

### 3. Description of Design & Construction Phases

#### 3.1 Overview

The Sunrise gas field development is flexible to allow for the adoption of two market scenarios, namely Onshore LNG (OLNG) and Floating LNG (FLNG) and, as such, this EIS assesses the environmental impacts of the following main elements of the upstream development:

- ❑ Wells (subsea and platform), subsurface, intrafield pipelines, flowlines, and risers from the gas field back to the PCUQ platform/FLNG or wellhead platform;
- ❑ Offshore facilities including PCUQ platform, wellhead platform, condensate export system and Floating Storage and Offloading (FSO) Vessel; and
- ❑ Gas export pipeline up to the inlet flange on the ‘Wye’ piece i.e. junction of the Sunrise and Bayu-Undan gas pipeline. This EIS does not address environmental issues associated with the export pipeline from the “Wye” to shore as this section of pipeline has already been assessed and approved under a separate approvals process.

It should be recognised that both the OLNG and FLNG plants fall outside the scope of approvals currently sought for the development of the Greater Sunrise gas field. FLNG and OLNG will be required to follow separate approvals environmental approvals processes.

The key elements pertaining to the Sunrise Project are summarised in **Table 3-1**.

In summary, the basis of the offshore facility is a PCUQ (Jack-Up) facility with a separate bridge-linked Wellhead Platform (WHP). A combination of subsea and/or WHP wells will be required, with gas and condensate processing by way of PCUQ and FSO facilities. Any subsea wells will be linked to the production platform by intra-field pipelines and export/import risers. Gas and condensate would be exported to Darwin via the main export pipeline and Bayu-Undan pipeline to the proposed Darwin LNG terminal. The two platforms, located in a water depth of 140–400 metres would be as follows:

- ❑ Wellhead Platform (WHP); and
- ❑ Production, Compression, Utilities and Quarters (PCUQ) Platform – with utilities and living quarters located on deck.

Drilling will commence 18 months prior to the installation of the field facilities. Initially, up to 11 wells are proposed from the WHP. A further 11–22 subsea wells will be drilled over the life of the project. **Figure 3-1a** illustrates the field development for an OLNG scenario and **Figure 3-1b** illustrates the field development under a FLNG scenario.

**Table 3-1 Key Characteristics of the Sunrise Gas Project**

Project Element	Characteristics
<b>Production Wells</b> (both FLNG & OLNG)	A combination of subsea and/or WHP wells linked to PCUQ Up to 16 platform wells (up to 10 km step-out) and up to 32 subsea wells linked to a PCUQ platform via flowlines and risers. Possible drill cuttings/produced water reinjection wells.
<b>Wellhead Platform (WHP)</b> (either OLNG or FLNG)	140 m to 400 m water depth. 24 x40 m platform. Steel Jacket with Bucket Foundation or Tension Leg Wellhead Platform Up to 16 platform wells with maximum 8–10 km reach. Tender Assisted Drilling using a semi-submersible vessel. Risers for export pipeline and subsea flowlines.
<b>PCUQ Platform</b> Offshore Production, Compression, Utilities & Quarters (PCUQ) Platform	140 m water depth. 60–100 m bridge link to wellhead platform. Production Jack-Up. Process/accommodation/utilities on deck. 100 x 80 m. 3 legs on bucket foundations – 40 m diameter and 7.5m skirt with 18 m main leg spacing. Accommodation for 80 workers, heli deck. Separation, cooling, pre-compression, de-hydration, dewpointing and export compression. 2 x 50% train basis; gas export compression units initially 5 x 25 %.

Project Element	Characteristics
	Condensate separation & stabilisation with offgas re-compression.
<b>Condensate Export System</b> Via Floating Storage & Offloading Vessel	8 inch, 2 km long export line to Floating Storage and Offloading Vessel (FSO). Turret moored FSO (gravity system or pile foundations). Every 17 days offloaded condensate product from FSO to tanker via floating hose. Additional heli-ops. FSO crew – 10–20 (approx.)
<b>Main Gas Export Pipeline</b>	Gas export pipeline for the export of gas/condensate to the Bayu-Undan Wye piece 36 inch 218 km to the Bayu-Undan Wye piece, carbon steel X-65. Pre-lay rock dump may be required Concrete coating Anti-corrosion coating: 5 mm asphalt enamel & sacrificial anodes.
<b>Flowlines and Risers</b>	Export and import risers to the process facilities including WHP, PCUQ and FLNG
<b>Intra-field Pipelines</b>	16 inch–24 inch carbon steel clad (corrosion resistant alloy and insulated) Length varies from 2–18 km

## 3.2 Gas Field Development Facilities

### 3.2.1 Location

The Greater Sunrise Gas Fields (Sunrise and Troubadour) are located approximately 450 km north-west of Darwin and 150 km from Timor, within Timor Sea permits NT/RL2, NT/P55, ZOCA 96-20 and ZOCA 95-19. Approximately 80% of the gas field lies within NT/RL2, where both the WHP and PCUQ platforms will be positioned. **Figure 3-2** illustrates the general reservoir layout and location.

Both platforms are planned to be installed in 140–400 m water depth on the shelf break in the south-east section of the field. The 140 m deep location is at a latitude of 9°36'13" S and longitude of 128°08'02 E.

### 3.2.2 Site Selection Criteria

In selecting the general location for the platforms several factors have been considered. Generally, shallow waters are preferred for the location of the platforms and deep-water locations for the wells, hence, a compromise has made between these two conflicting factors. Furthermore, it is important that the seabed is composed of a firm material to ensure stability.

The approach to the offshore facility is a significant consideration. Pipeline/flowline route selection in the area of the approach to fixed or floating offshore facilities, or subsea manifolds considers the following:

- ❑ To facilitate the anchoring of vessels for support and future construction activities at the offshore facility, pipelines close to offshore facilities are as far as possible arranged in corridors. Initiation and layout typically requires a straight route section;
- ❑ Risers are protected from the main activity around the offshore facility and located away from the living quarters;
- ❑ Location of the risers, fixed platform overhangs, flare boom;
- ❑ Anchoring of moored vessels at subsea drilling centres and liquid loading facilities;
- ❑ Orientation of manifold and location of flowline tie-in points;
- ❑ Location of the pipeline route corridor;
- ❑ Area for expansion loops;
- ❑ Pipeline initiation and termination laydown method;
- ❑ Designated anchoring areas and no-anchoring areas;
- ❑ Provision for future pipelines;
- ❑ Avoidance of areas where localised scour may occur;
- ❑ Avoidance of vessel anchor cables crossing the pipeline during construction;
- ❑ Minimisation of risk due to dropped objects and the consequent requirement for additional pipeline protection devices; and
- ❑ Avoidance of areas of shallow gas.

Max : 22 Subsea Wells

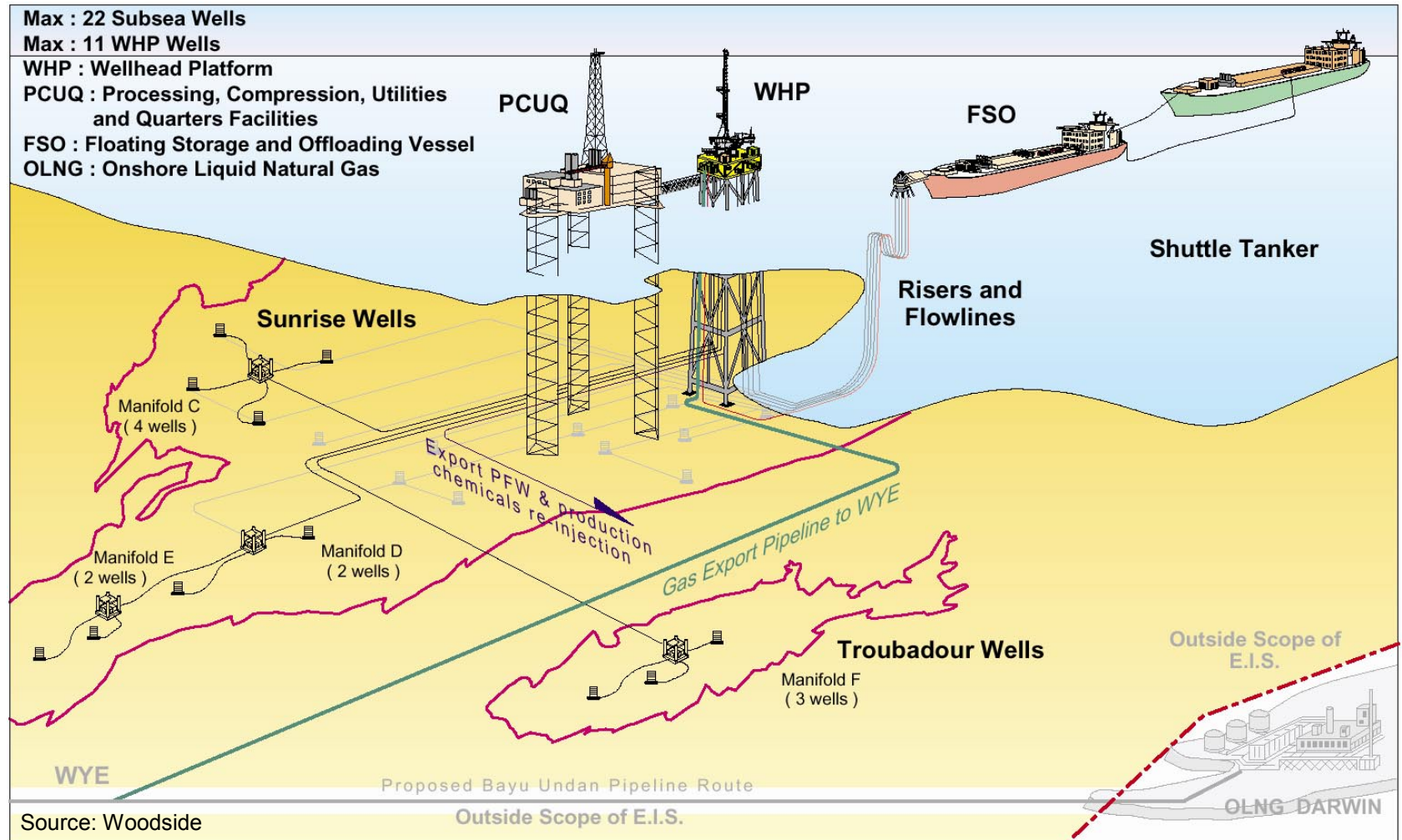
Max : 11 WHP Wells

WHP : Wellhead Platform

PCUQ : Processing, Compression, Utilities  
and Quarters Facilities

FSO : Floating Storage and Offloading Vessel

OLNG : Onshore Liquid Natural Gas



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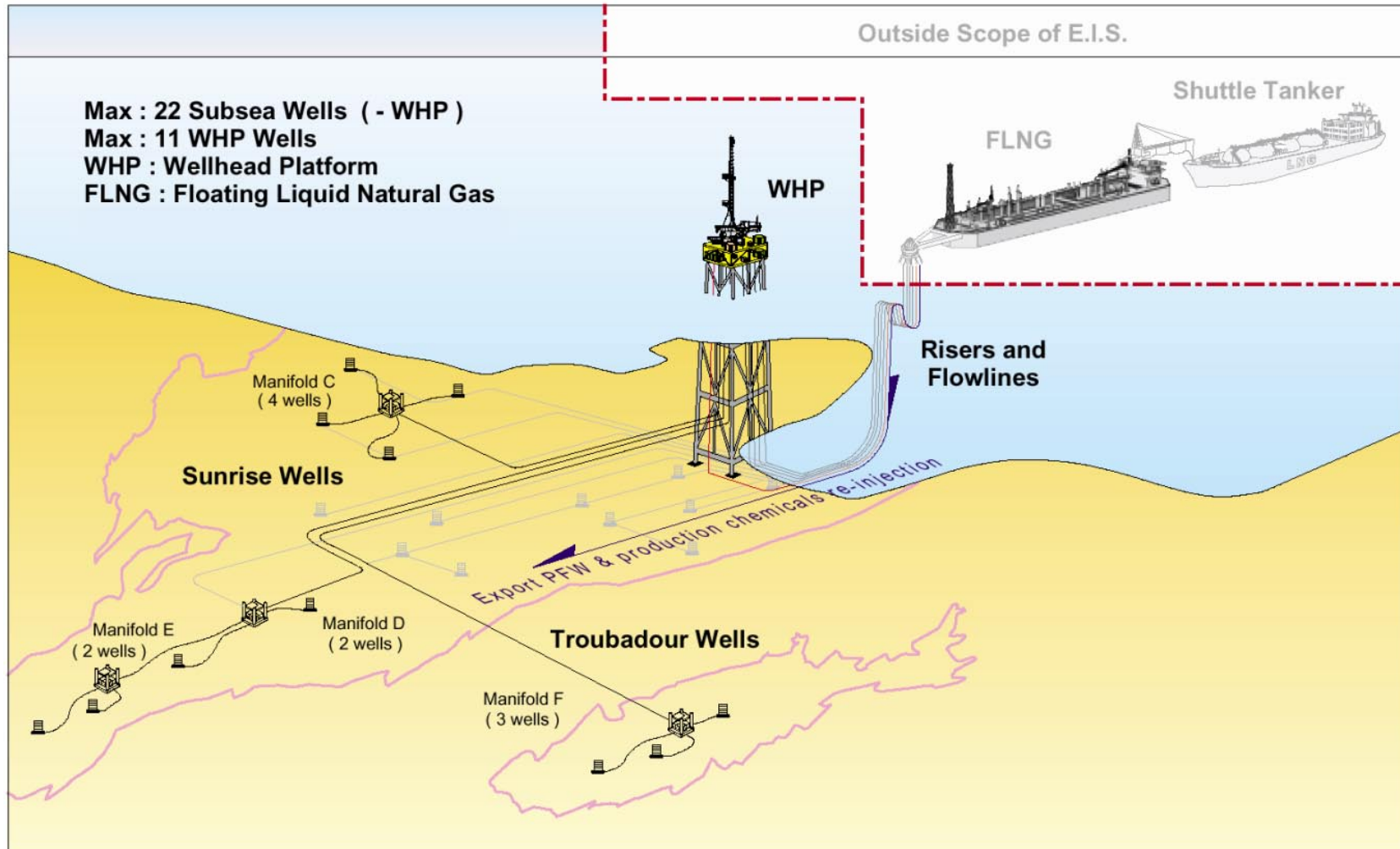
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**Scope of EIS Scenario 1:OLNG**

**Figure 3-1a**

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Figure prepared by: T.Lee  
Date Prepared: 16/10/01





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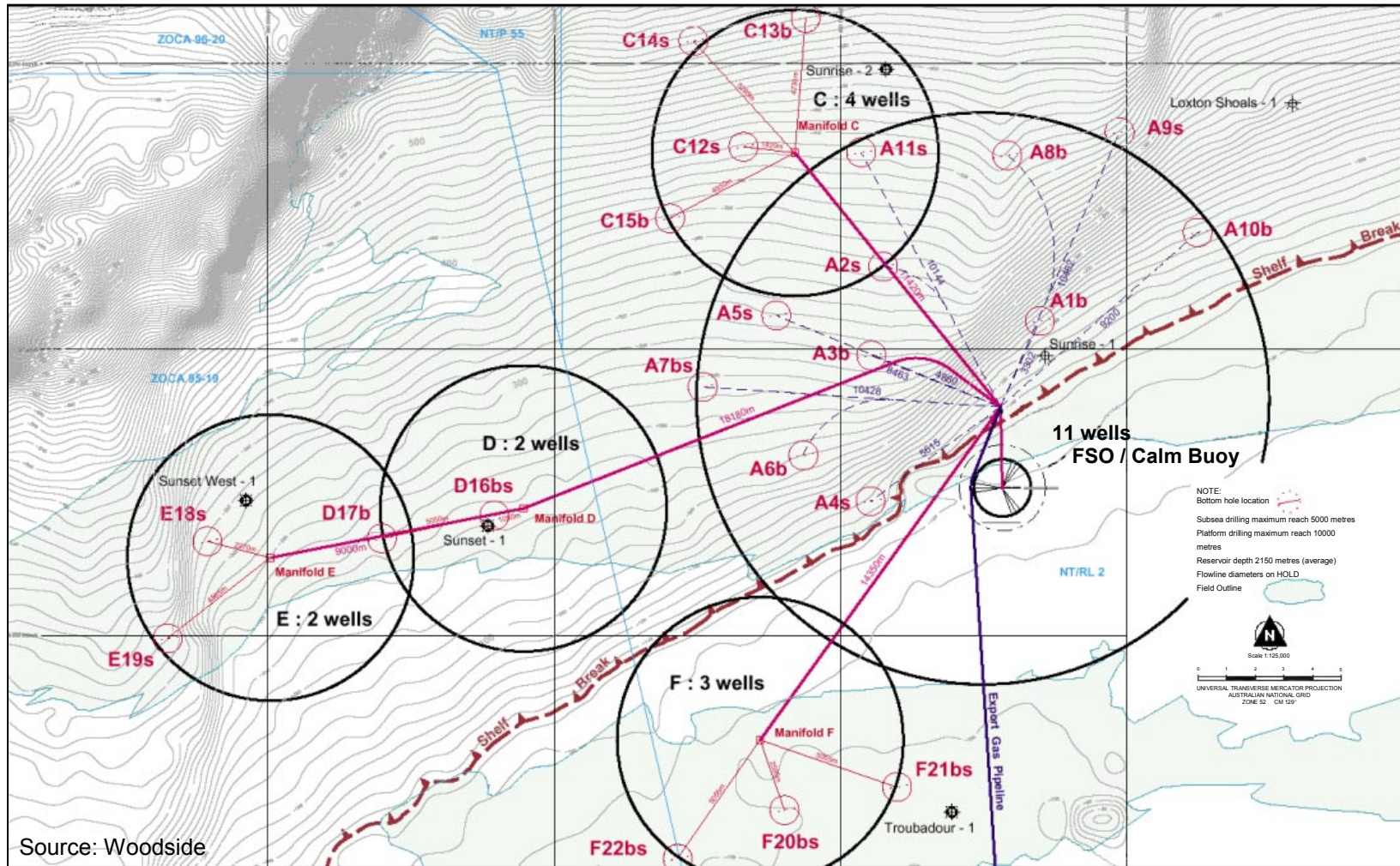
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**Scope of EIS Scenario 2:FLNG**

**Figure 3-1b**

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 Figure prepared by: T.Lee  
 Date Prepared: 16/10/01





Source: Woodside

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**General Gas Field Layout**

**Figure 3-2**  
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The main routing considerations for the approach to the offshore facility were identified as follows:

- The offshore facility is located in approximately 140 m depth of water;
- The platform is located towards the eastern end of the Sunrise Gas Field; and
- The final location of the risers will be influenced predominantly by the location of the drilling facilities, FSO, flare, living quarters, process facilities and support vessel offloading areas.

Subsea wells are planned to be tied into the proposed offshore facility. Because the subsea wells will be located to the west of the offshore facility the most likely location for the import risers is on the western side of the facility. The final location will be influenced as for the export riser above. Typically, all risers will be located adjacent to one another to simplify deck layout.

The main routing considerations for the flow lines are as follows:

- The edge of the Sahul Platform is predominantly silty/sandy and may be subject to local scour. The orientation of the flowlines and pipelines has a significant influence on scour, as it is driven by the magnitude and direction of the currents;
- Pockmarks are present over a wide area, particularly at the edge of the shelf. However, it is not believed that the pockmarks will present a serious risk to the integrity of the pipeline, due to their small size and depth. Appropriate strategies will be developed to deal with spans, caused by formation and migration of pockmarks, during operation of the pipeline; and
- Scour features (possible contourites) and gullies have been identified. The scour features are believed to have been formed recently, in a geological timeframe but may be inactive in terms of pipeline operating life. Ripples are present in some areas, which suggest high seabed currents and supports the supposition that the scour features are active. Flowlines and pipelines will be deviated to avoid any gullies. A span analysis will be performed to assess the requirement for seabed preparation and may result in a recommendation for deviation of the route.

### 3.2.3 Seabed Envelope & Sea Area Usage

The development area is large covering 40 km by 20 km. A 500 m diameter Safety Zone will be maintained around the facility restricting vessel movement in the area, in accordance with DNV OS-F101 (2000).

The nearest commercial fishery (Timor Reef Box) to the Sunrise Gas Field lies 75 km to the south-east, as described in **Sections 2.3.1 and 7.10**. For information relevant to the subsea pipeline, from the Sunrise Gas Field to the Wye piece, these sections should be referred to.

### 3.2.4 Design Standards and Limitations

Water depth over the reservoir area varies from 50 m to 700 m (Sunrise BOD 2001) and the platforms are located in approximately 140–400 m of water. However, the environmental conditions in the field are relatively benign.

The key relevant basis of design parameters can be summarised as follows:

- Water Depth 50–700 m
- Environment (100 year return):
  - Maximum Wave Height  $H_{max}$  11.3 m
  - Wind Speed  $U_g$  35.7 m/s
  - Surface Current  $V_o$  1.38 m/s
- Soil Conditions: Based on exploration wells, seismic etc.
- Reservoir Temperature: 100–170°C
- Final Flowing Tubing Head Pressure: 17 bara
- Design Life: 30 years minimum.

The estimated tidal levels for the Sunrise and Troubadour fields are included in **Table 3-2**.

**Table 3-2 Estimated Tidal Levels**

Location: Platform A		Tide Level (m)
Highest Astronomical Tide	HAT	2.96
Mean High Water Spring	MHWS	2.65
Mean High Water Neap	MHWN	1.83
Mean Sea Level	MSL	1.60
Mean Low Water Neap	MLWN	1.51
Mean Low Water Spring	MLWS	0.34
Lowest Astronomical Tide	LAT	0.0

Work to date has confirmed the integrity of the proposed Production Jackup substructures to survive 10,000 year storm events. The FSO moorings will also be designed to 10,000 year storm conditions.

### 3.2.5 Construction Location & Materials

The Production Jackup would be fabricated in modules in main construction yards in either Korea or Singapore. The bucket foundations will be constructed in South East Asia and transported on a barge to site. The Production Jack Up allows the possibility of topside modules construction in the same or another yard to the substructure.

There will be parallel construction of the hull, process and utility modules and accommodation. The construction methodology is based on modular approach with the production/utility/accommodation modules skidded onto the completed hull at the fabrication yard prior to loading onto barge for transport to site (**Figure 3-3**), which will take an estimated 30 days. Very little construction will be required on site. A summary of the construction material requirements is provided in **Table 3.3**.

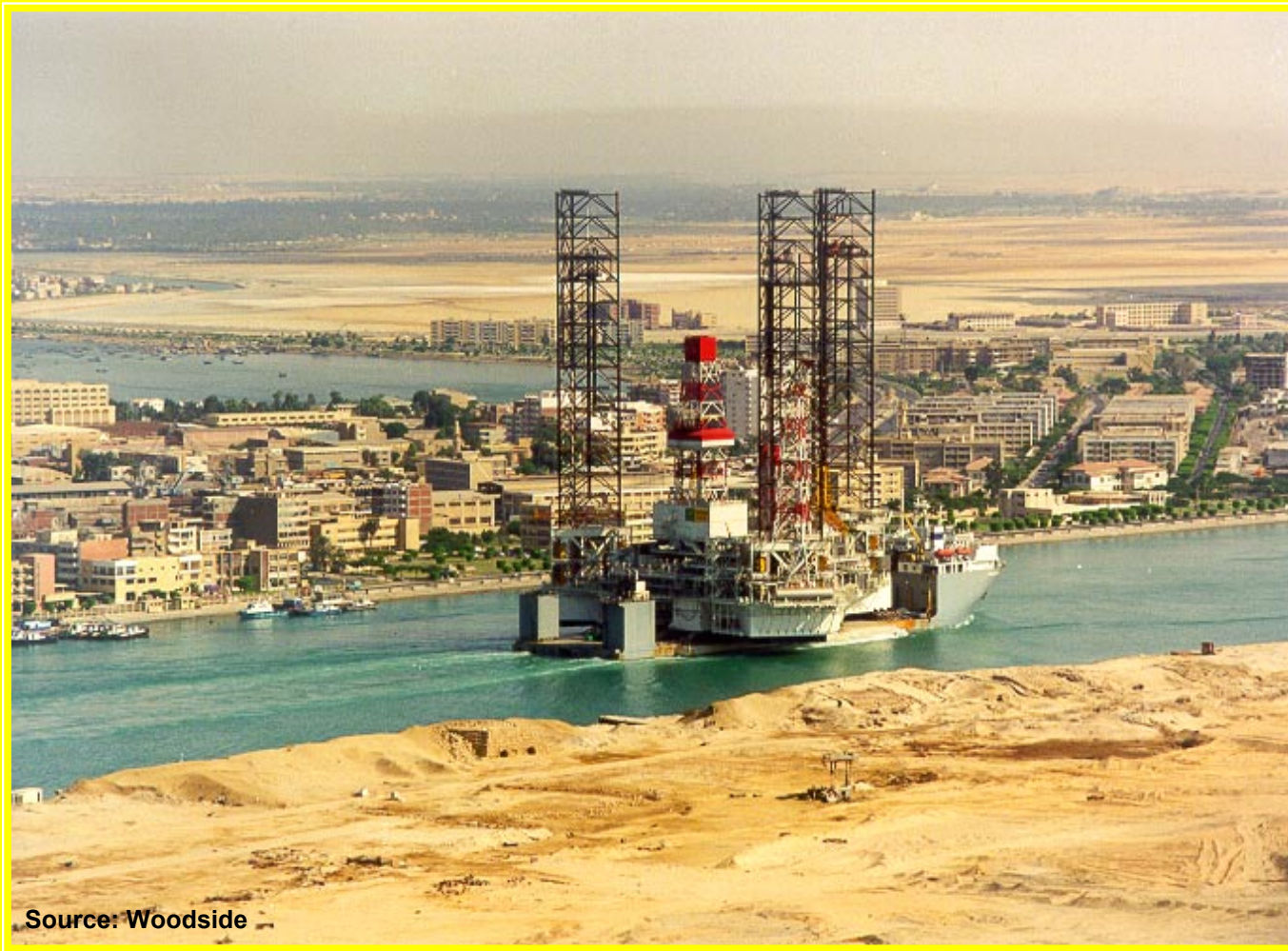
**Table 3-3 Construction Material, Types, Sources and Quantities**

Description	Factored Dry Weight (Modular) Tonnes
Topsides:	
Process	9,800
Structural Steel	5,700
<b>Topsides Total</b>	<b>15,500</b>
LQ/heli	1,000
Jacking	3,800
Hull	6,600
<b>Total Elevated Weight</b>	<b>26,900</b>
<b>Total Modelled Weight</b>	<b>29,000</b>
Hull	6,600
Legs	6,500
Foundation	600
<b>Grand Total</b>	<b>39,400</b>

### 3.2.6 Wellhead Platform

The wellhead platform is a fixed steel platform located on the shelf break in 140–400 m of water on the southern boundary of the Sunrise Gas Field. The platform would be installed by Heavy Lift Vessel in time for the scheduled initial drilling and main export pipeline pre-commissioning activities. It will stand-alone with the drilling tender for this initial period. The main production platform will be installed nearby and connected by a 60–100 m bridge link.

The wellhead platform will support up to 16 conductors for gas production, a boat landing and a main crane deck.



Source: Woodside

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**Transport of Jack Up on Barge**

**Figure 3-3**

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Date Prepared: 16/10/01



The wellhead platform topsides accommodate the Derrick Equipment Set (DES) as provided by the Semisubmersible Self-Erecting Tender Rig (SSETR). It will incorporate the wells, venturi flow-metering, production manifolding, pipeline and subsea flowline termination facilities, ie well controls, Emergency Shutdown Valve (ESDV) and Subsea Isolation Valve (SSIV) facilities, risers, J-tubes for umbilicals and pigging facilities, as well as craneage and emergency facilities. Risers will be provided for export pipeline and subsea flowlines.

The substructure comprises a four leg launched jacket secured to the seabed by bucket foundation. The estimated weight of the structure is 8,000 t. Following completion, the jacket will be towed to site and launch-installed with the assistance of a 500/600 class launch barge and 2,000 t capacity construction vessel.

The first phase of drilling is planned to be from the wellhead platform. It is proposed to drill these wells with a SSETR. Up to 16 wells are planned to access the reservoir in a semicircular pattern from the platform. Preliminary studies have confirmed that the rig can drill extended reach wells of up to 10 km step-out from the platform. The typical lithology of a well is illustrated in **Figure 3-4**.

The SSETR delivers and erects a DES to the drilling platform using its own heavy lift motion compensated crane. The derrick, draw-works, drill floor, solids control tanks and supporting substructure are all installed on the platform. In addition the DES is supplied with emergency power, high pressure mud pump and circulating tanks to ensure that well control can be maintained in the unlikely event that the SSETR tender has to pull away from the platform. All drilling services, storage and accommodation is provided by the SSETR tender, connected to the DES / platform via a telescoping bridge, flowlines, power and instrument cabling.

The Tender Assist Rig will be in place while the initial wells are being drilled from the wellhead platform, which will take about 3–5 years. Accommodation will be provided on board the Tender Assist Rig, which can accommodate approximately 100 crew. Shift changes will occur every 2 or 3 weeks.

### 3.2.7 Drilling Programme

#### *Wells*

Two different well types are being considered for development of the Sunrise Gas Project. These are:

- Platform Wells using Extended Reach Drilling (ERD) –from the wellhead platform; and
- Subsea Wells – drilled using a mobile offshore drilling unit (MODU).

Three options are being considered by Woodside with respect to the drilling programme and specifically the type/combination of wells that will be drilled:

- **Option 1:** Eleven platform wells up to 11 km in horizontal reach and eleven subsea wells with a requirement for both a wellhead and PCUQ platform;
- **Option 2:** Ten wellhead platform wells up to 8 km in length and twelve subsea wells requiring both a wellhead and a PCUQ platform; and
- **Option 3:** Twenty-two subsea wells, averaging 2 km vertical reach and 1 km horizontal reach, requiring a PCUQ platform but eliminating the need for a wellhead platform.

Options 1 and 2 will involve platform wells being drilled initially, taking up to 5 years to install, followed by the development of subsea wells. Alternatively, Option 3 will entail the installation of the following two types of subsea wells:

- Eleven wells using the daisy-chain system with flowlines back to the PCUQ platform. These subsea wells are laid out in a circular shape around the PCUQ platform and would replace the eleven wellhead platform wells; and

- Eleven wells using the manifold system with flowlines tied back to the PCUQ platform, i.e. Manifolds C, D, E, F, lying generally to the south and south west of the PCUQ platform.

The proposed wellhead platform wells range in length from 3–11 km with an average length of 7 km. The characteristics of a typical 7 km well is provided in **Table 3-4**. The cuttings volume for a 7 km well is expected to be about 800 m<sup>3</sup> and the cuttings mass 2,000 t. Drill cuttings are the crushed rock generated by the drill bit as it penetrates the seafloor. A large proportion of cuttings is retrieved from the wellbore, passed through a shale shaker to separate the cuttings from the drilling fluid and discharged overboard from the drill rig (URS, 2001). The subsea wells, being considerably shorter, will generate a much smaller quantity of cuttings. Re-injection of cuttings differs for platform and subsea wells, as described below and illustrated in **Figure 3.5**.

### ***Drilling Fluids***

All wells will be drilled using drilling fluids, frequently referred to as ‘muds’. In this EIS the term ‘mud’ is used for drilling fluids, although both terms are used interchangeably in the industry. This avoids confusion with the ‘base fluid’ (ie oil, paraffin or synthetic), one of the main constituents of the OBM or SBM (Craddock, 1999).

The drilling mud is circulated down the inside of the drill pipe to the rotary drill bit and flows up the annulus between the drill pipe and the wall of the hole (or cased hole) that has been drilled. The drilling mud carries the rock (formation) cuttings from the bit to the surface, where a variety of solids control equipment remove most of the fluids from the cuttings. Drill cuttings are usually disposed to the seabed below the installation (Craddock, 1999).

There are a number of different drilling muds used in the oil and gas industry, namely:

- Water-Based Muds (WBMs);
- Oil-Based Muds (OBMs); and
- Synthetic-Based Muds (SBMs) including Ester-based Muds (EBMs).

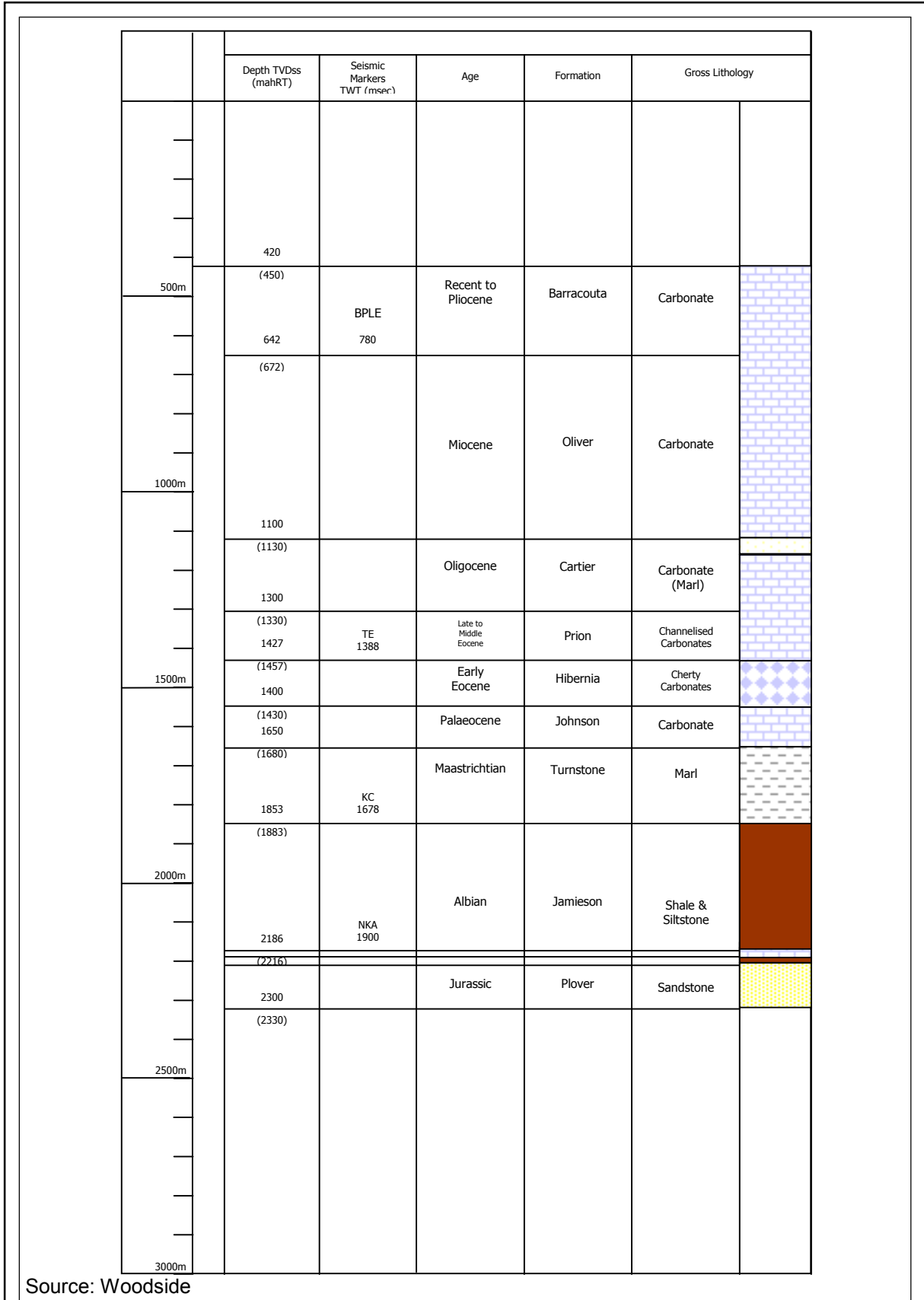
Both Water-Based and Synthetic-Based (including Ester-Based) Muds will be employed depending on the type of well, depths proposed and other well characteristics. Oil-Based Muds (OBMs) are not proposed for use in the drilling of either the subsea or platform wells, however, they may be suitable for the drilling of a closed-in fully contained system, eg re-injection well, should one be installed. The environmental impacts associated with the use of water-based, synthetic/ester and oil based muds are discussed below.

Drilling muds are used for the following (Macro-Environmental, 2001):

- Carrying cuttings to the surface;
- Supplying power to the drill bit;
- Cooling and cleaning the drill bit;
- Forming a filter cake on permeable formations and seal openings in formations drilled;
- Exerting a hydrostatic head to help prevent caving or sloughing of the formation, and to prevent flow of formation fluids into the borehole, or blowouts; and
- Suspension of cuttings and weight material such as barite when circulation is interrupted as when adding a new joint of drill-pipe.

### ***Oil-based-fluid cuttings (Wellhead Platform ERD wells)***

A wellhead platform would include from 6–11 extended reach wells, therefore generating a large amount of cuttings at a single location. Surface hole sections would be drilled using water based drilling muds, and deeper hole sections are likely to use Ester/Synthetic based (EBM, SBM) Muds.



Source: Woodside

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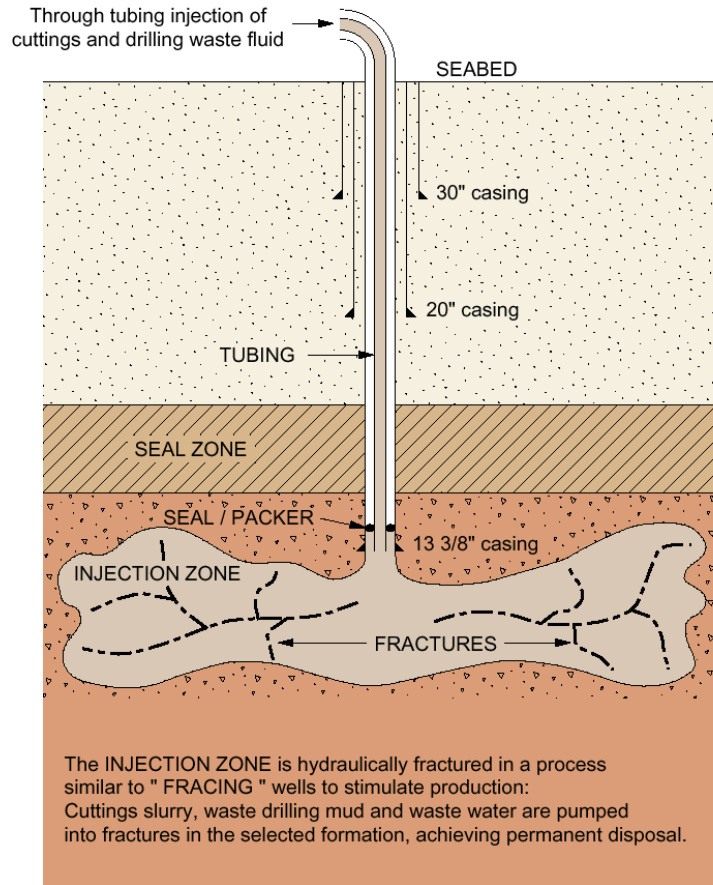
**Sunrise Generic Lithology vs Depth Plot**

**Figure 3-4**

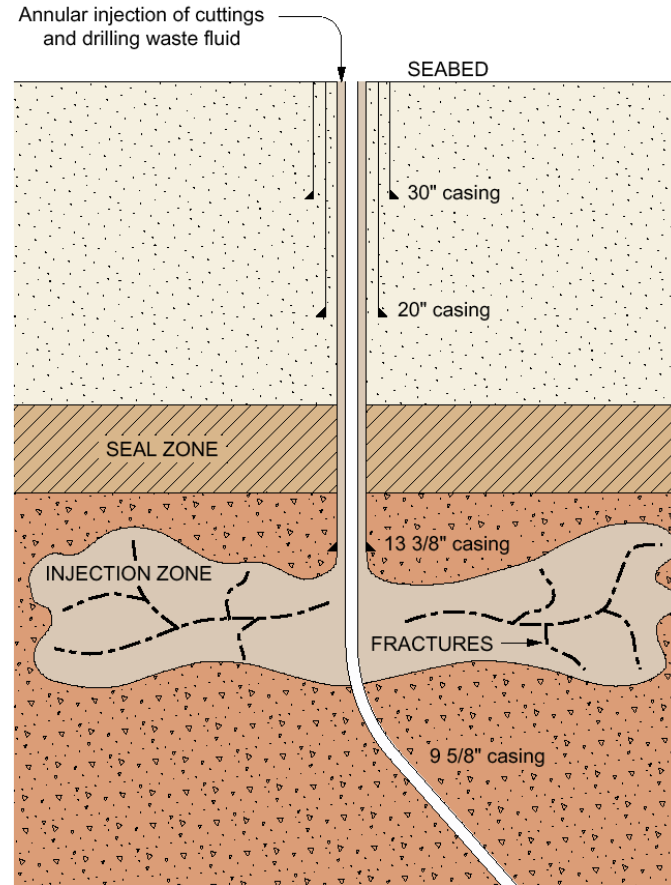
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**THROUGH TUBING INJECTION IN DEDICATED INJECTION WELL**



**ANNULAR INJECTION IN PRODUCTION WELL**



Source: Woodside

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**Schematic of Cuttings & Fluids Re-Injection**

**Figure 3-5**

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Disposal methods for non-water based fluids and cuttings generated using these drilling muds will depend on the results of feasibility work to establish the optimal system for the Sunrise Gas Field. Options include , transportation to shore (‘skip and ship’) and cuttings re-injection. Skip and ship involves the transportation of cuttings to a shore-based recycling or disposal facility. In a cuttings re-injection operation, waste muds and cuttings slurries are pumped (ie. injected) into a suitable formation approximately 1000m below the seabed.

Two options exist for cuttings re-injection (**Figure 3.5**). Injecting cuttings through tubing into a dedicated injection well and injection through the annulus between two casing strings on an existing production well. For cuttings re-injection to be viable, a suitable geological formation must be available for injection of the cuttings, together with a sealing formation to contain the cuttings and muds within the required zone. A detailed analysis would be undertaken in order to confirm whether a suitable injection zone exists in the Sunrise Gas field. A strategy has been developed for cuttings re-injection operations, should a wellhead style development be selected.

***Water-based-fluid cuttings***

Subsea wells will be drilled singly, at selected sites throughout the field. Cuttings re-injection would not be viable due to the lack of a nearby injection well. These wells are likely to be drilled using Water Based Mud systems due to their limited measured depth and relative ease of construction. The surface hole sections of wellhead platform wells would also be drilled with water based drilling fluids. Water based cuttings would normally be discharged to the seafloor, however in environmentally sensitive locations, it may be possible to implement a skip and ship operation as a back-up alternative.

**Table 3-4 Typical Profile of a Seven Kilometre Wellhead Platform Well**

Hole Diameter (Inches)	Bit Type	Lithology	Fluid Type	Fluid Wt (SG) <sup>1</sup>	Length (m)	Bulk Volume (m <sup>3</sup> )	Porosity	Cuttings Volume (m <sup>3</sup> )	Density (SG)
26.00	Milled Tooth	Barracouta	Seawater	1.00	350	120	20	96	2.40
17.50	Milled Tooth	Barracouta/ Oliver/ Cartier.	WBM <sup>1</sup>	1.10	3,200	497	15	422	2.50
12.25	PDC <sup>1</sup>	Prion/ Hibernia/ Johnstone/ Turnstone/ Jamieson/ Darwin.	EBM <sup>1</sup>	1.35	3,500	266	10	240	2.60
8.50	PDC	Plover	EBM	1.20	1,200	44	15	37	2.65
<b>Totals</b>					<b>8,250</b>	<b>927</b>		<b>795</b>	

Note<sup>1</sup>: SG–Specific Gravity, PDC–Poly Diamond Crystalite, WBM–Water Based Mud, EBM–Ester Based Mud

**3.2.8 Production Compression Utilities Quarters Platform (PCUQ)**

The PCUQ platform will be a production jack-up structure, with all facilities located on the topsides, connected by 60 to 100 m bridge link to the wellhead platform.

The construction methodology for the topsides is based on a modular approach with the production, utility, and accommodation quarters skidded onto the completed hull at the fabrication yard. After mechanical completion and pre-commissioning in the yard, the platform will be towed to a sheltered shallow location for fitting the foundations. The bucket foundations (**Figure 3-6**) will be offloaded at the shallow location and set in position on the seabed. The Jack-up legs will be temporarily jacked down and connected to the bucket foundation and welded in place. The tow to Sunrise field site will then be completed.

Installation at site is to be carried out by jacking down the three legs and locking them into position. Following PCUQ platform installation near the wellhead platform, the interconnecting bridge will be lift-installed by crane.

### 3.2.9 FSO

The FSO will most likely be built in Korea and towed to site. It is estimated that it will take 56 days to tow and install the FSO, on site 2km south of the PCUQ platform, with installation taking approximately 2–3 weeks.

### 3.2.10 Mooring Facilities

FSO and other 'permanent' floating installations will be moored to foundations designed to hold fast in extreme weather such as 3,000 to 10,000 year storm conditions. This type of mooring system will not have an adverse impact on the seabed given the absence of sensitive seabed habitats at the proposed mooring locations.

The foundation mooring system will comprise piles as in the case of Laminaria and Legendre fields or gravity bases in as in the case of Apache Stag. The pile system will typically comprise piles penetrating the seabed with a padeye (fastening point) to which the mooring lines are connected. The piles will protrude 2–3 metres above the seabed. The gravity system will comprise a box type structure that will be filled with iron ore.

Drilling facilities, temporary installations and mobile units used for drilling subsea wells will be anchored using conventional ship anchoring systems. The system selected will be suited to the seabed composition and condition, the loads to be applied and the vessel concerned. The system selected will be able to withstand severe weather conditions with a design criteria of a 10 year storm. Tender Assisted Drilling Rig for platform wells would be typically designed to withstand a 100 year storm with one broken line. Movement outside design limits during drilling operations is not tolerable and therefore anchor drag is not expected which can result in damage to the seabed.

Construction and installation vessels (short term use) for installing platform, pipeline and subsea structures will also be anchored using conventional ship anchoring systems. The system selected will suit the seabed composition and condition, the loads to be applied and the vessel concerned. This system would be able to withstand a 1 year storm. Anchor drag is not therefore expected which can result in damage to the seabed.

### 3.2.11 Future Subsea Facilities

Further subsea wells, are planned when reserves are required to be drained outside of the platform's sphere of influence (year 5 onwards). A number of subsea drilling centres have been identified to progressively develop the Sunrise and finally the Troubadour Fields. The future subsea facilities will comprise four production centres, C to F, with a total of up to 32 subsea wells each connected to a production centre comprised of a subsea manifold and cluster of wells. The step out range for subsea



Source: Woodside

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**Bucket Foundation for PCUQ Facility**

**Figure 3-6**

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Figure prepared by: T.Lee  
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wells is nominally limited to five kilometres. Each drilling centre will be drilled up before moving to the next centre.

Subsea development wells are to be drilled and completed from a conventional semi-submersible mobile offshore drilling unit (MODU), common to the SE Asian Region.

The MODU can drill in water depths of up to 350 m, deeper if pre-laid moorings and specialist mooring anchors / wire are employed, and they are typically capable of drilling 8,000 m along hole depth, with approximately 5,000 m horizontal reach from the wellhead. Thus it is proposed to drill subsea wells to a maximum 5 km horizontal reach, with the wellheads clustered about and connected by 50–100 m jumpers to a subsea manifold. The in-field flowlines will connect to, and control will come from, the wellhead platform. The MODU rig will accommodate and install the subsea equipment.

The Troubadour Gas Field is located in water depths of less than 100 m, is suitable to station a jack-up MODU drilling rig to drill a number of subsea wells, as for the Sunrise clustered subsea wells. Jack-up rigs are being considered for Troubadour, although this concept has not been matured since Troubadour wells are not planned to be drilled until some 10–15 years after start-up. The expectation is that a long legged jackup facility will be available in the region when the Troubadour wells are drilled.

The in-field flowlines will be manufactured from 13 per cent Cr steel or 316 SS clad carbon steel. The flowlines may incorporate a subsea isolation valve (SSIV) adjacent to the platform to protect the platform from the flowline inventory in the event of an emergency. Flowline termination facilities (ESDV facilities and risers) will be installed onto the platform when required.

### **3.2.12 Intrafield Flowlines**

The intrafield flowlines will transport reservoir fluid from the subsea manifolds to the PCUQ platform. Production centres C and F will be connected directly to the facility. Production Centres E and D will be connected in series to the platform. These subsea wells and flowlines will not be required until about year 2010.

The sizing of the flowlines is based on the following criteria:

- ❑ Minimum Flowing Tubing Head Pressure (FTHP) of 57 bara (bar absolute) to year 15–20, 17 bara thereafter. Platform arrival pressure of 42 bara to year 36, 10 bara thereafter.
- ❑ The produced fluids will contain 4.5% to 5.5% carbon dioxide, saturation water, and in later life, formation water; and will require the selection of a corrosion resistant alloy (CRA) flowline material in order to ensure its integrity over the design life. The line pipe will be manufactured from either 13 per cent Cr steel or carbon steel with an interior clad layer (3 mm) of stainless steel. External corrosion protection will be achieved by corrosion coating and sacrificial anodes.
- ❑ The flowlines generally do not pose slugging problems and no slug catcher or additional volume separator is provided.
- ❑ Hydrate conditions will occur in uninsulated subsea flowlines during normal steady state operations and on shutdown. The flowlines from Centres C, D and E will be insulated to mitigate against hydrate formation. The flowlines from Centre F do not require insulation due to higher ambient temperature (shallower water).

### 3.2.13 Waste Management Practices

Waste management practices will be undertaken in accordance with the Woodside 'Waste Management Policy' (**Appendix B**), and through specific waste management plans drawn up by contractors. Construction Contractors will be required to carry out all construction works in an environmentally sensitive manner. The Contractors will also be required to adhere to all relevant environmental legislation while carrying out the works.

All hazardous wastes will be documented, tracked and segregated from other waste. Hazardous wastes will be disposed of onshore in accordance with relevant waste legislation.

## 3.3 Subsea Pipeline

### 3.3.1 Route Selection Criteria

The Det Norske Veritas (DNV) OS-F101 (2000) Code, used in the design of the pipeline, specifies certain site selection criteria that must be considered in the routing of a subsea pipeline. The DNV code (2000) states that:

*“the pipeline route shall be selected with due regard to safety of the public and personnel, protection of the environment, and the probability of damage to the pipe or other facilities. Factors to take into consideration shall, at minimum, include the following:*

- Ship traffic;*
- Fishing activity;*
- Offshore installations;*
- Existing pipelines and cables;*
- Unstable seabed;*
- Subsidence;*
- Uneven seabed;*
- Turbidity flows;*
- Seismic activity;*
- Obstructions;*
- Dumping areas for waste, ammunition etc;*
- Mining activities;*
- Military exercise areas;*
- Archaeological sites; and*
- Exposure to environmental damage, and oyster beds”.*

DNV Code (2000) also states that *“expected future marine operations and anticipated developments in the vicinity of the pipeline shall be considered when selecting the pipeline route”.*

In relation to route surveys the following is required in accordance with DNV OS F101 (2000):

- “A survey shall be carried out along the planned pipeline route to provide sufficient data for design and installation related activities.*
- The survey corridor shall have sufficient width to define a pipeline corridor, which will ensure safe installation and operation of the pipeline.*
- The required survey accuracy may vary along the proposed route. Obstructions, highly varied seabed topography, or special sub-surface conditions may dictate more detailed investigations.*
- An investigation to identify possible conflicts with existing and planned installations and possible wrecks and obstructions shall be performed. Examples of such installations include other submarine pipelines, and power and communication cables. The results of the survey shall be presented on accurate route maps, showing the location of the pipeline and related facilities together with seabed properties and anomalies.*

- *All topographical features which may influence the stability and installation of the pipeline shall be covered by the route survey, including but not limited to:*
  - *obstructions in the form of rock outcrops, large boulders, pock marks, etc. that could necessitate levelling or removal operations to be carried out prior to pipeline installation; and*
  - *topographical features that contain potentially unstable slopes, sand waves, deep valleys and erosion in the form of scour patterns or material deposits”.*

Guidelines are also provided for determining seabed properties, such as geotechnical and soil parameters.

Woodside’s site selection criteria for subsea pipelines incorporates both environmental and technical criteria and states that the following should be considered:

- The pipeline route shall comply with the Australian State and Commonwealth regulations regarding traversing licensees’ blocks, consultation with fishing organisations, communication with local authorities and communication with interested parties;
- Avoidance of areas such as anchorages, sanctuaries, shipping lanes, and military reservations;
- Location of islands, shoals, reefs, atolls etc. along the route;
- The type and intensity of shipping and any designated shipping lanes in the area;
- The presence of fishing grounds (including sensitive fish/shell fish producing areas);
- The type and intensity of fishing activity in the area;
- The presence of military exercise zones, dumping grounds, submarine exercise areas;
- The presence of other pipelines, telecommunications cables, installations, wellheads, large rocks or boulders or other obstructions in the area. A separation of at least 500 m should normally be maintained between the pipeline route and any potential hazard, obstruction or existing/planned installation. Wrecks and sites of historic importance should be avoided;
- Navigation channels, recommended tracks, shipping lanes and principal shipping routes;
- The presence of regularly dredged channels or spoil dumping areas;
- The possibility of future developments in the area;
- The views of other operators whose blocks are crossed by the pipeline;
- Any undesirable geotechnical conditions such as unstable seabed slopes, deep valleys, sediment transport etc;
- The flatness and stability of the seabed, presence of sand waves, ‘pock’ marks etc., e.g. the avoidance of spans;
- Limitations of the installation equipment with regard to mooring requirements, lay curvature, initiation and termination. The water depth along the pipeline route should be selected such that it does not unduly limit the lay vessels that are able to lay the pipeline. The lay radius must be selected to take account of the minimum achievable radius and maximum acceptable stresses during operation;
- Stability of the pipeline and minimisation of primary (self-weight) and secondary stabilisation requirements (trenching, rock – dumping etc.);
- If trenching is to be employed, the presence of undesirable geotechnical features such as mud, silty sand, hard rock; and

### 3.3.2 Description of Preferred Pipeline Alignment and Implications

Route 05, the preferred alignment, runs southwards to the Bayu-Undan Wye piece through the JPDA. The route is aligned to avoid shoals and valleys, as much as possible, including the Melita Valley and ‘The Boxers’ (Refer to **Section 6.2** and **Figure 6-5**). The water depths through which the pipeline traverses range from approx. -140 m to -57 m LAT. The water is at its greatest depth in the vicinity of the Sunrise Gas Field (approx. -140 m) and until Kilometre Point (KP) 37 maintains a level of -100 m.

At KP 40 the level rises to -75 m LAT and until KP 83 fluctuates between -110 and -70 m LAT. From KP 57.48 to KP 57.55 pre-lay rock armour may be laid due to an uneven profile. From KP 85 to KP 100 similar depths are maintained but over this short distance rapid changes in water depth occur. Between KP 100 and KP 150, the western edge of Melita Valley is traversed and although a water depth of -150 m LAT is reached, a relatively gradual rise and fall through the valley is experienced. From KP 185 to KP 185.18 pre-lay rock armour may also be required.

Over only a very short distance 'The Boxers' is encountered (KP 212-213) where the water depth is at its shallowest reaching -57 m LAT. The Wye piece lies at a water depth of -73m at KP 216.7.

The implications of choosing Route 05 are:

- ❑ Quantity of rock armour minimised reducing the area of seabed and habitats covered;
- ❑ No secondary stabilisation is required reducing disturbance to the marine environment;
- ❑ No trenching or backfilling required due to depths of water encountered;
- ❑ Route is short following a relatively straight line; and
- ❑ No requirement for additional concrete coating.

From the Wye piece it is intended that a pipeline be installed to Wickham Point along the route already approved for Bayu-Undan gas.

### 3.3.3 Sea Area Usage

Refer to **Section 3.2.3**. No marine parks, subsea cables, ship wrecks etc. are found in close proximity to the gas development area or along the proposed pipeline to the Wye piece.

### 3.3.4 Infrastructure Requirements

Infrastructure requirements for the construction of the subsea pipeline are minimal, consisting mainly of service vessels. The laying of the pipeline will be a 24 hour per day operation with crew working in 12 hour shifts over a construction period of 70 days. Helicopter transport will be required for the transfer of workers on and off the lay barge. Service vessels will be required to transfer provisions to the barge.

As well as the S-Lay Barge, which is used for subsea pipeline installation (**Section 3.3.6**) a second barge may be required for offloading pre-lay rock dump prior to laying of the pipeline. This rock will be sourced in accordance with environmental regulations. The quantities of rock required, if any, will be small and hence the barge will not be required to spend an extended time offshore.

### 3.3.5 Pipeline Specifications

Specifications for the pipeline are provided in **Table 3-5**.

The export pipeline will be designed to accommodate to deliver dry gas with a design pressure of 198 barg.

The pipeline will be designed, constructed and operated in accordance with the requirements of the DNV OS-F101 (2000) code. The line pipe is DNV Grade 450, equivalent to API 5L X65 with a wall thickness to resist internal pressure, collapse and local buckling of 23.3 mm, including a 1.5 mm internal corrosion allowance. Internal corrosion is not expected to occur as the gas is considered dry, free of liquid water. A 5 mm external coating of asphalt enamel is selected for external corrosion protection. Concrete coating will be applied over the entire length of the pipeline mainly for stability purposes. The export pipeline route is shown in **Figure 5.1**.

**Table 3-5 Sunrise Export Pipeline Specifications**

Item	Specification
Pipeline Termination	Wye Piece located along the proposed Bayu-Undan pipeline.
Length	218 km Sunrise to Bayu-Undan Wye piece
Diameter	36 inch from Sunrise to Wye piece
MDQ flowrate	966 MMscfd
Maximum Allowable Operating Pressure (MAOP)	191 bar atmospheric (bara)
Design pressure	198 bar gauge (barg)
Steel Grade	DNV Grade 450 (ie API Grade X65)
Pipe Wall Thickness	23.3 mm
External Concrete Coating	40mm (density: 3040kg/m <sup>3</sup> )
External Anti-corrosion coating	5 mm Asphalt Enamel
Internal Coating	1.5 mm internal allowance
Cathodic Protection	Sacrificial Anodes
Pre Lay Rock Dump	As required
Expected Life Time (year)	30

*Note: This table only refers to the specifications of the Sunrise to Wye piece pipeline; it does not include details of the Phillips pipeline from the Wye piece to landfall.*

In selecting the route of the pipeline deep waters are preferred for technical reasons. One of these relates to cyclones and storm surges, as at greater water depths the effect of cyclones/storms on the pipeline are negligible. Furthermore, the external weight coating will be selected to achieve a stable pipeline, that will not be affected by cyclones and storm surges.

### **Coating & Corrosion**

Any damage incurred due to pipeline corrosion could be very costly. It could render a section of pipeline inoperable for a period of time while maintenance is being carried out. A section of pipe may need to be replaced if damage is potentially severe and a substantial loss of product may result from gas leakage. Gas leakage also represents a major safety and environmental hazard. With these aspects in mind it is vital to prevent the future occurrence of such incidents in the design and construction phases of the pipeline.

Internal corrosion should not be a factor as the condensate will be dewatered and the gas will be dehydrated to a dewpoint well below minimum operating temperature, operating in the absence of free water. The conditions are therefore considered to be non-corrosive. A small internal corrosion allowance will be provided to compensate for corrosion occurring prior to installation and during topsides upset operating conditions. As a precaution small amounts of corrosion inhibitor may be used. External corrosion can occur for a number of different reasons such as atmospheric, chemical or bacteriological attack and from corrosive currents, which may be present in the seabed. Protection against these forms of attack will be in the form of a combination of external coating and cathodic protection, as described below.

External coating will be applied to lengths of pipeline in a specific coating yard. The pipe will be cleaned and primed before application of the protective coating, a 5 mm layer of asphalt enamel, and concrete coating, which is applied for stability purposes.

A cathodic protection supplements the corrosion coating to prevent corrosion of any weak points in the external coating of the pipeline. Cathodic protection will be applied to the pipeline by applying sacrificial anodes at regular intervals. After the installation the cathodic protection system will be monitored frequently to ensure adequacy of protection.

### 3.3.6 Construction and Installation

The proposed pipeline has been designed to transport gas at a maximum operating pressure of 191 bara. This will allow a flow rate of 966 MMscfd to be achieved. The maximum depth of the pipeline under the sea will be -140 m LAT.

A detailed survey of the subsea pipeline route has been conducted to carry out freespan analysis and the results of this analysis has identified specific areas of the seabed which may require preparatory work before the pipeline can be laid.

For pre-lay rock dumping both large and small diameter sized material is required to create a filter layer, ensuring currents along the seabed do not disturb the rock and hence the position of the pipeline. The rock will be sourced from quarries located either in the Darwin or SE Asia region and transferred by barge offshore. The rock will be offloaded from a vessel preceding the lay barge.

The pipe lengths will be transported by barge from the pipeline coating yard directly to the S-Lay barge located offshore.

Following the pre-lay rock dumping, the pipeline will be laid directly on the seabed from the S-Lay barge. No trenching or backfilling is required, as shallow waters are not traversed. Anchor lines, which ensue tugs continually reposition according to progress, continually secure the lay barge. The pipeline will be lowered over the stern of the laybarge onto the seabed over a pipe support ramp called a stinger. A typical installation would use a third generation barge as shown in **Figure 3-7**.

The pipeline operation will commence with mobilisation of the lay barge to the site. The lay barge carries a supply of pipe lengths, or joints, sufficient for two or three days pipelaying. The stocks will be continually replenished by pipe haul vessels, which carry pipe from a nearby source – either a dockside or a larger bulk pipe carrier. Once the pipe joints are loaded onto the lay vessel they may be double jointed. This optional activity involves welding two joints of pipe together such that the pair of pipe joints is then handled as a single unit. After a section of the pipe has been laid, an as laid survey is performed to confirm that the pipe is undamaged and laid within the specified tolerance limits.

On completion of the lay operation, the precise end chainage position of the pipeline will be determined by the on-board computer. At this point a lay down head is welded to the end of the pipeline.

#### ***Onsite Welding***

Single or double pipe joints are fed onto the firing line where joints are welded into the pipeline prior to laying over the stern. The firing line will consist of a number of welding stations where progressive layers of the butt weld are deposited.

Following completion of the weld, the weld will be inspected using Non-Destructive Examination (NDE) techniques and if required weld repairs performed. Finally the field joint coating will be applied to the weld area and the void between adjacent concrete coatings filled with a suitable infill.

#### ***Accommodation***

During construction of the subsea pipeline the S-Lay barge will be fully contained and provide accommodation facilities. Approximately three hundred personnel will be accommodated on the S Lay Barge. Laying of the pipeline will be a 24 hour ongoing operation with changes in shift every 12 hours.



Source: Woodside

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**Typical Lay Barge for  
Subsea Pipeline Installation**

**Figure 3-7**  
Project No.: DE2090.100  
Figure prepared by: T.Lee  
Date Prepared: 16/10/01



### 3.3.7 Waste Minimisation and Management

As described in Section 3.2.13.

### 3.4 Pipeline Testing and Commissioning

Testing of the pipeline and ancillary components is an integral part of the commissioning of the pipeline system. Testing will generally take the following forms:

- ❑ Testing of all materials prior to construction: Woodside or its representatives will carry out quality assurance tests during manufacture of all materials. Any materials that fail the quality tests will be marked and quarantined so as to ensure that they are not used as part of the project.
- ❑ Testing of Welds: All welds will be checked in accordance with strict industry standards. Testing of welds will be carried out using NDE techniques.
- ❑ Flooding & Hydrostatic Testing: This test comprises water filling the pipeline and then pressurising to the required test pressure to prove strength and integrity. Due to the large volumes of water required for the hydrostatic testing of the pipeline the sourcing of a suitable water supply is a key environmental concern. This is discussed in more detail below.
- ❑ Drying: Following completion of testing the pipeline will be de-watered and dried prior to flowing gas and condensate. The disposal of the water after testing will ensure that it does not cause excessive erosion of the seabed or contaminate the receiving water body.
- ❑ Instrumentation: All instrumentation will be checked to ensure correct calibration. These tests will be carried out in accordance with appropriate industry guidelines.

All test methodologies and acceptance criteria will be approved prior to the carrying out of any test.

All test results and test parameters will be documented. Where test results fall outside the agreed acceptance criteria repair work or modifications will be carried out. Subsequently, the acceptance test will be repeated.

*Flooding:* The pipeline will be flooded with filtered seawater treated with corrosion inhibitors, oxygen scavengers and a biocide. The flooding spread consists of:

- ❑ Suction pump and supply hose;
- ❑ Chemical injection facilities;
- ❑ Discharge pumps to pump the filtered, treated seawater into the pipeline; and
- ❑ Temporary pig launcher on the pipeline end.

The filling operation will be performed by launching pipeline integrity gauges (pigs) into the pipeline propelled by treated seawater. This would typically comprise two cleaning pigs followed by two pigs fitted with gauge plates. They would generally be separated by 500–1000 m of filtered but not chemically treated seawater. The pig train is then pumped through the pipeline with filtered and chemically treated seawater. This operation typically takes between 2–3 days.

*Hydrostatic Testing:* Approximately 90,000 tonnes of treated seawater will be needed for hydrostatic testing of pipeline integrity. Test heads are installed at both ends of the pipeline. A pressure testing spread is mobilised to perform the operation. The pressure of the pipe is slowly raised until the required test pressure is reached. The pressure is allowed to stabilise then the 24 hour test period is commenced. The pressure is continuously monitored throughout the test period. Hydrotest water will be discharged at the Wye.

Minor variations in the test pressure often occur due to temperature change for example and unless these variations can be accounted for, such changes frequently lead to extension of the test period until

all parties are satisfied that no leak exists. The pipeline is then depressurised and a formal pressure test report prepared as evidence of a satisfactorily constructed pipeline.

*Treatment Chemicals:* The choice of chemicals used in the test seawater is important. The mix typically includes a biocide (non-agricultural pesticides) to kill biofouling organisms, an oxygen scavenger (to absorb oxygen thereby minimising corrosion potential) and a corrosion inhibitor to prevent rust formation. The rate at which these chemicals are added to the water and the specific products used will require detailed discussion with the authorities responsible for approving the eventual discharge of the test water. The large volume of treated water to be discharged, could affect marine life in the immediate vicinity of the discharge location. Aspects to consider include toxicity, persistence and tendency to bioaccumulate. The chemicals to be used have not yet been specified.

*Dewatering and Pre-commissioning:* Pre-commissioning will comprise bulk dewatering followed by drying operations to remove residual water. Bulk dewatering is achieved by propelling pigs through the pipeline with compressed air. Up to 30 bar pressure will be needed to overcome the hydrostatic head in addition to the frictional head of the water and pigs. When successive pigs fail to sweep appreciable quantities of water from the pipeline then bulk dewatering is considered complete and drying operations can be commenced.

### **3.5 Tie-In Location**

On completion of the pipe-laying operation the two offshore ends of the pipeline will be laid in close proximity on the seabed. A welded tie-in will then be made by hyperbaric welding. The Sunrise pipeline will terminate adjacent to the Wye, which will be installed on the Bayu-Undan pipeline. The Sunrise and Bayu-Undan Pipelines will be joined to the Wye by a connecting spool piece. The connection may be by flanges or by hyperbaric welding.

### **3.6 Gas Field Development – FLNG Scenario**

Approvals for a FLNG facility will fall under a separate legislative process and therefore is not described in this EIS. However, should a FLNG market scenario arise the development of the gas field will be take place within the scope described in the preceding sections. This scenario comprises a combination of subsea and WHP wells, with gas and condensate exported to an FLNG facility via a series of flowlines and risers, previously described. Under this option produced formation water including production chemicals may be transferred from the FLNG back to the field for re-injection during the commissioning/operation phases.