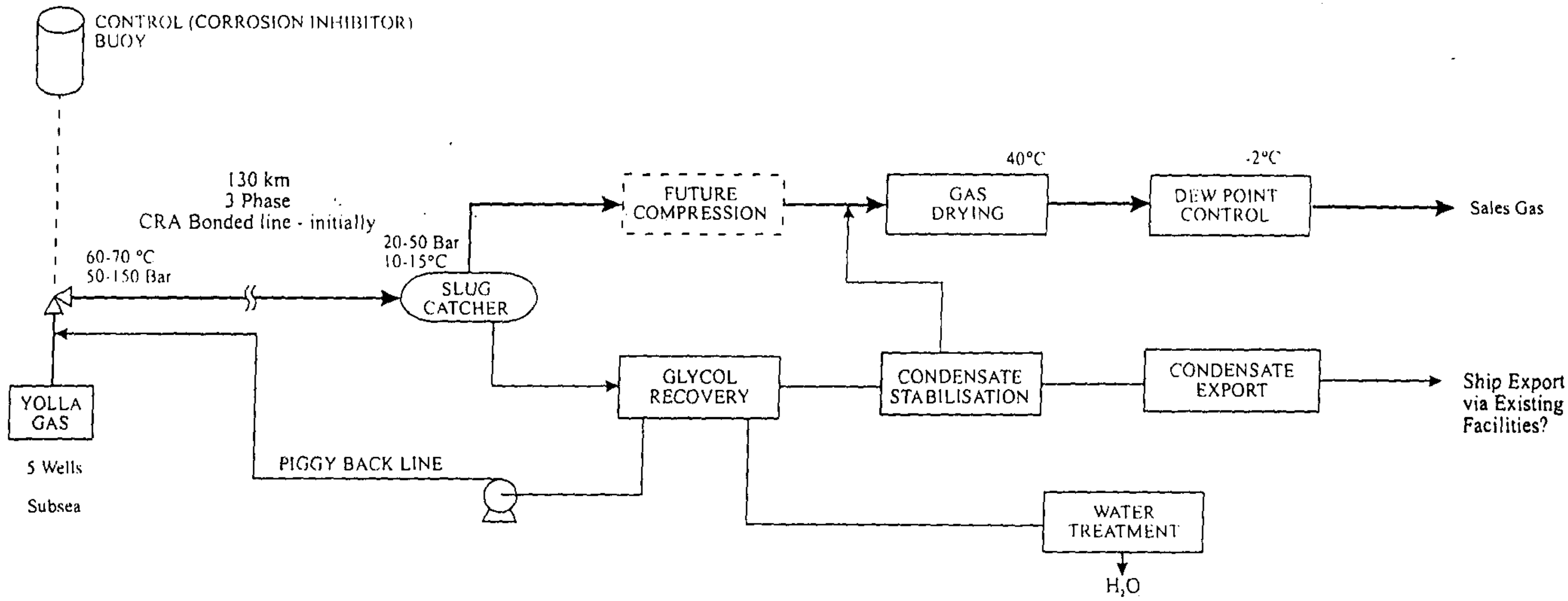
A	22/10/98		
REV	DATE	BY	CKD

Figure 2: Case 1B

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-02 | Rev A

644098



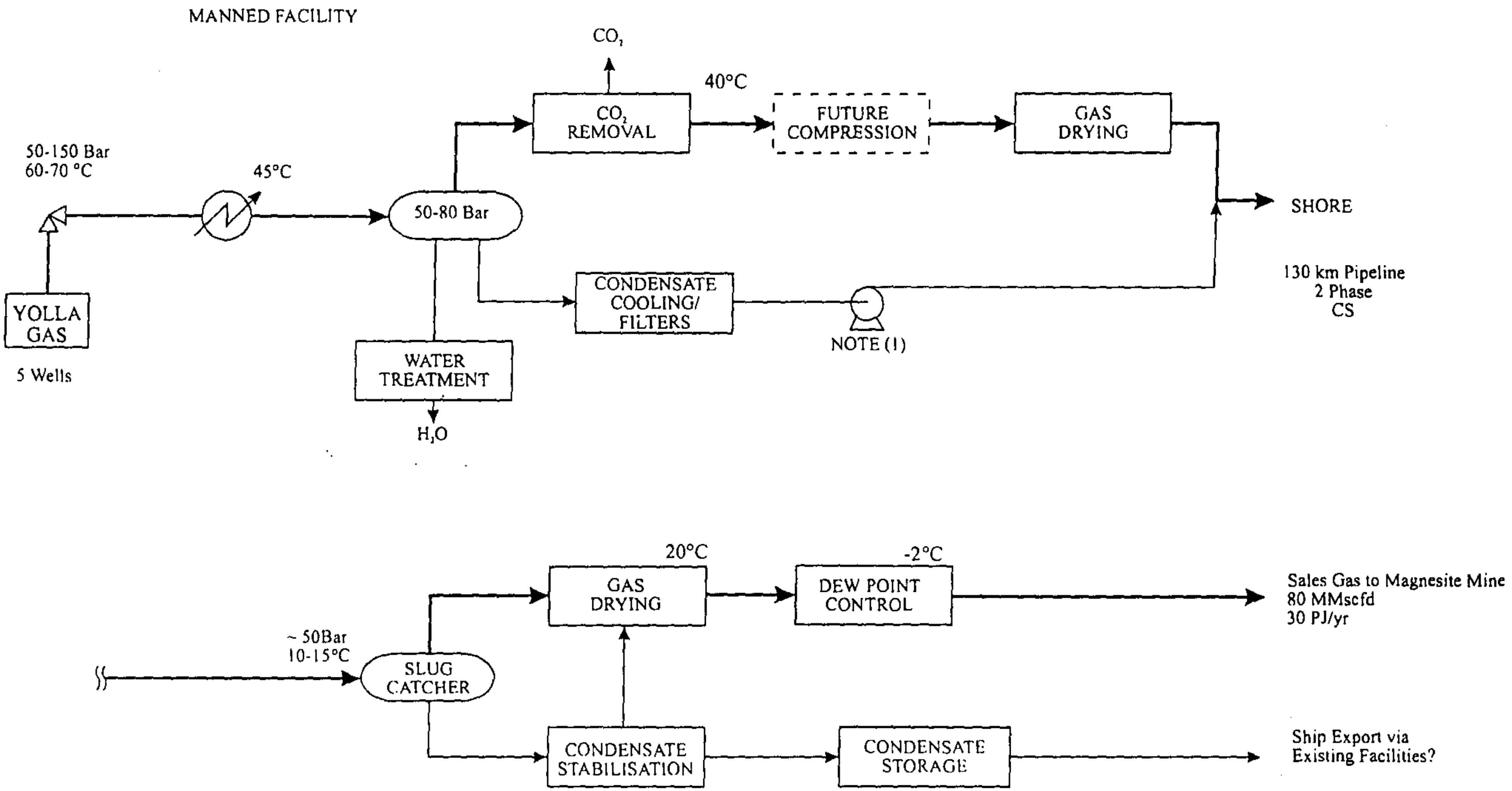
WOODHILL THORNTON

REV	DATE	BY	CKD
A	22/10/98		

Figure 3: Case 1C

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-03 | Rev A



(1) PUMP ONLY REQUIRED WHEN
BOOSTER COMPRESSION INSTALLED

WOODHILL THORNTON

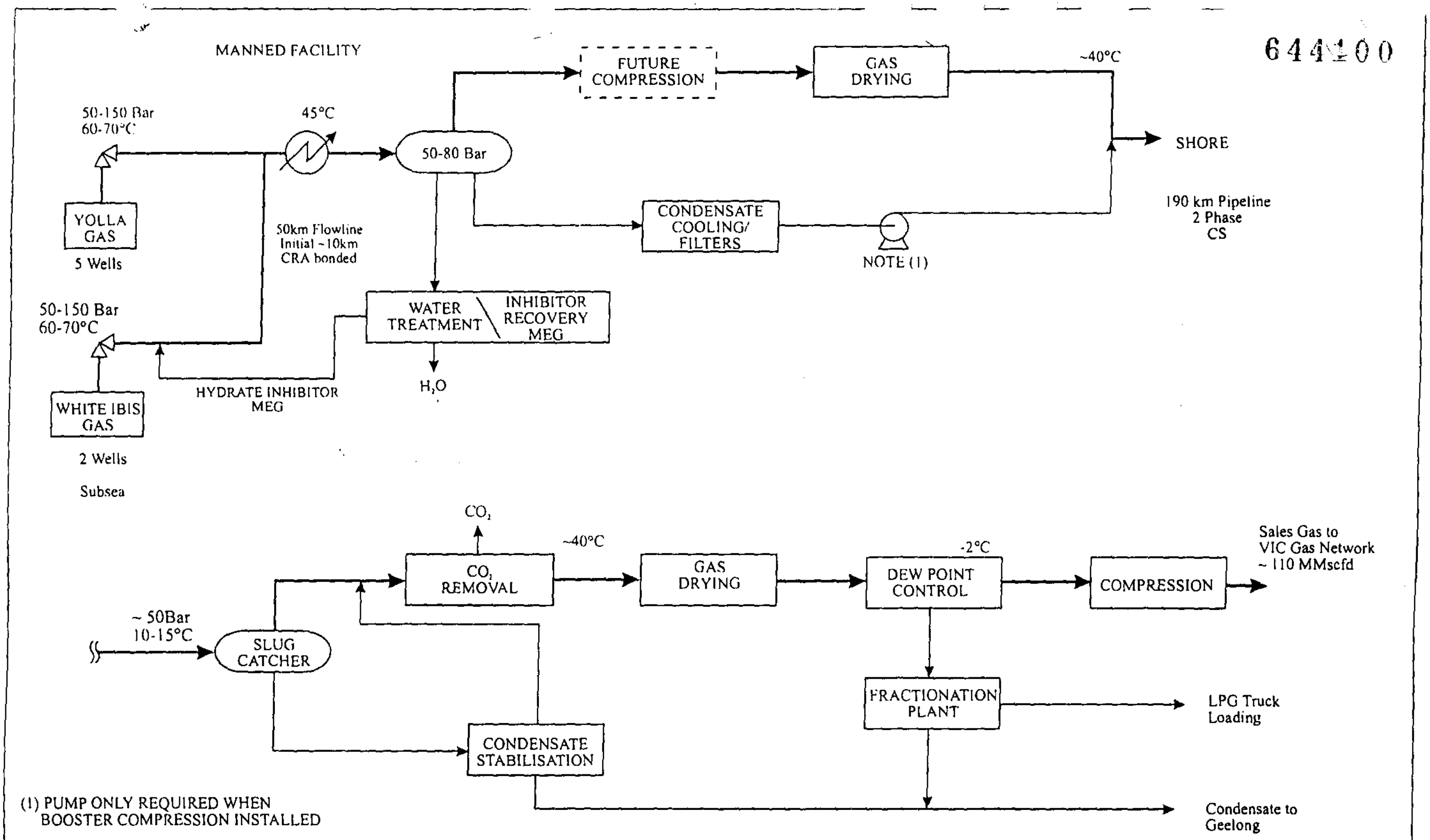
REV	DATE	BY	CKD
A	22/10/98		

Figure 4: Case 1D

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-04 | Rev A

644100



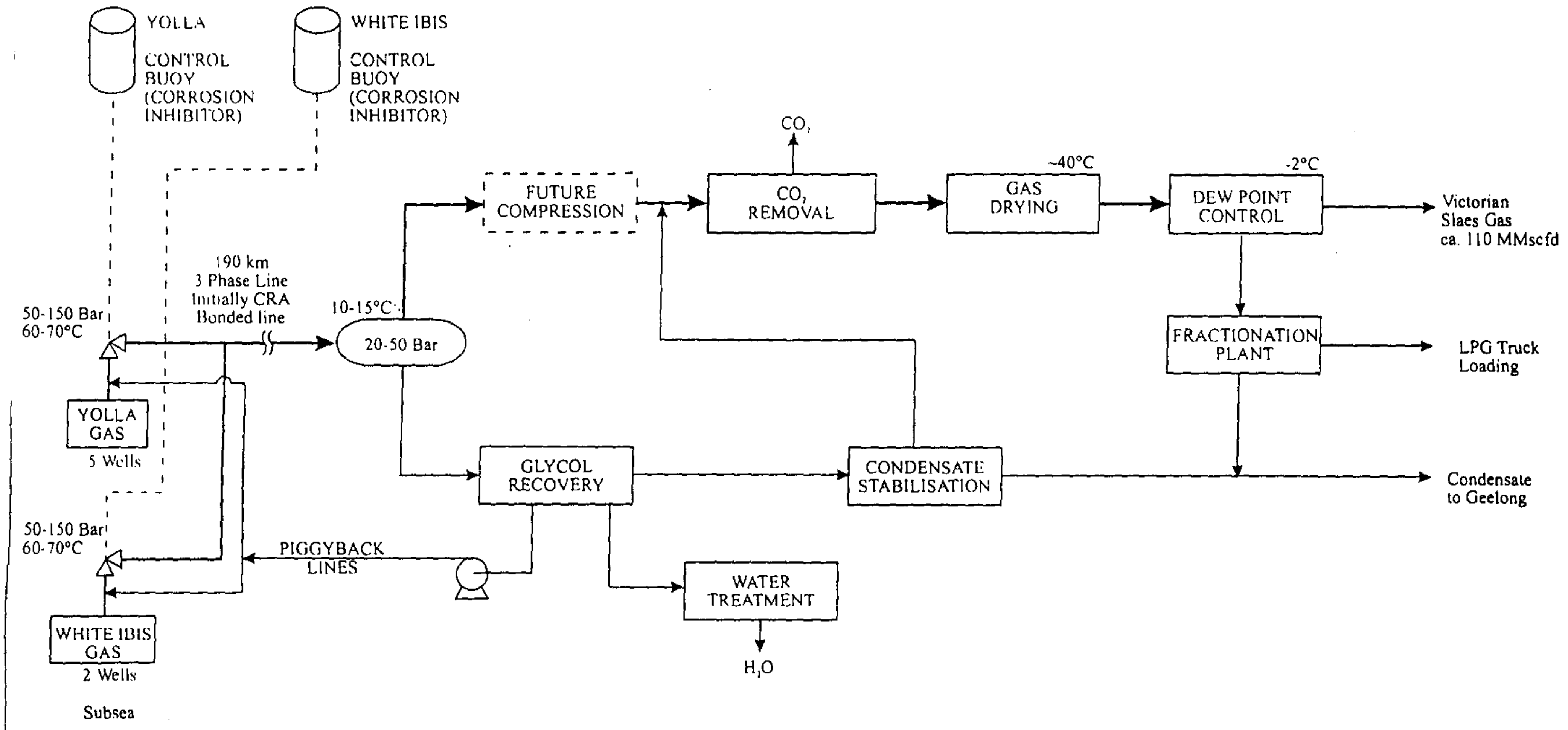
WOODHILL THORNTON

REV	DATE	BY	CKD
A	22/10/98		

Figure 5: Case 2A

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-05 | Rev A



WOODHILL THORNTON

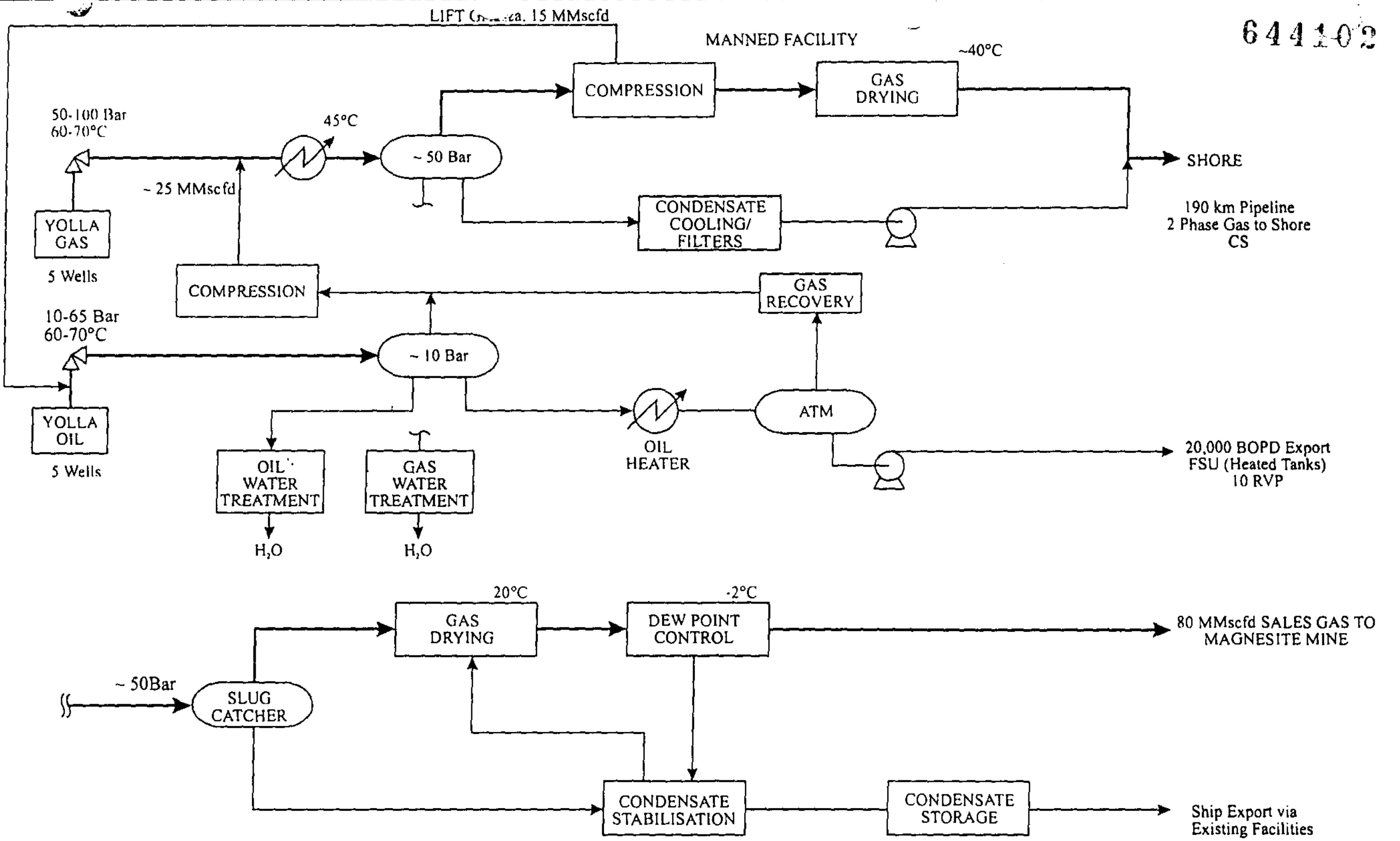
REV	DATE	BY	CKD
A	23/10/98		

Figure 6: Case 2B

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-06 | Rev A

644102



WOODHILL THORNTON

A	22/10/98		
REV	DATE	BY	CKD

Figure 7: Case 3A

BASS STRAIT COMERCIALISATION
PREMIER OIL

Doc No: 9843-SK-07 | Rev A

644403

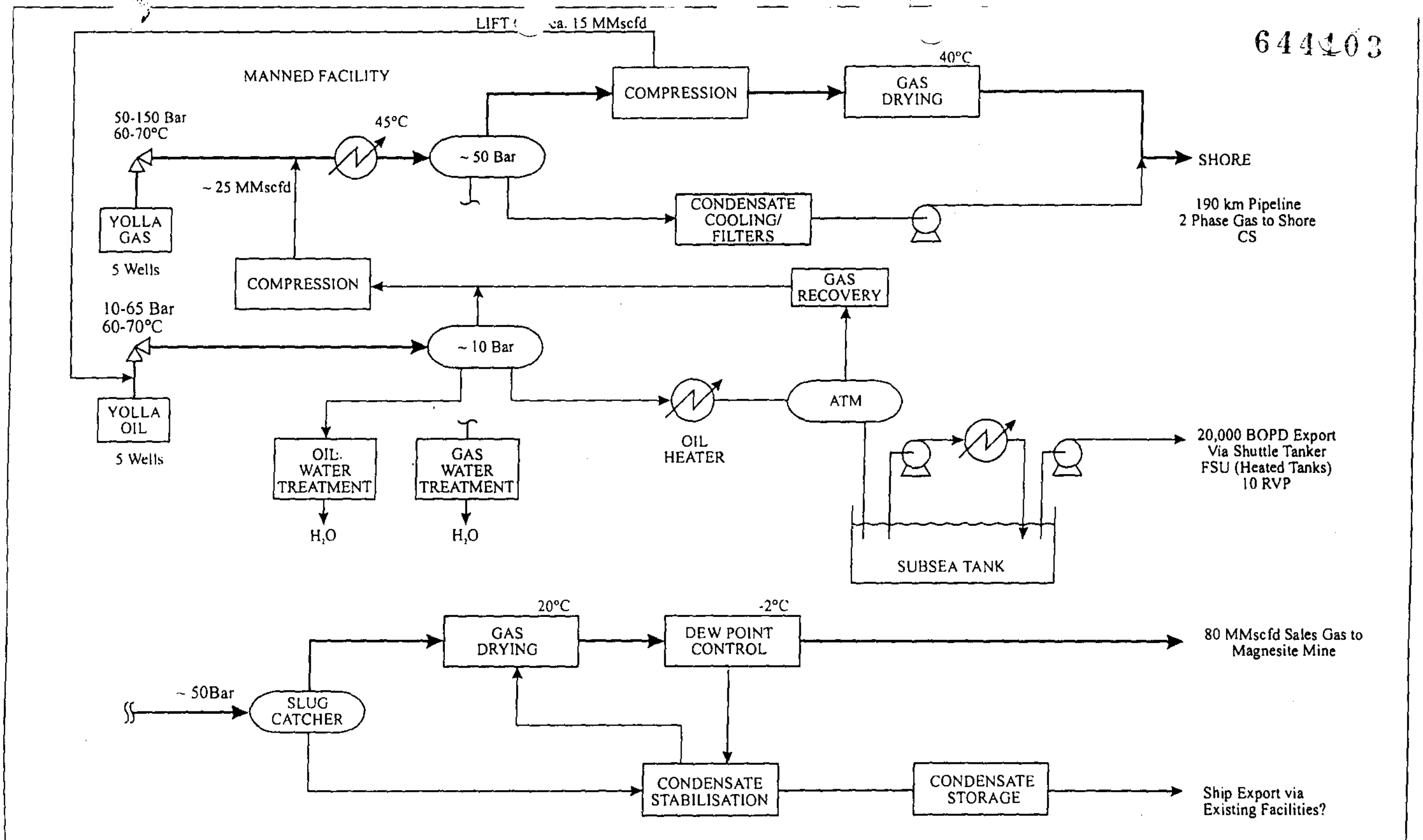


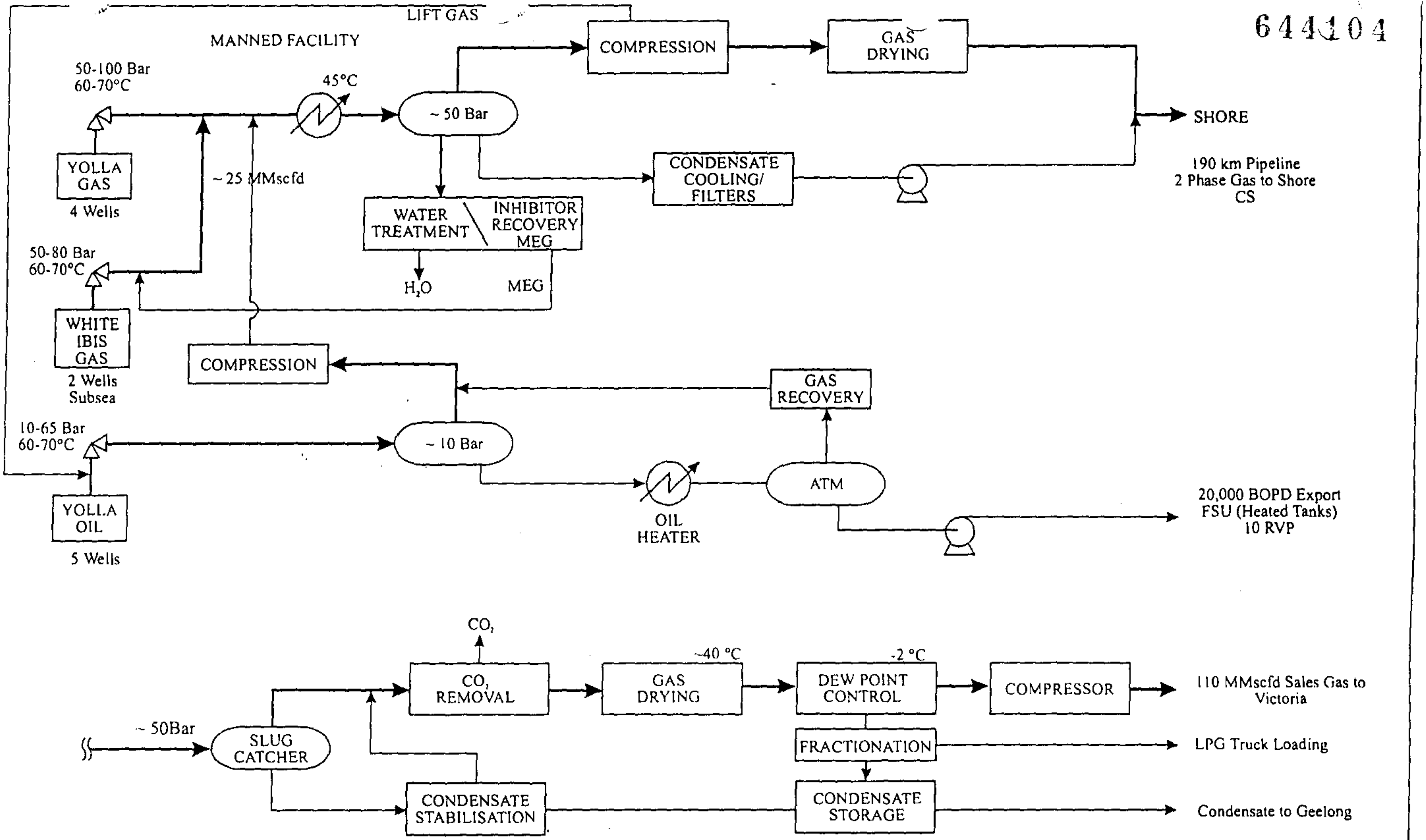
Figure 8: Case 3B

WOODHILL THORNTON

REV	DATE	BY	CKD
A	22/10/98		

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-08 | Rev A



WOODHILL THORNTON

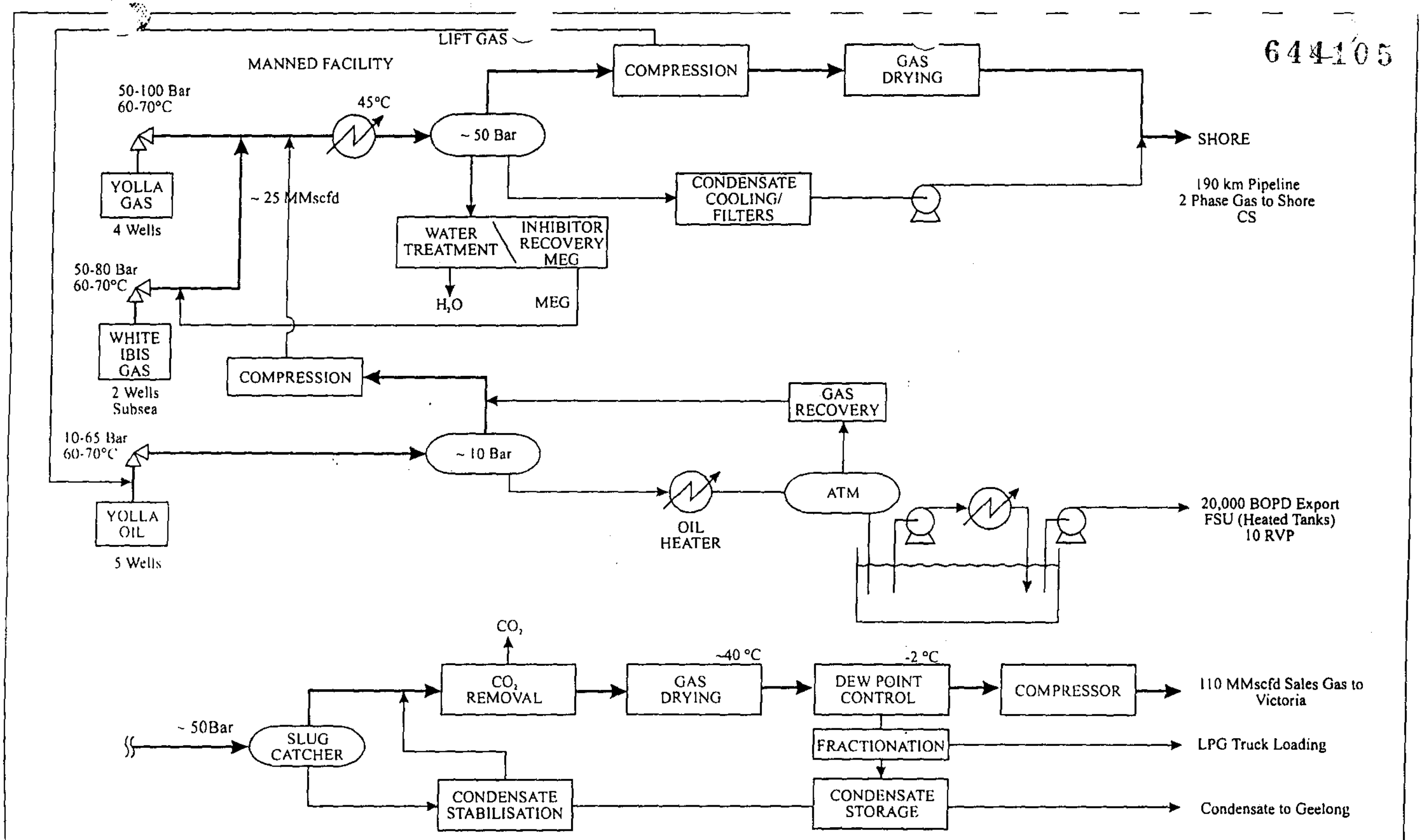
A	22/10/98		
REV	DATE	BY	CKD

Figure 9: Case 4A

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-09 — Rev A

644105



WOODHILL THORNTON

REV	DATE	BY	CKD
A	22/10/98		

Figure 10: Case 4B

YOLLA DEVELOPMENT STUDY
PREMIER OIL

Doc No: 9843-SK-10 | Rev A

APPENDIX 3

Process Reservoir Compositions

YOLLA DEVELOPMENT STUDY

RESERVOIR COMPOSITIONS

Component	Yolla Gas	White Ibis Gas	Yolla Oil (1)
H2S	0	0	0
CO2	19.46	8	5.49
N2	0.18	1.93	0.5
Methane	66.96	70.92	49.82
Ethane	6.35	5.85	6.54
Propane	2.69	3.55	3.88
i-Butane	0.53	1.61	0.76
n-Butane	0.81	1.37	1.04
i-Pentane	0.27	0.98	0.67
n-Pentane	0.28	0.7	0.65
n-Hexane	0.43	1.41	1.47
n-Heptane	0.65	1.67	3.67
n-Octane	0.39	0.77	3.07
n-Nonane	0.36	0.49	2.37
n-Decane	0.15	0.31	1.9
n-C11	0.07	0.16	1.38
n-C12	-	-	2.06
n-C13	-	-	1.79
n-C14	-	-	1.77
n-C15	-	-	2.17
n-C16	-	-	1.75
n-C17	-	-	1.88
n-C18	-	-	1.57
n-C19	-	-	1.42
n-C21	-	-	2.38
C12+ (Yolla)	0.42	-	-
c12+ (W Ibis)	-	0.28	-
TOTAL:	100	100	100

Hypothetical Component Information

Component	Density (kg/m³)	Mol Wt	BP (°C)
C12+ (Yolla)	860	240	323
c12+ (W Ibis)	822	191	257

NOTES

(1) Yolla oil reservoir gas cap composition produced by flashing the oil composition at 18,580kPag & 98.3°C (2695psig & 209°F).

APPENDIX 4

Assumed Victorian Gas Specification

YOLLA DEVELOPMENT STUDY

ASSUMED VICTORIAN GAS SPECIFICATION

Specification	Limit
CO2 Content	3 % (max)
Total Sulphur	115 mg/m³ (max)
Mercaptan Sulphur	23 mg/m³ (max)
H2S Content	11.5 mg/m³ (max)
Free Oxygen	0.2 % (max)
Gross Heating Value	966-1127 (36-42) Btu/scf (MJ/m³)
Wobbe Index	46 - 50.8 MJ/m³
Water Dewpoint	112 mg/m³ (max)
HC Dewpoint	2.2 °C
Supply Temperature	71 °C
Supply Pressure	6900 kPag

Data based on Ref 1.

644110

APPENDIX 5

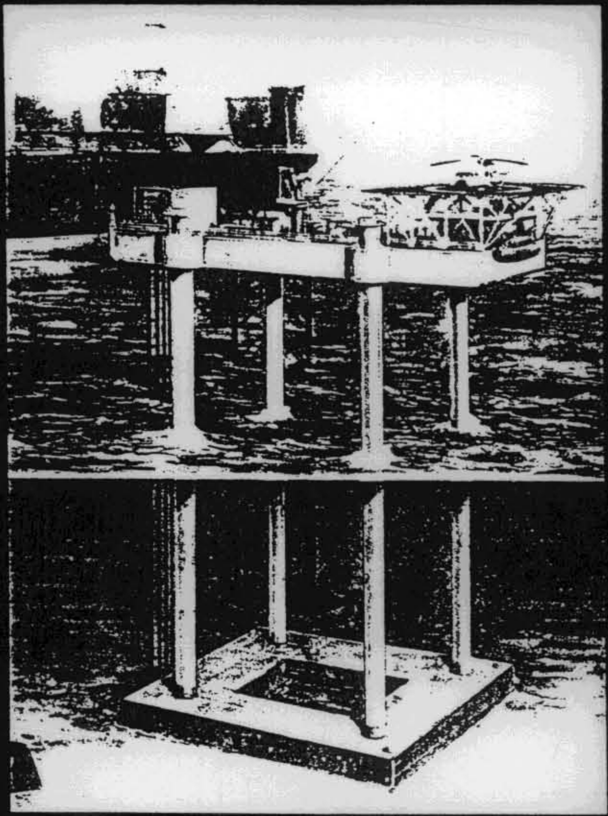
Ove Arup ACE 90 information

644111

STEEL SOLUTIONS

ACE 30, ACE 60 & ACE 90

Movable platforms for wellhead, production, compression



ACE 30

Typical Requirements

- *Platform to develop a marginal field*
- *Short field life*
- *Sand, silt or clay soils*
- *Up to 12 wells, some pre-drilled*
- *Water depth 25m - 45m ACE 30*
  45m - 65m ACE 60
  65m - 95m ACE 90

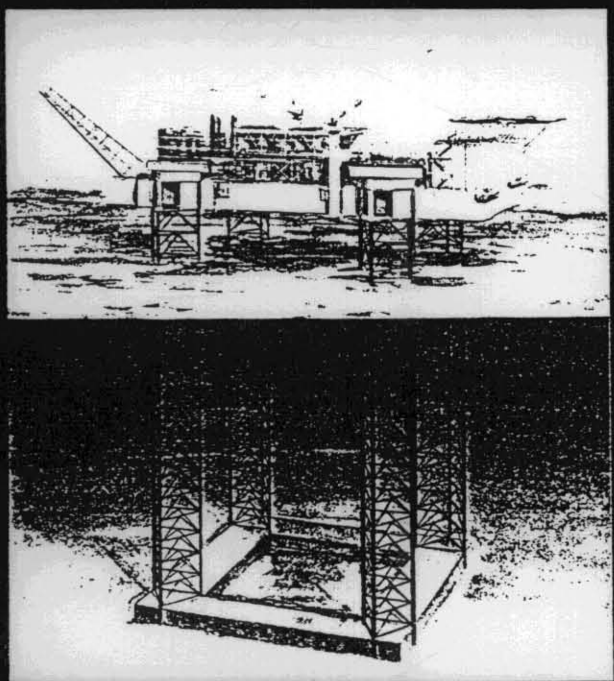
The Solution

ACE 30, ACE 60 & ACE 90

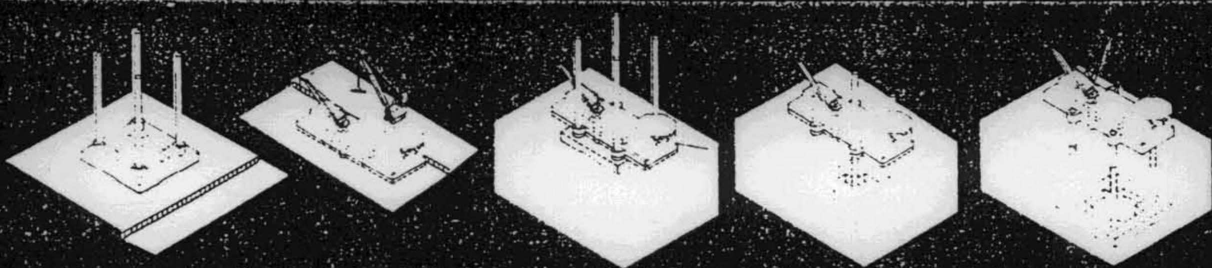
- *Self installing, movable, reusable*
- *Pre-assembled topside equipment on a single level deck*

Benefits

- *Low CAPEX*
- *Rapid delivery*
- *Steel gravity base footing applicable to most seabed soils*
- *Single level barge deck for layout flexibility*
- *Internal or external drilling*
- *Shipyard fabrication*
- *Quayside installation of topside equipment*
- *Minimal offshore hook up and commissioning*
- *High residual value through potential for re-use*



ACE 90



1. Fabricate base in dry dock or on quayside
2. Fabricate barge and install prefabricated topsides
3. Mate barge and base at wharf (and install tubular support)
4. Tow to field and lower base to seabed
5. Raise deck to achieve required air gap

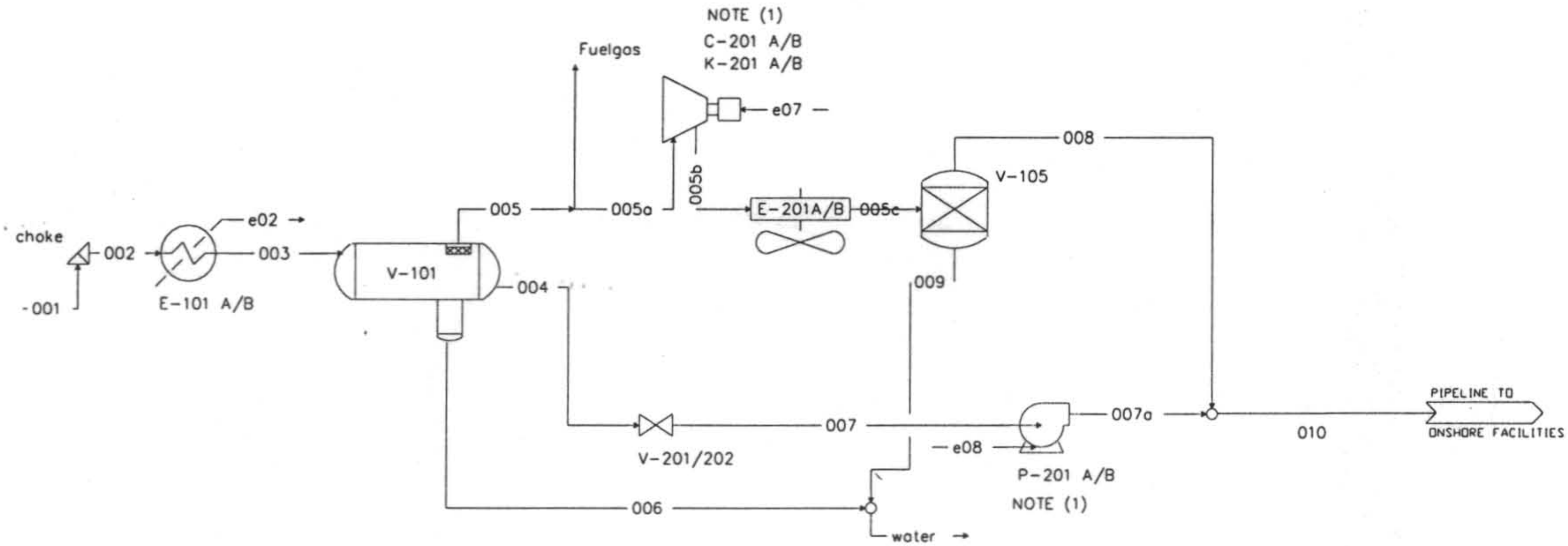
ARUP Energy

APPENDIX 6

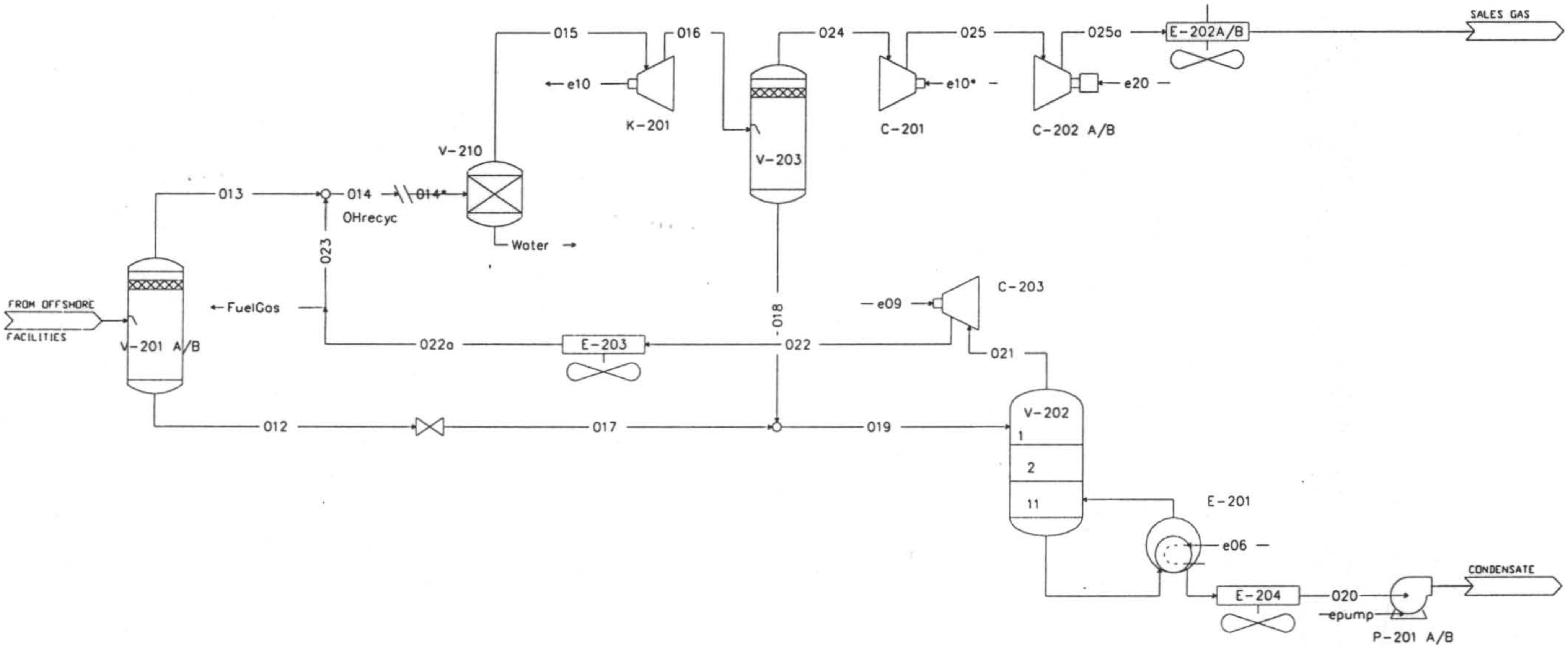
Process Schematics

NOTES

(1) FUTURE EQUIPMENT



WOODHILL THORNTON	PremierOil AUSTRALASIA
REFERENCE DRAWINGS: DRAWING No / DESCRIPTION	YOLLA DEVELOPMENT STUDY
REVISIONS: REV A, DATE 25/11/98, DRN MWM, CKD, APP, DETAILS ISSUED FOR CLIENT REVIEW	PROCESS FLOW SCHEMATIC -OFFSHORE CASE 1A - 30PJ/y High CO2 Gas to Tasmania Sheet 1 of 2
SCALE NTS	CAD REF / DRAWING No 9843-SK-002 / REV. A



WOODHILL THORNTON
LEVEL 2, 225 ST. GEORGES TERRACE PERTH, WESTERN AUSTRALIA
TEL 61 8 9486-7233 FAX 61 8 9486-7244

DRAWING No.	DESCRIPTION
	-

REV.	DATE	DRN.	CKD.	APP.	DETAILS
A	25/11/98	MVH			ISSUED FOR CLIENT REVIEW

REFERENCE DRAWINGS

REVISIONS

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YOLLA DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC - ONSHORE
CASE 1A - 30PJ/y High CO2 Gas to Tasmania
Sheet 2 of 2

SCALE:	CAD REF.	DRAWING No.	REV.
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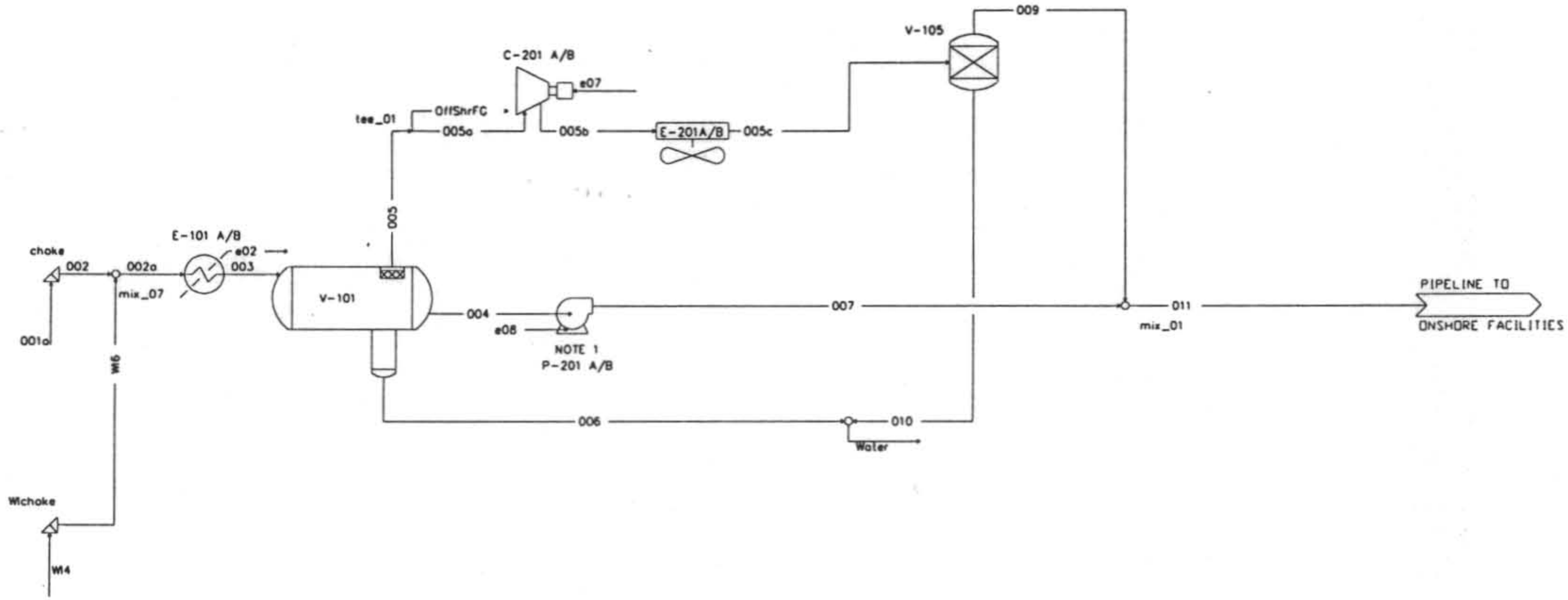

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REFERENCE DRAWINGS

DRAWING No.	DESCRIPTION

REVISIONS

REV.	DATE	DRN.	CKD.	APP.	DETAILS
A	25/11/98	MWM			ISSUED FOR CLIENT REVIEW

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DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC - OFFSHORE
CASE 2A - 40PJ/y Low CO2 Gas to Victoria
Sheet 1 of 2

SCALE:	CAD REF.	DRAWING No.	REV.
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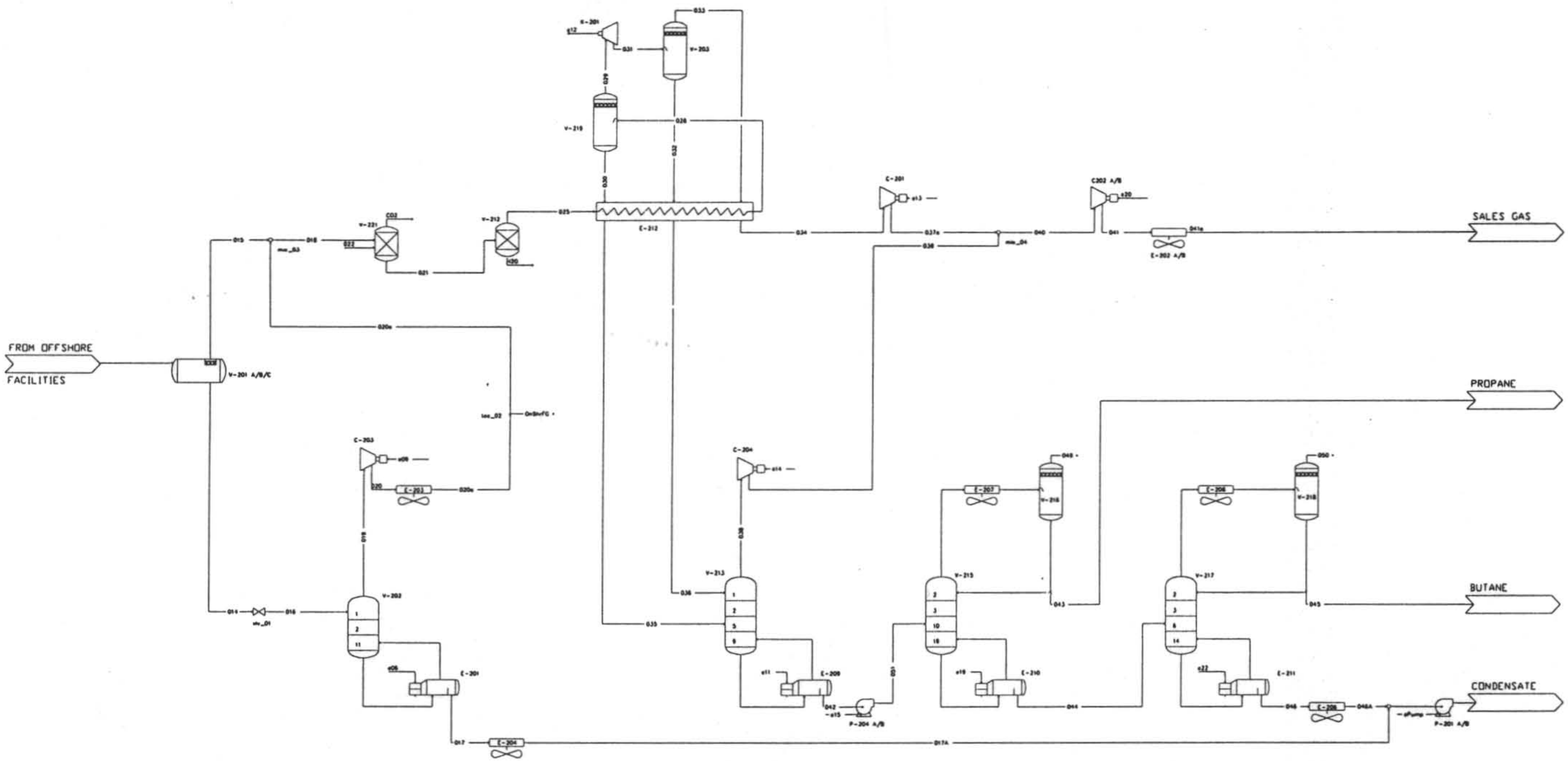
694145



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REFERENCE DRAWINGS

DRAWING No.	DESCRIPTION

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REV.	DATE	DRN.	CKD.	APP.	DETAILS
A	25/11/98	MWH			ISSUED FOR CLIENT REVIEW

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YOLLA DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC - ONSHORE
CASE 2A - 40PJ/y Low CO2 Gas to Victoria
Sheet 2 of 2

SCALE	CAD REF.	DRAWING No.	REV.
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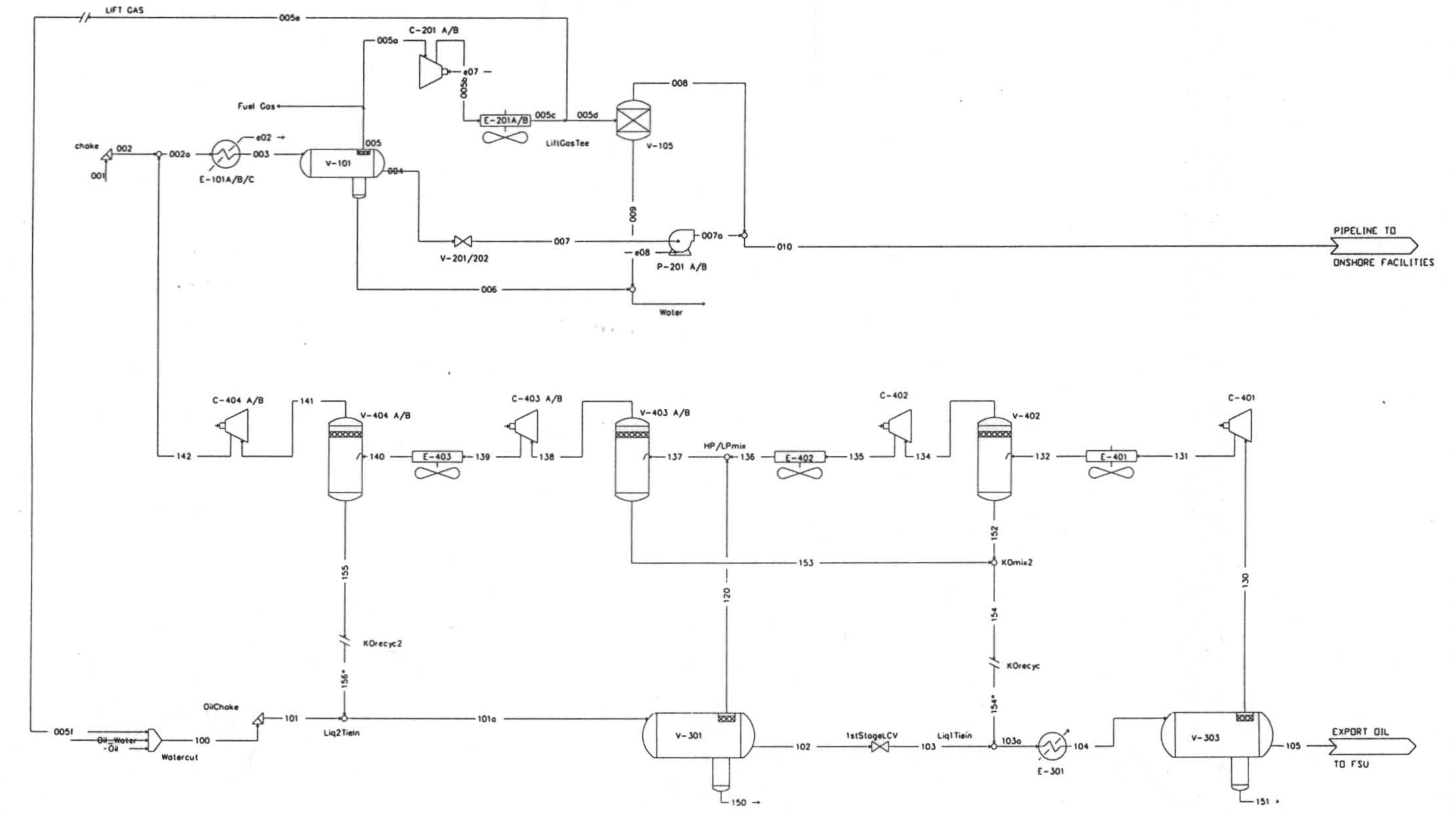

WOODHILL THORNTON

REFERENCE DRAWINGS		REVISIONS						
DRAWING No	DESCRIPTION	REV	DATE	DRN	CKD	APP	DETAILS	
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YOLLA DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC - OFFSHORE
CASE 3A - 30PJ/y High CO2 Gas to Tasmania
+ 20,000 STBOPD Offshore Export (Sht 1of2)

SCALE	CAD REF	DRAWING No.	REV
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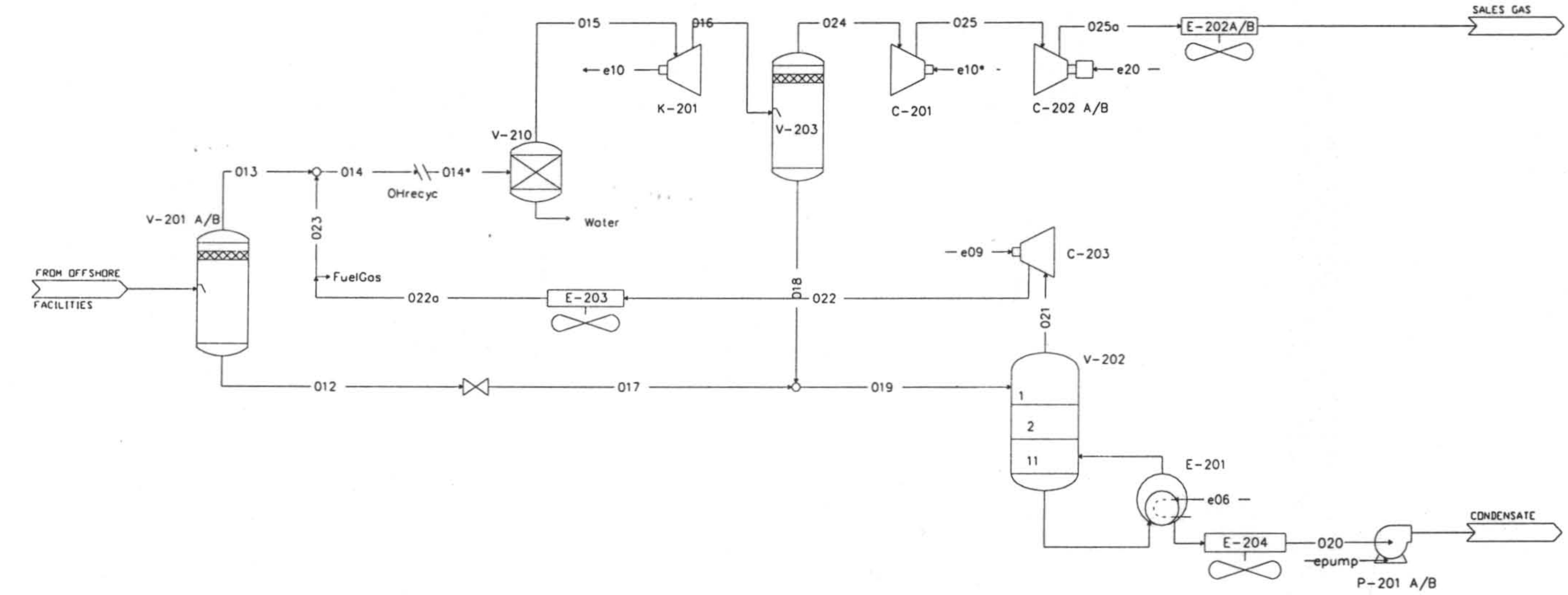

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			REV.	DATE	DRN.	CKD.	APP.	DETAILS

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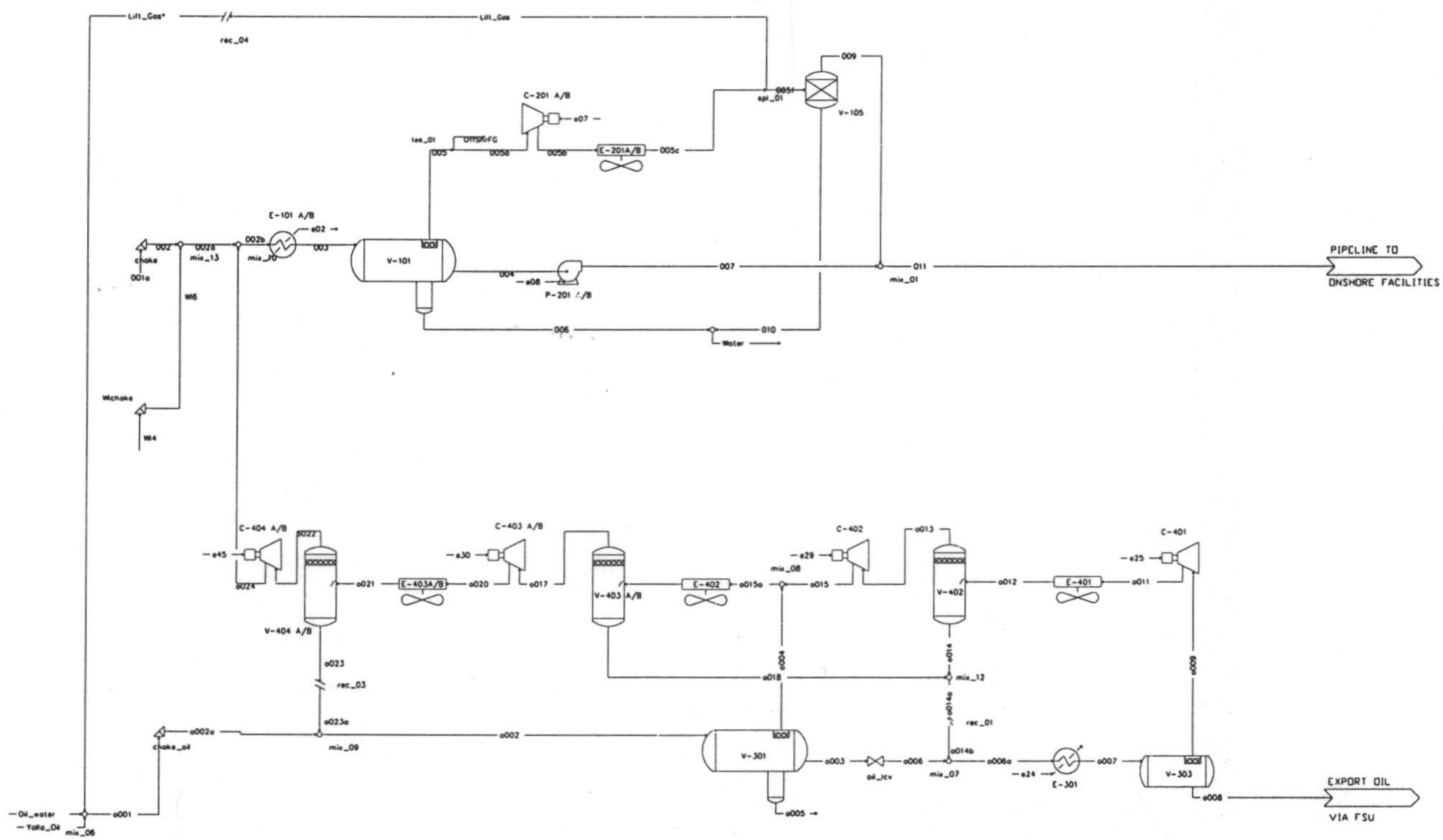
YOLLA DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC - ONSHORE
CASE 3A - 30PJ/y High CO2 Gas to Tasmania
+ 20,000 STBOPD Offshore Export (Sht 2of2)

SCALE:	CAD REF	DRAWING No.	REV.
NTS		9843-SK-006	A

S 1449



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REV	DATE	DRN	CKD	APP	DETAILS
A	25/11/98	MWH			ISSUED FOR CLIENT REVIEW

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DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC - OFFSHORE
CASE 4A - 40PJ/y Low CO2 Gas to Victoria
+ 20,000 STBOPD Offshore Export (Sht 1of2)

SCALE	CAD REF.	DRAWING No.	REV.
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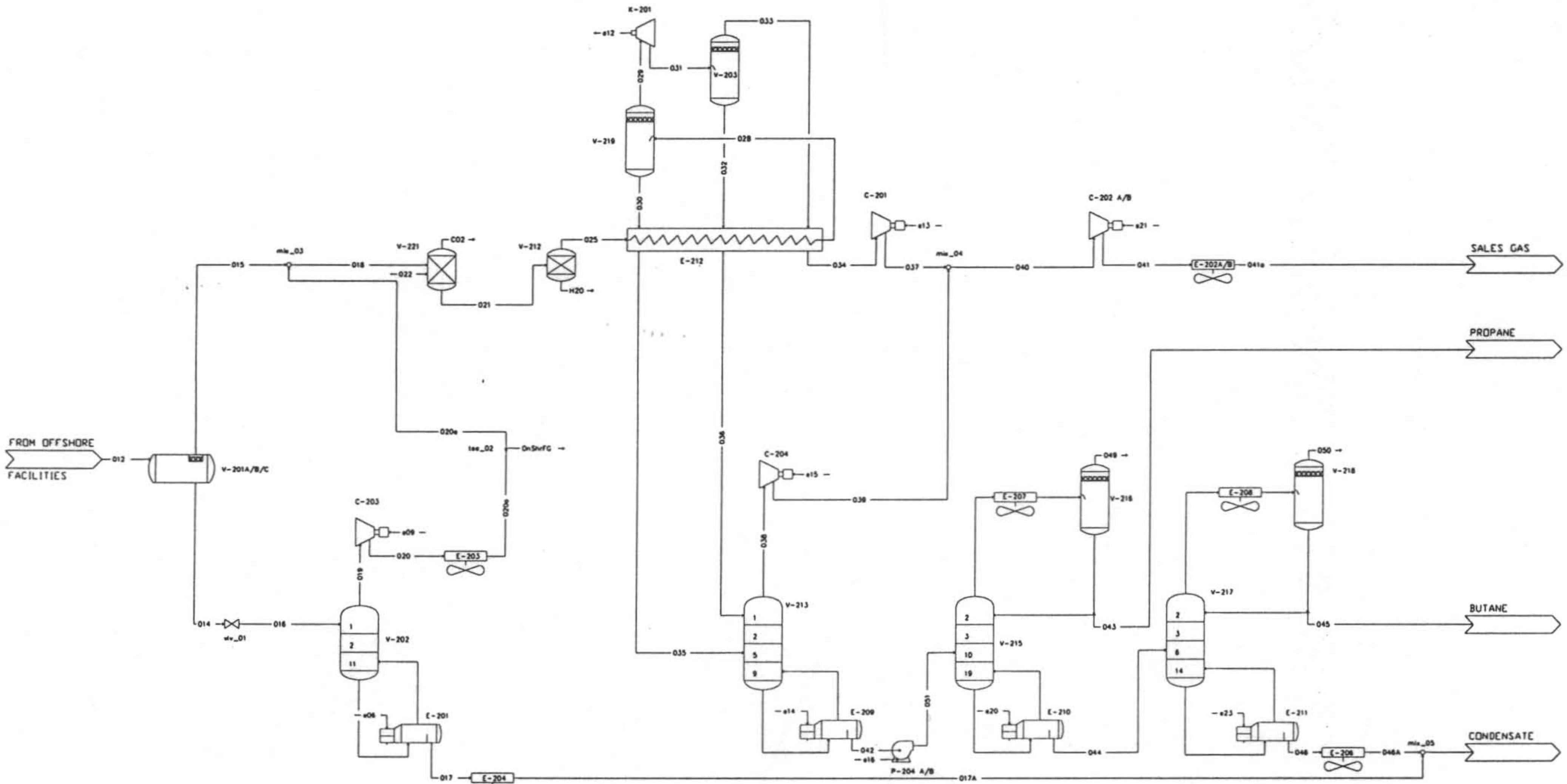

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REFERENCE DRAWINGS

DRAWING No.	DESCRIPTION

REVISIONS

REV.	DATE	DRN.	CKD.	APP.	DETAILS
A	25/11/98	MWM			ISSUED FOR CLIENT REVIEW

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DEVELOPMENT STUDY

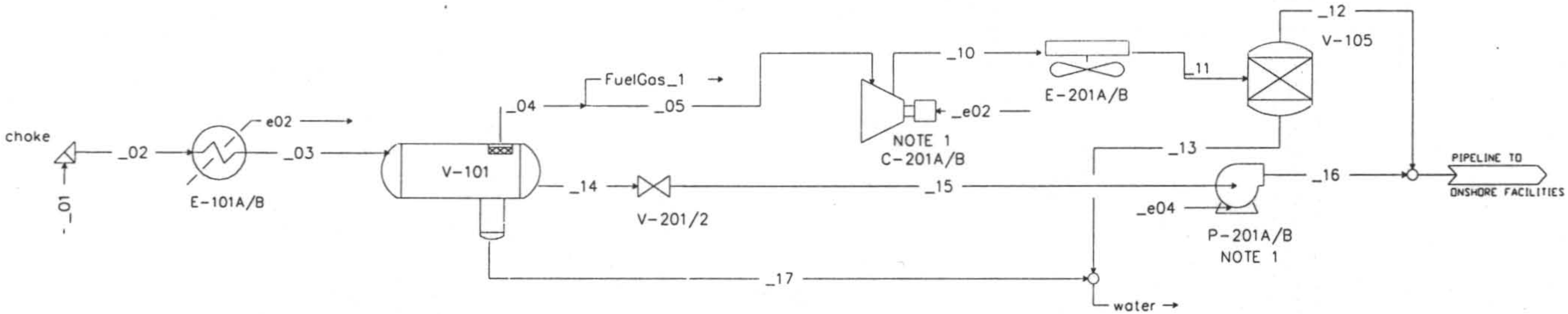
PROCESS FLOW SCHEMATIC - ONSHORE
CASE 4A - 40PJ/y Low CO2 Gas to Victoria
+ 20,000 STBOPD Offshore Export (Sht 2of2)

SCALE	CAD REF.	DRAWING No.	REV.
NTS		9843-SK-007	A

644120

NOTES

(1) FUTURE EQUIPMENT



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REV.	DATE	DRN.	CKD.	APP.	DETAILS
A	25/11/98	MWM			ISSUED FOR CLIENT REVIEW

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YOLLA DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC - OFFSHORE
CASE 1B - 30PJ/y Low CO2 Gas to Tasmania
Sheet 1 of 2

SCALE	CAD REF	DRAWING No.	REV
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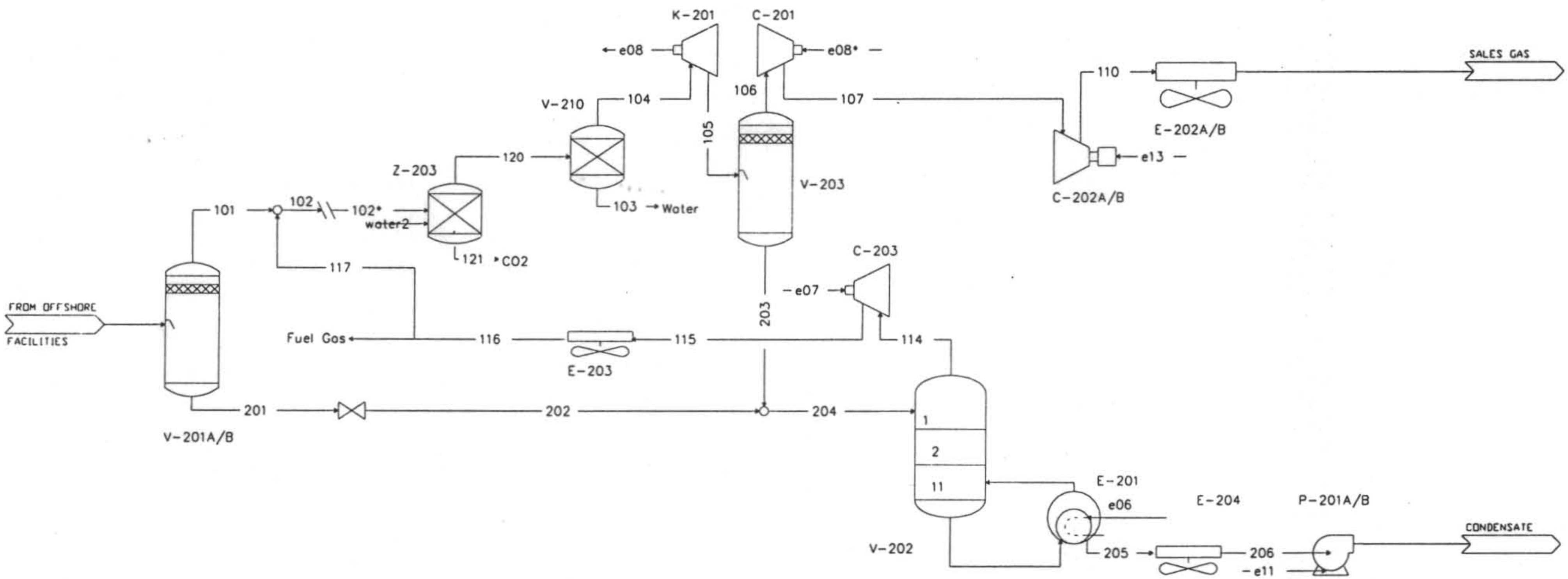
644121



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TEL 61 8 9486-7233 FAX 61 8 9486-7244

REFERENCE DRAWINGS	
DRAWING No.	DESCRIPTION

REV.	DATE	DRN.	CKD.	APP.	DETAILS
A	25/11/98	MWM			ISSUED FOR CLIENT REVIEW

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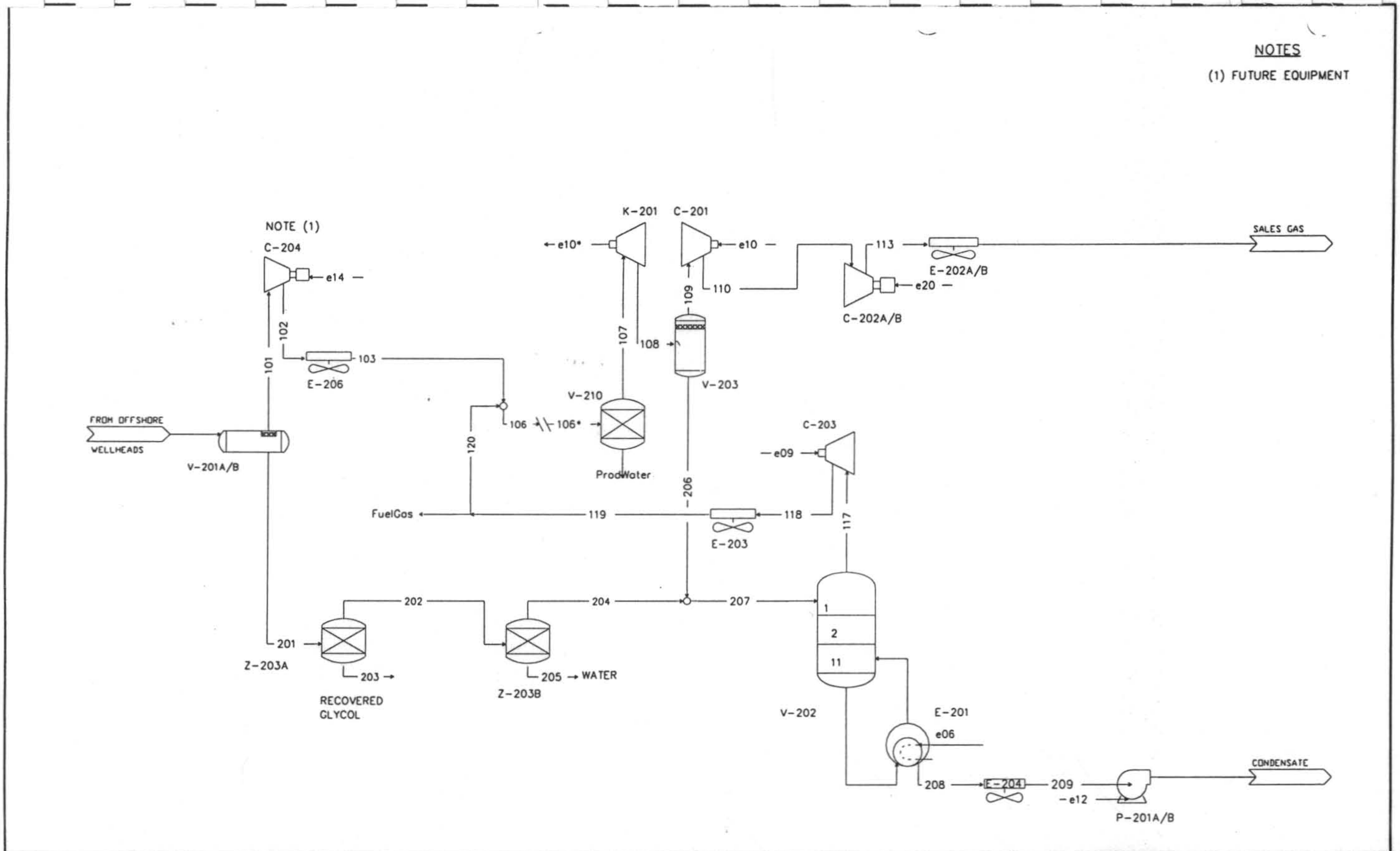
YOLLA DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC - OFFSHORE
CASE 1B - 30PJ/y Low CO2 Gas to Tasmania
Sheet 2 of 2

SCALE: NTS | CAD REF | DRAWING No. 9843-SK-003 | REV. A

644122



WOODHILL THORNTON LEVEL 2, 225 ST.GEORGES TERRACE PERTH, WESTERN AUSTRALIA TEL 61 8 [illegible] FAX 61 8 [illegible]	REFERENCE DRAWINGS	DRAWING No.	DESCRIPTION	

REV.	DATE	DRN.	CKD.	APP.	DETAILS
A	25/11/98	MVH			ISSUED FOR CLIENT REVIEW

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DEVELOPMENT STUDY

PROCESS FLOW SCHEMATIC (Sheet 1 of 1)
CASE 1C - 30PJ/y High CO2 Gas to Tasmania
Subsea/Wellhead Tower Option

SCALE:	CAD REF	DRAWING No.	REV.
NTS		9843-SK-004	A

644123

APPENDIX 7

Equipment Lists

OLLA DEVELOPMENT CASE 1A

PROCESS/UTILITY EQUIPMENT LIST

OFFSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
WH-101A..E	5	PRODUCTION WELLHEADS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
V-101	1	PRODUCTION SEPARATOR	100 MMscfd	13900	90	1.5 ID x 4.5 T/T	H					CS	18	13.0	16.2	CRA CLAD
V-102	1	TEST SEPARATOR	25 MMscfd	13900	90	0.8 ID x 2.8 T/T	H					CS	8	2.5	3.6	CRA CLAD
V-103A	1	BOOSTER COMPRESSOR SUCTION DRUM	50 MMscfd	13900	90	1.2 ID x 4.1 T/T	V					CS	4	8.3	9.2	CRA CLAD
V-103B	1	BOOSTER COMPRESSOR SUCTION DRUM	50 MMscfd	13900	90	1.2 ID x 4.1 T/T	V					CS	4	8.3	9.2	CRA CLAD
V-104	1	TEG INLET SEPARATOR	100 MMscfd	13900	90	1.5 ID x 4.5 T/T	V					CS	9	13.9	16.7	CRA CLAD
V-105	1	TEG CONTACTOR	100 MMscfd	13900	90	1.2 ID x 8.0 T/T	V					CS	4	14.0	22.8	CRA CLAD
V-201	1	CONDENSATE FILTER	4000 BCPD	13900	90	0.4 ID x 1.2 T/T	V					CS	1	0.6	0.7	
V-202	1	CONDENSATE COALESCER	4000 BCPD	13900	90	0.8 ID x 1.8 T/T	H					CS	4	1.9	2.5	
V-301	1	LP FLARE / DRAIN DRUM		350	90	1.5 ID x 4.5 T/T	H					CS	18	3.1	7.0	DRAINAGE FROM V-101
V-302	1	PRODUCED WATER DEGASSER	1000 BWPD	350	90	1.0 ID x 3.5 T/T	H					CS	15	1.4	3.3	
V-303	1	HP FLARE DRUM	50 MMscfd	350	90	2.1 ID x 6.4 T/T	V					CS	9	8.0	11.9	
V-304	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	13900	90	0.5 ID x 1.8 T/T	V					CS	2	0.9	1.1	CRA CLAD
HC-301	1	PRODUCED WATER HYDROCYCLONE	2000 BWPD	13900	90	0.7 ID x 2.0 T/T	H					CS	8	0.5	0.7	INCLUDES 100% SPARE CAPACITY; SS LINERS
E-101A	1	PRODUCTION COOLER		13900	90	12.0 L x 2.5 W	AIR CLR		1100	93.6	AIR	CRA TB	30	6.4	7.0	2 x 50%; MOUNTED ABOVE COMPRESSOR SKIDS
E-101B	1	PRODUCTION COOLER		13900	90	12.0 L x 2.5 W	AIR CLR		1100	93.6	AIR	CRA TB	30	6.4	7.0	2 x 50%; MOUNTED ABOVE COMPRESSOR SKIDS
E-201A	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 2.5 W	AIR CLR		3200	156.7	AIR	CRA TB	30	11.0	12.1	FUTURE; 2 x 50%; MOUNTED ABOVE COMPR. SKIDS
E-201B	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 2.5 W	AIR CLR		3200	156.7	AIR	CRA TB	30	11.0	12.1	FUTURE; 2 x 50%; MOUNTED ABOVE COMPR. SKIDS
E-202	1	GAS / TEG EXCHANGER		13900	110	6.7 L x 0.4 W	S&T		50	30.0	GAS / TEG	CS	7	6.5	9.8	
C-201A	1	BOOSTER COMPRESSOR	1120 act.m3/hr	13900	150			8500	2150				6			FUTURE
C-201B	1	BOOSTER COMPRESSOR	1120 act.m3/hr	13900	150			8500	2150				6			FUTURE
K-201A	1	BOOSTER COMPRESSOR DRIVER				10.0 L x 3.0 W							30	16.3	22.5	FUTURE - 2 x 50% SOLAR CENTAURS
K-201B	1	BOOSTER COMPRESSOR DRIVER				10.0 L x 3.0 W							30	16.3	22.5	FUTURE - 2 x 50% SOLAR CENTAURS
P-201A	1	CONDENSATE BOOSTER PUMP	30 m3/hr	13900	90	5.0 L x 2.0 W		8500	78				10	1.7	1.7	FUTURE - 2 x 50%
P-201B	1	CONDENSATE BOOSTER PUMP	30 m3/hr	13900	90	5.0 L x 2.0 W		8500	78				10	1.7	1.7	FUTURE - 2 x 50%
P-202A	1	LP FLARE / DRAIN DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4	0.4	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-202B	1	LP FLARE / DRAIN DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4	0.4	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-301A	1	HP FLARE DRUM PUMP	30 m3/hr	13900	90	6.0 L x 2.5 W		12650	160				15	2.7	2.7	2 x 50%
P-301B	1	HP FLARE DRUM PUMP	30 m3/hr	13900	90	6.0 L x 2.5 W		12650	160				15	2.7	2.7	2 x 50%
Z-201	1	TEG REGENERATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3	57.4	DESIGN WATER FLOW 40 BWPD
X-100	1	PIG LAUNCHER		13900	90	0.8 ID x 7.0 T/T						CS	14	4.8	4.8	
	1	POWER GENERATION				10.0 L x 10.0 W			1500				100	23.0	30.0	NORMAL / STANDBY / EMERGENCY
	1	FLARE TIP / IGNITION SYSTEM	50 MMscfd			1.0 L x 5.0 W							5	0.6	1.0	
	2	FIRE PUMPS	1500 GPM			6.0 L x 3.0 W							20	15.0	20.0	
	1	WORKOVER FACILITIES												20.0	20.0	
	1	ACCOMMODATION	15 PPL/30 BEDS			15.0 L x 10.0 W							150	150.0	150.0	
	1	POTABLE WATER PACKAGE				7.0 L x 8.0 W							60	10.0	15.0	
	1	HVAC				3.0 L x 3.0 W							10	3.0	5.0	
	1	CRANE												30.0	30.0	
	1	INSTRUMENT / SERVICE AIR PACKAGE				4.0 L x 8.0 W							35	17.0	25.0	
	1	DIESEL FUEL SUPPLY / TREATMENT	10 DAYS			3.0 L x 3.0 W							10	5.0	8.5	
	1	GLYCOL STORAGE / TRANSFER PUMP	5 m3			2.0 L x 3.0 W							10	5.0	8.0	
	2	SURVIVAL CRAFT	20 MEN											5.0	7.0	
	1	SEWAGE TREATMENT UNIT	30 MEN			2.0 L x 3.0 W							6	1.0	3.0	
	1	HELIDECK												100.0	100.0	
												TOTAL	824	607.6	719.1	

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Vessel Weights Updated	24NOV98	[signature]	[signature]
B	Issued for Information	19NOV98	DAF	NJP
A	Initial Draft For Cost Estimating	03NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 1A

PREMIER OIL

PAGE 1 of 3

Doc. No.: 9843EL1A

644125

ONSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S & T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
V-201A	1	SLUGCATCHER	800 BBL	9300	80	3.0 ID x 30.0 T/T	H					CS	140	149.5		2 x 50%, EPOXY LINED
V-201B	1	SLUGCATCHER	800 BBL	9300	80	3.0 ID x 30.0 T/T	H					CS	140	149.5		2 x 50%, EPOXY LINED
V-202	1	CONDENSATE STABILISATION COLUMN	4000 BBL/d	2000	230	1.5 ID x 18.3 T/T	V					CS	4	15.7		22 TRAYS
V-203	1	LOW TEMPERATURE SEPARATOR	95 MMscfd	6000	-29	1.8 ID x 6.0 T/T	V					CS	6	11.5		
V-204A	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-204B	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-205A	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-205B	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-206	1	GAS RECOVERY COMP. SUCTION DRUM	3.5 MMscfd	2000	90	0.8 ID x 2.5 T/T	V					CS	4	1.0		
V-207	1	FLARE DRUM	50 MMscfd	350	80	2.4 ID x 7.2 T/T	H					CS	24	10.7		
V-208	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	7000	120	0.8 ID x 2.5 T/T	V					CS	4	2.3		EXPECTED FUEL GAS RATE 2.0 MMscfd
V-209	1	TEG INLET SEPARATOR	100 MMscfd	9300	90	1.5 ID x 4.5 T/T	V					CS	4	4.8		
V-210	1	TEG CONTACTOR	100 MMscfd	9300	90	1.2 ID x 8.0 T/T	V					CS	4	14.0		CRA CLAD
V-211A	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-211B	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-212	1	HOT OIL FILTER		1800	250	0.3 L x 0.3 W						CS	1	0.5		
E-201	1	CONDENSATE STABILISATION REBOILER		2000	250	1.1 ID x 6.3 T/T	KETL		3000	60	HOT OIL	CS	14	6.3		
E-202A	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 1.5 W	AIR CLR		880	42	AIR	CS	42	2.7		2 x 50%
E-202B	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 1.5 W	AIR CLR		880	42	AIR	CS	42	2.7		2 x 50%
E-203	1	GAS RECOVERY COMP. AFTERCOOLER		7000	150	12.0 L x 1.5 W	AIR CLR		250	11	AIR	CS	28	2.0		
E-204	1	CONDENSATE RUNDOWN COOLER		2000	250	12.0 L x 2.5 W	AIR CLR		2000	66	AIR	CS	56	5.4		
E-205	1	GAS / TEG EXCHANGER		9300	90	6.7 L x 0.4 W	S&T		50	30	GAS / TEG	CS	3	2.6		
C-201	1	BOOSTER COMPRESSOR		7000	90			1300	1100							DRIVEN BY TURBO EXPANDER K-201
C-202A	1	SALES GAS COMPRESSOR		9300	125			4200	2800							2 x 100%
C-202B	1	SALES GAS COMPRESSOR		9300	125			4200	2800							2 x 100%
C-203	1	GAS RECOVERY COMPRESSOR		2000	120			3900	180							
K-201	1	TURBO EXPANDER		6000	-29	3.0 L x 6.0 W		2450	1250				18	15.0		DRIVES SALES GAS COMPRESSOR LP STAGE C-201
K-202A	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3100				30	16.3		2 x 100% SOLAR CENTAUR
K-202B	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3100				30	16.3		2 x 100% SOLAR CENTAUR
K-203	1	GAS RECOVERY COMPRESSOR DRIVER				7.0 L x 3.0 W			250				21	15.8		GAS ENGINE
P-201A	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-201B	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-202A	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-202B	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-203A	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
P-203B	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
T-200A	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-200B	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-201	1	FIREWATER TANK	18000 BBL			7.3 ID x 12.2 T/T							100	61.5		
Z-201	1	ONSHORE TEG DEHYDRATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3		
Z-202A	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
Z-202B	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
X-200	1	PIG RECEIVER		13900	90	0.8 ID x 7.0 T/T	H					CS	12	4.8		TRUNKLINE PIG RECEIVER
X-201	1	PIG LAUNCHER		13900	90	0.6 ID x 6.0 T/T	H					CS	10	3.2		SALES GAS LINE PIG LAUNCHER
	1	POWER GENERATION	1 MW													
	1	CONTROL ROOM														
	1	WAREHOUSE														
	1	OFFICES														
	1	WORKSHOP														
	1	STORE														
	1	CPI SEPARATOR				3.0 L x 3.0 W							24			
	2	FIREWATER PUMPS		2000	80	3.4 L x 1.5 W							16	10.9		
	1	INSTRUMENT / SERVICE AIR PACKAGE		2000	80									30.0		
	1	STORM WATER DRAINAGE										TOTAL	1972	684.6	N/A	

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Vessel Weights Updated	24NOV98	[illegible signature]	[illegible signature]
B	Issued for Information	19NOV98	DAF	NJP
A	Initial Draft For Cost Estimating	03NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 1A

PREMIER OIL

PAGE 2 of 3 Doc. No.: 9843EL1A

YOLLA DEVELOPMENT CASE 1A
PROCESS/UTILITY EQUIPMENT LIST

PIPELINES

TAG NO.	QTY	DESCRIPTION	NOMINAL CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
	1	GAS / CONDENSATE SUBSEA PIPELINE	90 MMscfd	13900	100	12" x 130km x 10mmWT					CS				OFFSHORE FACILITY TO SHORE; 2 PHASE; API5LX65
	1	SALES GAS EXPORT PIPELINE	85 MMscfd	9300	100	10" x 30km x 7.9mmWT					CS				GAS EXPORT TO MAGNESITE MINE; API5LX52

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Vessel Weights Updated	24NOV98	MRH	DAF
B	Issued for Information	19NOV98	DAF	NJP
A	Initial Draft For Cost Estimating	03NOV98	MRH	NJP

WOODHILL THORNTON

Doc. No.: 9843EL1A

YOLLA DEVELOPMENT CASE 1A

PREMIER OIL

644127

OFFSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF. HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
WH-101A/B/C/D/E	5	PRODUCTION WELLHEADS - YOLLA														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
WH-102A/B	2	PRODUCTION WELLHEADS - WHITE IBIS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
V-101	1	PRODUCTION SEPARATOR	160 MMscfd	13900	90	2.5 ID x 14.0 T/T	H					CS	64	79.7	98.8	CRA CLAD
V-102	1	TEST SEPARATOR	25 MMscfd	13900	90	0.8 ID x 2.8 T/T	H					CS	8	2.5	3.6	CRA CLAD
V-103A	1	BOOSTER COMPRESSOR SUCTION DRUM	80 MMscfd	13900	90	1.5 ID x 5.1 T/T	V					CS	9	14.1	15.0	CRA CLAD
V-103B	1	BOOSTER COMPRESSOR SUCTION DRUM	80 MMscfd	13900	90	1.5 ID x 5.1 T/T	V					CS	9	14.1	15.0	CRA CLAD
V-104	1	TEG INLET SEPARATOR	160 MMscfd	13900	90	1.9 ID x 5.7 T/T	V					CS	9	24.2	28.2	CRA CLAD
V-105	1	TEG CONTACTOR	160 MMscfd	13900	90	1.5 ID x 8.0 T/T	V					CS	9	20.2	32.9	CRA CLAD
V-201	1	CONDENSATE FILTER	6700 BCPD	13900	90	0.5 ID x 1.5 T/T	V					CS	4	0.6	0.3	
V-202	1	CONDENSATE COALESCER	6700 BCPD	13900	90	1.0 ID x 2.2 T/T	H					CS	6	1.9	2.4	
V-301	1	LP FLARE / DRAIN DRUM		350	90	1.9 ID x 5.7 T/T	H					CS	21	5.3	10.2	DRAINAGE FROM V-101
V-302	1	PRODUCED WATER DEGASSER	1000 BWPD	350	90	1.0 ID x 3.5 T/T	H					CS	10	1.4	3.3	
V-303	1	HP FLARE DRUM	50 MMscfd	350	90	2.1 ID x 6.4 T/T	V					CS	9	8.0	11.9	
V-304	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	13900	90	0.5 ID x 1.8 T/T	V					CS	2	1.1	1.3	CRA CLAD
V-305	1	MEG STORAGE DRUM	200 BBL	350	90	3.0 ID x 4.5 T/T	H					CS	24	4.8	39.8	
HC-301	1	PRODUCED WATER HYDROCYCLONE	1000 BWPD	13900	90	0.7 ID x 2.0 T/T	H					CS	5	0.5	0.7	INCLUDES 100% SPARE CAPACITY, SS LINERS
E-101A	1	PRODUCTION COOLER		13900	90	12.0 L x 3.5 W	AIR CLR		2 x 1500	46.6	AIR	CRA TB	42	8.1	9.0	2 x 50%
E-101B	1	PRODUCTION COOLER		13900	90	12.0 L x 3.5 W	AIR CLR		2 x 1500	46.6	AIR	CRA TB	42	8.1	9.0	2 x 50%
E-201A	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 5.0 W	AIR CLR		2 x 5900	215.0	AIR	CRA TB	60	18.3	20.2	2 x 50%, MOUNTED ABOVE COMPR. SKIDS
E-201B	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 5.0 W	AIR CLR		2 x 5900	215.0	AIR	CRA TB	60	18.3	20.2	2 x 50%, MOUNTED ABOVE COMPR. SKIDS
E-202	1	GAS / TEG EXCHANGER		13900	110	6.7 L x 0.4 W	S&T		50	30.0	GAS / TEG	CS	3	6.5	9.8	
C-201A	1	BOOSTER COMPRESSOR	1870 act.m3/hr	13900	150	INCL IN DRIVER		8500	2900				INCLUDED IN DRIVER			
C-201B	1	BOOSTER COMPRESSOR	1870 act.m3/hr	13900	150	INCL IN DRIVER		8500	2900				INCLUDED IN DRIVER			
K-201A	1	BOOSTER COMPRESSOR DRIVER				8.5 L x 2.4 W							21	16.3	22.5	2 x 50% SOLAR CENTAUR 50'S
K-201B	1	BOOSTER COMPRESSOR DRIVER				8.5 L x 2.4 W							21	16.3	22.5	2 x 50% SOLAR CENTAUR 50'S
P-201A	1	CONDENSATE BOOSTER PUMP	50 m3/hr	13900	90	5.0 L x 2.0 W		8500	170				10	2.0	2.0	2 x 50%
P-201B	1	CONDENSATE BOOSTER PUMP	50 m3/hr	13900	90	5.0 L x 2.0 W		8500	170				10	2.0	2.0	2 x 50%
P-202A	1	LP FLARE / DRAIN DRUM PUMP	40 m3/hr	500	90	3.0 L x 1.0 W		350	7.3				3	0.6	0.6	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-202B	1	LP FLARE / DRAIN DRUM PUMP	40 m3/hr	500	90	3.0 L x 1.0 W		350	7.3				3	0.6	0.6	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-301A	1	HP FLARE DRUM PUMP	40 m3/hr	13900	90	6.0 L x 2.5 W		12650	267				15	4.0	4.0	2 x 50%
P-301B	1	HP FLARE DRUM PUMP	40 m3/hr	13900	90	6.0 L x 2.5 W		12650	267				15	4.0	4.0	2 x 50%
P-302A	1	MEG INJECTION PUMPS	0.3 m3/hr	1000	90	1.0 L x 1.0 W		500	0.5				1	0.2	0.2	2 x 100%
P-302B	1	MEG INJECTION PUMPS	0.3 m3/hr	1000	90	1.0 L x 1.0 W		500	0.5				1	0.2	0.2	2 x 100%
X-100	1	PIG LAUNCHER		13900	90	0.8 ID x 7.0 T/T						CS	12	4.8	4.8	
Z-201	1	TEG REGENERATION PACKAGE	160 MMscfd			9.0 L x 4.5 W							41	49.7	97.0	DESIGN WATER FLOW 1200 BWPD
Z-301	1	MEG REGENERATION PACKAGE	140BPD			5.0 L x 2.0 W							10	8.0	15.6	DESIGN 100BWPD, 40BPD OF MEG
	1	POWER GENERATION				10.0 L x 10.0 W			1500				100	23.0	30.0	NORMAL / STANDBY / EMERGENCY
	1	FLARE TIP / IGNITION SYSTEM	50 MMscfd			1.0 L x 5.0 W							5	0.6	1.0	
	2	FIRE PUMPS	1500 GPM			6.0 L x 3.0 W							20	15.0	20.0	
	1	WORKOVER FACILITIES												20.0	20.0	
	1	ACCOMMODATION	15 PPL/30 BEDS			15.0 L x 10.0 W							150	150.0	150.0	
	1	POTABLE WATER PACKAGE				7.0 L x 8.0 W							60	10.0	15.0	
	1	HVAC				3.0 L x 3.0 W							10	3.0	5.0	
	1	CRANE												30.0	30.0	
	1	INSTRUMENT / SERVICE AIR PACKAGE				4.0 L x 8.0 W							35	17.0	25.0	
	1	DIESEL FUEL SUPPLY / TREATMENT	10 DAYS			3.0 L x 3.0 W							10	5.0	8.5	
	1	GLYCOL STORAGE / TRANSFER PUMP	5 m3			2.0 L x 3.0 W							10	5.0	8.0	
	2	SURVIVAL CRAFT	20 MEN											5.0	7.0	
	1	HELIDECK												100.0	100.0	
	1	SEWAGE TREATMENT UNIT	30 MEN			2.0 L x 3.0 W							6	1.0	3.0	
												TOTAL	985	751.0	957.0	

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	DAF	NJP
C	Vessel Weights Updated	24NOV98	MRH	DAF
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 2A

PREMIER OIL

PAGE 1 of 4 Doc. No.: 9843EL2A

644128

ONSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF. HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
V-201A	1	SLUGCATCHER	2100 BBL	9300	80	3.5 ID x 35.0 T/T	H					CS	200	226.0		3 x 33%, EPOXY LINED
V-201B	1	SLUGCATCHER	2100 BBL	9300	80	3.5 ID x 35.0 T/T	H					CS	200	226.0		3 x 33%, EPOXY LINED
V-201C	1	SLUGCATCHER	2100 BBL	9300	80	3.5 ID x 35.0 T/T	H					CS	200	226.0		3 x 33%, EPOXY LINED
V-202	1	CONDENSATE STABILISER COLUMN	8500 BBL/d	2000	230	2.2 ID x 18.3 T/T	V					CS	9	27.5		22 TRAYS (SS)
V-203	1	LOW TEMPERATURE SEPARATOR	130 MMscfd	6000	-70	2.1 ID x 7.0 T/T	V					SS	9	8.5		
V-204A	1	SALES GAS COMP. SUCTION DRUM	65 MMscfd	4000	90	1.6 ID x 5.6 T/T	V					CS	9	6.1		2 x 50%
V-204B	1	SALES GAS COMP. SUCTION DRUM	65 MMscfd	4000	90	1.6 ID x 5.6 T/T	V					CS	9	6.1		2 x 50%
V-205A	1	SALES GAS COMP. DISCHARGE DRUM	65 MMscfd	12000	90	1.3 ID x 4.4 T/T	V					CS	9	10.3		2 x 50%
V-205B	1	SALES GAS COMP. DISCHARGE DRUM	65 MMscfd	12000	90	1.3 ID x 4.4 T/T	V					CS	9	10.3		2 x 50%
V-206	1	GAS RECOVERY COMP. SUCTION DRUM	3.5 MMscfd	2000	90	0.8 ID x 2.5 T/T	V					CS	4	0.9		
V-207	1	FLARE DRUM	50 MMscfd	350	80	2.4 ID x 7.2 T/T	H					CS	24	11.4		
V-208	1	FUEL GAS KNOCKOUT DRUM	10 MMscfd	7000	120	0.8 ID x 2.5 T/T	V					CS	4	1.5		EXPECTED FUEL GAS RATE 10.0 MMscfd
V-209	1	TEG INLET SEPARATOR	135 MMscfd	9300	90	1.8 ID x 5.4 T/T	V					CS	6.5	14.9		
V-210A	1	HOT OIL DRUM		1000	250	2.1 ID x 6.3 T/T	H					CS	21	7.3		
V-210B	1	HOT OIL DRUM		1000	250	2.1 ID x 6.3 T/T	H					CS	21	7.3		
V-211	1	HOT OIL FILTER		1800	250	0.5 L x 0.5 W	V					CS	1	0.3		
V-212	1	TEG CONTACTOR	135 MMscfd	9300	90	1.4 ID x 8.0 T/T	V					CS	6.5	12.5		
V-213	1	DE-ETHANISER	5100 BBL/d	2500	160	1.0 ID x 15.0 T/T	V					CS	4	6.6		
V-214	1	DE-ETHANISER OVERHEADS COMP. SUCTI	4.3 MMscfd	2500	90	0.8 ID x 2.5 T/T	V					CS	4	1.0		
V-215	1	DEPROPANISER	2800 BBl/d	2500	160	1.7 ID x 25.0 T/T	V					CS	6.5	26.8		
V-216	1	DEPROPANISER REFLUX DRUM	7300 BBl/d	2500	90	2.0 ID x 5.5 T/T	H					CS	21	7.1		
V-217	1	DEBUTANISER	1800 BBl/d	1000	160	1.7 ID x 19.0 T/T	V					CS	9	19.3		
V-218	1	DEBUTANISER REFLUX DRUM	6600 BBl/d	1000	90	2.0 ID x 5.5 T/T	H					CS	21	5.8		
V-219	1	COLD SEPARATOR	130 MMscfd	9300	-20	1.7 ID x 5.1 T/T	V					CS	9	12.8		
V-220	1	AMINE CONTACTOR INLET SEPARATOR	160 MMscfd	9300	90	1.8 ID x 5.4 T/T	V					CS	6.5	3.2		
V-221	1	AMINE CONTACTOR	160 MMscfd	9300	90	2.7 ID x 18.0 T/T	V					CS	16	72.4		SS CLAD
V-222	1	AMINE CONTACTOR OUTLET SEPARATOR	135 MMscfd	9300	90	1.5 ID x 4.5 T/T	V					CS	9	9.2		SS CLAD
V-223	1	AMINE STRIPPING COLUMN	2850 USgpm	350	135	5.7 ID x 16.0 T/T	V					CS	50	92.3		SS CLAD
V-224	1	AMINE SURGE TANK	2850 USgpm	350	90	4.7 ID x 18.8 T/T	H					CS	120	82.0		SS CLAD
V-225	1	AMINE STRIPPER REFLUX DRUM	2850 USgpm	350	90	4.1 ID x 4.7 T/T	H					CS	36	15.9		SS CLAD
V-226	1	AMINE FLASH TANK	2850 USgpm	350	90	4.7 ID x 18.8 T/T	H					CS	120	82.0		SS CLAD
V-227	1	AMINE CARBON FILTER	2850 USgpm	350	90	4.1 ID x 4.7 T/T	H					SS	36	15.9		SS CLAD
V-228	1	AMINE PHYSICAL FILTER	2850 USgpm	350	90	4.1 ID x 4.7 T/T	H					SS	36	15.9		
V-229	1	MERCURY GUARD BED	130 MMscfd	9300	90	2.3 ID x 3.5 T/T	V					CS	13	8.0		
E-201	1	CONDENSATE STABILISER REBOILER		2000	250	1.4 ID x 5.0 T/T	KETTLE		6000	120	HOT OIL	CS	21	8.5		
E-202A	1	SALES GAS COMP. AFTERCOOLER		12000	190	12.0 L x 3.2 W	ACHE		2 x 3900	135	AIR	CS	48	9.6		2 x 50%
E-202B	1	SALES GAS COMP. AFTERCOOLER		12000	190	12.0 L x 3.2 W	ACHE		2 x 3900	135	AIR	CS	48	9.6		2 x 50%
E-203	1	GAS RECOVERY COMP. AFTERCOOLER		7000	160	12.0 L x 1.0 W	ACHE		320	10	AIR	CS	12	0.7		
E-204	1	CONDENSATE RUNDOWN COOLER		2000	250	12.0 L x 4.0 W	ACHE		3900	66	AIR	CS	48	10.1		
E-205	1	GAS / TEG EXCHANGER		9300	90	6.7 L x 0.4 W	S&T		50	30	GAS / TEG	CS	3	2.6		
E-206	1	RECOVERED LIQUIDS RUNDOWN COOLER		1000	160	12.0 L x 1.0 W	ACHE		140	8	AIR	CS	12	0.7		
E-207	1	DEPROPANISER CONDENSER		2500	90	12.0 L x 4.5 W	ACHE		1900	180	AIR	CS	60	12.4		
E-208	1	DEBUTANISER CONDENSER		1000	90	12.0 L x 5.0 W	ACHE		2600	325	AIR	CS	66	22.5		
E-209	1	DE-ETHANISER REBOILER		2500	250	0.5 ID x 5.2 T/T	KETTLE		810	7	HOT OIL	CS	11	1.1		
E-210	1	DEPROPANISER REBOILER		2500	250	0.8 ID x 3.2 T/T	KETTLE		2200	25	HOT OIL	CS	10	1.8		
E-211	1	DEBUTANISER REBOILER		1000	160	0.8 ID x 2.7 T/T	KETTLE		2200	25	HOT OIL	CS	8	1.5		
E-212	1	PLATEFIN EXCHANGER		9300	90/-70	4.0 L x 3.0 W	PLATE-FIN		3720		GAS/GAS	AL	12	3.0		
E-213	1	AMINE STRIPPER REBOILER		350	135		KETTLE		60,000	3000	HOT OIL	CS				SS CLAD, SS TUBES
E-214	1	RICH-LEAN AMINE EXCHANGER		350	135	4.0 L x 3.0 W	S&T		38,000	3000	PROCESS	CS	12	20.0		SS CLAD, SS TUBES
E-215	1	AMINE COOLER		9300	90	12.0 L x 4.0 W	ACHE		12,500	121	AIR	CS	48	9.6		SS TUBES
E-216	1	AMINE STRIPPER REFLUX CONDENSER		350	90	12.0 L x 2.5 W	ACHE		25,000	62	AIR	CS	30	5.4		SS TUBES

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	DAF	NJP
C	Vessel Weights Updated	24NOV98	MRH	DAF
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT

CASE 2A

PREMIER OIL

Doc. No.: 9843EL2A

64129

ONSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
C-201	1	BOOSTER COMPRESSOR		7000	90	INCL IN DRIVER		2000	1800			CS	INCLUDED IN DRIVER			DRIVEN BY TURBO EXPANDER K-201
C-202A	1	SALES GAS COMPRESSOR		10,000	190	INCL IN DRIVER		6000	2 x 3850			CS	INCLUDED IN DRIVER			2 x 50%
C-202B	1	SALES GAS COMPRESSOR		10,000	190	INCL IN DRIVER		6000	2 x 3850			CS	INCLUDED IN DRIVER			2 x 50%
C-203	1	GAS RECOVERY COMPRESSOR		6000	120	INCL IN DRIVER		3900	405			CS	INCLUDED IN DRIVER			
C-204	1	DE-ETHANISER OH'S COMPRESSOR		7000	90	INCL IN DRIVER		1000	75			CS	INCLUDED IN DRIVER			
K-201	1	TURBO EXPANDER		9300	-70	7.0 L x 4.0 W		3150	1900				28	10.5		DRIVES BOOSTER COMPRESSOR C-201
K-202A	1	SALES GAS COMPRESSOR DRIVER				8.5 L x 2.4 W			2 x 4700				21	16.3		2 x 100% SOLAR TAURUS (APPROX SITE RATED DUTY)
K-202B	1	SALES GAS COMPRESSOR DRIVER				8.5 L x 2.4 W			2 x 4700				21	16.3		2 x 100% SOLAR TAURUS (APPROX SITE RATED DUTY)
K-203	1	GAS RECOVERY COMPRESSOR DRIVER				7.9 L x 3.6 W			425				29	23.6		ELECTRIC MOTOR
K-204	1	DE-ETHANISER OH'S COMPRESSOR DRIVER				6.0 L x 3.0 W			80				18	5.9		ELECTRIC MOTOR
P-201A	1	CONDENSATE PRODUCT PUMP	55 m3/hr	8000	90	3.0 L x 2.0 W		5000	135				6	2.5		2 x 100%, TO BE CONFIRMED
P-201B	1	CONDENSATE PRODUCT PUMP	55 m3/hr	8000	90	3.0 L x 2.0 W		5000	135				6	2.5		2 x 100%, TO BE CONFIRMED
P-202A	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	7.3				3	0.6		2 x 100%
P-202B	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	7.3				3	0.6		2 x 100%
P-203A	1	HOT OIL PUMP	210 m3/hr	1800	250	1.8 L x 0.7 W			2 x 40				2	1.0		2 x 50%
P-203B	1	HOT OIL PUMP	210 m3/hr	1800	250	1.8 L x 0.7 W			2 x 40				2	1.0		2 x 50%
P-204A	1	DEPROPANISER FEED PUMP	20 m3/hr	2500	250	2.0 L x 1.0 W		300	3				2	0.5		2 x 100%
P-204B	1	DEPROPANISER FEED PUMP	20 m3/hr	2500	250	2.0 L x 1.0 W		300	3				2	0.5		2 x 100%
P-205A	1	AMINE PUMP	2850 USgpm	1000	135	5.0 L x 2 W		4500	1000				10	10.0		2 x 100%
P-205B	1	AMINE PUMP	2850 USgpm	1000	135	5.0 L x 2 W		4500	1000				10	10.0		2 x 100%
P-206A	1	AMINE BOOSTER PUMP	2850 USgpm	9300	135	3.0 L x 1.5 W		500	126				4.5	2.0		2 x 100%
P-206B	1	AMINE BOOSTER PUMP	2850 USgpm	9300	135	3.0 L x 1.5 W		500	126				4.5	2.0		2 x 100%
P-207A	1	AMINE STRIPPER REFLUX PUMP		350	90	3.0 L x 1.5 W		500	126				4.5	2.0		2 x 100%
P-207B	1	AMINE STRIPPER REFLUX PUMP		350	90	3.0 L x 1.5 W		500	126				4.5	2.0		2 x 100%
P-208A	1	PROPANE LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-208B	1	PROPANE LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-208C	1	PROPANE LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-209A	1	LPG LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-209B	1	LPG LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-209C	1	LPG LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
T-200A	1	CONDENSATE STORAGE TANK	50,000 BBL	17	80	26.0 ID x 16.0 H	V					CS	830			EACH TANK 6 DAYS STORAGE
T-200B	1	CONDENSATE STORAGE TANK	50,000 BBL	17	80	26.0 ID x 16.0 H	V					CS	830			EACH TANK 6 DAYS STORAGE
T-201	1	FIREWATER TANK	18000 BBL			7.3 ID x 12.2 T/T							100	61.5		
T-202A	1	PROPANE STORAGE SPHERES	830 tonnes	2000	90	9.6 ID	V					CS	144	120.0		EACH SPHERE 5 DAYS STORAGE
T-202B	1	PROPANE STORAGE SPHERES	830 tonnes	2000	90	9.6 ID	V					CS	144	120.0		EACH SPHERE 5 DAYS STORAGE
T-203A	1	LPG STORAGE SPHERES	1040 tonnes	1000	90	9.6 ID	V					CS	144	120.0		EACH SPHERE 5 DAYS STORAGE
T-203B	1	LPG STORAGE SPHERES	1040 tonnes	1000	90	9.6 ID	V					CS	144	120.0		EACH SPHERE 5 DAYS STORAGE
Z-201	1	ONSHORE TEG DEHYDRATION PACKAGE	155 MMscfd			9.0 L x 4.5 W							41	49.7		
Z-202A	1	WASTE HEAT RECOVERY UNIT		1800	250	10.5 L x 10.2 W			10,600				110	60.0		
Z-202B	1	WASTE HEAT RECOVERY UNIT		1800	250	10.5 L x 10.2 W			10,600				110	60.0		
Z-203	1	FIRED HEATER							61,000							
Z-204	1	PROPANE EXPORT METERING SKID	324 m3/hr	700	90	7.0 L x 6.0 W						CS	42	10.0		
Z-205	1	LPG EXPORT METERING SKID	324 m3/hr	700	90	7.0 L x 6.0 W						CS	42	10.0		
X-200	1	PIG RECEIVER		13900	90	1.1 ID x 9.6 T/T	H					CS	22	14.0		TRUNKLINE PIG RECEIVER
X-201	1	PIG LAUNCHER		13900	90	0.6 ID x 6.0 T/T	H					CS	10	4.7		SALES GAS LINE PIG LAUNCHER
	1	POWER GENERATION	2.5 MW													
	1	CONTROL ROOM														
	1	WAREHOUSE														
	1	OFFICES														
	1	WORKSHOP														
	1	STORE														
	1	CPI SEPARATOR				3.0 L x 3.0 W							24			
	2	FIREWATER PUMPS		2000	80	3.4 L x 1.5 W							16	10.9		
	1	INSTRUMENT / SERVICE AIR PACKAGE		2000	80									30.0		
	1	STORM WATER DRAINAGE														
												TOTAL	4694	2315.7	N/A	

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	[illegible]	[illegible]
C	Vessel Weights Updated	24NOV98	MRH	DAF
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 2A

PREMIER OIL

Doc. No.: 9843EL2A

64130

PIPELINES

TAG NO.	QTY	DESCRIPTION	NOMINAL CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS	DIFF. HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
	1	GAS / CONDENSATE SUBSEA PIPELINE	160 MMscfd	13,900	100	16" x 190km x 11.8mmWT					CS				OFFSHORE FACILITY TO VICTORIA; 2 PHASE; API5LX65
															CRA COATED FOR FIRST 24km (MECH BONDED)
	1	SALES GAS EXPORT PIPELINE	130 MMscfd	12,000	100	12" x 35km x 7.9mmWT					CS				SALESGAS LINE; API5LX52
	1	WHITE IBIS FLOWLINE	45 MMscfd	23,200	100	8" x 40km x 10.9mmWT					CS				WHITE IBIS FLOWLINE; API5LX65
															CRA COATED FOR FIRST 20km (MECH BONDED)
	1	WHITE IBIS MEG INJECTION PIGGY-BACK LI	40BMEGPD	23,200	100	2" x 40km x 5.2mmWT					CS				MEG PIGGY BACK LINE TO WHITE IBIS WELL; API5LX65

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	[signature]	[signature]
C	Vessel Weights Updated	24NOV98	MRH	DAF
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 2A

PREMIER OIL

Doc. No.: 9843EL2A

PROCESS/UTILITY EQUIPMENT LIST

OFFSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	POWER / DUTY (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
WH-101A..E	5	GAS PRODUCTION WELLHEADS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
WH-301A..E	5	OIL PRODUCTION WELLHEADS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
V-101	1	GAS PRODUCTION SEPARATOR	100 MMscfd	13900	90	1.7 ID x 5.0 T/T	H					CS	18	16.8	20.0	CRA CLAD
V-102	1	GAS TEST SEPARATOR	25 MMscfd	13900	90	0.8 ID x 2.8 T/T	H					CS	8	2.5	3.6	CRA CLAD
V-103A	1	BOOSTER COMPRESSOR SUCTION DRUM	100 MMscfd	13900	90	1.4 ID x 4.9 T/T	V					CS	4	12.2	14.5	CRA CLAD, 2 x 50%
V-103B	1	BOOSTER COMPRESSOR SUCTION DRUM	100 MMscfd	13900	90	1.4 ID x 4.9 T/T	V					CS	4	12.2	14.5	CRA CLAD, 2 x 50%
V-104	1	TEG INLET SEPARATOR	100 MMscfd	13900	90	1.5 ID x 4.5 T/T	V					CS	9	13.9	16.7	CRA CLAD
V-105	1	TEG CONTACTOR	100 MMscfd	13900	90	1.2 ID x 8.0 T/T	V					CS	4	14.0	20.8	CRA CLAD
V-201	1	CONDENSATE FILTER	4000 BCPD	13900	90	0.4 ID x 1.2 T/T	V					CS	1	0.8	0.7	
V-202	1	CONDENSATE COALESCER	4000 BCPD	13900	90	0.8 ID x 1.8 T/T	H					CS	4	1.9	2.4	
V-301	1	OIL FIRST STAGE SEPARATOR	20000 BOPD	2500	90	2.1 ID x 7.9 T/T	H					CS	27	12.7	26.4	5 MIN OIL, EPOXY COATED, INSULATED, HEAT TRACED
V-302	1	OIL TEST SEPARATOR	5000 BOPD	2500	900	1.4 ID x 4.4 T/T	H					CS	12	3.8	7.2	5 MIN OIL, EPOXY COATED, INSULATED, HEAT TRACED
V-303	1	SECOND STAGE SEPARATOR	20000 BOPD	2500	90	2.7 ID x 11.0 T/T	H					CS	42	26.2	57.7	15 MINUTES OIL RESIDENCE TIME
V-401	1	LP GR COMPRESSOR SUCTION DRUM	2 MMscfd	2500	90	0.8 ID x 1.8 T/T	V					CS	4	0.8	1.1	
V-402	1	LP GR COMPRESSOR INTERSTAGE DRUM	2 MMscfd	2500	120	0.8 ID x 1.8 T/T	V					CS	4	0.8	1.1	
V-403A	1	HP GR COMPRESSOR SUCTION DRUM	25 MMscfd	3000	120	1.0 ID x 2.5 T/T	V					CS	4	1.7	2.3	2 x 50%
V-403B	1	HP GR COMPRESSOR SUCTION DRUM	25 MMscfd	3000	120	1.0 ID x 2.5 T/T	V					CS	4	1.7	2.3	2 x 50%
V-404A	1	HP GR COMPRESSOR INTERSTAGE DRUM	25 MMscfd	3000	120	1.0 ID x 2.5 T/T	V					CS	4	1.7	2.3	2 x 50%
V-404B	1	HP GR COMPRESSOR INTERSTAGE DRUM	25 MMscfd	3000	120	1.0 ID x 2.5 T/T	V					CS	4	1.7	2.3	2 x 50%
V-501	1	LP FLARE / DRAIN DRUM		350	90	2.7 ID x 11.0 T/T	H					CS	42	26.2	57.7	
V-502	1	GAS PRODUCED WATER DEGASSER	1000 BWPD	350	90	1.0 ID x 3.5 T/T	H					CS	10	1.4	3.3	
V-503	1	HP FLARE DRUM	75 MMscfd	350	90	2.6 ID x 7.6 T/T	V					CS	13	12.8	24.9	
V-504	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	13900	90	0.7 ID x 2.0 T/T	V					CS	2	0.9	1.1	CRA CLAD
V-505	1	OIL PRODUCED WATER DEGASSER	20000 BWPD	350	90	3.0 ID x 9.0 T/T	H					CS	40	18.8	50.6	CRA CLAD
HC-101	1	GAS PRODUCED WATER HYDROCYCLONE	1000 BWPD	13900	90	0.7 ID x 2.0 T/T	H					CS	8	0.5	0.7	SS LINERS
HC-301	1	OIL PRODUCED WATER HYDROCYCLONE	20000 BWPD	2500	90	3.8 L x 3.2 W						CS	12	2.0	2.7	
E-101A	1	PRODUCTION COOLER		13900	90	12.0 L x 3.0 W	AIR CLR		1250	90.8	AIR	CRA TB	36	6.4	7.0	3 x 33%
E-101B	1	PRODUCTION COOLER		13900	90	12.0 L x 3.0 W	AIR CLR		1250	90.8	AIR	CRA TB	36	6.4	7.0	3 x 33%
E-101C	1	PRODUCTION COOLER		13900	90	12.0 L x 3.0 W	AIR CLR		1250	90.8	AIR	CRA TB	36	6.4	7.0	3 x 33%
E-201A	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	90	12.0 L x 5.0 W	AIR CLR		4000	195.5	AIR	CRA TB	60	13.6	15.0	2 x 50%
E-201B	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	90	12.0 L x 5.0 W	AIR CLR		4000	195.5	AIR	CRA TB	60	13.6	15.0	2 x 50%
E-202	1	GAS / TEG EXCHANGER		13900	110	6.7 L x 0.4 W	S&T		50	30.0	GAS / TEG	CS	3	6.5	9.8	
E-301	1	OIL HEATER		2500	90		S&T		TBA		ELECTRIC	CS				
E-401	1	LP GR COMPRESSOR INTERCOOLER		2500	120	12.0 L x 1.0 W	AIR CLR		80	4.9	AIR	CRA TB	12	0.9	1.0	
E-402	1	LP GR COMPRESSOR AFTERCOOLER		3000	120	12.0 L x 1.0 W	AIR CLR		90	4.8	AIR	CRA TB	12	0.9	1.0	
E-403A	1	HP GR COMPRESSOR INTERCOOLER		3000	120	12.0 L x 2.5 W	AIR CLR		1200	68.0	AIR	CRA TB	30	5.4	6.0	2 x 50%
E-403B	1	HP GR COMPRESSOR INTERCOOLER		3000	120	12.0 L x 2.5 W	AIR CLR		1200	68.0	AIR	CRA TB	30	5.4	6.0	2 x 50%
C-201A	1	BOOSTER COMPRESSOR		13900	150			8500	2400							
C-201B	1	BOOSTER COMPRESSOR		13900	150			8500	2400							
K-201A	1	BOOSTER COMPRESSOR DRIVER				10.0 L x 3.0 W			3000				30	16.3	22.5	2 x 50% SOLAR CENTAURS
K-201B	1	BOOSTER COMPRESSOR DRIVER				10.0 L x 3.0 W			3000				30	16.3	22.5	2 x 50% SOLAR CENTAURS
C-401	1	LP GAS RECOVERY COMPRESSOR STAGE 1		2500	150			3000	60							
C-402	1	LP GAS RECOVERY COMPRESSOR STAGE 2		2500	150			8000	60							
K-401	1	LP GAS RECOVERY COMPRESSOR DRIVER				7.0 L x 2.5 W			150				18	8.0	11.0	
C-403A	1	HP GAS RECOVERY COMPRESSOR STAGE 1		3000	150			12000	950							2 x 50%
C-403B	1	HP GAS RECOVERY COMPRESSOR STAGE 1		3000	150			12000	950							2 x 50%
C-404A	1	HP GAS RECOVERY COMPRESSOR STAGE 2		9300	150			12000	950							2 x 50%
C-404B	1	HP GAS RECOVERY COMPRESSOR STAGE 2		9300	150			12000	950							2 x 50%
K-402A	1	HP GAS RECOVERY COMPRESSOR DRIVER				8.0 L x 2.0 W			1100				16	12.0	16.6	2 x 50% SOLAR SATURNS
K-402B	1	HP GAS RECOVERY COMPRESSOR DRIVER				8.0 L x 2.0 W			1100				16	12.0	16.6	2 x 50% SOLAR SATURNS
P-101A	1	LP FLARE / DRAIN DRUM PUMP	40 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4	0.4	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-101B	1	LP FLARE / DRAIN DRUM PUMP	40 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4	0.4	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-102A	1	HP FLARE DRUM PUMP	40 m3/hr	13900	90	6.0 L x 2.5 W		12650	160				15	2.7	2.7	2 x 100%
P-102B	1	HP FLARE DRUM PUMP	40 m3/hr	13900	90	6.0 L x 2.5 W		12650	160				15	2.7	2.7	2 x 100%
P-201A	1	CONDENSATE BOOSTER PUMP	30 m3/hr	13900	90	5.0 L x 2.0 W		8500	60				10	1.7	1.7	2 x 100%
P-201B	1	CONDENSATE BOOSTER PUMP	30 m3/hr	13900	90	5.0 L x 2.0 W		8500	60				10	1.7	1.7	2 x 100%
P-301A	1	CRUDE EXPORT PUMP	150 m3/hr	2500	90	4.0 L x 2.0 W		1200	50				8	1.2	1.2	2 x 100%
P-301B	1	CRUDE EXPORT PUMP	150 m3/hr	2500	90	4.0 L x 2.0 W		1200	50				8	1.2	1.2	2 x 100%
												TOTAL	1224	766.6	1011.5	

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Vessel Weights Updated	24NOV98	[signature]	[signature]
B	Issued for Information	19NOV98	DAF	NJP
A	Initial Draft For Cost Estimating	06NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 3A

PREMIER OIL

Doc. No.: 9843EL3A

641132

YOLLA DEVELOPMENT CASE 3A
PROCESS/UTILITY EQUIPMENT LIST

OFFSHORE EQUIPMENT - MISCELLANEOUS AND PACKAGED EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	POWER / DUTY (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
X-100	1	PIG LAUNCHER		13900	90	0.8 ID x 7.0 T/T						CS	14	4 8	4 8	
Z-201	1	TEG REGENERATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3	57 4	DESIGN WATER FLOW 40 BWPD
	1	POWER GENERATION				10.0 L x 10.0 W			2000				100	23.0	30.0	NORMAL / STANDBY / EMERGENCY
	1	FLARE TIP / IGNITION SYSTEM	75 MMscfd			1.0 L x 5.0 W							5	0.6	1.0	
	2	FIRE PUMPS	1500 GPM			6.0 L x 3.0 W							20	15.0	20.0	
	1	WORKOVER FACILITIES												20.0	20.0	
	1	ACCOMMODATION	15 PPL/30 BEDS			15.0 L x 10.0 W							150	150.0	150.0	
	1	POTABLE WATER PACKAGE	*			7.0 L x 8.0 W							60	10.0	15.0	
	1	HVAC				3.0 L x 3.0 W							10	3.0	5.0	
	1	CRANE												30.0	30.0	
	1	INSTRUMENT / SERVICE AIR PACKAGE				4.0 L x 8.0 W							35	17.0	25.0	
	1	DIESEL FUEL SUPPLY / TREATMENT	10 DAYS			3.0 L x 3.0 W							10	5.0	8.5	
	1	GLYCOL STORAGE / TRANSFER PUMP	5 m3			2.0 L x 3.0 W							10	5.0	8.0	
	1	SURVIVAL CRAFT												5.0	7.0	
	1	SEWAGE TREATMENT UNIT	30 MEN			2.0 L x 3.0 W							6	1.0	3.0	
	1	HELIDECK												100.0	100.0	
	1	CALM BUOY														
	1	OFFSHORE LOADING LINE				250NB x 2km										
												TOTAL	1224	766.6	1011.5	

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Vessel Weights Updated	24NOV98	[signature]	[signature]
B	Issued for Information	19NOV98	DAF	NJP
A	Initial Draft For Cost Estimating	06NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 3A

PREMIER OIL

PAGE 2 of 4 | Doc. No.: 9843EL3A

644133

ONSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S & T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
V-201A	1	SLUGCATCHER	800 BBL	9300	80	3.0 ID x 30.0 T/T	H					CS	140	149.5		2 x 50%, EPOXY LINED
V-201B	1	SLUGCATCHER	800 BBL	9300	80	3.0 ID x 30.0 T/T	H					CS	140	149.5		2 x 50%, EPOXY LINED
V-202	1	CONDENSATE STABILISATION COLUMN	4000 BBL/d	2000	230	1.5 ID x 18.3 T/T	V					CS	4	15.7		22 TRAYS
V-203	1	LOW TEMPERATURE SEPARATOR	95 MMscfd	6000	-29	1.8 ID x 6.0 T/T	V					CS	6	11.5		
V-204A	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-204B	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-205A	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-205B	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-206	1	GAS RECOVERY COMP. SUCTION DRUM	3.5 MMscfd	2000	90	0.8 ID x 2.5 T/T	V					CS	4	1.0		
V-207	1	FLARE DRUM	50 MMscfd	350	80	2.4 ID x 7.2 T/T	H					CS	24	10.7		
V-208	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	7000	120	0.8 ID x 2.5 T/T	V					CS	4	2.3		EXPECTED FUEL GAS RATE 2.0 MMscfd
V-209	1	TEG INLET SEPARATOR	100 MMscfd	9300	90	1.5 ID x 4.5 T/T	V					CS	4	4.8		
V-210	1	TEG CONTACTOR	100 MMscfd	9300	90	1.2 ID x 8.0 T/T	V					CS	4	14.0		CRA CLAD
V-211A	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-211b	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-212	1	HOT OIL FILTER		1800	250	0.3 L x 0.3 W						CS	1	0.5		
E-201	1	CONDENSATE STABILISATION REBOILER		2000	250	1.1 ID x 6.3 T/T	KETL		3000	60	HOT OIL	CS	14	6.3		
E-202A	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 1.5 W	AIR CLR		880	42	AIR	CS	42	2.7		2 x 50%
E-202B	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 1.5 W	AIR CLR		880	42	AIR	CS	42	2.7		2 x 50%
E-203	1	GAS RECOVERY COMP. AFTERCOOLER		7000	150	12.0 L x 1.5 W	AIR CLR		250	11	AIR	CS	28	2.0		
E-204	1	CONDENSATE RUNDOWN COOLER		2000	250	12.0 L x 2.5 W	AIR CLR		2000	66	AIR	CS	56	5.4		
E-205	1	GAS / TEG EXCHANGER		9300	90	6.7 L x 0.4 W	S&T		50	30	GAS / TEG	CS	3	2.6		
C-201	1	BOOSTER COMPRESSOR		7000	90			1300	1100							DRIVEN BY TURBO EXPANDER K-201
C-202A	1	SALES GAS COMPRESSOR		9300	125			4200	2800							2 x 100%
C-202B	1	SALES GAS COMPRESSOR		9300	125			4200	2800							2 x 100%
C-203	1	GAS RECOVERY COMPRESSOR		2000	120			3900	180							
K-201	1	TURBO EXPANDER		6000	-29	3.0 L x 6.0 W		2450	1250				18	15.0		DRIVES SALES GAS COMPRESSOR LP STAGE C-201
K-202A	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3100				30	16.3		2 x 100% SOLAR CENTAUR
K-202B	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3100				30	16.3		2 x 100% SOLAR CENTAUR
K-203	1	GAS RECOVERY COMPRESSOR DRIVER				7.0 L x 3.0 W			250				21	15.8		GAS ENGINE
P-201A	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-201B	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-202A	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-202B	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-203A	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
P-203B	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
T-200A	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-200B	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-201	1	FIREWATER TANK	18000 BBL			7.3 ID x 12.2 T/T							100	61.5		
Z-201	1	ONSHORE TEG DEHYDRATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3		
Z-202A	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
Z-202B	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
X-200	1	PIG RECEIVER		13900	90	0.8 ID x 7.0 T/T	H					CS	12	4.8		TRUNKLINE PIG RECEIVER
X-201	1	PIG LAUNCHER		13900	90	0.6 ID x 6.0 T/T	H					CS	10	3.2		SALES GAS LINE PIG LAUNCHER
	1	POWER GENERATION	1 MW													
	1	CONTROL ROOM														
	1	WAREHOUSE														
	1	OFFICES														
	1	WORKSHOP														
	1	STORE														
	1	CPI SEPARATOR				3.0 L x 3.0 W							24			
	2	FIREWATER PUMPS		2000	80	3.4 L x 1.5 W							16	10.9		
	1	INSTRUMENT / SERVICE AIR PACKAGE		2000	80									30.0		
	1	STORM WATER DRAINAGE														
												TOTAL	1972	684.6	N/A	

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Vessel Weights Updated	24NOV98	[signature]	[signature]
B	Issued for Information	19NOV98	DAF	NJP
A	Initial Draft For Cost Estimating	06NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 3A

PREMIER OIL

Doc. No.: 9843EL3A

644434

ONSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H S & T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
V-201A	1	SLUGCATCHER	800 BBL	9300	80	3.0 ID x 30.0 T/T	H					CS	140	149.5		2 x 50% EPOXY LINED
V-201B	1	SLUGCATCHER	800 BBL	9300	80	3.0 ID x 30.0 T/T	H					CS	140	149.5		2 x 50% EPOXY LINED
V-202	1	CONDENSATE STABILISATION COLUMN	4000 BBL/d	2000	230	1.5 ID x 18.3 T/T	V					CS	4	15.7		22 TRAYS
V-203	1	LOW TEMPERATURE SEPARATOR	95 MMscfd	6000	-29	1.8 ID x 6.0 T/T	V					CS	6	11.5		
V-204A	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-204B	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-205A	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-205B	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-206	1	GAS RECOVERY COMP. SUCTION DRUM	3.5 MMscfd	2000	90	0.8 ID x 2.5 T/T	V					CS	4	1.0		
V-207	1	FLARE DRUM	50 MMscfd	350	80	2.4 ID x 7.2 T/T	H					CS	24	10.7		
V-208	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	7000	120	0.8 ID x 2.5 T/T	V					CS	4	2.3		EXPECTED FUEL GAS RATE 2.0 MMscfd
V-209	1	TEG INLET SEPARATOR	100 MMscfd	9300	90	1.5 ID x 4.5 T/T	V					CS	4	4.8		
V-210A	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-210B	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-211	1	HOT OIL FILTER		1800	250	0.3 L x 0.3 W						CS	1	0.5		
E-201	1	CONDENSATE STABILISATION REBOILER		2000	250	1.1 ID x 6.3 T/T	KETL		3000	60	HOT OIL	CS	14	6.3		
E-202A	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 1.5 W	AIR CLR		880	42	AIR	CS	42	2.7		2 x 50%
E-202B	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 1.5 W	AIR CLR		880	42	AIR	CS	42	2.7		2 x 50%
E-203	1	GAS RECOVERY COMP. AFTERCOOLER		7000	150	12.0 L x 1.5 W	AIR CLR		250	11	AIR	CS	28	2.0		
E-204	1	CONDENSATE RUNDOWN COOLER		2000	250	12.0 L x 2.5 W	AIR CLR		2000	66	AIR	CS	56	5.4		
E-205	1	GAS / TEG EXCHANGER		9300	90	6.7 L x 0.4 W	S&T		50	30	GAS / TEG	CS	3	2.6		
C-201	1	BOOSTER COMPRESSOR		7000	90			1300	1100							DRIVEN BY TURBO EXPANDER K-201
C-202A	1	SALES GAS COMPRESSOR		9300	125			4200	2800							2 x 100%
C-202B	1	SALES GAS COMPRESSOR		9300	125			4200	2800							2 x 100%
C-203	1	GAS RECOVERY COMPRESSOR		2000	120			3900	180							
K-201	1	TURBO EXPANDER		6000	-29	3.0 L x 6.0 W		2450	1250				18	15.0		DRIVES SALES GAS COMPRESSOR LP STAGE C-201
K-202A	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3100				30	16.3		2 x 100% SOLAR CENTAUR
K-202B	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3100				30	16.3		2 x 100% SOLAR CENTAUR
K-203	1	GAS RECOVERY COMPRESSOR DRIVER				7.0 L x 3.0 W			250				21	15.8		GAS ENGINE
P-201A	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-201B	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-202A	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-202B	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-203A	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
P-203B	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
T-200A	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-200B	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-201	1	FIREWATER TANK	18000 BBL			7.3 ID x 12.2 T/T							100	61.5		
Z-201	1	ONSHORE TEG DEHYDRATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3		
Z-202A	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
Z-202B	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
X-200	1	PIG RECEIVER		13900	90	0.8 ID x 7.0 T/T	H					CS	12	4.8		TRUNKLINE PIG RECEIVER
X-201	1	PIG LAUNCHER		13900	90	0.6 ID x 6.0 T/T	H					CS	10	3.2		SALES GAS LINE PIG LAUNCHER
	1	POWER GENERATION	1 MW													
	1	CONTROL ROOM														
	1	WAREHOUSE														
	1	OFFICES														
	1	WORKSHOP														
	1	STORE														
	1	CPI SEPARATOR				3.0 L x 3.0 W							24			
	2	FIREWATER PUMPS		2000	80	3.4 L x 1.5 W							16	10.9		
	1	INSTRUMENT / SERVICE AIR PACKAGE		2000	80									30.0		
	1	STORM WATER DRAINAGE														
												TOTAL	1968	670.6	N/A	

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Vessel Weights Updated	24NOV98	MRH	DAF
B	Issued for Information	19NOV98	DAF	NJP
A	Initial Draft For Cost Estimating	06NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 3A

PREMIER OIL

PAGE 3 of 4 (b) Doc. No.: 9843EL3A

YOLLA DEVELOPMENT CASE 3A
PROCESS/UTILITY EQUIPMENT LIST

PIPELINES

TAG NO.	QTY	DESCRIPTION	NOMINAL CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP (°C)	DIMENSIONS	DIFF. HEAD (kPa)	POWER / DUTY (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
	1	GAS / CONDENSATE SUBSEA PIPELINE	90 MMscfd	13900	100	12" x 130km x 10.0mmWT					CS				OFFSHORE FACILITY TO SHORE, 2 PHASE, API5XL65
	1	SALES GAS EXPORT PIPELINE	85 MMscfd	9300	100	10" x 30km x 7.9mmWT					CS				GAS EXPORT TO MAGNESITE MINE, API5XL52

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Vessel Weights Updated	24NOV98	MRH	DAF
B	Issued for Information	19NOV98	DAF	NJP
A	Initial Draft For Cost Estimating	06NOV98	MRH	NJP

WOODHILL THORNTON

PAGE 4 of 4

Doc. No.: 9843EL3A

YOLLA DEVELOPMENT CASE 3A

PREMIER OIL

644136

PROCESS/UTILITY EQUIPMENT LIST

OFFSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF. HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
WH-101A/B/C/D/E	5	PRODUCTION WELLHEADS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
WH-102A/B	2	PRODUCTION WELLHEADS - WHITE IBIS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
WH-301A..E	5	OIL PRODUCTION WELLHEADS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
V-101	1	PRODUCTION SEPARATOR	175 MMscfd	13900	90	2.5 ID x 14.0 T/T	H					CS	64	79.7	98.8	CRA CLAD
V-102	1	TEST SEPARATOR	25 MMscfd	13900	90	0.8 ID x 2.8 T/T	H					CS	8	2.5	3.6	CRA CLAD
V-103A	1	BOOSTER COMPRESSOR SUCTION DRUM	85 MMscfd	13900	90	1.6 ID x 5.4 T/T	V					CS	9	16.6	19.9	CRA CLAD
V-103B	1	BOOSTER COMPRESSOR SUCTION DRUM	85 MMscfd	13900	90	1.6 ID x 5.4 T/T	V					CS	9	16.6	19.9	CRA CLAD
V-104	1	TEG INLET SEPARATOR	160 MMscfd	13900	90	1.9 ID x 5.7 T/T	V					CS	9	24.2	28.2	CRA CLAD
V-105	1	TEG CONTACTOR	160 MMscfd	13900	90	1.5 ID x 8.0 T/T	V					CS	9	20.2	32.9	CRA CLAD
V-201	1	CONDENSATE FILTER	6700 BCPD	13900	90	0.5 ID x 1.5 T/T	V					CS	4	0.6	0.3	
V-202	1	CONDENSATE COALESCER	6700 BCPD	13900	90	1.0 ID x 2.2 T/T	H					CS	6	1.9	2.4	
V-301	1	OIL FIRST STAGE SEPARATOR	20000 BOPD	2500	90	2.1 ID x 7.9 T/T	H					CS	27	12.7	26.4	5 MINS OIL, EPOXY COATED; INSULATED, HEAT TRACED
V-302	1	OIL TEST SEPARATOR	5000 BOPD	2500	900	1.4 ID x 4.4 T/T	H					CS	12	3.8	7.2	5 MINS OIL, EPOXY COATED, INSULATED, HEAT TRACED
V-303	1	SECOND STAGE SEPARATOR	20000 BOPD	2500	90	2.7 ID x 11.0 T/T	H					CS	42	26.2	57.7	15 MINUTES OIL RESIDENCE TIME
V-401	1	LP GR COMPRESSOR SUCTION DRUM	2 MMscfd	2500	90	0.8 ID x 1.8 T/T	V					CS	4	0.8	1.1	
V-402	1	LP GR COMPRESSOR INTERSTAGE DRUM	2 MMscfd	2500	120	0.8 ID x 1.8 T/T	V					CS	4	0.8	1.1	
V-403A	1	HP GR COMPRESSOR SUCTION DRUM	25 MMscfd	3000	120	1.0 ID x 2.5 T/T	V					CS	4	1.7	2.3	2 x 50%
V-403B	1	HP GR COMPRESSOR SUCTION DRUM	25 MMscfd	3000	120	1.0 ID x 2.5 T/T	V					CS	4	1.7	2.3	2 x 50%
V-404A	1	HP GR COMPRESSOR INTERSTAGE DRUM	25 MMscfd	3000	120	1.0 ID x 2.5 T/T	V					CS	4	1.7	2.3	2 x 50%
V-404B	1	HP GR COMPRESSOR INTERSTAGE DRUM	25 MMscfd	3000	120	1.0 ID x 2.5 T/T	V					CS	4	1.7	2.3	2 x 50%
V-501	1	LP FLARE / DRAIN DRUM		350	90	2.7 ID x 11.0 T/T	H					CS	42	26.2	57.7	DRAINAGE FROM V-303
V-502	1	GAS PRODUCED WATER DEGASSER	1000 BWPD	350	90	1.0 ID x 3.5 T/T	H					CS	10	1.4	3.3	
V-503	1	HP FLARE DRUM	75 MMscfd	350	90	2.6 ID x 7.6 T/T	V					CS	9	12.8	16.7	
V-504	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	13900	90	0.7 ID x 2.0 T/T	V					CS	2	0.9	1.1	CRA CLAD
V-505	1	OIL PRODUCED WATER DEGASSER	20000 BWPD	350	90	3.0 ID x 9.0 T/T	H					CS	40	18.8	50.6	CRA CLAD
V-506	1	MEG STORAGE DRUM	200 BBL	350	90	3.0 ID x 4.5 T/T	H					CS	24	10.0	45.0	5 DAYS STORAGE
HC-301	1	PRODUCED WATER HYDROCYCLONE	1000 BWPD	13900	90	0.7 ID x 2.0 T/T	H					CS	5	0.5	0.7	INCLUDES 100% SPARE CAPACITY, SS LINERS
HC-301	1	OIL PRODUCED WATER HYDROCYCLONE	20000 BWPD	2500	90	3.6 L x 3.2 W						CS	12	2.0	2.7	
E-101A	1	PRODUCTION COOLER		13900	90	12.0 L x 4.0 W	AIR CLR		2 x 1650	142.0	AIR	CRA TB	48	9.6	10.6	2 x 50%
E-101B	1	PRODUCTION COOLER		13900	90	12.0 L x 4.0 W	AIR CLR		2 x 1650	142.0	AIR	CRA TB	48	9.6	10.6	2 x 50%
E-201A	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 5.0 W	AIR CLR		2 x 6500	290.0	AIR	CRA TB	60	20.2	22.2	2 x 50%, MOUNTED ABOVE COMPR. SKIDS
E-201B	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 5.0 W	AIR CLR		2 x 6500	290.0	AIR	CRA TB	60	20.2	22.2	2 x 50%, MOUNTED ABOVE COMPR. SKIDS
E-202	1	GAS / TEG EXCHANGER		13900	110	6.7 L x 0.4 W	S&T		50	30.0	GAS / TEG	CS	3	6.5	9.8	
E-301	1	OIL HEATER		2500	90		S&T		TBA		ELECTRIC	CS				
E-401	1	LP GR COMPRESSOR INTERCOOLER		2500	120	12.0 L x 1.0 W	AIR CLR		80	4.9	AIR	CRA TB	12	0.9	1.0	
E-402	1	LP GR COMPRESSOR AFTERCOOLER		3000	120	12.0 L x 1.0 W	AIR CLR		90	4.8	AIR	CRA TB	12	0.9	1.0	
E-403A	1	HP GR COMPRESSOR INTERCOOLER		3000	120	12.0 L x 2.5 W	AIR CLR		1200	68.0	AIR	CRA TB	30	5.4	6.0	2 x 50%
E-403B	1	HP GR COMPRESSOR INTERCOOLER		3000	120	12.0 L x 2.5 W	AIR CLR		1200	68.0	AIR	CRA TB	30	5.4	6.0	2 x 50%
C-201A	1	BOOSTER COMPRESSOR	1870 act.m3/hr	13900	150	INCL IN DRIVER		8500	2900				INCLUDED IN DRIVER			
C-201B	1	BOOSTER COMPRESSOR	1870 act.m3/hr	13900	150	INCL IN DRIVER		8500	2900				INCLUDED IN DRIVER			
C-401	1	LP GAS RECOVERY COMPRESSOR STAGE 1		2500	150			3000	60							
C-402	1	LP GAS RECOVERY COMPRESSOR STAGE 2		2500	150			8000	60							
C-403A	1	HP GAS RECOVERY COMPRESSOR STAGE 1		3000	150			12000	950							2 x 50%
C-403B	1	HP GAS RECOVERY COMPRESSOR STAGE 1		3000	150			12000	950							2 x 50%
C-404A	1	HP GAS RECOVERY COMPRESSOR STAGE 2		9300	150			12000	950							2 x 50%
C-404B	1	HP GAS RECOVERY COMPRESSOR STAGE 2		9300	150			12000	950							2 x 50%
K-201A	1	BOOSTER COMPRESSOR DRIVER				8.5 L x 2.4 W							21	16.3	22.5	2 x 50% SOLAR CENTAUR 50'S
K-201B	1	BOOSTER COMPRESSOR DRIVER				8.5 L x 2.4 W							21	16.3	22.5	2 x 50% SOLAR CENTAUR 50'S
K-401	1	LP GAS RECOVERY COMPRESSOR DRIVER				7.0 L x 2.5 W			150				18	8.0	11.0	
K-402A	1	HP GAS RECOVERY COMPRESSOR DRIVER				8.0 L x 2.0 W			1100				16	12.0	16.6	2 x 50% SOLAR SATURNS
K-402B	1	HP GAS RECOVERY COMPRESSOR DRIVER				8.0 L x 2.0 W			1100				16	12.0	16.6	2 x 50% SOLAR SATURNS

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	DAF	NJP
C	Vessel Weights Updated	24NOV98	MRH	NJP
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 4A

PREMIER OIL

Doc. No.: 9843EL4A

PROCESS/UTILITY EQUIPMENT LIST

OFFSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
P-101A	1	LP FLARE / DRAIN DRUM PUMP	40 m3/hr	500	90	3.0 L x 1.0 W		350	7.3				3	0.6	0.6	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-101B	1	LP FLARE / DRAIN DRUM PUMP	40 m3/hr	500	90	3.0 L x 1.0 W		350	7.3				3	0.6	0.6	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-102A	1	HP FLARE DRUM PUMP	40 m3/hr	13900	90	6.0 L x 2.5 W		12650	267				15	4.0	4.0	2 x 50%
P-102B	1	HP FLARE DRUM PUMP	40 m3/hr	13900	90	6.0 L x 2.5 W		12650	267				15	4.0	4.0	2 x 50%
P-201A	1	CONDENSATE BOOSTER PUMP	50 m3/hr	13900	90	5.0 L x 2.0 W		8500	170				10	2.0	2.0	2 x 50%
P-201B	1	CONDENSATE BOOSTER PUMP	50 m3/hr	13900	90	5.0 L x 2.0 W		8500	170				10	2.0	2.0	2 x 50%
P-301A	1	CRUDE EXPORT PUMP	150 m3/hr	2500	90	4.0 L x 2.0 W		1200	50				8	1.2	1.2	2 x 100%
P-301B	1	CRUDE EXPORT PUMP	150 m3/hr	2500	90	4.0 L x 2.0 W		1200	50				8	1.2	1.2	2 x 100%
P-302A	1	MEG INJECTION PUMPS	0.3 m3/hr	1000	90	1.0 L x 1.0 W		500	0.5				1	0.2	0.2	2 x 100%
P-302B	1	MEG INJECTION PUMPS	0.3 m3/hr	1000	90	1.0 L x 1.0 W		500	0.5				1	0.2	0.2	2 x 100%
X-100	1	PIG LAUNCHER		13900	90	0.8 ID x 7.0 T/T						CS	12	7.2	7.2	
Z-201	1	TEG REGENERATION PACKAGE	160 MMscfd			9.0 L x 4.5 W							41	49.7	97.0	DESIGN WATER FLOW 1200 BWPD
Z-301	1	MEG REGENERATION PACKAGE	140BPD			5.0 L x 2.0 W							10	8.0	15.6	DESIGN 100 BWPD, 40 BPD OF MEG
	1	POWER GENERATION				10.0 L x 10.0 W			2000				100	23.0	30.0	NORMAL / STANDBY / EMERGENCY
	1	FLARE TIP / IGNITION SYSTEM	75 MMscfd			1.0 L x 5.0 W							5	0.6	1.0	
	2	FIRE PUMPS	1500 GPM			6.0 L x 3.0 W							20	15.0	20.0	
	1	WORKOVER FACILITIES				5.0 L x 5.0 W							25	20.0	20.0	
	1	ACCOMMODATION	15 PPL/30 BEDS			15.0 L x 10.0 W							150	150.0	150.0	
	1	POTABLE WATER PACKAGE				7.0 L x 8.0 W							60	10.0	15.0	
	1	HVAC				3.0 L x 3.0 W							10	3.0	5.0	
	1	CRANE												30.0	30.0	
	1	INSTRUMENT / SERVICE AIR PACKAGE				4.0 L x 8.0 W							35	17.0	25.0	
	1	DIESEL FUEL SUPPLY / TREATMENT	10 DAYS			3.0 L x 3.0 W							10	5.0	8.5	
	1	GLYCOL STORAGE / TRANSFER PUMP	5 m3			2.0 L x 3.0 W							10	5.0	8.0	
	2	SURVIVAL CRAFT	20 MEN											5.0	7.0	
	1	SEWAGE TREATMENT UNIT	30 MEN			2.0 L x 3.0 W							6	1.0	3.0	
	1	HELIDECK												100.0	100.0	
	1	OFFSHORE LOADING LINE														
	1	CALM BUOY														
												TOTAL	1276	898.8	1234.2	

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	DAF	NJP
C	Vessel Weights Updated	24NOV98	MRH	NJP
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 4A
PREMIER OIL

Doc. No.: 9843EL4A

64138

ONSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
V-201A	1	SLUGCATCHER	2100 BBL	9300	80	3.5 ID x 35.0 T/T	H					CS	200	226.0		2 x 33%, EPOXY LINED
V-201B	1	SLUGCATCHER	2100 BBL	9300	80	3.5 ID x 35.0 T/T	H					CS	200	226.0		2 x 33%, EPOXY LINED
V-201C	1	SLUGCATCHER	2100 BBL	9300	80	3.5 ID x 35.0 T/T	H					CS	200	226.0		2 x 33%, EPOXY LINED
V-202	1	CONDENSATE STABILISER COLUMN	8500 BBL/d	2000	230	2.2 ID x 18.3 T/T	V					CS	9	27.5		22 TRAYS (SS)
V-203	1	LOW TEMPERATURE SEPARATOR	130 MMscfd	6000	-70	2.1 ID x 7.0 T/T	V					SS	9	8.5		
V-204A	1	SALES GAS COMP. SUCTION DRUM	65 MMscfd	4000	90	1.6 ID x 5.6 T/T	V					CS	9	6.1		2 x 50%
V-204B	1	SALES GAS COMP. SUCTION DRUM	65 MMscfd	4000	90	1.6 ID x 5.6 T/T	V					CS	9	6.1		2 x 50%
V-205A	1	SALES GAS COMP. DISCHARGE DRUM	65 MMscfd	12000	90	1.3 ID x 4.4 T/T	V					CS	9	10.3		2 x 50%
V-205B	1	SALES GAS COMP. DISCHARGE DRUM	65 MMscfd	12000	90	1.3 ID x 4.4 T/T	V					CS	9	10.3		2 x 50%
V-206	1	GAS RECOVERY COMP. SUCTION DRUM	3.5 MMscfd	2000	90	0.8 ID x 2.5 T/T	V					CS	4	0.9		
V-207	1	FLARE DRUM	50 MMscfd	350	80	2.4 ID x 7.2 T/T	H					CS	24	11.4		
V-208	1	FUEL GAS KNOCKOUT DRUM	10 MMscfd	7000	120	0.8 ID x 2.5 T/T	V					CS	4	1.5		EXPECTED FUEL GAS RATE 10.0 MMscfd
V-209	1	TEG INLET SEPARATOR	135 MMscfd	9300	90	1.8 ID x 5.4 T/T	V					CS	6.5	14.9		
V-210A	1	HOT OIL DRUM		1000	250	2.1 ID x 6.3 T/T	H					CS	21	7.3		
V-210B	1	HOT OIL DRUM		1000	250	2.1 ID x 6.3 T/T	H					CS	21	7.3		
V-211	1	HOT OIL FILTER		1800	250	0.5 L x 0.5 W	V					CS	1	0.3		
V-212	1	TEG CONTACTOR	135 MMscfd	9300	90	1.4 ID x 8.0 T/T	V					CS	6.5	12.5		
V-213	1	DE-ETHANISER	5100 BBL/d	2500	160	1.0 ID x 15.0 T/T	V					CS	4	6.6		
V-214	1	DE-ETHANISER OVERHEADS COMP. SUCTI	4.3 MMscfd	2500	90	0.8 ID x 2.5 T/T	V					CS	4	1.0		
V-215	1	DEPROPANISER	2800 BBl/d	2500	160	1.7 ID x 25.0 T/T	V					CS	6.5	26.8		
V-216	1	DEPROPANISER REFLUX DRUM	7300 BBl/d	2500	90	2.0 ID x 5.5 T/T	H					CS	21	7.1		
V-217	1	DEBUTANISER	1800 BBl/d	1000	160	1.7 ID x 19.0 T/T	V					CS	9	19.3		
V-218	1	DEBUTANISER REFLUX DRUM	6600 BBl/d	1000	90	2.0 ID x 5.5 T/T	H					CS	21	5.8		
V-219	1	COLD SEPARATOR	130 MMscfd	9300	-20	1.7 ID x 5.1 T/T	V					CS	9	12.8		
V-220	1	AMINE CONTACTOR INLET SEPARATOR	160 MMscfd	9300	90	1.8 ID x 5.4 T/T	H					CS	10	3.2		
V-221	1	AMINE CONTACTOR	160 MMscfd	9300	90	2.7 ID x 18.0 T/T	V					CS	16	72.4		SS CLAD
V-222	1	AMINE CONTACTOR OUTLET SEPARATOR	135 MMscfd	9300	90	1.5 ID x 4.5 T/T	V					CS	9	9.2		SS CLAD
V-223	1	AMINE STRIPPING COLUMN	2850 USgpm	350	135	5.7 ID x 16.0 T/T	V					CS	50	92.3		SS CLAD
V-224	1	AMINE SURGE TANK	2850 USgpm	350	90	4.7 ID x 18.8 T/T	H					CS	120	82.0		SS CLAD
V-225	1	AMINE STRIPPER REFLUX DRUM	2850 USgpm	350	90	4.1 ID x 4.7 T/T	H					CS	36	15.9		SS CLAD
V-226	1	AMINE FLASH TANK	2850 USgpm	350	90	4.7 ID x 18.8 T/T	H					CS	120	82.0		SS CLAD
V-227	1	AMINE CARBON FILTER	2850 USgpm	350	90	4.1 ID x 4.7 T/T	H					SS	36	15.9		
V-228	1	AMINE PHYSICAL FILTER	2850 USgpm	350	90	4.1 ID x 4.7 T/T	H					SS	36	15.9		
V-229	1	MERCURY GUARD BED	130 MMscfd	9300	90	2.3 ID x 3.5 T/T	V					CS	13	12.0		
E-201	1	CONDENSATE STABILISER REBOILER		2000	250	1.4 ID x 5.0 T/T	KETTLE		6000	120	HOT OIL	CS	21	8.5		
E-202A	1	SALES GAS COMP. AFTERCOOLER		12000	190	12.0 L x 3.2 W	ACHE		2 x 3900	135	AIR	CS	48	9.6		2 x 50%
E-202B	1	SALES GAS COMP. AFTERCOOLER		12000	190	12.0 L x 3.2 W	ACHE		2 x 3900	135	AIR	CS	48	9.6		2 x 50%
E-203	1	GAS RECOVERY COMP. AFTERCOOLER		7000	160	12.0 L x 1.0 W	ACHE		320	10	AIR	CS	12	0.7		
E-204	1	CONDENSATE RUNDOWN COOLER		2000	250	12.0 L x 4.0 W	ACHE		3900	66	AIR	CS	48	10.1		
E-205	1	GAS / TEG EXCHANGER		9300	90	6.7 L x 0.4 W	S&T		50	30	GAS / TEG	CS	3	2.6		
E-206	1	RECOVERED LIQUIDS RUNDOWN COOLER		1000	160	12.0 L x 1.0 W	ACHE		140	8	AIR	CS	12	0.7		
E-207	1	DEPROPANISER CONDENSER		2500	90	12.0 L x 4.5 W	ACHE		1900	180	AIR	CS	60	12.4		
E-208	1	DEBUTANISER CONDENSER		1000	90	12.0 L x 5.0 W	ACHE		2600	325	AIR	CS	66	22.5		
E-209	1	DE-ETHANISER REBOILER		2500	250	0.5 ID x 5.2 T/T	KETTLE		810	7	HOT OIL	CS	11	1.1		
E-210	1	DEPROPANISER REBOILER		2500	250	0.8 ID x 3.2 T/T	KETTLE		2200	25	HOT OIL	CS	10	1.8		
E-211	1	DEBUTANISER REBOILER		1000	160	0.8 ID x 2.7 T/T	KETTLE		2200	25	HOT OIL	CS	8	1.5		
E-212	1	PLATEFIN EXCHANGER		9300	90/-70	4.0 L x 3.0 W	PLATE-FIN		3720		GAS/GAS	AL	12	3.0		
E-213	1	AMINE STRIPPER REBOILER		350	135		KETTLE		60,000	3000	HOT OIL	CS				SS CLAD, SS TUBES
E-214	1	RICH-LEAN AMINE EXCHANGER		350	135	4.0 L x 3.0 W	S&T		38,000	3000	PROCESS	CS	12	20.0		SS CLAD, SS TUBES
E-215	1	AMINE COOLER		9300	90	12.0 L x 4.0 W	ACHE		12,500	121	AIR	CS	48	9.6		SS TUBES
E-216	1	AMINE STRIPPER REFLUX CONDENSER		350	90	12.0 L x 2.5 W	ACHE		25,000	62	AIR	CS	30	5.4		SS TUBES

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	[illegible]	[illegible]
C	Vessel Weights Updated	24NOV98	MRH	NJP
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 4A

PREMIER OIL

Doc. No.: 9843EL4A

PROCESS/UTILITY EQUIPMENT LIST

ONSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
C-201	1	BOOSTER COMPRESSOR		7000	90	INCL IN DRIVER		2000	1800			CS	INCLUDED IN DRIVER			DRIVEN BY TURBO EXPANDER K-201
C-202A	1	SALES GAS COMPRESSOR		10,000	190	INCL IN DRIVER		6000	2 x 3850			CS	INCLUDED IN DRIVER			2 x 50%
C-202B	1	SALES GAS COMPRESSOR		10,000	190	INCL IN DRIVER		6000	2 x 3850			CS	INCLUDED IN DRIVER			2 x 50%
C-203	1	GAS RECOVERY COMPRESSOR		6000	120	INCL IN DRIVER		3900	405			CS	INCLUDED IN DRIVER			
C-204	1	DE-ETHANISER OH'S COMPRESSOR		7000	90	INCL IN DRIVER		1000	75			CS	INCLUDED IN DRIVER			
K-201	1	TURBO EXPANDER		9300	-70	7.0 L x 4.0 W		3150	1900				28	10.5		DRIVES BOOSTER COMPRESSOR C-201
K-202A	1	SALES GAS COMPRESSOR DRIVER				8.5 L x 2.4 W			2 x 4700				21	16.3		2 x 100% SOLAR TAURUS (APPROX SITE RATED DUTY)
K-202B	1	SALES GAS COMPRESSOR DRIVER				8.5 L x 2.4 W			2 x 4700				21	16.3		2 x 100% SOLAR TAURUS (APPROX SITE RATED DUTY)
K-203	1	GAS RECOVERY COMPRESSOR DRIVER				7.9 L x 3.6 W			425				29	23.6		ELECTRIC MOTOR
K-204	1	DE-ETHANISER OH'S COMPRESSOR DRIVER				6.0 L x 3.0 W			80				18	5.9		ELECTRIC MOTOR
P-201A	1	CONDENSATE PRODUCT PUMP	55 m3/hr	8000	90	3.0 L x 2.0 W		5000	135				6	2.5		2 x 100%, TO BE CONFIRMED
P-201B	1	CONDENSATE PRODUCT PUMP	55 m3/hr	8000	90	3.0 L x 2.0 W		5000	135				6	2.5		2 x 100%, TO BE CONFIRMED
P-202A	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	7.3				3	0.6		2 x 100%
P-202B	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	7.3				3	0.6		2 x 100%
P-203A	1	HOT OIL PUMP	210 m3/hr	1800	250	1.8 L x 0.7 W			2 x 40				2	1.0		2 x 50%
P-203B	1	HOT OIL PUMP	210 m3/hr	1800	250	1.8 L x 0.7 W			2 x 40				2	1.0		2 x 50%
P-204A	1	DEPROPANISER FEED PUMP	20 m3/hr	2500	250	2.0 L x 1.0 W		300	3				2	0.5		2 x 100%
P-204B	1	DEPROPANISER FEED PUMP	20 m3/hr	2500	250	2.0 L x 1.0 W		300	3				2	0.5		2 x 100%
P-205A	1	AMINE PUMP	2850 USgpm	1000	135	5.0 L x 2 W		4500	1000				10	10.0		2 x 100%
P-205B	1	AMINE PUMP	2850 USgpm	1000	135	5.0 L x 2 W		4500	1000				10	10.0		2 x 100%
P-206A	1	AMINE BOOSTER PUMP	2850 USgpm	9300	135	3.0 L x 1.5 W		500	126				4.5	2.0		2 x 100%
P-206B	1	AMINE BOOSTER PUMP	2850 USgpm	9300	135	3.0 L x 1.5 W		500	126				4.5	2.0		2 x 100%
P-207A	1	AMINE STRIPPER REFLUX PUMP		350	90	3.0 L x 1.5 W		500	126				4.5	2.0		2 x 100%
P-207B	1	AMINE STRIPPER REFLUX PUMP		350	90	3.0 L x 1.5 W		500	126				4.5	2.0		2 x 100%
P-208A	1	PROPANE LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-208B	1	PROPANE LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-208C	1	PROPANE LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-209A	1	LPG LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-209B	1	LPG LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
P-209C	1	LPG LOADING PUMP	50 m3/hr	700	90	3.0 L x 2.0 W		500	3 x 15				6	1.0		3 x 33%
T-200A	1	CONDENSATE STORAGE TANK	50,000 BBL	17	80	26.0 ID x 16.0 H	V					CS	830			EACH TANK 6 DAYS STORAGE
T-200B	1	CONDENSATE STORAGE TANK	50,000 BBL	17	80	26.0 ID x 16.0 H	V					CS	830			EACH TANK 6 DAYS STORAGE
T-201	1	FIREWATER TANK	18000 BBL			7.3 ID x 12.2 T/T							100	61.5		
T-202A	1	PROPANE STORAGE SPHERES	830 tonnes	2000	90	9.6 ID	V					CS	144	120.0		EACH SPHERE 5 DAYS STORAGE
T-202B	1	PROPANE STORAGE SPHERES	830 tonnes	2000	90	9.6 ID	V					CS	144	120.0		EACH SPHERE 5 DAYS STORAGE
T-203A	1	LPG STORAGE SPHERES	1040 tonnes	1000	90	9.6 ID	V					CS	144	120.0		EACH SPHERE 5 DAYS STORAGE
T-203B	1	LPG STORAGE SPHERES	1040 tonnes	1000	90	9.6 ID	V					CS	144	120.0		EACH SPHERE 5 DAYS STORAGE
Z-201	1	ONSHORE TEG DEHYDRATION PACKAGE	155 MMscfd			9.0 L x 4.5 W							41	49.7		
Z-202A	1	WASTE HEAT RECOVERY UNIT		1800	250	10.5 L x 10.2 W			10,000				110	60.0		
Z-202B	1	WASTE HEAT RECOVERY UNIT		1800	250	10.5 L x 10.2 W			10,000				110	60.0		
Z-203	1	FIRED HEATER							61,000							
Z-204	1	PROPANE EXPORT METERING SKID	324 m3/hr	700	90	7.0 L x 6.0 W						CS	42	10.0		
Z-205	1	LPG EXPORT METERING SKID	324 m3/hr	700	90	7.0 L x 6.0 W						CS	42	10.0		
X-200	1	PIG RECEIVER		13900	90	1.1 ID x 9.6 T/T	H					CS	22	14.0		TRUNKLINE PIG RECEIVER
X-201	1	PIG LAUNCHER		13900	90	0.6 ID x 6.0 T/T	H					CS	10	4.7		SALES GAS LINE PIG LAUNCHER
	1	POWER GENERATION	2.5 MW													
	1	CONTROL ROOM														
	1	WAREHOUSE														
	1	OFFICES														
	1	WORKSHOP														
	1	STORE														
	1	CPI SEPARATOR				3.0 L x 3.0 W							24			
	2	FIREWATER PUMPS		2000	80	3.4 L x 1.5 W							16	10.9		
	1	INSTRUMENT / SERVICE AIR PACKAGE		2000	80									30.0		
	1	STORM WATER DRAINAGE														
												TOTAL	4698	2319.7	N/A	

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	DAF	NJP
C	Vessel Weights Updated	24NOV98	MRH	NJP
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 4A

PREMIER OIL

Doc. No.: 9843EL4A

64140

PIPELINES

TAG NO.	QTY	DESCRIPTION	NOMINAL CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS	DIFF. HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
	1	GAS / CONDENSATE SUBSEA PIPELINE	160 MMscfd	13,900	100	16" x 190km x 11.8mmWT					CS				OFFSHORE FACILITY TO VICTORIA; 2 PHASE; API5LX65
															CRA COATED FOR FIRST 24km (MECH BONDED)
	1	SALES GAS EXPORT PIPELINE	130 MMscfd	12,000	100	12" x 35km x 7.9mmWT					CS				SALESGAS LINE; API5LX52
	1	WHITE IBIS FLOWLINE	45 MMscfd	23,200	100	8" x 40km x 10.9mmWT					CS				WHITE IBIS FLOWLINE; API5LX65
															CRA COATED FOR FIRST 20km (MECH BONDED)
	1	WHITE IBIS MEG INJECTION PIGGY-BACK LI	40BMEGPD	23,200	100	2" x 40km x 5.2mmWT					CS				MEG PIGGY BACK LINE TO WHITE IBIS WELL; API5LX65

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised for Report	18DEC98	MRH	NJP
C	Vessel Weights Updated	24NOV98	MRH	NJP
B	Issued for Information	19NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 4A

PREMIER OIL

Doc. No.: 9843EL4A

141

PROCESS/UTILITY EQUIPMENT LIST

OFFSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
WH-101A..E	5	PRODUCTION WELLHEADS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
V-101	1	PRODUCTION SEPARATOR	100 MMscfd	13900	90	1.5 ID x 4.5 T/T	H					CS	18	13.0	16.2	CRA CLAD
V-102	1	TEST SEPARATOR	25 MMscfd	13900	90	0.8 ID x 2.8 T/T	H					CS	8	2.5	3.6	CRA CLAD
V-103A	1	BOOSTER COMPRESSOR SUCTION DRUM	50 MMscfd	13900	90	1.2 ID x 4.1 T/T	V					CS	4	8.3	9.2	CRA CLAD
V-103B	1	BOOSTER COMPRESSOR SUCTION DRUM	50 MMscfd	13900	90	1.2 ID x 4.1 T/T	V					CS	4	8.3	9.2	CRA CLAD
V-104	1	TEG INLET SEPARATOR	100 MMscfd	13900	90	1.5 ID x 4.5 T/T	V					CS	9	13.9	16.7	CRA CLAD
V-105	1	TEG CONTACTOR	100 MMscfd	13900	90	1.2 ID x 8.0 T/T	V					CS	4	14.0	22.8	CRA CLAD
V-201	1	CONDENSATE FILTER	4000 BCPD	13900	90	0.4 ID x 1.2 T/T	V					CS	1	0.6	0.7	
V-202	1	CONDENSATE COALESCER	4000 BCPD	13900	90	0.8 ID x 1.8 T/T	H					CS	4	1.9	2.5	
V-301	1	LP FLARE / DRAIN DRUM		350	90	1.5 ID x 4.5 T/T	H					CS	18	3.1	7.0	DRAINAGE FROM V-101
V-302	1	PRODUCED WATER DEGASSER	1000 BWPD	350	90	1.0 ID x 3.5 T/T	H					CS	15	1.4	3.3	
V-303	1	HP FLARE DRUM	50 MMscfd	350	90	2.1 ID x 6.4 T/T	V					CS	9	8.0	11.9	
V-304	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	13900	90	0.5 ID x 1.8 T/T	V					CS	2	0.9	1.1	CRA CLAD
HC-301	1	PRODUCED WATER HYDROCYCLONE	2000 BWPD	13900	90	0.7 ID x 2.0 T/T	H					CS	8	0.5	0.7	INCLUDES 100% SPARE CAPACITY, SS LINERS
E-101A	1	PRODUCTION COOLER		13900	90	12.0 L x 2.5 W	AIR CLR		1100	93.6	AIR	CRA TB	30	6.4	7.0	2 x 50%, MOUNTED ABOVE COMPRESSOR SKIDS
E-101B	1	PRODUCTION COOLER		13900	90	12.0 L x 2.5 W	AIR CLR		1100	93.6	AIR	CRA TB	30	6.4	7.0	2 x 50%, MOUNTED ABOVE COMPRESSOR SKIDS
E-201A	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 2.5 W	AIR CLR		3200	156.7	AIR	CRA TB	30	11.0	12.1	FUTURE, 2 x 50%, MOUNTED ABOVE COMPR. SKIDS
E-201B	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 2.5 W	AIR CLR		3200	156.7	AIR	CRA TB	30	11.0	12.1	FUTURE, 2 x 50%, MOUNTED ABOVE COMPR. SKIDS
E-202	1	GAS / TEG EXCHANGER		13900	110	6.7 L x 0.4 W	S&T		50	30.0	GAS / TEG	CS	7	6.5	9.8	
C-201A	1	BOOSTER COMPRESSOR	1120 act m3/hr	13900	150			8500	2150				6			FUTURE
C-201B	1	BOOSTER COMPRESSOR	1120 act m3/hr	13900	150			8500	2150				6			FUTURE
K-201A	1	BOOSTER COMPRESSOR DRIVER				10.0 L x 3.0 W							30	16.3	22.5	FUTURE - 2 x 50% SOLAR CENTAURS
K-201B	1	BOOSTER COMPRESSOR DRIVER				10.0 L x 3.0 W							30	16.3	22.5	FUTURE - 2 x 50% SOLAR CENTAURS
P-201A	1	CONDENSATE BOOSTER PUMP	30 m3/hr	13900	90	5.0 L x 2.0 W		8500	78				10	1.7	1.7	FUTURE - 2 x 50%
P-201B	1	CONDENSATE BOOSTER PUMP	30 m3/hr	13900	90	5.0 L x 2.0 W		8500	78				10	1.7	1.7	FUTURE - 2 x 50%
P-202A	1	LP FLARE / DRAIN DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4	0.4	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-202B	1	LP FLARE / DRAIN DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4	0.4	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-301A	1	HP FLARE DRUM PUMP	30 m3/hr	13900	90	6.0 L x 2.5 W		12650	160				15	2.7	2.7	2 x 50%
P-301B	1	HP FLARE DRUM PUMP	30 m3/hr	13900	90	6.0 L x 2.5 W		12650	160				15	2.7	2.7	2 x 50%
Z-201	1	TEG REGENERATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3	57.4	DESIGN WATER FLOW 40 BWPD
X-100	1	PIG LAUNCHER		13900	90	0.8 ID x 7.0 T/T						CS	14	4.8	4.8	
	1	POWER GENERATION				10.0 L x 10.0 W			1500				100	23.0	30.0	NORMAL / STANDBY / EMERGENCY
	1	FLARE TIP / IGNITION SYSTEM	50 MMscfd			1.0 L x 5.0 W							5	0.6	1.0	
	2	FIRE PUMPS	1500 GPM			6.0 L x 3.0 W							20	15.0	20.0	
	1	WORKOVER FACILITIES												20.0	20.0	
	1	ACCOMMODATION	15 PPL/30 BEDS			15.0 L x 10.0 W							150	150.0	150.0	
	1	POTABLE WATER PACKAGE				7.0 L x 8.0 W							60	10.0	15.0	
	1	HVAC				3.0 L x 3.0 W							10	3.0	5.0	
	1	CRANE												30.0	30.0	
	1	INSTRUMENT / SERVICE AIR PACKAGE				4.0 L x 8.0 W							35	17.0	25.0	
	1	DIESEL FUEL SUPPLY / TREATMENT	10 DAYS			3.0 L x 3.0 W							10	5.0	8.5	
	1	GLYCOL STORAGE / TRANSFER PUMP	5 m3			2.0 L x 3.0 W							10	5.0	8.0	
	2	SURVIVAL CRAFT	20 MEN											5.0	7.0	
	1	SEWAGE TREATMENT UNIT	30 MEN			2.0 L x 3.0 W							6	1.0	3.0	
	1	HELIDECK												100.0	100.0	
												TOTAL	824	607.6	719.1	

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	24NOV98	[signature]	[signature]
A	Initial Draft For Cost Estimating	20NOV98	DAF	NJP

WOODHILL THORNTON

PAGE 1 of 3 — Doc. No.: 9843EL1-1A2

YOLLA DEVELOPMENT
CASE 1A2

PREMIER OIL

241446

ONSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H, S & T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
V-201A	1	SLUGCATCHER	1380 BBL	9300	80	3.6 ID x 38.0 T/T	H					CS	200	285.0		2 x 50%, EPOXY LINED
V-201B	1	SLUGCATCHER	1380 BBL	9300	80	3.6 ID x 38.0 T/T	H					CS	200	285.0		2 x 50%, EPOXY LINED
V-202	1	CONDENSATE STABILISATION COLUMN	4000 BBL/d	2000	230	1.5 ID x 18.3 T/T	V					CS	4	15.7		22 TRAYS
V-203	1	LOW TEMPERATURE SEPARATOR	95 MMscfd	6000	-29	1.8 ID x 6.0 T/T	V					CS	6	11.5		
V-204A	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-204B	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-205A	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-205B	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-206	1	GAS RECOVERY COMP. SUCTION DRUM	3.5 MMscfd	2000	90	0.8 ID x 2.5 T/T	V					CS	4	1.0		
V-207	1	FLARE DRUM	50 MMscfd	350	80	2.4 ID x 7.2 T/T	H					CS	24	10.7		
V-208	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	7000	120	0.8 ID x 2.5 T/T	V					CS	4	2.3		EXPECTED FUEL GAS RATE 2.0 MMscfd
V-209	1	TEG INLET SEPARATOR	100 MMscfd	9300	90	1.5 ID x 4.5 T/T	V					CS	4	4.8		
V-210	1	TEG CONTACTOR	100 MMscfd	9300	90	1.2 ID x 8.0 T/T	V					CS	4	14.0		CRA CLAD
V-211A	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-211B	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-212	1	HOT OIL FILTER		1800	250	0.3 L x 0.3 W						CS	1	0.5		
E-201	1	CONDENSATE STABILISATION REBOILER		2000	250	1.1 ID x 6.3 T/T	KETL		3000	60	HOT OIL	CS	14	6.3		
E-202A	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 1.5 W	AIR CLR		880	42	AIR	CS	42	2.7		2 x 50%
E-202B	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 1.5 W	AIR CLR		880	42	AIR	CS	42	2.7		2 x 50%
E-203	1	GAS RECOVERY COMP. AFTERCOOLER		7000	150	12.0 L x 1.5 W	AIR CLR		250	11	AIR	CS	28	2.0		
E-204	1	CONDENSATE RUNDOWN COOLER		2000	250	12.0 L x 2.5 W	AIR CLR		2000	66	AIR	CS	56	5.4		
E-205	1	GAS / TEG EXCHANGER		9300	90	6.7 L x 0.4 W	S&T		50	30	GAS / TEG	CS	3	2.6		
C-201	1	BOOSTER COMPRESSOR		7000	90			1300	1100							DRIVEN BY TURBO EXPANDER K-201
C-202A	1	SALES GAS COMPRESSOR		9300	125			4200	2800							2 x 100%
C-202B	1	SALES GAS COMPRESSOR		9300	125			4200	2800							2 x 100%
C-203	1	GAS RECOVERY COMPRESSOR		2000	120			3900	180							
K-201	1	TURBO EXPANDER		6000	-29	3.0 L x 6.0 W		2450	1250				18	15.0		DRIVES SALES GAS COMPRESSOR LP STAGE C-201
K-202A	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3100				30	16.3		2 x 100% SOLAR CENTAUR
K-202B	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3100				30	16.3		2 x 100% SOLAR CENTAUR
K-203	1	GAS RECOVERY COMPRESSOR DRIVER				7.0 L x 3.0 W			250				21	15.8		GAS ENGINE
P-201A	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-201B	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-202A	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-202B	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-203A	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
P-203B	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
T-200A	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-200B	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-201	1	FIREWATER TANK	18000 BBL			7.3 ID x 12.2 T/T							100	61.5		
Z-201	1	ONSHORE TEG DEHYDRATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3		
Z-202A	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
Z-202B	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
X-200	1	PIG RECEIVER		13900	90	0.8 ID x 7.0 T/T	H					CS	12	4.8		TRUNKLINE PIG RECEIVER
X-201	1	PIG LAUNCHER		13900	90	0.6 ID x 6.0 T/T	H					CS	10	3.2		SALES GAS LINE PIG LAUNCHER
	1	POWER GENERATION	1 MW													
	1	CONTROL ROOM														
	1	WAREHOUSE														
	1	OFFICES														
	1	WORKSHOP														
	1	STORE														
	1	CPI SEPARATOR				3.0 L x 3.0 W							24			
	2	FIREWATER PUMPS		2000	80	3.4 L x 1.5 W							16	10.9		
	1	INSTRUMENT / SERVICE AIR PACKAGE		2000	80									30.0		
	1	STORM WATER DRAINAGE														
												TOTAL	2092	955.6	N/A	

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	24NOV98	MRH	NJP
A	Initial Draft For Cost Estimating	20NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT
CASE 1A2

PREMIER OIL

Doc. No.: 9843EL1-1A2

64443

YOLLA DEVELOPMENT CASE 1A2

PROCESS/UTILITY EQUIPMENT LIST

PIPELINES

TAG NO	QTY	DESCRIPTION	NOMINAL CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
	1	GAS / CONDENSATE SUBSEA PIPELINE	90 MMscfd	13900	100	12" x 170km x 10.0mmWT					CS				OFFSHORE FACILITY TO SHORE, 2 PHASE, API5LX65 CRA COATED FOR FIRST 50km (MECH BONDED)
	1	SALES GAS EXPORT PIPELINE	85 MMscfd	9300	100	10" x 30km x 7.9mmWT					CS				GAS EXPORT TO MAGNESITE MINE, API5LX52

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	24NOV98	MCH	DAF
A	Initial Draft For Cost Estimating	20NOV98	DAF	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 1A2

PREMIER OIL

Doc. No.: 9843EL1-1A2

PROCESS/UTILITY EQUIPMENT LIST

OFFSHORE EQUIPMENT

TAG NO.	QTY	DESCRIPTION	CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
WH-101A E	5	PRODUCTION WELLHEADS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
V-101	1	PRODUCTION SEPARATOR	100 MMscfd	13900	90	1.5 ID x 4.5 T/T	H					CS	18	13.0	16.2	CRA CLAD
V-102	1	TEST SEPARATOR	25 MMscfd	13900	90	0.8 ID x 2.8 T/T	H					CS	8	2.5	3.6	CRA CLAD
V-103A	1	BOOSTER COMPRESSOR SUCTION DRUM	50 MMscfd	13900	90	1.2 ID x 4.1 T/T	V					CS	4	8.3	9.2	CRA CLAD
V-103B	1	BOOSTER COMPRESSOR SUCTION DRUM	50 MMscfd	13900	90	1.2 ID x 4.1 T/T	V					CS	4	8.3	9.2	CRA CLAD
V-104	1	TEG INLET SEPARATOR	100 MMscfd	13900	90	1.5 ID x 4.5 T/T	V					CS	9	13.9	16.7	CRA CLAD
V-105	1	TEG CONTACTOR	100 MMscfd	13900	90	1.2 ID x 8.0 T/T	V					CS	4	14.0	22.8	CRA CLAD
V-201	1	CONDENSATE FILTER	4000 BCPD	13900	90	0.4 ID x 1.2 T/T	V					CS	1	0.6	0.7	
V-202	1	CONDENSATE COALESCER	4000 BCPD	13900	90	0.8 ID x 1.8 T/T	H					CS	4	1.9	2.5	
V-301	1	LP FLARE / DRAIN DRUM		350	90	1.5 ID x 4.5 T/T	H					CS	18	3.1	7.0	DRAINAGE FROM V-101
V-302	1	PRODUCED WATER DEGASSER	1000 BWPD	350	90	1.0 ID x 3.5 T/T	H					CS	15	1.4	3.3	
V-303	1	HP FLARE DRUM	50 MMscfd	350	90	2.1 ID x 6.4 T/T	V					CS	9	8.0	11.9	
V-304	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	13900	90	0.5 ID x 1.8 T/T	V					CS	2	0.9	1.1	CRA CLAD
HC-301	1	PRODUCED WATER HYDROCYCLONE	2000 BWPD	13900	90	0.7 ID x 2.0 T/T	H					CS	8	0.5	0.7	INCLUDES 100% SPARE CAPACITY, SS LINERS
E-101A	1	PRODUCTION COOLER		13900	90	12.0 L x 2.5 W	AIR CLR		1100	93.6	AIR	CRA TB	30	6.4	7.0	2 x 50%; MOUNTED ABOVE COMPRESSOR SKIDS
E-101B	1	PRODUCTION COOLER		13900	90	12.0 L x 2.5 W	AIR CLR		1100	93.6	AIR	CRA TB	30	6.4	7.0	2 x 50%; MOUNTED ABOVE COMPRESSOR SKIDS
E-201A	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 2.5 W	AIR CLR		3200	156.7	AIR	CRA TB	30	11.0	12.1	FUTURE; 2 x 50%; MOUNTED ABOVE COMPR. SKIDS
E-201B	1	BOOSTER COMPRESSOR AFTERCOOLER		13900	150	12.0 L x 2.5 W	AIR CLR		3200	156.7	AIR	CRA TB	30	11.0	12.1	FUTURE; 2 x 50%; MOUNTED ABOVE COMPR. SKIDS
E-202	1	GAS / TEG EXCHANGER		13900	110	6.7 L x 0.4 W	S&T		50	30.0	GAS / TEG	CS	7	6.5	9.8	
C-201A	1	BOOSTER COMPRESSOR	1120 act.m3/hr	13900	150			8500	2150				6			FUTURE
C-201B	1	BOOSTER COMPRESSOR	1120 act.m3/hr	13900	150			8500	2150				6			FUTURE
K-201A	1	BOOSTER COMPRESSOR DRIVER				10.0 L x 3.0 W							30	16.3	22.5	FUTURE - 2 x 50% SOLAR CENTAURS
K-201B	1	BOOSTER COMPRESSOR DRIVER				10.0 L x 3.0 W							30	16.3	22.5	FUTURE - 2 x 50% SOLAR CENTAURS
P-201A	1	CONDENSATE BOOSTER PUMP	30 m3/hr	13900	90	5.0 L x 2.0 W		8500	78				10	1.7	1.7	FUTURE - 2 x 50%
P-201B	1	CONDENSATE BOOSTER PUMP	30 m3/hr	13900	90	5.0 L x 2.0 W		8500	78				10	1.7	1.7	FUTURE - 2 x 50%
P-202A	1	LP FLARE / DRAIN DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4	0.4	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-202B	1	LP FLARE / DRAIN DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4	0.4	LP FLARE DRUM LIQUID PUMPED TO HP FLARE DRUM
P-301A	1	HP FLARE DRUM PUMP	30 m3/hr	13900	90	6.0 L x 2.5 W		12650	160				15	2.7	2.7	2 x 50%
P-301B	1	HP FLARE DRUM PUMP	30 m3/hr	13900	90	6.0 L x 2.5 W		12650	160				15	2.7	2.7	2 x 50%
Z-201	1	TEG REGENERATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3	57.4	DESIGN WATER FLOW 40 BWPD
X-100	1	PIG LAUNCHER		13900	90	0.8 ID x 7.0 T/T						CS	14	4.8	4.8	
	1	POWER GENERATION				10.0 L x 10.0 W			1500				100	23.0	30.0	NORMAL / STANDBY / EMERGENCY
	1	FLARE TIP / IGNITION SYSTEM	50 MMscfd			1.0 L x 5.0 W							5	0.6	1.0	
	2	FIRE PUMPS	1500 GPM			6.0 L x 3.0 W							20	15.0	20.0	
	1	WORKOVER FACILITIES												20.0	20.0	
	1	ACCOMMODATION	15 PPL/30 BEDS			15.0 L x 10.0 W							150	150.0	150.0	
	1	POTABLE WATER PACKAGE				7.0 L x 8.0 W							60	10.0	15.0	
	1	HVAC				3.0 L x 3.0 W							10	3.0	5.0	
	1	CRANE												30.0	30.0	
	1	INSTRUMENT / SERVICE AIR PACKAGE				4.0 L x 8.0 W							35	17.0	25.0	
	1	DIESEL FUEL SUPPLY / TREATMENT	10 DAYS			3.0 L x 3.0 W							10	5.0	8.5	
	1	GLYCOL STORAGE / TRANSFER PUMP	5 m3			2.0 L x 3.0 W							10	5.0	8.0	
	2	SURVIVAL CRAFT	20 MEN											5.0	7.0	
	1	SEWAGE TREATMENT UNIT	30 MEN			2.0 L x 3.0 W							6	1.0	3.0	
	1	HELIDECK												100.0	100.0	
												TOTAL	824	607.6	719.1	

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	24NOV98		
A	Initial Draft For Cost Estimating	20NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 1B

PREMIER OIL

Doc. No.: 9843EL1B

94447

ONSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
V-201A	1	SLUGCATCHER	800 BBL	9300	80	3.0 ID x 30.0 T/T	H					CS	140	149.5		2 x 50%, EPOXY LINED
V-201B	1	SLUGCATCHER	800 BBL	9300	80	3.0 ID x 30.0 T/T	H					CS	140	149.5		2 x 50%, EPOXY LINED
V-202	1	CONDENSATE STABILISATION COLUMN	4000 BBL/d	2000	230	1.5 ID x 18.3 T/T	V					CS	4	15.7		22 TRAYS
V-203	1	LOW TEMPERATURE SEPARATOR	80 MMscfd	6000	-29	1.7 ID x 5.2 T/T	V					CS	6	8.9		
V-204A	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-204B	1	SALES GAS COMP. SUCTION DRUM	50 MMscfd	7000	90	1.0 ID x 3.5 T/T	V					CS	4	4.3		2 x 50%
V-205A	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-205B	1	SALES GAS COMP. DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-206	1	GAS RECOVERY COMP. SUCTION DRUM	3.5 MMscfd	2000	90	0.8 ID x 2.5 T/T	V					CS	4	1.0		
V-207	1	FLARE DRUM	50 MMscfd	350	80	2.4 ID x 7.2 T/T	H					CS	24	10.7		
V-208	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	7000	120	0.8 ID x 2.5 T/T	V					CS	4	2.3		EXPECTED FUEL GAS RATE 2.0 MMscfd
V-209	1	TEG INLET SEPARATOR	100 MMscfd	9300	90	1.5 ID x 4.5 T/T	V					CS	4	4.8		
V-210	1	TEG CONTACTOR	100 MMscfd	9300	90	1.2 ID x 8.0 T/T	V					CS	4	14.0		CRA CLAD
V-211A	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-211B	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-212	1	HOT OIL FILTER		1800	250	0.3 L x 0.3 W						CS	1	0.5		
E-201	1	CONDENSATE STABILISATION REBOILER		2000	250	1.1 ID x 6.3 T/T	KETL		3000	60	HOT OIL	CS	14	6.3		
E-202A	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 2.5 W	AIR CLR		1620	65	AIR	CS	30	5.4		2 x 50%
E-202B	1	SALES GAS COMP. AFTERCOOLER		9300	150	12.0 L x 2.5 W	AIR CLR		1620	65	AIR	CS	30	5.4		2 x 50%
E-203	1	GAS RECOVERY COMP. AFTERCOOLER		7000	150	12.0 L x 1.5 W	AIR CLR		250	11	AIR	CS	18	2.0		
E-204	1	CONDENSATE RUNDOWN COOLER		2000	250	12.0 L x 2.5 W	AIR CLR		2000	66	AIR	CS	30	5.4		
E-205	1	GAS / TEG EXCHANGER		9300	90	6.7 L x 0.4 W	S&T		50	30	GAS / TEG	CS	3	2.6		
C-201	1	BOOSTER COMPRESSOR		7000	90			3250	1900							DRIVEN BY TURBO EXPANDER K-201
C-202A	1	SALES GAS COMPRESSOR		9300	125			4800	3000							2 x 100%
C-202B	1	SALES GAS COMPRESSOR		9300	125			4800	3000							2 x 100%
C-203	1	GAS RECOVERY COMPRESSOR		2000	120			3900	180							
K-201	1	TURBO EXPANDER		6000	-29	3.5 L x 7.0 W		1500	1710				24	18.0		DRIVES SALES GAS COMPRESSOR LP STAGE C-201
K-202A	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3200				30	16.3		2 x 100% SOLAR CENTAUR
K-202B	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			3200				30	16.3		2 x 100% SOLAR CENTAUR
K-203	1	GAS RECOVERY COMPRESSOR DRIVER				7.0 L x 3.0 W			250				21	15.8		GAS ENGINE
P-201A	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W	-	5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-201B	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100%, TO BE CONFIRMED
P-202A	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-202B	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-203A	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
P-203B	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
T-200A	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-200B	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-201	1	FIREWATER TANK	18000 BBL			7.3 ID x 12.2 T/T							100	61.5		
Z-201	1	ONSHORE TEG DEHYDRATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3		
Z-202A	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
Z-202B	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
Z-203	1	AMINE PACKAGE	95 MMscfd			15.0 L x 24.0 W							360	700.0		
X-200	1	PIG RECEIVER		13900	90	0.8 ID x 7.0 T/T	H					CS	12	7.2	7.2	TRUNKLINE PIG RECEIVER
X-201	1	PIG LAUNCHER		13900	90	0.6 ID x 6.0 T/T	H					CS	10	4.7	4.7	SALES GAS LINE PIG LAUNCHER
	1	POWER GENERATION	1 MW													
	1	CONTROL ROOM														
	1	WAREHOUSE														
	1	OFFICES														
	1	WORKSHOP														
	1	STORE														
	1	CPI SEPARATOR				3.0 L x 3.0 W							24			
	2	FIREWATER PUMPS		2000	80	3.4 L x 1.5 W							16	10.9		
	1	INSTRUMENT / SERVICE AIR PACKAGE		2000	80									30.0		
	1	STORM WATER DRAINAGE														
												TOTAL	2278	1394.3	N/A	

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	24NOV98	MRH	NJP
A	Initial Draft For Cost Estimating	20NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 1B

PREMIER OIL

Doc. No.: 9843EL1B

94476

YOLLA DEVELOPMENT CASE 1B
PROCESS/UTILITY EQUIPMENT LIST

PIPELINES

TAG NO	QTY	DESCRIPTION	NOMINAL CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
	1	GAS / CONDENSATE SUBSEA PIPELINE	90 MMscfd	13900	100	12" x 130km x 10mmWT					CS				OFFSHORE FACILITY TO SHORE, 2 PHASE, API5LX65
	1	SALES GAS EXPORT PIPELINE	70 MMscfd	9300	100	10" x 30km x 7 9mmWT					CS				GAS EXPORT TO MAGNESITE MINE; API5LX52

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	24NOV98	MRH	NJP
A	Initial Draft For Cost Estimating	20NOV98	MRH	NJP

WOODHILL THORNTON

PAGE 3 of 3 — Doc. No.. 9843EL1B

YOLLA DEVELOPMENT CASE 1B

PREMIER OIL

64474

YOLLA DEVELOPMENT CASE 1C

PROCESS/UTILITY EQUIPMENT LIST

OFFSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP. (°C)	DIMENSIONS (m)	TYPE V/H, S&T / AIR CLR	DIFF HEAD (kPa)	POWER / DUTY (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
WH-101A..E	5	PRODUCTION SUBSEA WELLHEADS														CRA LINED FLOWLINES / PRODUCTION MANIFOLDS
	1	SUBSEA MANIFOLD														
V-101	1	CORROSION INHIBITOR STORAGE TANK	11 m3													BUILT INTO STRUCTURE; SS LINED
V-102	1	DIESEL STORAGE TANK	12 m3													BUILT INTO STRUCTURE
V-103	1	HYDRAULIC FLUID RESERVOIR TANK	1.5 m3													STAINLESS STEEL
V-104	1	BILGE TANK	2 m3													BUILT INTO STRUCTURE
P-101A	1	CORROSION INHIBITOR INJECTION PUMP		30000	45	0.5 L x 0.5 W			0.3				1	0.1		
P-101B	1	CORROSION INHIBITOR INJECTION PUMP		30000	45	0.5 L x 0.5 W			0.3				1	0.1		
P-101C	1	CORROSION INHIBITOR INJECTION PUMP		30000	45	0.5 L x 0.5 W			0.3				1	0.1		
P-102A	1	DIESEL TRANSFER PUMP		700	60	0.5 L x 0.2 W			0.5				1	0.0		
P-102B	1	DIESEL TRANSFER PUMP		700	60	0.5 L x 0.2 W			0.5				1	0.0		
P-103A	1	BILGE PUMP		1000	60	0.2 L x 0.2 W			0.5				1	0.2		
P-103B	1	BILGE PUMP		1000	60	0.2 L x 0.2 W			0.5				1	0.2		
E-101	1	GENERATOR HEAT EXCHANGER														BUILT INTO STRUCTURE
	1	HVAC			45	1.0 L x 1.5 W			1.2				2	0.2		
	1	POWER GENERATION	25 kW			3.0 L x 4.2 W							13	12.3		
	1	CONTROL SYSTEMS				1.5 L x 2.2 L			1.0				3	0.4		
												TOTAL	24	13.4	0.0	

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	26NOV98	[signature]	[signature]
A	Initial Draft For Cost Estimating	20NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 1C

PREMIER OIL

PAGE 1 of 3 Doc. No.: 9843EL1C

844449

ONSHORE EQUIPMENT

TAG NO	QTY	DESCRIPTION	CAPACITY	DESIGN PRES (kPag)	DESIGN TEMP (°C)	DIMENSIONS (m)	TYPE V/H S&T / AIR CLR	DIFF HEAD (kPa)	DUTY / POWER (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
V-201A	1	SLUGCATCHER	1550 BBL	9300	80	3.7 ID x 40.0 T/T	H					CS	202	286.0		2 x 50% EPOXY LINED
V-201B	1	SLUGCATCHER	1550 BBL	9300	80	3.7 ID x 40.0 T/T	H					CS	202	286.0		2 x 50% EPOXY LINED
V-202	1	CONDENSATE STABILISATION COLUMN	4000 BBL/d	2000	230	1.5 ID x 18.3 T/T	V					CS	4	15.7		22 TRAYS
V-203	1	LOW TEMPERATE SEPARATOR	95 MMscfd	6000	-29	2.2 ID x 7.2 T/T	V					CS	9	18.3		
V-204A	1	SALES GAS COMP SUCTION DRUM	50 MMscfd	7000	90	1.8 ID x 6.0 T/T	V					CS	4	12.5		2 x 50%
V-204B	1	SALES GAS COMP SUCTION DRUM	50 MMscfd	7000	90	1.8 ID x 6.0 T/T	V					CS	4	12.5		2 x 50%
V-205A	1	SALES GAS COMP DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-205B	1	SALES GAS COMP DISCHARGE DRUM	50 MMscfd	9300	90	1.3 ID x 4.4 T/T	V					CS	4	6.9		2 x 50%
V-206	1	GAS RECOVERY COMP SUCTION DRUM	4 MMscfd	2000	90	0.8 ID x 2.5 T/T	V					CS	4	1.0		
V-207	1	FLARE DRUM	50 MMscfd	350	80	2.4 ID x 7.2 T/T	H					CS	24	10.7		
V-208	1	FUEL GAS KNOCKOUT DRUM	2 MMscfd	7000	120	0.8 ID x 2.5 T/T	V					CS	4	2.3		EXPECTED FUEL GAS RATE 2.0 MMscfd
V-209	1	TEG INLET SEPARATOR	100 MMscfd	9300	90	1.5 ID x 4.5 T/T	V					CS	4	4.8		
V-210	1	TEG CONTACTOR	100 MMscfd	9300	90	1.2 ID x 8.0 T/T	V					CS	4	14.0		CRA CLAD
V-211A	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-211B	1	HOT OIL DRUM		1000	250	1.5 ID x 4.5 T/T	H					CS	10	4.1		
V-212	1	HOT OIL FILTER		1800	250	0.3 L x 0.3 W						CS	1	0.5		
V-213	1	INLET COMPRESSOR DISCHARGE DRUM	95 MMscfd	9300	90	1.7 ID x 5.2 T/T	V					CS	6	13.0		
V-214	1	MEG STORAGE DRUM	600 BBL	350	90	4.2 ID x 6.8 T/T	H					CS	40	23.8		
V-215	1	INLET COMPRESSOR SUCTION DRUM	95 MMscfd	9300	80	1.9 ID x 6.0 T/T	V					CS	9	17.8		
E-201	1	CONDENSATE STABILISATION REBOILER		2000	250	1.[illegible] ID x 6.3 T/T	KETL		3000	60	HOT OIL	CS	14	6.3		
E-202A	1	SALES GAS COMP AFTERCOOLER		9300	150	12.0 L x 2.5 W	AIR CLR		2300	87	AIR	CS	30	6.4		2 x 50%
E-202B	1	SALES GAS COMP AFTERCOOLER		9300	150	12.0 L x 2.5 W	AIR CLR		2300	87	AIR	CS	30	6.4		2 x 50%
E-203	1	GAS RECOVERY COMP AFTERCOOLER		7000	150	12.0 L x 1.5 W	AIR CLR		250	11	AIR	CS	28	2.0		
E-204	1	CONDENSATE RUNDOWN COOLER		2000	250	12.0 L x 2.5 W	AIR CLR		2000	66	AIR	CS	56	5.4		
E-205	1	GAS / TEG EXCHANGER		9300	90	6.7 L x 0.4 W	S&T		50	30	GAS / TEG	CS	3	2.6		
E-206	1	INLET COMPRESSOR AFTERCOOLER		9300	90	12.0 L x 2.5 W	AIR CLR		2500	169	AIR	CS	30	11.0		
C-201	1	BOOSTER COMPRESSOR		7000	90			1800	2600							DRIVEN BY TURBO EXPANDER K-201
C-202A	1	SALES GAS COMPRESSOR		9300	135			4700	4000							
C-202B	1	SALES GAS COMPRESSOR		9300	135			4700	4000							
C-203	1	GAS RECOVERY COMPRESSOR		2000	120			3900	180							
C-204	1	INLET COMPRESSOR		9300	90			1900	1640							
K-201	1	TURBO EXPANDER		6000	-29	4.5 L x 8.0 W		3350	2800				36	30.0		DRIVES BOOSTER COMPRESSOR C-201
K-202A	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			4210				30	16.3		2 x 50% SOLAR CENTAURS
K-202B	1	SALES GAS COMPRESSOR DRIVER				10.0 L x 3.0 W			4210				30	16.3		2 x 50% SOLAR CENTAURS
K-203	1	GAS RECOVERY COMPRESSOR DRIVER				7.0 L x 3.0 W			250				21	15.8		GAS ENGINE
K-204	1	INLET COMPRESSOR DRIVER				10.0 L x 3.0 W			2000				30	16.3		1 x 100% SOLAR CENTAUR
P-201A	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100% TO BE CONFIRMED
P-201B	1	CONDENSATE PRODUCT PUMP	35 m3/hr	13900	90	5.0 L x 2.0 W		5000	67				10	1.7		2 x 100% TO BE CONFIRMED
P-202A	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-202B	1	FLARE DRUM PUMP	30 m3/hr	500	90	3.0 L x 1.0 W		350	4.4				3	0.4		2 x 100%
P-203A	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
P-203B	1	HOT OIL PUMP		1800	250	1.8 L x 0.7 W			75				2	1.0		2 x 100%
P-204A	1	MEG INJECTION PUMP	1 m3/hr	1000	90	2.0 L x 1.0 W		500	1.5				2	0.5		2 x 100%
P-204B	1	MEG INJECTION PUMP	1 m3/hr	1000	90	2.0 L x 1.0 W		500	1.5				2	0.5		2 x 100%
T-200A	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-200B	1	CONDENSATE STORAGE TANK	24000 BBL	17	80	20.0 ID x 12.5 H	V					CS	484			EACH TANK 6 DAYS STORAGE
T-201	1	FIREWATER TANK	18000 BBL			7.3 ID x 12.2 T/T							100	61.5		
Z-201	1	TEG DEHYDRATION PACKAGE	100 MMscfd			7.0 L x 3.5 W							25	38.3		
Z-202A	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
Z-202B	1	WASTE HEAT RECOVERY UNIT		1800	250	6.4 L x 6.2 W			3880				60	21.8		
Z-203	1	MEG REGENERATION PACKAGE	380 BBL/d			5.0 L x 4.0 W							20	16.0		DESIGN 260 BWPD 120 BBL/d MEG
X-201	1	PIG LAUNCHER		13900	90	0.6 ID x 6.0 T/T	H					CS	10	4.7		SALES GAS LINE PIG LAUNCHER
	1	POWER GENERATION	1 MW													
	1	CONTROL ROOM														
	1	WAREHOUSE														
	1	OFFICES														
	1	WORKSHOP														
	1	STORE														
	1	CPI SEPARATOR				3.0 L x 3.0 W							24			
	2	FIREWATER PUMPS		2000	80	3.4 L x 1.5 W							16	10.9		
	1	INSTRUMENT / SERVICE AIR PACKAGE		2000	80									30.0		
	1	STORM WATER DRAINAGE														
												TOTAL	2165	1044.2	N/A	

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	26NOV98	MRH	NJP
A	Initial Draft For Cost Estimating	20NOV98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT CASE 1C

PREMIER OIL

Doc No.: 9843EL1C

YOLLA DEVELOPMENT CASE 1C
PROCESS/UTILITY EQUIPMENT LIST

PIPELINES

TAG NO.	QTY	DESCRIPTION	NOMINAL CAPACITY	DESIGN PRES. (kPag)	DESIGN TEMP (°C)	DIMENSIONS	DIFF. HEAD (kPa)	POWER / DUTY (kW)	HEAT TRNFR AREA (m2)	HEAT / COOL MEDIUM	MOC	FTPRNT AREA (m2)	DRY WEIGHT (te)	OPTG WEIGHT (te)	REMARKS
	1	GAS / CONDENSATE SUBSEA PIPELINE	95 MMscfd	13900	100	18" x 130km x 12.8mmWT					CS/CRA				W/HDS TO SHORE, 30km CRA LINED, 2 PHASE, API5LX65
	1	SALES GAS EXPORT PIPELINE	85 MMscfd	9300	100	10" x 30km x 7.9mmWT					CS				GAS EXPORT TO MAGNESITE MINE, API5LX52
	1	MEG INJECTION PIGGY-BACK LINE	120 BBL/d	13,900	100	2" x 130km x 5.2mmWT					CS				MEG PIGGY BACK LINE TO WELL, API5LX65

REV	DESCRIPTION	DATE	PREPD	CHKD
B	Vessel Weights Updated	26NOV98	MRH (signed)	NJP (signed)
A	Initial Draft For Cost Estimating	20NOV98	MRH	NJP

WOODHILL THORNTON

Doc. No.: 9843EL1C

YOLLA DEVELOPMENT CASE 1C

PREMIER OIL

644150

644151

APPENDIX 8

Sales Gas, LPG and Condensate Quantity and Quality Data

644152

YOLLA DEVELOPMENT STUDY

PRODUCT QUANTITY AND QUALITY DATA

Base Cases

Based on (lean) Yolla 2 composition.

Gas [illegible]

CASE NO.	1A	2A	3A	4A
SALESGAS				
MMscfd	85	97	80	96
TJ/d	82	110	82	110
PJ/y	30	40	30	40
%CO2	20.0	2.5	16.6	2.2
HHV	918	1076	968	1087
WI	38	50	40	50
HCDP (°C)	-14	-37	-12	-36
MW	23.7	18.7	23.1	18.8
CONDENSATE				
bbl/d	3500	6360	2630	5220
RVP	9.5	9.9	8.7	9.7
PROPANE				
tpd		55.6		61.3
%C2		5.0		5.0
%C3		93.0		93.0
%C4		2.0		2.0
BUTANE				
tpd		77.2		76.9
%C3		1.5		1.5
%C4		94.5		94.5
%C5+		4.0		4.0
YOLLA CRUDE				
bbl/d			20,000	20,000
RVP			8.0	8.0
NOTES				

LPG tonnes per TJ salesgas — 1.2073 — 1.256

Note: Yolla Year 1 CGR of 38.3bbl/MMscf declines
to 24.6bbl/MMscf over the field life.

Get 109.59 TJ/d from 127.82 MMscf/d (Premier Report Appendix 1)
Ratio 0.8574

→ In Case [illegible] LPG yield = 1.2073 x [illegible]

1.04 ktonne/bcf

132.8 / [illegible] = 1.04 ktonne/bcf

644153

PRODUCT QUANTITY AND QUALITY DATA

Alternative Cases

CASE NO.	1A2	1B	1C	1C2	1D	2B	3B	3C	4B
SALESGAS									
MMscfd	85	70	85	85	70	97	80	80	96
TJ/d	82	82	82	82	82	110	82	82	110
PJ/y	30	30	30	30	30	40	30	30	40
%CO2	20.0	2.4	20.0	20.0	2.8	2.5	16.6	16.6	2.2
HHV	918	1120	920	920	1109	1076	968	968	1087
WI	38	51	38	38	51	50	40	40	50
HCDP (°C)	-14	-14	-14	-14	-18	-37	-12	-12	-36
MW	23.7	19.3	23.7	23.7	19.2	18.7	23.1	23.1	18.8
CONDENSATE									
bbl/d	3500	3520	3470	3470	3600	6360	2630	2630	5220
RVP	9.5	9.6	9.5	9.5	9.5	9.9	8.7	8.7	9.7
PROPANE									
tpd						55.6			61.3
%C2						5.0			5.0
%C3						93.0			93.0
%C4						2.0			2.0
BUTANE									
tpd						77.2			76.9
%C3						1.5			1.5
%C4						94.5			94.5
%C5+						4.0			4.0
YOLLA CRUDE									
bbl/d							20,000	20,000	20,000
RVP							8.0	8.0	8.0
NOTES									
	As per 1A			As per 1C		As per 2A	As per 3A	As per 3A	As per 4A

Note: Yolla Year 1 CGR of 38.3bbl/MMscf declines
to 24.6bbl/MMscf over the field life.

YOLLA DEVELOPMENT STUDY

PRODUCT QUANTITY AND QUALITY DATA

Additional Cases

CASE NO.	1A3	2A2	2A3	3A2	4A2
SALESGAS					
MMscfd	57	97	72	80	72
TJ/d	55	110	82	82	82
PJ/y	20	40	30	30	30
%CO2	20.0	2.5	2.5	16.6	2.2
HHV	918	1076	1076	968	1087
WI	38	50	50	40	50
HCDP (°C)	-14	-37	-37	-12	-36
MW	23.7	18.7	18.7	23.1	18.8
CONDENSATE					
bbl/d	2333.3333	6360	4770	2630	3915
RVP	9.5	9.9	9.9	8.7	9.7
PROPANE					
tpd		55.6	41.7		45.975
%C2		5.0	5.0		5.0
%C3		93.0	93.0		93.0
%C4		2.0	2.0		2.0
BUTANE					
tpd			57.9		57.675
%C3			1.5		1.5
%C4			94.5		94.5
%C5+			4.0		4.0
YOLLA CRUDE					
bbl/d				10,000	20,000
RVP				8.0	8.0
NOTES					
	As per 1A,	As per 2A	As per 2A,	As per 3A,	As per 4A,
	but 20PJ/y		but 30PJ/y	but 10kbpd	but 30PJ/y
			(nil swing)		(nil swing)

Note: Yolla Year 1 CGR of 38.3bbl/MMscf declines
to 24.6bbl/MMscf over the field life.

APPENDIX 9

Base Case Cost Estimate Summaries

DEVELOPMENT SCENARIO 1A - COST ESTIMATE SUMMARY

ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	71.40	4 Platform based Gas Wells
Platform	**150.38**	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	89.79	Manned 2000 tonne Topsides with gas processing facilities including separation, compression (future), gas drying, water treatment and condensate pumps (future).
Gas Production Pipeline	83.65	135km x 300mm NB Pipeline to Tasmania (Burnie)
Onshore Process Facility	67.92	Onshore process facility including slugcatcher, gas drying, dewpoint control sales gas compression and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	5.00	50km x 100mm NB Condensate Line to P. Latta.
Project Management (10%)	30.69	(Excludes wells.)
TOTAL CAPEX	409.04	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
Jacket	18.18	42.41	
Topsides		44.90	33.22
Production Pipeline		29.28	54.37
Onshore Facility		33.96	33.96
Export Pipelines			5.00
Project Managemen	3.07	13.37	13.37
TOTAL	21.24	163.92	211.33

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	0.00	0.00	0.00

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides	11.67		
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Managemen	0.88		
TOTAL	12.55	0.00	0.00

Opex PA	A$M
All Wells (Platform and Subsea)	0.66
Jacket	0.91
Topsides	8.98
Production Pipeline	0.84
Onshore Facility	4.08
Export Pipelines	0.10
TOTAL OPEX PA	15.56

Abandonment Costs	A$M
Wells	8.00
Subsea	
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	6.80
Export Pipelines	0.25
TOTAL	31.55

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Well Costs Revised	28JAN99	DAF	DTC
C	General Revision	19JAN99	DAF	DTC
B	Issued for Client Review	09DEC98	MRH	NJP

WOODHILL THORNTON

PAGE 1 of 1 — Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

64156

DEVELOPMENT SCENARIO 2A - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Yolla Wells	71.40	4 Platform based Gas Wells at Yolla
White Ibis Facilities	124.49	
Wells	36.73	2 Subsea Gas Wells (A$18.36M each).
Subsea Manifold	36.21	3 Well Template with MPFM's and Control System tied back to Yolla
Flowline	51.56	40km x 300mm NB CRA/CS Pipeline to Yolla and 50mm MEG piggyback line
Platform	174.82	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	114.23	Manned 2600 tonne Topsides with gas processing facilities including separation, compression, gas drying, water treatment/MEG recovery and condensate pumps.
Gas Production Pipeline	137.13	210km x 400mm NB Pipeline to Victoria (Black Rock)
Onshore Process Facility	137.98	Onshore process facility including slugcatcher, CO2 removal, gas drying, dew point control, sales gas compression and condensate stabilisation, LPG fractionation, storage and export.
Onshore Gas and Condensate Pipelines	12.58	35km x 300mm NB Gas Line and 35km x 100mm NB Condensate Line to Geelong.
Project Management (10%)	55.03	(Excludes Wells.)
TOTAL CAPEX	713.43	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
White Ibis Subsea			
Jacket	18.18	42.41	
Topsides		57.12	57.12
Production Pipeline		48.00	89.14
Onshore Facility		68.99	68.99
Export Pipelines			12.58
Project Management	5.50	19.96	19.96
TOTAL	**23.68**	**236.47**	**319.18**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
White Ibis Subsea		74.69	49.80
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management		5.76	3.84
TOTAL	**0.00**	**80.46**	**53.64**

Opex PA	A$M
All Wells (Platform and Subsea)	1.33
White Ibis Subsea	1.32
Jacket	0.91
Topsides	11.42
Production Pipeline	1.37
Onshore Facility	8.28
Export Pipelines	0.25
TOTAL OPEX PA	**24.88**

Abandonment Costs	A$M
Wells	12.00
Subsea	0.50
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	13.80
Export Pipelines	0.25
TOTAL	**43.05**

REV	DESCRIPTION	DATE	PREPD	CHKD
E	Revised Well Costs	28JAN99	DAF	DTC
D	General Revision	19JAN99	DAF	DTC
C	Revised for Report	18DEC98	DAF	NJP

WOODHILL THORNTON

PAGE 1 of 1 | Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

DEVELOPMENT SCENARIO 3A - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	123.00	4 Platform based Gas Wells and 3 Platform based mulitateral Oil Wells
Platform	188.33	
Substructure	62.12	12 Slot Steel Piled Jacket in 80m
Topsides	126.20	Manned 2700 tonne Topsides with separate gas and oil processing facilities including separation, compression, gas drying, water treatment, condensate pumps and oil shipping pumps.
Calm Buoy and Loading Line	15.08	2km x 250 NB Line from platform to CALM Buoy with leased FSU
Gas Production Pipeline	83.65	135km x 300mm NB Pipeline to Tasmania (Burnie)
Onshore Process Facility	67.92	Onshore process facility including slugcatcher, gas drying, dewpoint control, sales gas compression, and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	5.00	50km x 100mm NB Condensate Line to P. Latta.
Project Management (10%)	36.00	(Excludes Wells)
TOTAL CAPEX	518.97	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			123.00
Jacket	18.64	43.48	
Topsides		63.10	63.10
Calm Buoy/Loading			15.08
Production Pipeline		29.28	54.37
Onshore Facility		33.96	33.96
Export Pipelines			5.00
Project Management	3.60	16.20	16.20
TOTAL	22.24	186.02	310.71

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	0.00	0.00	0.00

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	0.00	0.00	0.00

Opex PA	A$M
All Wells (Platform and Subsea)	1.16
Jacket	0.93
Topsides	12.62
CALM Buoy and Loading Line incl FSU (NOTE 1)	25.65
Production Pipeline	0.84
Onshore Facility	4.08
Export Pipelines	0.10
TOTAL OPEX PA	45.37

Abandonment Costs	A$M
Wells	14.00
Subsea	
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	1.50
Production Pipelines	0.50
Onshore Facility	6.80
Export Pipelines	0.25
TOTAL	39.05

NOTES
(1) FSU/CALM BUOY NOT REQUIRED AFTER YEAR 5.

REV	DESCRIPTION	DATE	PREPD	CHKD
E	Revised Yolla Well Costs	09FEB99	MWM	NJP
D	Revised Well Costs	28JAN99	DAF	DTC
C	General Review	19JAN99	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT

PREMIER OIL

PAGE 1 of 1 Doc. No.: SUMMARY.xls

64158

DEVELOPMENT SCENARIO 4A - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Yolla Wells	**123.00**	4 Platform based Gas Wells and 3 mulilateral Oil Wells
White Ibis Facilities	**124.49**	
Wells	36.73	2 Subsea Gas Wells at White Ibis
Subsea Manifold	36.21	3 Well Template with MPFM's and Control System tied back to Yolla
Flowline	51.56	40km x 300mm NB CRA/CS Pipeline to Yolla and 50mm MEG Line
Platform	**217.01**	
Substructure	62.12	12 Slot Steel Piled Jacket in 80m
Topsides	154.89	Manned 3300 tonne Topsides with gas processing facilities including separation, compression, gas drying, water treatment/MEG recovery and condensate pumps.
Calm Buoy and Loading Line	**15.08**	2km x 250mm NB Line from platform to CALM Buoy with leased FSU
Gas Production Pipeline	**137.13**	210km x 400mm NB Pipeline to Victoria (Black Rock)
Onshore Process Facility	**137.98**	Onshore process facility including slugcatcher, CO2 removal, gas drying, dew point control, sales gas compression and condensate stabilisation, LPG fractionation, storage and export.
Onshore Gas and Condensate Pipelines	**12.58**	35km x 300mm NB Gas Line and 35km 100mm NB Condensate Line to Geelong.
Project Management (10%)	**60.75**	(Excludes Wells)
TOTAL CAPEX	**828.03**	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			123.00
White Ibis Subsea			
Jacket	18.64	43.48	
Topsides		77.45	77.45
Calm Buoy/Loading			15.08
Production Pipeline		48.00	89.14
Onshore Facility		68.99	68.99
Export Pipelines			12.58
Project Management	6.08	22.77	22.77
TOTAL	**24.71**	**260.69**	**409.00**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
White Ibis Subsea		74.69	49.80
Jacket			
Topsides			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management		5.48	3.65
TOTAL	**0.00**	**80.17**	**53.45**

Opex PA	A$M
All Wells (Platform and Subsea)	1.83
White Ibis Subsea	1.32
Jacket	0.93
Topsides	15.49
CALM Buoy and Loading Line incl FSU (NOTE 1)	25.65
Production Pipeline	1.37
Onshore Facility	8.28
Export Pipelines	0.25
TOTAL OPEX PA	**55.12**

Abandonment Costs	A$M
Wells	18.00
Subsea	0.50
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	1.50
Production Pipelines	0.50
Onshore Facility	13.80
Export Pipelines	0.25
TOTAL	**50.55**

NOTES
(1) FSU/CALM BUOY NOT REQUIRED AFTER YEAR 5.

REV	DESCRIPTION	DATE	PREPD	CHKD
F	Revised Yolla Well Costs	09FEB99	MWN	NTP
E	Revised Well Costs	28JAN99	DAF	DTC
D	General Revision	19JAN99	DAF	DTC

WOODHILL THORNTON

YOLLA DEVELOPMENT

PREMIER OIL

PAGE 1 of 1 Doc. No.: SUMMARY.xls

64159

644160

APPENDIX 10

Alternative Case Cost Estimate Summaries

DEVELOPMENT SCENARIO 1B - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	71.40	4 Platform based Gas Wells
Platform	150.38	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	89.79	Manned 2000 tonne Topsides with gas processing facilities including separation, compression (future), gas drying, water treatment and condensate pumps (future).
Gas Production Pipeline	83.65	135km x 300mm NB Pipeline to Tasmania (Burnie).
Onshore Process Facility	87.09	Onshore process facility including slugcatcher, CO2 removal, gas drying, dewpoint control sales gas compression and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	5.00	50km x 100mm NB Condensate Line to P. Latta
Project Management (10%)	32.61	(Excludes wells.)
TOTAL CAPEX	430.13	

Opex PA	A$M
All Wells (Platform and Subsea)	0.66
Jacket	0.91
Topsides	8.98
Production Pipeline	0.84
Onshore Facility	5.23
Export Pipelines	0.10
TOTAL OPEX PA	16.71

Abandonment Costs	A$M
Wells	8.00
Subsea	
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	8.70
Export Pipelines	0.25
TOTAL	33.45

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
Jacket	18.18	42.41	
Topsides		44.90	33.22
Production Pipeline		29.28	54.37
Onshore Facility		43.55	43.55
Export Pipelines			5.00
Project Management	3.26	14.23	14.23
TOTAL	21.44	174.36	221.77

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	0.00	0.00	0.00

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides	11.67		
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management	0.89		
TOTAL	12.56	0.00	0.00

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Well Costs	28JAN99	DAF	DTC
C	General Revision	19JAN99	DAF	DTC
B	Issued for Client Review	09DEC98	MRH	NJP

WOODHILL THORNTON

PAGE 1 of 1 Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

644161

DEVELOPMENT SCENARIO 1C - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Subsea Wells	**69.00**	4 Subsea wells
Subsea Manifold	**35.51**	6 Well Template with MPFM's and Control System
NCC Buoy	**23.07**	Unmanned NCC Buoy with Control System and Corrosion Inhibitor equipment
Gas Production Pipeline	**172.17**	135km x 450mm NB CRA/CS Pipeline to Tasmania (Burnie) and 50mm piggyback MEG Line
Onshore Process Facility	**98.88**	Onshore process facility including slugcatcher, raw gas compression (future), glycol recovery, gas drying, dew point control, sales gas compression and condensate stabilisation, storage and export
Onshore Gas and Condensate Pipelines	**5.00**	50km x 100mm NB Condensate Line to P. Latta
Project Management (10%)	**33.46**	(Excludes wells)
TOTAL CAPEX	**437.08**	

Opex PA	A$M
All Wells (Platform and Subsea)	1.34
Subsea Facilities	0.53
NCC Buoy	1.15
Production Pipeline	1.72
Onshore Facility	5.93
Export Pipelines	0.10
TOTAL OPEX PA	**10.78**

Abandonment Costs	A$M
Wells	8.00
Subsea	0.50
Buoy	11.50
Jacket	
Topsides	
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	9.90
Export Pipelines	0.25
TOTAL	**30.65**

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			69.00
Manifold		21.30	14.20
NCC Buoy		13.84	9.23
Production Pipeline		60.26	111.91
Onshore Facility		38.66	42.42
Export Pipelines			5.00
Project Management		16.05	16.05
TOTAL	**-**	**150.11**	**267.81**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +6 A$M	RFSU +7 A$M	RFSU +8 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			17.80
Export Pipelines			
Project Management			1.36
TOTAL	**0.00**	**0.00**	**19.16**

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Well Costs	28JAN99	DAF	DTC
C	General Revision	19JAN99	DAF	DTC
B	Issued for Client Review	08DEC98	MRH	NJP

WOODHILL THORNTON

YOLLA DEVELOPMENT

PREMIER OIL

Doc. No.: SUMMARY.xls

644162

DEVELOPMENT SCENARIO 1A2 - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	71.40	4 Platform based Gas Wells
Platform	150.38	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	89.79	Manned 2000 tonne Topsides with gas processing facilities including separation, compression (future), gas drying, water treatment and condensate pumps (future).
Gas Production Pipeline	99.03	170km x 300mm NB Pipeline to Tasmania (Bell Bay)
Onshore Process Facility	70.49	Onshore process facility including slugcatcher, gas drying, dewpoint control sales gas compression and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	NIL	Gas to local power station/process plant, condensate to local export facilities.
Project Management (10%)	31.99	(Excludes wells.)
TOTAL CAPEX	423.28	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
Jacket	18.18	42.41	
Topsides		44.90	33.22
Production Pipeline		34.66	64.37
Onshore Facility		35.24	35.24
Export Pipelines			
Project Management	3.20	13.95	13.95
TOTAL	21.37	171.16	218.19

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	0.00	0.00	0.00

Opex PA	A$M
All Wells (Platform and Subsea)	0.66
Jacket	0.91
Topsides	8.98
Production Pipeline	0.99
Onshore Facility	4.23
Export Pipelines	NIL
TOTAL OPEX PA	15.77

Abandonment Costs	A$M
Wells	8.00
Subsea	
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	7.10
Export Pipelines	0.25
TOTAL	31.85

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides	11.67		
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management	0.88		
TOTAL	12.56	0.00	0.00

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Well Costs	28JAN99	DAF	TJC
C	General Revision	19JAN99	DAF	DTC
B	Issued for Client Review	09DEC98	MRH	NJP

WOODHILL THORNTON

PAGE 1 of 1 — Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

64163

DEVELOPMENT SCENARIO 1C2 - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	**71.40**	4 Platform based Gas Wells
Platform	**72.00**	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	11.42	Unmanned Wellhead Topsides with well testing and chemical injection facilities
Gas Production Pipeline	**172.17**	135km x 450mm NB CRA/CS Pipeline to Tasmania (Bumie) and 50mm MEG Line
Onshore Process Facility	**98.88**	Onshore process facility including slugcatcher, glycol recovery, gas drying, dew point control, sales gas compression and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	**5.00**	50km x 100mm NB Condensate Line to P. Latta.
Project Management (10%)	**34.81**	
TOTAL CAPEX	**454.26**	

Opex PA	A$M
All Wells (Platform and Subsea)	0.66
Jacket	0.91
Topsides	1.14
Production Pipeline	1.72
Onshore Facility	5.93
Export Pipelines	0.10
TOTAL OPEX PA	**10.46**

Abandonment Costs	A$M
Wells	8.00
Subsea	
Buoy	
Jacket	13.00
Topsides	1.50
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	9.90
Export Pipelines	0.25
TOTAL	**33.15**

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
Jacket		18.18	42.41
Topsides			11.42
Production Pipeline		60.26	111.91
Onshore Facility		38.66	42.42
Export Pipelines			5.00
Project Management		16.72	16.72
TOTAL	-	**133.82**	**301.28**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +6 A$M	RFSU +7 A$M	RFSU +8 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			17.80
Export Pipelines			
Project Management			1.36
TOTAL	**0.00**	**0.00**	**19.16**

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Well Costs	28JAN99	[illegible]	[illegible]
C	General Revision	19JAN99	DAF	DTC
B	Issued for Client Review	09DEC98	MRH	NJP

WOODHILL THORNTON

PAGE 1 of 1 Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

64164

DEVELOPMENT SCENARIO 3B - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	**123.00**	4 Platform based Gas Wells and 3 Platform based multilateral Oil Wells
Platform	**188.33**	
Substructure	62.12	12 Slot Steel Piled Jacket in 80m
Topsides	126.20	Manned 2700 tonne Topsides with separate gas and oil processing facilities including separation, compression, gas drying, water treatment, condensate pumps and oil shipping pumps.
Tank	**38.15**	Subsea Storage Tank 120m x 60m x 12m
Calm Buoy and Loading Line	**15.08**	2km x 250 NB Line from platform to CALM Buoy with leased FSU
Gas Production Pipeline	**83.65**	135km x 300mm NB Pipeline to Tasmania (Burnie)
Onshore Process Facility	**67.92**	Onshore process facility including slugcatcher, gas drying, dewpoint control, sales gas compression, and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	**5.00**	50km x 100mm NB Condensate Line to P. Latta.
Project Management (10%)	**39.81**	(Excludes Wells)
TOTAL CAPEX	**560.93**	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			123.00
Jacket	18.64	43.48	
Topsides		63.10	63.10
Tank		9.54	28.61
Calm Buoy/Loading			15.08
Production Pipeline		29.28	54.37
Onshore Facility		33.96	33.96
Export Pipelines			5.00
Project Managemen	3.98	17.92	17.92
TOTAL	**22.62**	**197.28**	**341.03**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Tank			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Opex PA	A$M
All Wells (Platform and Subsea)	1.16
Jacket	0.93
Topsides	12.62
Tank	1.91
CALM Buoy and Loading Line (NOTE 1)	0.38
Production Pipeline	0.84
Onshore Facility	4.08
Export Pipelines	0.10
TOTAL OPEX PA	**22.01**

Abandonment Costs	A$M
Wells	14.00
Subsea	
Buoy	
Jacket	13.00
Topsides	3.00
Tank	2.40
CALM Buoy	1.50
Production Pipelines	0.50
Onshore Facility	6.80
Export Pipelines	0.25
TOTAL	**41.45**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Tank			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

NOTES
(1) CALM BUOY NOT REQUIRED AFTER YEAR 5.

REV	DESCRIPTION	DATE	PREPD	CHKD
F	Revised Yolla Well Costs	9FEB99	MWM	NTT
E	Revised Well Costs	28JAN99	DAF	DTC
D	General Revision	18JAN99	DAF	DTC

WOODHILL THORNTON

YOLLA DEVELOPMENT

PREMIER OIL

 Doc. No.: SUMMARY.xls

644165

DEVELOPMENT SCENARIO 4B - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Yolla Wells	**123.00**	4 Platform based Gas Wells and 3 multilateral Oil Wells
White Ibis Facilities	**124.49**	
Wells	36.73	2 Subsea Gas Wells at White Ibis
Subsea Manifold	36.21	3 Well Template with MPFM's and Control System tied back to Yolla
Flowline	51.56	40km x 300mm NB CRA/CS Pipeline to Yolla and 50mm MEG Line
Platform	**217.01**	
Substructure	62.12	12 Slot Steel Piled Jacket in 80m
Topsides	154.89	Manned 3300 tonne Topsides with gas processing facilities including separation, compression (future), gas drying, water treatment/MEG recovery and condensate pumps.
Tank	**38.15**	Subsea Storage Tank 120m x 60m x 12m
Calm Buoy and Loading Line	**15.08**	Line from platform to CALM Buoy with leased FSU
Gas Production Pipeline	**137.13**	210km x 400mm NB Pipeline to Victoria (Black Rock)
Onshore Process Facility	**137.98**	Onshore process facility including slugcatcher, CO2 removal, gas drying, dew point control, sales gas compression and condensate stabilisation, LPG fractionation, storage and export.
Onshore Gas and Condensate Pipelines	**12.58**	35km x 300mm NB Gas Line and 35km 100mm NB Condensate Line to Geelong.
Project Management (10%)	**64.57**	(Excludes Wells)
TOTAL CAPEX	**869.99**	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			123.00
White Ibis Subsea			
Jacket	18.64	43.48	
Topsides		77.45	77.45
Tank		9.54	28.61
Calm Buoy/Loading			15.08
Production Pipeline		48.00	89.14
Onshore Facility		68.99	68.99
Export Pipelines			12.58
Project Management		27.66	27.66
TOTAL	**18.64**	**275.12**	**442.50**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Tank			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
White Ibis Subsea		74.69	49.80
Jacket			
Topsides			
Tank			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management		5.54	3.70
TOTAL	**0.00**	**80.24**	**53.49**

Opex PA	A$M
All Wells (Platform and Subsea)	1.83
White Ibis Subsea	1.32
Jacket	0.93
Topsides	15.49
Tank	1.91
CALM Buoy and Loading Line (NOTE 1)	0.38
Production Pipeline	1.37
Onshore Facility	8.28
Export Pipelines	0.25
TOTAL OPEX PA	**31.75**

Abandonment Costs	A$M
Wells	18.00
Subsea	0.50
Buoy	
Jacket	13.00
Topsides	3.00
Tank	2.40
CALM Buoy	1.50
Production Pipelines	0.50
Onshore Facility	13.80
Export Pipelines	0.25
TOTAL	**52.95**

NOTES
(1) CALM BUOY NOT REQUIRED AFTER YEAR 5.

REV	DESCRIPTION	DATE	PREPD	CHKD
F	Revised Yolla Well Costs	9FEB99	MWM	NT
E	Revised Well Costs	28JAN99	DAF	DTC
D	General Revision	19JAN99	DAF	DTC

WOODHILL THORNTON

YOLLA DEVELOPMENT

PREMIER OIL

PAGE 1 of 1 Doc. No.: SUMMARY.xls

644166

644167

APPENDIX 11

Sensitivity Case Cost Estimate Summaries

DEVELOPMENT SCENARIO 1A3 - COST ESTIMATE SUMMARY

ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	54.00	3 Platform based Gas Wells
Platform	135.59	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	75.00	Manned 1600 tonne Topsides with gas processing facilities including separation, compression (future), gas drying, water treatment and condensate pumps (future).
Gas Production Pipeline	78.10	135km x 250mm NB Pipeline to Tasmania (Burnie)
Onshore Process Facility	60.00	Onshore process facility including slugcatcher, gas drying, dewpoint control sales gas compression and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	5.00	50km x 100mm NB Condensate Line to P. Latta.
Project Management (10%)	27.87	(Excludes wells.)
TOTAL CAPEX	~~360.56~~	= 273.69 + 10% PM = 310.1

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			54.00
Jacket	18.18	42.41	
Topsides		37.50	27.75
Production Pipeline		27.34	50.77
Onshore Facility		30.00	30.00
Export Pipelines			5.00
Project Managemen	2.79	12.16	12.16
TOTAL	**20.96**	**149.41**	**179.68**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides	9.75		
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Managemen	0.75		
TOTAL	**10.50**	**0.00**	**0.00**

Opex PA	A$M
All Wells (Platform and Subsea)	0.50
Jacket	0.91
Topsides	7.50
Production Pipeline	0.78
Onshore Facility	3.60
Export Pipelines	0.10
TOTAL OPEX PA	**13.39**

Abandonment Costs	A$M
Wells	6.00
Subsea	
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	6.00
Export Pipelines	0.25
TOTAL	**28.75**

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Well Costs	28JAN99	DAF	TEG
C	General Revision	19JAN99	DAF	DTC
B	Issued for Client Review	15DEC98	MRH	NJP

WOODHILL THORNTON — PAGE 1 of 1 — Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

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64169

DEVELOPMENT SCENARIO 1A4 - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Yolla Wells	**71.40**	4 Platform based Gas Wells
White Ibis Facilities	**124.49**	
Wells	36.73	2 Subsea Gas Wells (A$18.36M each).
Subsea Manifold	36.21	3 Well Template with MPFM's and Control System tied back to Yolla
Flowline	51.56	40km x 300mm NB CRA/CS Pipeline to Yolla and 50mm MEG piggyback line
Platform	**164.29**	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	103.70	Manned 2400 tonne Topsides with gas processing facilities including separation, compression, gas drying, water treatment/MEG recovery and condensate pumps.
Gas Production Pipeline	**112.70**	170km x 350mm NB Pipeline to Tasmania (Bell Bay)
Onshore Process Facility	**86.20**	Onshore process facility including slugcatcher, gas drying, dewpoint control sales gas compression and condensate stabilisation, storage and export. + CO_2, LPG
Onshore Gas and Condensate Pipelines	**NIL**	Gas to local power station/process plant, condensate to local export facilities.
Project Management (10%)	**45.10**	(Excludes Wells.)
TOTAL CAPEX	**604.18** -467.24	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
White Ibis Subsea			
Jacket	18.18	42.41	
Topsides		51.85	51.85
Production Pipeline		39.45	73.26
Onshore Facility		43.10	43.10
Export Pipelines			
Project Management	4.51	15.65	15.65
TOTAL	**22.69**	**192.45**	**255.25**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
White Ibis Subsea		74.69	49.80
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management		5.58	3.72
TOTAL	**0.00**	**80.27**	**53.51**

Opex PA	A$M
All Wells (Platform and Subsea)	0.66
White Ibis Subsea	1.32
Jacket	0.91
Topsides	10.37
Production Pipeline	1.13
Onshore Facility	5.17
Export Pipelines	NIL
TOTAL OPEX PA	**19.55**

Abandonment Costs	A$M
Wells	12.00
Subsea	0.50
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	8.60
Export Pipelines	
TOTAL	**37.60**

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Revised Well Costs	28JAN99	DAF	DTC
B	General Revision	19JAN99	DAF	DTC
A	Issued for Client Review	15JAN99	DAF	DTC

WOODHILL THORNTON — PAGE 1 of 1 — Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

644169

DEVELOPMENT SCENARIO 1A5 - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Yolla Wells	**71.40**	4 Platform based Gas Wells
White Ibis Facilities	**124.49**	
Wells	36.73	2 Subsea Gas Wells (A$18.36M each).
Subsea Manifold	36.21	3 Well Template with MPFM's and Control System tied back to Yolla
Flowline	51.56	40km x 300mm NB CRA/CS Pipeline to Yolla and 50mm MEG piggyback line
Platform	**164.29**	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	103.70	Manned 2400 tonne Topsides with gas processing facilities including separation, compression, gas drying, water treatment/MEG recovery and condensate pumps.
Gas Production Pipeline	**96.80**	135km x 350mm NB Pipeline to Tasmania (Burnie)
Onshore Process Facility	**83.90**	Onshore process facility including slugcatcher, gas drying, dewpoint control sales gas compression and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	**5.00**	50km x 100mm NB Condensate Line to P. Latta.
Project Management (10%)	**43.78**	(Excludes Wells.) Gas 344.99 + 10% PM = 379.5
TOTAL CAPEX	**589.66**	

Opex PA	A$M
All Wells (Platform and Subsea)	0.66
White Ibis Subsea	1.32
Jacket	0.91
Topsides	10.37
Production Pipeline	0.97
Onshore Facility	5.03
Export Pipelines	0.25
TOTAL OPEX PA	**19.51**

Abandonment Costs	A$M
Wells	12.00
Subsea	0.50
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	8.40
Export Pipelines	0.25
TOTAL	**37.65**

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
White Ibis Subsea			
Jacket	18.18	42.41	
Topsides		51.85	51.85
Production Pipeline		33.88	62.92
Onshore Facility		41.95	41.95
Export Pipelines			
Project Management	4.38	15.08	15.08
TOTAL	**22.55**	**185.17**	**243.20**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
White Ibis Subsea		74.69	49.80
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management		5.55	3.70
TOTAL	**0.00**	**80.24**	**53.49**

REV	DESCRIPTION	DATE	PREPD	CHKD
C	Revised Well Costs	28JAN99	DAF	TTC
B	General Revision	19JAN99	DAF	DTC
A	Issued for Client Review	15JAN99	DAF	DTC

WOODHILL THORNTON

YOLLA DEVELOPMENT

PREMIER OIL

PAGE 1 of 1 Doc. No.: SUMMARY.xls

0 7 4 4 9

DEVELOPMENT SCENARIO 2A2 - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Yolla Wells	**71.40**	4 Platform based Gas Wells at Yolla
White Ibis Facilities	**124.49**	
Wells	36.73	2 Subsea Gas Wells (A$18.36M each).
Subsea Manifold	36.21	3 Well Template with MPFM's and Control System tied back to Yolla
Flowline	51.56	40km x 300mm NB CRA/CS Pipeline to Yolla and 50mm MEG piggyback line
Platform	**174.82**	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	114.23	Manned 2600 tonne Topsides with gas processing facilities including separation, compression, gas drying, water treatment/MEG recovery and condensate pumps.
Gas Production Pipeline	**87.20**	122km x 350mm NB Pipeline to Victoria (Tarwin Meadows / Venus Bay)
Onshore Process Facility	**137.98**	Onshore process facility including slugcatcher, CO2 removal, gas drying, dew point control, sales gas compression and condensate stabilisation, LPG fractionation, storage and export.
Onshore Gas and Condensate Pipelines	**55.00**	100km x 400mm NB Gas Line and 100km x 150mm NB Condensate Line to Moe.
Project Management (10%)	**54.28**	(Excludes Wells.)
TOTAL CAPEX	**705.16**	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
White Ibis Subsea			
Jacket	18.18	42.41	
Topsides		57.12	57.12
Production Pipeline		30.52	56.68
Onshore Facility		68.99	68.99
Export Pipelines			55.00
Project Management	5.43	19.63	19.63
TOTAL	**23.60**	**218.67**	**328.82**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
White Ibis Subsea		74.69	49.80
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management		5.75	3.83
TOTAL	**0.00**	**80.44**	**53.63**

Opex PA	A$M
All Wells (Platform and Subsea)	1.33
White Ibis Subsea	1.32
Jacket	0.91
Topsides	11.42
Production Pipeline	1.37
Onshore Facility	8.28
Export Pipelines	0.25
TOTAL OPEX PA	**24.88**

Abandonment Costs	A$M
Wells	12.00
Subsea	0.50
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	13.80
Export Pipelines	0.25
TOTAL	**43.05**

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Well Costs	28JAN99	DAF	DTC
C	General Revision	19JAN99	DAF	DTC
B	Revised for Report	18DEC98	DAF	NJP

WOODHILL THORNTON

PAGE 1 of 1 Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

644171

DEVELOPMENT SCENARIO 2A3 - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Yolla Wells	**71.40**	4 Platform based Gas Wells at Yolla
Platform	**150.38**	
Substructure	60.59	8 Slot Steel Piled Jacket in 80m
Topsides	89.79	Manned 2000 tonne Topsides with gas processing facilities including separation, compression, gas drying, water treatment and condensate pumps.
Gas Production Pipeline	**130.10**	210km x 350mm NB Pipeline to Victoria (Black Rock)
Onshore Process Facility	**102.00**	Onshore process facility including slugcatcher, CO2 removal, gas drying, dew point control, sales gas compression and condensate stabilisation, LPG fractionation, storage and export.
Onshore Gas and Condensate Pipelines	**12.58**	35km x 250mm NB Gas Line and 35km x 100mm NB Condensate Line to Geelong.
Project Management (10%)	**39.51**	(Excludes Wells.)
TOTAL CAPEX	**505.96**	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			71.40
White Ibis Subsea		-	-
Jacket	18.18	42.41	
Topsides		40.41	38.87
Production Pipeline		45.54	84.57
Onshore Facility		51.00	51.00
Export Pipelines			12.58
Project Management	3.95	17.37	17.37
TOTAL	**22.13**	**196.72**	**275.78**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides	10.51		
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management	0.82		
TOTAL	**11.34**	**0.00**	**0.00**

Opex PA	A$M
All Wells (Platform and Subsea)	0.66
White Ibis Subsea	
Jacket	0.91
Topsides	8.98
Production Pipeline	1.30
Onshore Facility	6.36
Export Pipelines	0.25
TOTAL OPEX PA	**18.46**

Abandonment Costs	A$M
Wells	8.00
Subsea	0.50
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	10.20
Export Pipelines	0.25
TOTAL	**35.45**

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Well Costs	25JAN99		
C	General Revision	19JAN99	DAF	DTC
B	Revised for Report	18DEC98	DAF	NJP

WOODHILL THORNTON

PAGE 1 of 1 Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

64172

DEVELOPMENT SCENARIO 3A2 - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	**105.00**	4 Gas Wells and 2 multilateral Oil Wells
Platform	**175.92**	
Substructure	62.12	12 Slot Steel Piled Jacket in 80m
Topsides	113.80	Manned 2400 tonne Topsides with separate gas and oil processing facilities including separation, compression, gas drying, water treatment, condensate pumps and oil shipping pumps.
Calm Buoy and Loading Line	**15.08**	2km x 250 NB Line from platform to CALM Buoy with leased FSU
Gas Production Pipeline	**83.65**	135km x 300mm NB Pipeline to Tasmania (Burnie)
Onshore Process Facility	**67.92**	Onshore process facility including slugcatcher, gas drying, dewpoint control, sales gas compression, and condensate stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	**5.00**	50km x 100mm NB Condensate Line to P. Latta.
Project Management (10%)	**34.76**	(Excludes Wells)
TOTAL CAPEX	**487.32**	

Opex PA	A$M
All Wells (Platform and Subsea)	1.00
Jacket	0.93
Topsides	11.38
CALM Buoy and Loading Line incl FSU (NOTE 1)	25.65
Production Pipeline	0.84
Onshore Facility	4.08
Export Pipelines	0.10
TOTAL OPEX PA	**43.97**

Abandonment Costs	A$M
Wells	12.00
Subsea	
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	1.50
Production Pipelines	0.50
Onshore Facility	6.80
Export Pipelines	0.25
TOTAL	**37.05**

NOTES

(1) FSU/CALM BUOY NOT REQUIRED AFTER YEAR 5.

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells		-	105.00
Jacket	18.64	43.48	
Topsides		56.90	56.90
Calm Buoy/Loading			15.08
Production Pipeline		29.28	54.37
Onshore Facility		33.96	33.96
Export Pipelines			5.00
Project Management	3.48	15.64	15.64
TOTAL	**22.11**	**179.26**	**285.95**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Yolla Well Costs	09FEB99	MWM	NJP
C	Revised Well Costs	28JAN99	DAF	DTC
B	General Revision	19JAN99	DAF	DTC

WOODHILL THORNTON — PAGE 1 of 1 — Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

64173

DEVELOPMENT SCENARIO 3B2 - COST ESTIMATE SUMMARY

ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	101.00	4 Gas Wells and 2 deviated Oil/Gas Wells
Platform	168.80	
Substructure	55.00	Ove Arup ACE 90 substructure concept with integrated oil storage.
Topsides	113.80	Manned 2400 tonne Topsides with gas processing facilities including separation, compression (future), gas drying, water treatment and condensate pumps (future).
Calm Buoy and Loading Line	15.08	2km x 250 NB Line from platform to CALM Buoy with leased FSU
Gas Production Pipeline	83.65	135km x 300mm NB Pipeline to Tasmania (Burnie)
Onshore Process Facility	67.92	Onshore process facility including slugcatcher, gas drying, dewpoint control sales gas compression and condensate/crude stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	5.00	50km x 100mm NB Condensate Line to P. Latta
Project Management (10%)	34.04	(Excludes wells.)
TOTAL CAPEX	475.49	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			101.00
ACE90	16.50	38.50	
Topsides		56.90	42.11
Calm Buoy/Loading			15.08
Production Pipeline		29.28	54.37
Onshore Facility		33.96	33.96
Export Pipelines			5.00
Project Managemen	3.40	14.79	14.79
TOTAL	19.90	173.43	266.30

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
ACE 90			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	0.00	0.00	0.00

Opex PA	A$M
All Wells (Platform and Subsea)	0.99
Ove Arup ACE 90	1.10
Topsides	11.38
CALM Buoy and Loading Line	0.38
Production Pipeline	0.84
Onshore Facility	4.08
Export Pipelines	0.10
TOTAL OPEX PA	18.86

Abandonment Costs	A$M
Wells	12.00
Subsea	
Buoy	
Ove Arup ACE 90 (Assumed cost - to be confirmed)	5.00
Topsides	3.00
Tank	
CALM Buoy	1.50
Production Pipelines	0.50
Onshore Facility	9.80
Export Pipelines	0.25
TOTAL	32.05

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
ACE 90			
Topsides	14.79		
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Managemen	1.06		
TOTAL	15.85	0.00	0.00

NOTES
(1) CALM BUOY NOT REQUIRED AFTER YEAR 5.

REV		DATE	PREPD	CHKD		
B	Revised Yolla Well Costs	09FEB99	MWM	NJP	WOODHILL THORNTON	YOLLA DEVELOPMENT
A	Preliminary Issue	29JAN99	DAF	NJP	PAGE 1 of 1 — Doc. No.: SUMMARY.xls	PREMIER OIL

644174

DEVELOPMENT SCENARIO 3D - COST ESTIMATE SUMMARY

ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Wells	101.00	4 Gas Wells and 2 deviated Oil/Gas Wells
Platform	175.92	
Substructure	62.12	12 Slot Steel Piled Jacket in 80m
Topsides	113.80	Manned 2400 tonne Topsides with gas processing facilities including separation, compression (future), gas drying, water treatment and condensate pumps (future).
Gas Production Pipeline	83.65	135km x 300mm NB Pipeline to Tasmania (Burnie)
Onshore Process Facility	97.70	Onshore process facility including slugcatcher, gas drying, dewpoint control sales gas compression and condensate/crude stabilisation, storage and export.
Onshore Gas and Condensate Pipelines	10.00	50km x 200mm NB Condensate Line to P. Latta.
Project Management (10%)	36.73	(Excludes wells.)
TOTAL CAPEX	504.99	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			101.00
Jacket	18.64	43.48	
Topsides		56.90	42.11
Production Pipeline		29.28	54.37
Onshore Facility		48.85	48.85
Export Pipelines			10.00
Project Managemen	3.67	15.99	15.99
TOTAL	22.31	194.50	272.31

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	0.00	0.00	0.00

Opex PA	A$M.
All Wells (Platform and Subsea)	0.99
Jacket	0.93
Topsides	11.38
Production Pipeline	0.84
Onshore Facility	5.86
Export Pipelines	0.20
TOTAL OPEX PA	20.20

Abandonment Costs	A$M
Wells	12.00
Subsea	
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	
Production Pipelines	0.50
Onshore Facility	9.80
Export Pipelines	0.25
TOTAL	38.55

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides	14.79		
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Managemen	1.08		
TOTAL	15.87	0.00	0.00

REV	DESCRIPTION	DATE	PREPD	CHKD
D	Revised Yolla Well Costs	09FEB99	MWM	NJP
C	Revised Well Costs	28JAN99	DAF	DTC
B	General Revision	19JAN99	DAF	DTC

WOODHILL THORNTON

PAGE 1 of 1 — Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

644175

DEVELOPMENT SCENARIO 4A2 - COST ESTIMATE SUMMARY

Building Block	Cost (A$M)	Comments
Yolla Wells	**123.00**	4 Platform based Gas Wells and 3 mutilateral Oil Wells
Platform	**188.32**	
Substructure	62.12	12 Slot Steel Piled Jacket in 80m
Topsides	126.20	Manned 2700 tonne Topsides with gas processing facilities including separation, compression, gas drying, water treatment/MEG recovery and condensate pumps.
Calm Buoy and Loading Line	**15.08**	Line from platform to CALM Buoy with leased FSU
Gas Production Pipeline	**130.10**	210km x 350mm NB Pipeline to Victoria (Black Rock)
Onshore Process Facility	**102.00**	Onshore process facility including slugcatcher, CO2 removal, gas drying, dew point control, sales gas compression and condensate stabilisation, LPG fractionation, storage and export.
Onshore Gas and Condensate Pipelines	**12.58**	35km x 250mm NB Gas Line and 35km 100mm NB Condensate Line to Geelong.
Project Management (10%)	**44.81**	(Excludes Wells)
TOTAL CAPEX	**615.88**	

Capex Phasing	RFSU -3 A$M	RFSU -2 A$M	RFSU -1 A$M
Gas Prod'n Wells			123.00
White Ibis Subsea		-	-
Jacket	18.64	43.48	
Topsides		63.10	63.10
Calm Buoy/Loading			15.08
Production Pipeline		45.54	84.57
Onshore Facility		51.00	51.00
Export Pipelines			12.58
Project Management	4.48	20.16	20.16
TOTAL	**23.12**	**223.28**	**369.48**

Capex Phasing	RFSU A$M	RFSU +1 A$M	RFSU +2 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Capex Phasing	RFSU +3 A$M	RFSU +4 A$M	RFSU +5 A$M
Gas Prod'n Wells			
Jacket			
Topsides			
Calm Buoy/Loading			
Production Pipeline			
Onshore Facility			
Export Pipelines			
Project Management			
TOTAL	**0.00**	**0.00**	**0.00**

Opex PA	A$M
All Wells (Platform and Subsea)	1.16
White Ibis Subsea	
Jacket	0.93
Topsides	12.62
CALM Buoy and Loading Line incl FSU (NOTE 1)	25.65
Production Pipeline	1.30
Onshore Facility	6.12
Export Pipelines	0.25
TOTAL OPEX PA	**48.03**

Abandonment Costs	A$M
Wells	14.00
Subsea	0.50
Buoy	
Jacket	13.00
Topsides	3.00
Tank	
CALM Buoy	1.50
Production Pipelines	0.50
Onshore Facility	10.20
Export Pipelines	0.25
TOTAL	**42.95**

NOTES

(1) FSU/CALM BUOY NOT REQUIRED AFTER YEAR 5.

REV	DESCRIPTION	DATE	PREPD	CHKD	
E	Revised Yolla Well Costs	09FEB99	MWM	NW	
D	Revised Well Costs	28JAN99	DAF	DTC	
C	General Revision	19JAN99	DAF	DTC	

WOODHILL THORNTON

PAGE 1 of 1 | Doc. No.: SUMMARY.xls

YOLLA DEVELOPMENT

PREMIER OIL

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APPENDIX 12

Cost Estimate Building Blocks

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

WHITE IBIS SUBSEA GAS WELLS (EACH) OPTION 2A/4A/4B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	INTANGIBLES	
	RIG COSTS (Semi Sub/Deep Water Jack-up)	5.97
	RIG SERVICES	1.86
	WELL TESTING (3000m TVD)	0.44
	BOATS (1 Standby, 1 Supply)	1.39
	ONSHORE SUPPORT	0.77
	SUPERVISION & MANAGEMENT	0.47
		10.90
	TANGIBLES	
	CASING	0.50
	TUBING & COMPLETION EQUIPMENT	0.50
	XMAS TREE	2.73
		3.73
	OTHER	
	PROJECT MANAGEMENT	0.75
	PROJECT ITEMS	1.32
		2.07
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	1.67
		1.67
	TOTAL WELL COST (EACH)	**18.36**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

SUBSEA FACILITIES - YOLLA 1C

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT AND MATERIALS	
	SUBSEA CONTROL SYSTEM	6.35
	MANIFOLD AND WELL METERING (5 MPFM's, ie 1 per well)	11.75
	PRECOMMISSIONING	0.57
		18.67
	MOB/DEMOB	
	DSV	1.80
		1.80
	INSTALLATION	
	TRANSPORTATION	0.40
	INSTALLATION	1.24
	COMMISSIONING	5.00
		6.64
	ENGINEERING AND INDIRECTS	
	DESIGN	2.71
	FABRICATION AND INSTALLATION MANAGEMENT	2.71
		5.42
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	2.98
		2.98
	TOTAL SUBSEA FACILITIES - YOLLA	**35.51**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

SUBSEA FACILITIES - WHITE IBIS 2A/4A/4B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT AND MATERIALS	
	SUBSEA CONTROL SYSTEM INCL UMBILICAL	14.03
	MANIFOLD AND WELL METERING (2 MPFM's)	5.42
	PRECOMMISSIONING	0.57
		20.02
	MOB/DEMOB	
	DSV	1.80
		1.80
	INSTALLATION	
	TRANSPORTATION	1.30
	INSTALLATION	2.52
	COMMISSIONING	2.00
		5.82
	ENGINEERING AND INDIRECTS	
	DESIGN	2.76
	FABRICATION AND INSTALLATION MANAGEMENT	2.76
		5.53
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	3.04
		3.04
	TOTAL SUBSEA FACILITIES - YOLLA	**36.21**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

SUBSEA FLOWLINE OPTION 2A/4A/4B - WHITE IBIS TO YOLLA

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	PIPELINE MATERIALS	
	LINEPIPE (40km, 300mm NB, 14.6mm WT, API5L X65)	22.12
	CORROSION AND WEIGHT COATING (50mm Concrete)	4.01
		26.13
	MOB/DEMOB	
	LAYBARGE/DSV (ex Singapore)	-
	LINEPIPE TRANSPORT	0.90
	PLOUGH	-
		0.90
	PIPELAY	
	PRELIMINARIES	0.25
	PIPELAY	15.12
	TIE-IN'S	0.72
	REMEDIAL	0.70
		16.79
	STABILISATION (30km Ploughed)	
		-
		-
	HYDROTEST AND COMMISSIONING	
		0.85
		0.85
	ENGINEERING AND DESIGN DATA	
		0.87
		0.87
	PROJECT MANAGEMENT AND INDIRECTS	
	CONTRACTOR'S ENGINEERING	0.60
	CONTRACTOR'S MANAGEMENT	0.73
		1.33
	PROJECT ALLOWANCES	
	UNALLOCATED PROVISION (10%)	4.69
		4.69
	WHITE IBIS - YOLLA FLOWLINE COST	**51.56**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

JACKET OPTION 1A/1A2/1B/1C2/2A

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	MATERIALS (4 Leg, 8 Slot Jacket)	
	PRIMARY	3.59
	SECONDARY (Primary + Secondary = 2552 te)	1.97
	PILES (3540 te)	6.31
		11.87
	FABRICATION (Barry's Beach)	
	PRIMARY	8.62
	SECONDARY	5.52
	PILES	7.40
		21.54
	MOB/DEMOB	
	BARGE AND HAMMER	2.50
		2.50
	LOADOUT & TRANSPORT	
	TRAILERS, BARGE AND TUGS	1.43
		1.43
	INSTALLATION	
	INSTALLATION AND PILING	11.80
		11.80
	ENGINEERING AND INDIRECTS	
	DESIGN	1.67
	GEOTECHNICAL INVESTIGATIONS	3.00
	FABRICATION AND INSTALLATION MANAGEMENT	1.27
		5.94
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	5.51
		5.51
	TOTAL JACKET	**60.59**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

JACKET OPTION 3A/3B/4A/4B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	MATERIALS (4 Leg. 12 Slot Jacket)	
	PRIMARY	3.84
	SECONDARY	2.10
	PILES	6.31
		12.25
	FABRICATION	
	PRIMARY	9.20
	SECONDARY	5.92
	PILES	7.40
		22.52
	MOB/DEMOB	
	BARGE AND HAMMER	2.50
		2.50
	LOADOUT & TRANSPORT	
	TRAILERS, BARGE AND TUGS	1.43
		1.43
	INSTALLATION	
	INSTALLATION AND PILING	11.80
		11.80
	ENGINEERING AND INDIRECTS	
	DESIGN	1.69
	GEOTECHNICAL INVESTIGATIONS	3.00
	FABRICATION AND INSTALLATION MANAGEMENT	1.29
		5.98
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	5.65
		5.65
	TOTAL JACKET	**62.12**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

TOPSIDES OPTION 1A/1A2/1B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	1.68
	HEAT EXCHANGERS	0.43
	PUMPS	0.31
	PACKAGES	0.60
	UTILITIES	6.25
	CONTROL SYSTEMS AND TELECOMMUNICATIONS	3.70
	ACCOMMODATION AND HELIDECK	2.61
		15.58
	BULKS PROCUREMENT	
	PIPING (CS)	3.40
	PIPING (SS)	4.40
	ELECTRICAL	1.22
	INSTRUMENTATION	5.00
	OTHERS	0.45
	STRUCTURAL	1.47
		15.95
	FABRICATION	
	EQUIPMENT	0.88
	PIPING (CS)	4.45
	PIPING (SS)	2.50
	ELECTRICAL	1.46
	INSTRUMENTATION	3.39
	OTHERS	0.71
	STRUCTURAL	10.81
	ACCOMMODATION AND HELIDECK	3.25
	COMMISSIONING	2.95
		30.39
	TRANSPORT AND INSTALLATION	
	TRANSPORT	1.28
	INSTALLATION	0.28
	COMMISSIONING	0.14
		1.69
	FUTURE EQUIPMENT (Year 3)	
	COMPRESSORS, DRIVERS, COOLERS AND PUMPS	10.61
		10.61
	ENGINEERING	
	GENERAL (10%)	7.42
		7.42
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	8.16
		8.16
	TOTAL TOPSIDES	**89.79**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

TOPSIDES OPTION 1C2

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	WELLHEAD PANEL, MULTI PHASE METERS (1 Products, 1 Test)	1.93
		1.93
	BULKS PROCUREMENT	
	PIPING, ELECTRICAL, INSTRUMENTATION, OTHERS AND STRUCTURAL	2.18
		2.18
	FABRICATION	
	GENERAL	1.58
		1.58
	TRANSPORT AND INSTALLATION	
	GENERAL	1.58
	COMMISSIONING	0.60
		2.18
	ENGINEERING AND INDIRECTS	
	FABRICATION AND MANAGEMENT	1.94
	INSTALLATION AND MANAGEMENT	0.58
		2.52
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	1.04
		1.04
	TOTAL TOPSIDES	**11.42**

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YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

TOPSIDES OPTION 2A

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)	
	EQUIPMENT PROCUREMENT		
	VESSELS	2.83	+ 1.15
	HEAT EXCHANGERS	0.29	- 0.14
	PUMPS	0.49	+ 0.18
	PACKAGES	1.65	+ 1.05
	UTILITIES	6.29	+ 0.04
	CONTROL SYSTEMS AND TELECOMMUNICATIONS	3.70	=
	ACCOMMODATION AND HELIDECK	2.61	=
		17.85	+ 2.27
	BULKS PROCUREMENT		
	PIPING (CS)	4.69	+ 1.29
	PIPING (SS)	6.08	+ 1.68
	ELECTRICAL	1.61	+ 0.39
	INSTRUMENTATION	7.64	+ 2.64 ←
	OTHERS	0.62	+ 0.17
	STRUCTURAL	1.93	+ 0.46
		22.57	6.63
	FABRICATION		
	EQUIPMENT	1.25	+ 0.37
	PIPING (CS)	6.14	+ 1.69
	PIPING (SS)	3.45	+ 0.95
	ELECTRICAL	1.91	+ 0.45
	INSTRUMENTATION	5.18	+ 1.79
	OTHERS	0.98	+ 0.27
	STRUCTURAL	14.13	+ 3.32 ←
	ACCOMMODATION AND HELIDECK	3.25	=
	COMMISSIONING	3.85	+ 0.90
		40.14	+ 9.75
	TRANSPORT AND INSTALLATION		
	TRANSPORT	1.28	=
	INSTALLATION	0.28	=
	COMMISSIONING	0.14	=
		1.69	=
	FUTURE EQUIPMENT		
	COMPRESSORS, DRIVERS, COOLERS AND PUMPS	12.16	+ 1.65
		12.16	+ 1.65
	ENGINEERING		
	GENERAL (10%)	9.44	+ 2.02
		9.44	+ 2.02
	CONTINGENCY		
	UNALLOCATED PROVISION (10%)	10.38	+ 2.22
		10.38	
	TOTAL TOPSIDES	**114.23**	+ 24.24.

94.4

107.8

WOODHILL THORNTON

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

TOPSIDES OPTION 3A/3B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	4.15
	HEAT EXCHANGERS	2.53
	COMPRESSORS	15.08
	PUMPS	0.73
	PACKAGES	0.60
	UTILITIES	6.25
	CONTROL SYSTEMS AND TELECOMMUNICATIONS	3.70
	ACCOMMODATION AND HELIDECK	2.61
		35.65
	BULKS PROCUREMENT	
	PIPING (CS)	5.02
	PIPING (SS)	6.50
	ELECTRICAL	1.89
	INSTRUMENTATION	8.17
	OTHERS	0.75
	STRUCTURAL	2.02
		24.35
	FABRICATION	
	EQUIPMENT	1.28
	PIPING (CS)	6.57
	PIPING (SS)	3.69
	ELECTRICAL	2.25
	INSTRUMENTATION	5.54
	OTHERS	1.18
	STRUCTURAL	14.81
	ACCOMMODATION AND HELIDECK	3.25
	COMMISSIONING	4.04
		42.61
	TRANSPORT AND INSTALLATION	
	TRANSPORT	1.28
	INSTALLATION	0.28
	COMMISSIONING	0.14
		1.69
	FUTURE EQUIPMENT	
	COMPRESSORS, DRIVERS, COOLERS AND PUMPS	-
		-
	ENGINEERING	
	GENERAL (10%)	10.43
		10.43
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	11.47
		11.47
	TOTAL TOPSIDES	**126.20**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

TOPSIDES OPTION 4A/4B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	4.52
	HEAT EXCHANGERS	1.86
	COMPRESSORS	5.78
	PUMPS	0.72
	PACKAGES	1.65
	UTILITIES	6.25
	CONTROL SYSTEMS AND TELECOMMUNICATIONS	3.70
	ACCOMODATION AND HELIDECK	2.61
		27.08
	BULKS PROCUREMENT	
	PIPING (CS)	6.44
	PIPING (SS)	8.35
	ELECTRICAL	2.33
	INSTRUMENTATION	10.92
	OTHERS	0.92
	STRUCTURAL	2.50
		31.46
	FABRICATION	
	EQUIPMENT	1.66
	PIPING (CS)	8.44
	PIPING (SS)	4.73
	ELECTRICAL	2.78
	INSTRUMENTATION	7.40
	OTHERS	1.43
	STRUCTURAL	18.31
	ACCOMODATION AND HELIDECK	3.25
	COMMISSIONING	4.99
		53.00
	TRANSPORT AND INSTALLATION	
	TRANSPORT	1.28
	INSTALLATION	0.28
	COMMISSIONING	0.14
		1.69
	FUTURE EQUIPMENT	
	COMPRESSORS, DRIVERS, COOLERS AND PUMPS	14.78
		14.78
	ENGINEERING	
	GENERAL (10%)	12.80
		12.80
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	14.08
		14.08
	TOTAL TOPSIDES	**154.89**

WOODHILL THORNTON

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

BUOY OPTION 1C

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT & MATERIALS	2.90
	FABRICATION & COATING	4.96
	LOADOUT & TRANSPORTATION	0.96
	MOB/DEMOB	1.34
	INSTALLATION	5.01
	CONSTRUCTION ENGINEERING	0.68
	COMMISSIONING	3.38
	ENGINEERING	1.74
		20.97
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	2.10
		2.10
	TOTAL BUOY	**23.07**

644190

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

CALM BUOY AND LOADING LINE OPTIONS 3A/3B/4A/4B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	CALM BUOY - PROCUREMENT	
	GENERAL	9.23
		9.23
	LOADING LINE - PROCUREMENT	
	GENERAL	0.29
		0.29
	INSTALLATION	
	BUOY	2.04
	PIPELINE (2km x 250mm NB)	1.40
		3.44
	ENGINEERING AND INDIRECTS	
	ENGINEERING	0.10
	INSTALLATION AND MANAGEMENT	0.65
		0.75
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	1.37
		1.37
	TOTAL CALM BUOY AND LOADING LINE	**15.08**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

SUBSEA TANK OPTION 3B/4B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	MATERIALS	7.86
	FABRICATION & COATING	19.90
	LOADOUT & TRANSPORTATION	0.92
	MOB/DEMOB	1.38
	INSTALLATION	2.65
	ENGINEERING (6%)	1.96
		34.68
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	3.47
		3.47
	TOTAL SUBEA TANK	**38.15**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

OFFSHORE PRODUCTION PIPELINE OPTION 1A/1B/3A/3B - YOLLA TO BURNIE

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	PIPELINE MATERIALS	
	LINEPIPE (135km, 300mm NB, 10.3mm WT, API 5L X65)	17.05
	CORROSION AND WEIGHT COATING (50mm concrete)	10.05
		27.10
	MOB/DEMOB	
	LAYBARGE (ex Singapore)	7.70
	LINEPIPE TRANSPORT	8.00
	PLOUGH	1.35
		17.05
	PIPELAY	
	PRELIMINARIES (Survey, beach crossing)	0.90
	PIPELAY	21.75
	TIE-IN AND CROSSING	1.75
	REMEDIAL	1.75
		26.15
	STABILISATION (30km ploughed)	
		1.69
		1.69
	HYDROTEST AND COMMISSIONING	
		0.85
		0.85
	ENGINEERING AND DESIGN DATA	
		1.20
		1.20
	PROJECT MANAGEMENT AND INDIRECTS	
	CONTRACTOR'S ENGINEERING	0.90
	CONTRACTOR'S MANAGEMENT	1.10
		2.00
	PROJECT ALLOWANCES	
	UNALLOCATED PROVISION (10%)	7.60
		7.60
	YOLLA - BURNIE PIPELINE COST	**83.65**

72

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

OFFSHORE PRODUCTION PIPELINE OPTION 1C/1C2 - YOLLA TO BURNIE

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	PIPELINE MATERIALS	
	LINEPIPE (135km, 450mm NB, 17.5mm WT, API 5L X65, includes 25km of CRA lining)	74.21
	CORROSION AND WEIGHT COATING	14.17
		88.38
	MOB/DEMOB	
	LAYBARGE (ex Singapore)	7.70
	LINEPIPE TRANSPORT	8.00
	PLOUGH	1.35
		17.05
	PIPELAY	
	PRELIMINARIES (Survey, beach crossing)	1.15
	PIPELAY	39.50
	TIE-IN AND CROSSING	1.75
	REMEDIAL	2.45
		44.85
	STABILISATION	
	GENERAL	1.69
		1.69
	HYDROTEST AND COMMISSIONING	
	GENERAL	0.85
		0.85
	ENGINEERING AND DESIGN DATA	
	GENERAL	1.20
		1.20
	PROJECT MANAGEMENT AND INDIRECTS	
	CONTRACTOR'S ENGINEERING	0.90
	CONTRACTOR'S MANAGEMENT	1.60
		2.50
	PROJECT ALLOWANCES	
	UNALLOCATED PROVISION (10%)	15.65
		15.65
	YOLLA - BURNIE PIPELINE COST	**172.17**

644194

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

OFFSHORE PRODUCTION PIPELINE OPTION 1A2 - YOLLA TO BELL BAY

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	PIPELINE MATERIALS	
	LINEPIPE (170km, 300mm NB, 10.3mm WT, API5L X65)	21.48
	CORROSION AND WEIGHT COATING (400micron FBE, 50mm Concrete)	12.65
		34.14
	MOB/DEMOB	
	LAYBARGE (ex Singapore)	7.70
	LINEPIPE TRANSPORT	8.00
	PLOUGH	1.35
		17.05
	PIPELAY	
	PRELIMINARIES	1.15
	PIPELAY	27.25
	TIE-IN AND CROSSING	1.75
	REMEDIAL	2.45
		32.60
	STABILISATION (30km ploughed)	
		1.69
		1.69
	HYDROTEST AND COMMISSIONING	
		0.85
		0.85
	ENGINEERING AND DESIGN	
		1.20
		1.20
	PROJECT MANAGEMENT AND INDIRECTS	
	CONTRACTOR'S ENGINEERING	0.90
	CONTRACTOR'S MANAGEMENT	1.60
		2.50
	PROJECT ALLOWANCES	
	UNALLOCATED PROVISION (10%)	9.00
		9.00
	YOLLA - BELL BAY PIPELINE COST	**99.03**

644195

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

OFFSHORE PRODUCTION PIPELINE OPTION 2A/4A/4B - YOLLA TO BLACK ROCK

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	PIPELINE MATERIALS	
	LINEPIPE (210km, 400mm NB, 11.8mm WT, API5L X65)	34.00
	CORROSION AND WEIGHT COATING (400micron FBE, 50 mm concrete)	19.03
		53.03
	MOB/DEMOB	
	LAYBARGE (ex Singapore)	7.70
	LINEPIPE TRANSPORT	8.00
	PLOUGH	1.35
		17.05
	PIPELAY	
	PRELIMINARIES	1.15
	PIPELAY	43.00
	TIE-IN AND CROSSING	1.75
	REMEDIAL	2.45
		48.35
	STABILISATION (30km Ploughed)	
		1.69
		1.69
	HYDROTEST AND COMMISSIONING	
		0.85
		0.85
	ENGINEERING AND DESIGN DATA	
		1.20
		1.20
	PROJECT MANAGEMENT AND INDIRECTS	
	CONTRACTOR'S ENGINEERING	0.90
	CONTRACTOR'S MANAGEMENT	1.60
		2.50
	PROJECT ALLOWANCES	
	UNALLOCATED PROVISION (10%)	12.47
		12.47
	YOLLA - BLACK ROCK PIPELINE COST	**137.13**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

ONSHORE PLANT OPTION 1C/1C2

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	4.00
	HEAT EXCHANGERS	0.63
	COMPRESSORS	12.10
	PUMPS	0.28
	TANKS	1.23
	PACKAGES	2.18
	UTILITIES	1.65
		22.06
	BULK PROCUREMENT AND INSTALLATION	
	CIVILS	3.68
	STRUCTURAL	2.21
	PIPING	11.03
	INLEC	7.35
	MISCELLANEOUS	1.47
	INDIRECTS	17.65
	COMMISSIONING	2.21
		45.59
	FUTURE EQUIPMENT INCL. PROCUREMENT & INSTALLATION (Year 8)	
	COMPRESSORS, DRIVERS, COOLERS AND PUMPS	15.05
		15.05
	ENGINEERING	
	GENERAL (8%)	7.19
		7.19
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	8.99
		8.99
	TOTAL ONSHORE PLANT	**98.88**

644197

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

ONSHORE PLANT OPTION 1A/3A/3B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	3.15
	HEAT EXCHANGERS	0.33
	COMPRESSORS	10.74
	PUMPS	0.23
	TANKS	1.23
	PACKAGES	1.20
	UTILITIES	1.65
		18.52
	BULK PROCUREMENT AND INSTALLATION	
	CIVILS	3.09
	STRUCTURAL	1.85
	PIPING	9.26
	INLEC	6.17
	MISCELLANEOUS	1.23
	INDIRECTS	14.82
	COMMISSIONING	1.85
		38.28
	ENGINEERING	
	GENERAL (8%)	4.94
		4.94
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	6.17
		6.17
	TOTAL ONSHORE PLANT	**67.92**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-25%

ONSHORE PLANT OPTION 1A2 - ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	3.85
	HEAT EXCHANGERS	0.33
	COMPRESSORS	10.74
	PUMPS	0.23
	TANKS	1.23
	PACKAGES	1.20
	UTILITIES	1.65
		19.22
	BULK PROCUREMENT AND INSTALLATION	
	CIVILS	3.20
	STRUCTURAL	1.92
	PIPING	9.61
	INLEC	6.41
	MISCELLANEOUS	1.28
	INDIRECTS	15.38
	COMMISSIONING	1.92
		39.73
	ENGINEERING	
	GENERAL (8%)	5.13
		5.13
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	6.41
		6.41
	TOTAL ONSHORE PLANT	**70.49**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

ONSHORE PLANT OPTION 1B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	3.11
	HEAT EXCHANGERS	0.39
	COMPRESSORS	11.45
	PUMPS	0.23
	TANKS	1.23
	PACKAGES	5.70
	UTILITIES	1.65
		23.75
	BULK PROCUREMENT AND INSTALLATION	
	CIVILS	3.96
	STRUCTURAL	2.38
	PIPING	11.88
	INLEC	7.92
	MISCELLANEOUS	1.58
	INDIRECTS	19.00
	COMMISSIONING	2.38
		49.09
	ENGINEERING	
	GENERAL (8%)	6.33
		6.33
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	7.92
		7.92
	TOTAL ONSHORE PLANT	**87.09**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-30%

ONSHORE PLANT OPTION 2A/4A/4B

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	9.19
	HEAT EXCHANGERS	3.07
	COMPRESSORS	12.09
	PUMPS	2.14
	TANKS	3.72
	PACKAGES	5.29
	UTILITIES	2.14
		37.63
	BULK PROCUREMENT AND INSTALLATION	
	CIVILS	6.27
	STRUCTURAL	3.76
	PIPING	18.82
	INLEC	12.54
	MISCELLANEOUS	2.51
	INDIRECTS	30.10
	COMMISSIONING	3.76
		77.77
	ENGINEERING	
	GENERAL (8%)	10.03
		10.03
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	12.54
		12.54
	TOTAL ONSHORE PLANT	**137.98**

YOLLA FIELD DEVELOPMENT - CONCEPTUAL ESTIMATE +/-40%

ONSHORE PLANT OPTION 3D

ESTIMATE SUMMARY

	DESCRIPTION	50/50 COST (A$M)
	EQUIPMENT PROCUREMENT	
	VESSELS	7.12
	HEAT EXCHANGERS	0.59
	COMPRESSORS	11.46
	PUMPS	0.58
	TANKS	2.77
	PACKAGES	2.48
	UTILITIES	1.65
		26.64
	BULK PROCUREMENT AND INSTALLATION	
	CIVILS	4.44
	STRUCTURAL	2.66
	PIPING	13.32
	INLEC	8.88
	MISCELLANEOUS	1.78
	INDIRECTS	21.32
	COMMISSIONING	2.66
		55.06
	ENGINEERING	
	GENERAL (8%)	7.11
		7.11
	CONTINGENCY	
	UNALLOCATED PROVISION (10%)	8.88
		8.88
	TOTAL ONSHORE PLANT	**97.69**

644202

APPENDIX 13

Calculation List

644203

YOLLA DEVELOPMENT STUDY

CALCULATION LIST

Calculation Number	Calculation Title
9843-CAL-01	Case 1A Offshore Equipment Sizing
9843-CAL-02	Case 1A Onshore Equipment Sizing
9843-CAL-03	Case 2A Onshore Equipment Sizing
9843-CAL-04	Case 4A Offshore Equipment Sizing
9843-CAL-05	Case 2A Offshore Equipment Sizing
9843-CAL-06	Case 4A Onshore Equipment Sizing
9843-CAL-07	Case 3A Offshore Equipment Sizing
9843-CAL-08	Case 3A Onshore Equipment Sizing
9843-CAL-09	Case 1C Offshore Pipeline Glycol Injection Rate
9843-CAL-10	Case 1A Offshore Pipeline Sizing
9843-CAL-11	Case 1A Onshore Pipeline Sizing
9843-CAL-12	Case 2A Onshore Pipeline Sizing
9843-CAL-14	Case 2A Offshore Pipeline Sizing
9843-CAL-15	Case 3A Offshore Pipeline Sizing
9843-CAL-16	Case 1A Offshore Structure Size & Weight
9843-CAL-17	Case 2A Offshore Structure Size & Weight
9843-CAL-18	Case 3A Offshore Structure Size & Weight
9843-CAL-19	Case 4A Offshore Structure Size & Weight
9843-CAL-20	Case 1A Hysim Simulation
9843-CAL-21	Case 1B Hysim Simulation
9843-CAL-22	Case 1C Hysim Simulation
9843-CAL-23	Case 1C_2 Hysim Simulation
9843-CAL-24	Case 1D Hysim Simulation
9843-CAL-25	Case 2A Hysim Simulation
9843-CAL-26	Case 3A Hysim Simulation
9843-CAL-27	Case 4A Hysim Simulation
9843-CAL-28	Case 1C Onshore Equipment Sizing
9843-CAL-29	Case 3A Onshore Pipeline Sizing
9843-CAL-30	Case 4A Offshore Pipeline Sizing
9843-CAL-31	Case 4A Onshore Pipeline Sizing
9843-CAL-32	Case 2A / 4A White Ibis Production Flowline Sizing
9843-CAL-33	Case 1C Offshore Pipeline Sizing
9843-CAL-34	Case 1A2 Onshore Pipeline Sizing
9843-CAL-35	Case 1A2 Equipment Sizing (Off & Onshore)
9843-CAL-36	Case 2B Offshore Pipeline Sizing
9843-CAL-37	Case 1B Onshore Equipment Sizing
9843-CAL-38	CGR vs Reservoir Conditions
9843-CAL-39	Case 2A - LPG Recovery vs Reservoir Conditions
9843-CAL-40	CGR & HHV of Yolla Oil Reservoir Gas Cap