

ENVIRONMENT PLAN

Beehive-1 Exploration Drilling

2-Activity Description

WA-488-P

17 May 2024

Rev 6

eog resources

2. Activity Description

This chapter provides a description of the proposed Beehive-1 exploration drilling program in accordance with Regulation 21(1) of the OPGGS(E).

2.1. Activity Location

The activity described in the EP is proposed to be conducted within Commonwealth petroleum exploration permit area WA-488-P, located in the Petrel Sub-basin (Bonaparte Basin) in the JBG, WA (see Figure 2.1).

Coordinates for the well location are provided in Table 2.1, noting that this may shift up to 1,500 m from this location based on continuous refinement during the well planning process. The operational area defines the spatial boundary of the proposed activity and for the purposes of this EP, the operational area is set as a 500 m radius around the final well location (which reflects the area of the Petroleum Safety Zone [PSZ] that will be gazetted around the MODU while it is on location).

Table 2.1. Coordinates for the proposed Beehive-1 well

Degrees, minutes, seconds		Eastings and northings	
Latitude	Longitude	Easting (m)	Northing (m)
14° 03' 16.41" S	128° 34' 14.54" E	453,651.86	8,446,199.05

GDA2020, UTM 52S.

The distances of key natural and socio-economic features from the Beehive-1 well are listed in Table 2.2.

Table 2.2. Distance to key features from Beehive-1

Feature	Distance and direction from Beehive-1
Natural features	
Closest mainland point	80 km south
Lacrosse Island (WA)	81 km south-southwest
Cape Domett (WA)	87 km south-southwest
Dorcherty Island (NT)	97 km east
Marine protected areas (nearest points)	
Joseph Bonaparte Gulf Australian Marine Park (AMP)	35 km east
North Kimberley Marine Park (WA)	68 km south
Oceanic Shoals AMP	158 km northwest
Petroleum infrastructure	
Blacktip gas export pipeline (nearest point)	12 km north-northeast
Blacktip unmanned wellhead platform	20 km northwest

Feature	Distance and direction from Beehive-1
Towns	
Port Keats (Wadeye), NT	103 km east-southeast
Wyndham (WA)	173 km south-southwest
Kununurra (WA)	190 km south
Darwin (NT)	300 km northeast

2.2. Timing

The activity is scheduled to commence no earlier than 1st of January 2024 and will be completed no later than 31st of December 2025. The start of the activity depends primarily on EP acceptance and MODU availability.

Drilling activities are estimated to take approximately 55 days, or up to approximately 100 days if re-spud or mitigating problems is required, or a Drill Stem Test (DST) is performed. The drilling duration may be subject to change based on geological conditions and potential for operational challenges. Operations will be conducted 24 hours per day, seven days per week.

2.3. Project Management

Labrador Petro Management (LPM) is the Drilling Management Contractor (DMC) appointed to this project by EOG. LPM is responsible for assisting EOG in project management and well delivery services for Beehive-1.

LPM's Well Construction Management Process (WCMP, MAN02-06) is a central component of the LPM Management System, which is accredited to ISO 9001:2015 (Quality Management Systems) (see Section 9.3.2). This management system process (approved by EOG) is used as a reference manual for all LPM drilling operations, from planning through execution and post-well analysis. It ensures that the well activity is planned and managed efficiently and with due consideration to good oilfield practice, local and international standards as they relate to well design, operations planning, construction and then subsequent suspension or abandonment operations.

The LPM WCMP works through five core phases that apply to managing well construction operations, these being:

- Phase 1; Define Scope of Work and Complete Pre-Planning – describes the process from initial client contact through to the submission and approval of a formal proposal and the contract management responsibilities between LPM and the client or titleholder;
- Phase 2; Concept Development, Contracting and Logistics – describes the initial engineering planning and design work in order to identify and select a preferred option;
- Phase 3; Detailed Well Design, Procurement and Regulatory – describes the detailed engineering planning and design work to take the preferred option through to endorsement of the final well design;
- Phase 4; Implementation and Readiness for Start Up – describes how LPM demonstrates the requirement to display the readiness to commence operations. Includes final operational programs and HSE documentation being endorsed and approved, with all regulatory approvals being in place; and
- Phase 5; Operate and Close Out – describes how LPM undertakes the safe execution of programmed operations for the scope of work and concluding with final well reporting.

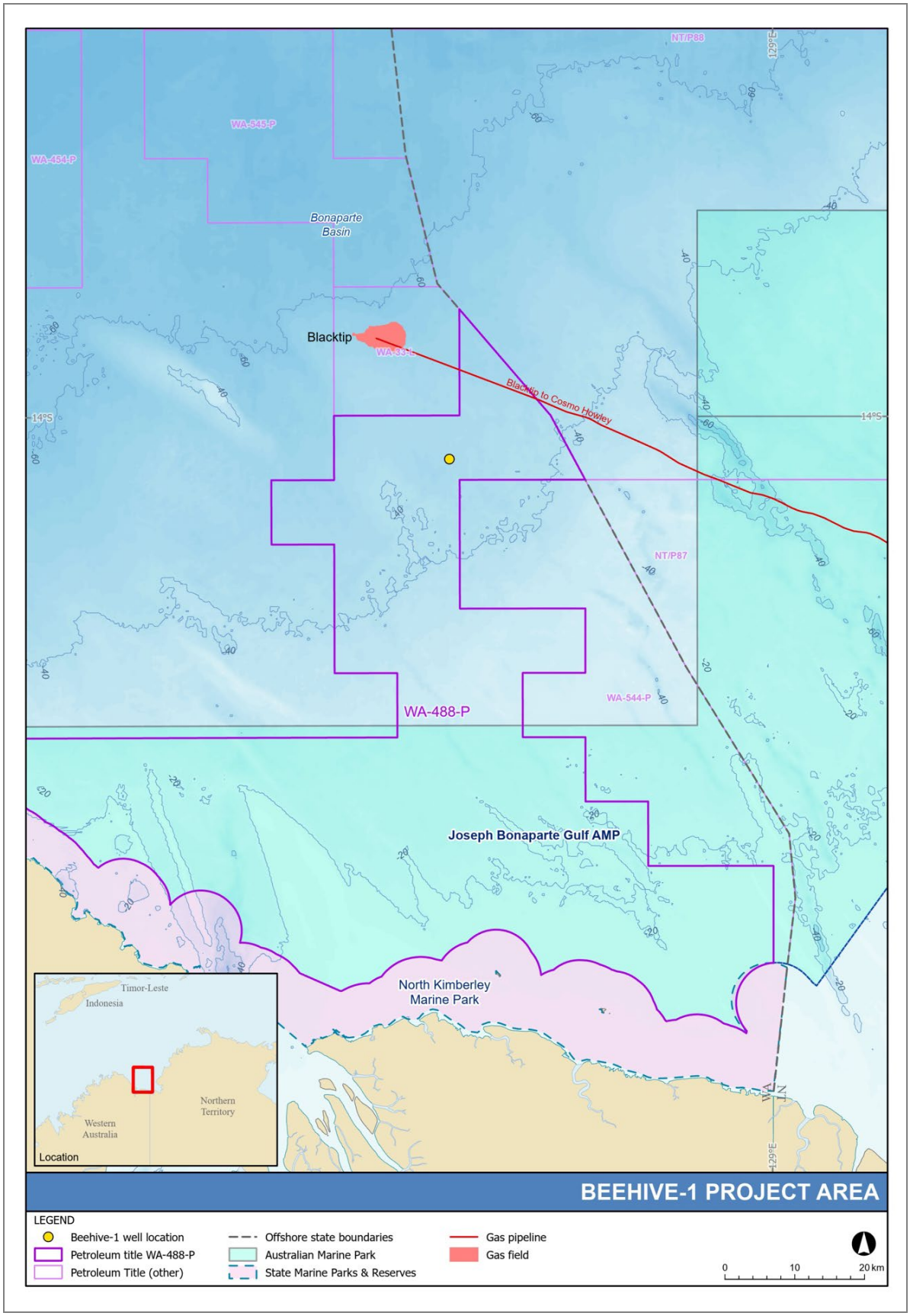


Figure 2.1. Location of the Beehive-1 well in the Joseph Bonaparte Gulf

2.4. Reservoir Characteristics

EOG is targeting the Sunbird (primary) and Tanmurra (secondary) formations. There are numerous large gas discoveries in the region close to Beehive. These are tied back to the Permian, gas-prone source rocks. Although the Lower Carboniferous oil-prone source rocks could be in the present-day gas window, filling the Beehive structure with gas, oil is the higher likelihood and therefore that is what EOG has selected as the basis for well blowout modelling.

EOG narrowed down oils in the region with a similar API to be Jabiru, Puffin, Mutineer-Exeter and Legendre crudes (all of which have APIs between 42° and 44°). Based on having an API closest to that expected at Beehive-1, together with being the most conservative in terms of the residual components, EOG has determined that Jabiru crude is the most analogous oil. Nearby oil samples from the Turtle and Barnett fields would have been ideal since they area sourced from the same petroleum system, but no crude assay information is available from those discoveries as those oils were only tested, not produced.

Table 2.3 presents the properties of the oil based on the crude oil assay for Jabiru. Jabiru is from a different petroleum system but has comparable oil properties to what is expected at Beehive. EOG has determined that the API gravity most likely for the Beehive-1 oil target is 43° (light crude).

Table 2.3. Compositional analysis of Jabiru crude oil

Element	Unit of measurement	Measurement
API gravity	°API	42.3
Specific gravity	60°F	0.8143
Density @ 15°C	g/ml	0.8139
Total sulphur	wgt %	0.05
Flash point	°C	<15
Total nitrogen	ppm	170
Water content	Vol %	0.025
Pour point	°C	18
Wax content	wgt %	5.9
Wax melting point	°C	47
Viscosity @20°C	cST	3.694
Viscosity @40°C	cST	2.462
Asphaltenes	wgt %	0.45
Nickel	ppm	<0.5
Vanadium	ppm	<1.0
Mercury	ppm	<0.01

2.5. Drilling Operation

This section provides details on the drilling activity relating to the MODU, support vessels, helicopter and supply base for the activity.

2.5.1. MODU

The well will be drilled using a jack-up MODU (drill rig) (such as that shown in Photo 2.1, the *Noble Tom Prosser*). Jack-up MODUs are typically used for drilling in water depths of less than 150 m. The characteristics of jack-up MODUs are generally similar, regardless of which rig is used, and the following points describe jack-up MODUs:

- The MODU will be towed into position by support vessels.
- Once in the desired location and with the MODU stationary, the legs are lowered to be in complete contact with the seabed, the rig hull is raised +/-3 m draft and then zero air gap when rig stabilisation activities are conducted (pre-loading).
- When pre-loading activities are completed, the MODU raises itself approximately 20 m above the sea surface. At this point, the drilling derrick is cantilevered over the edge of the MODU in readiness for drilling. Figure 2.2 provides a simplified overview of this process.



Photo 2.1. The *Noble Tom Prosser* jack-up MODU

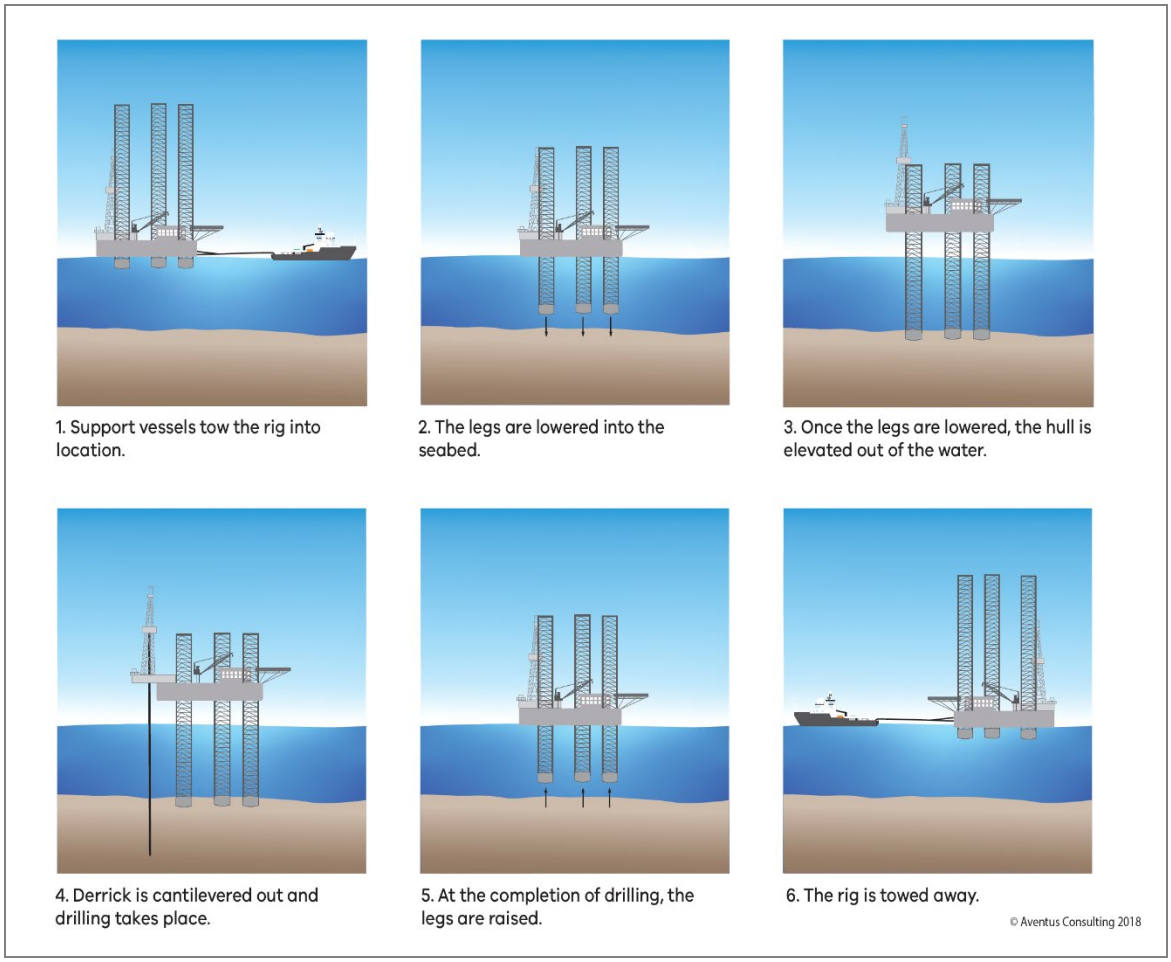


Figure 2.2. Simplified outline of the MODU positioning process

Environmental Credentials

EOG's screening of potential MODUs will involve ensuring that the MODU has, at a minimum, the following current and valid environmental credentials in place:

- International Oil Pollution Prevention (IOPP) certificate in accordance with International Convention for the Prevention of Pollution from ships (MARPOL) Annex I (enacted under the Australian Maritime Safety Authority (AMSA) Marine Orders Part 91, Marine Pollution Prevention – Oil);
- International Sewage Pollution Prevention (ISPP) certificate in accordance with MARPOL Annex IV (enacted under AMSA Marine Orders Part 96, Marine Pollution Prevention – Sewage);
- International Air Pollution Prevention (IAPP), Engine International Air Pollution Prevention (EIAPP) and International Energy Efficiency (IEE) certificates and Ship Energy Efficiency Management Plan (SEEMP) in accordance with MARPOL Annex VI (enacted under AMSA Marine Orders Part 97, Marine Pollution Prevention – Air Pollution);
- International Anti-fouling System certificate in accordance with the International Convention on the Control of Harmful Anti-fouling Systems on Ships 2008 (enacted under AMSA Marine Orders Part 98, Marine Pollution Prevention – Anti-fouling Systems);
- Shipboard Marine Pollution Emergency Plan (SMPEP) in accordance with MARPOL Annex I (enacted under AMSA Marine Orders Part 93, Marine Pollution Prevention – Noxious Liquid Substances); and

- Shipboard Garbage Management Plan (GMP) in accordance with MARPOL Annex V (enacted under AMSA Marine Orders Part 95, Marine Pollution Prevention – Garbage).

EOG will arrange for an inspection of the MODU (e.g., condition survey, hazardous area and equipment survey, Blowout Preventer (BOP) and control system acceptance) by an independent MODU inspection contractor to ensure that the MODU is in good operating order. In addition, EOG will also conduct its own audit of the contractor's HSE management systems and pre-drilling inspection against the EP commitments to ensure that systems and processes meet legislative and activity requirements.

Regulatory Jurisdiction

The MODU is considered part of a 'petroleum activity' (as defined by Regulation 5 of the OPGGS(E)) while within the operational area and therefore subject to the OPGGS Act. While on location, hydrocarbon spills to sea from the MODU will be combatted in accordance with the MODU's SMPEP and the activity-specific OPEP (99616-2022-Beehive#1-OPEP-RevA).

An application for a temporary PSZ (an area encompassing a 500 m radius) around the MODU will be submitted to NOPSEMA to cover the duration of drilling. When the MODU is outside the gazetted PSZ (e.g., on tow to or from location) but within Australian waters, it comes under the regulatory jurisdiction of the *Navigation Act* 2012 (Cth), which is administered by AMSA. Accordingly, this EP does not cover MODU activities while outside the PSZ.

2.5.2. Support Vessels

Typically, two support vessels will be required to assist the MODU; however, this EP accounts for up to four (used for towing, equipment and material transfers, standby operations and emergency response). The support vessels are yet to be contracted but are usually offshore multiple purpose or anchor handling vessels.

Equipment and material transfers may include, but are not limited to, crew supplies, hydrocarbons (diesel, engine oil, hydraulic fluids, grease, etc.), bulk drilling products, MODU and drilling equipment and parts, and waste. MODU cranes will be used for transfers between the MODU and support vessels.

Bulk products will also be transferred via hose from the support vessels and the MODU. Such products include drilling fluids and solids, brine, drilling water, cement and fuel oil (diesel).

At least one support vessel will remain on standby within a short distance of the MODU. This is to ensure that the 500 m PSZ around the MODU is maintained, and to provide support in the event of an emergency or unplanned event (e.g., spills to the marine environment).

Support vessels will not anchor within 500 m of the MODU but may anchor in the permit area during the activity. No at-sea refuelling of support vessels will take place within the operational area.

Environmental Credentials

As part of the Invitation to Tender process, an initial screening of potential vessels will be conducted to ensure they have, at a minimum, current and valid environmental credentials that are the same as for the MODU described previously.

Regulatory Jurisdiction

The support vessels are considered part of the 'petroleum activity' while they are within a 500 m radius of the MODU (the PSZ). While a support vessel is located within this area, hydrocarbon spills to sea from the support vessels will be combatted in accordance with the vessel SMPEP and/or the activity-specific OPEP (depending on the size of the spill).

When the support vessels are outside the PSZ (e.g., steaming to or from location, or holding position outside the PSZ) and remain within Australian waters, they come under the regulatory jurisdiction of the *Navigation Act* 2012 (Cth), which is administered by AMSA. Accordingly, this EP does not cover activities performed by the support vessels while outside the PSZ.

The 500 m radius PSZ limit has been selected because within this zone, the support vessels must comply with the MODU operating procedures as detailed in the MODU's Facility Safety Case. Outside of this zone, the support vessels operate as trading ships as defined in Section 6(1) of the *Navigation Act* 2012 (Cth), and the combat of hydrocarbon spills is the responsibility of the vessel operator and AMSA in line with the National Plan for Maritime Environmental Emergencies (NatPlan) (AMSA, 2020).

2.5.3. Aviation Support

Helicopters will be used primarily for crew change and medical evacuation, and occasionally equipment and material transfers. Helicopter flights will occur several times a week dependent on the progress of the drilling program and logistical constraints. Refuelling of helicopters may take place on the MODU.

Regulatory Jurisdiction

As with the support vessel, a helicopter is considered part of the 'petroleum activity' while it is within the 500 m radius PSZ around the MODU. This EP does not cover activities performed by the helicopters while outside the PSZ.

At all times, helicopter operations come under the regulatory jurisdiction of the *Air Navigation Act* 1920 (Cth), Civil Aviation Safety Regulations 1998 (Cth) and the Federal Aviation Regulations, which are managed by the Civil Aviation Safety Authority (CASA).

2.6. Pre-drilling Geophysical Activities

As outlined in Chapter 2 of the NOPSEMA-accepted Beehive Pre-Drill Seabed Assessment (PDSA) EP (996161-2022-Beehive#1-PDSA-EP-Rev2), there is the potential that some geophysical activities may need to be repeated immediately prior to MODU mobilisation. This would likely be limited to side-scan sonar and specifically excludes two-dimensional (2D) shallow seismic surveying.

The purpose of this additional site clearance survey would be to reconfirm the absence of seabed hazards and meet the warranty requirements of the MODU owner. If this additional site clearance survey is required after the end of August 2022, it is included in the scope of this EP. Alternatively, a Remotely Operated Vehicle (ROV) may be deployed from one of the support vessels or from the MODU prior to jacking up to undertake the site clearance survey to meet the MODU owner's warranty requirements.

In accordance with Regulation 56 of the OPGGS(E), EOG refers the reader to following sections of the PDSA EP (available here) to describe the possible investigations that may take place:

- Section 2.4 – description of geophysical investigations (excluding 2D shallow seismic); and
- Section 2.7 – description of typical vessels.

Any geophysical activities required immediately prior to the MODU mobilisation will occur within the same activity area as that outlined in Section 2.1 of the PDSA EP, which includes this activity's operational area.

2.7. Drilling Program

The Beehive-1 well will be drilled as a vertical well to target the Sunbird (primary) and Tanmurra (secondary) formations.

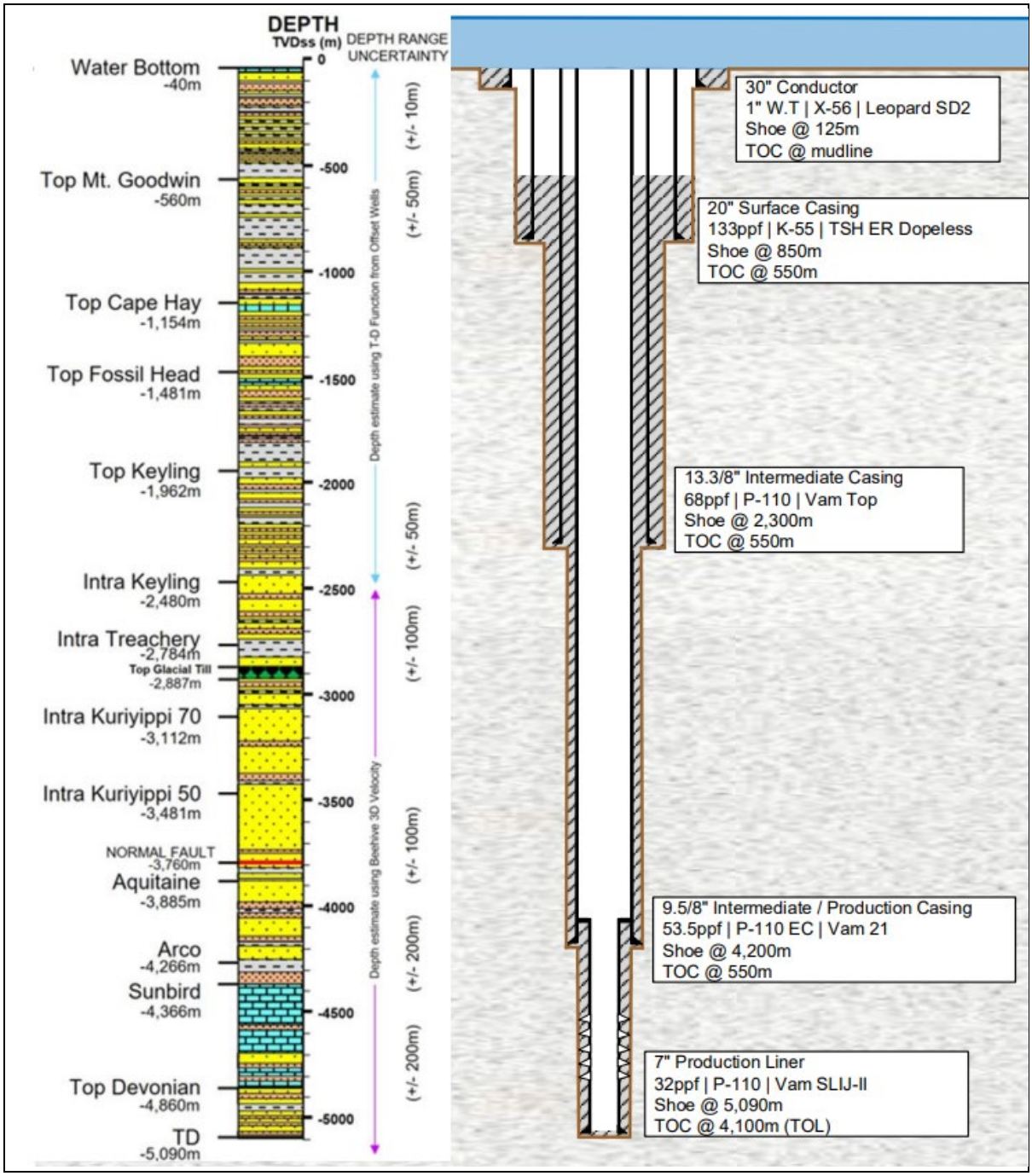
The well design includes drilling a conductor hole (and run conductor) and surface hole section (and run surface casing). The surface wellhead and BOP will be installed and tested before the well is drilled to total depth (TD). The planned TD is approximately 5,090 m total vertical depth subsea (TVDSS), however, the TD may be less or more depending on the geology and operational issues.

The following phases describe the planned drilling activity:

- Move the MODU to location, position MODU, pre-load and jack-up to operational elevation;
- Drill conductor hole and run conductor;
- Drill surface hole section;
- Run and cement surface casing;
- Install surface wellhead and BOP;
- Perform pressure test;
- Drill intermediate hole section(s);
- Run and cement intermediate strings;
- Drill remaining sections to well TD;
- Run well evaluation program (wireline logging, sidewall cores, formation testing, vertical seismic profiling [VSP], possibly a DST);
- Plug and Abandon (P&A) the well; and
- Demobilise the MODU.

The prognosed formation tops, depth uncertainties and lithological descriptions for Beehive-1 are illustrated in Figure 2.3. Note all depths are relative to mean sea level (MSL). This geological prognosis has been used to ensure the proposed well design achieves the evaluation objectives of the target formations and mitigates the potential formation-related drilling risks per the offset well experience.

Table 2.4 describes the notional Beehive-1 design.



Note: Cement tops are notional.

Figure 2.3. Beehive-1 planned well design

Table 2.4. Notional Beehive-1 design

Well section	Description
36” (914 mm) hole 30” (762 mm) conductor	A 36” hole will be drilled and 30” diameter, 1.0” wall thickness, X-56 conductor will be set approximately 125 m below the mudline in accordance with offset well design. It is planned to cement the 30” conductor to the seabed using an inner drill pipe string and tag in sub.
26” (660 mm) hole 20” (508 mm) surface casing	Section TD in the 26” hole section is planned to be in the Mt Goodwin shale at 855 m MSL. The shoe depth will also provide sufficient shoe strength for drilling to the next casing point. 20” casing will then be set ~5 m off bottom and cemented in place with the BOPs installed thereafter. Based on the shallow hazards analysis commissioned by EOG, encountering shallow gas to this shoe depth has been assessed as low risk.
17½” (444 mm) hole 13⅜” (340 mm) intermediate casing	The 13⅜” shoe is planned to be set within the Keyling formation at 2,300 m MSL. Section TD is based on pushing the 13⅜” shoe as deep as possible, maximising shoe strength to circulate out any overpressure kick in the 12¼” hole section with the next casing point planned to be within the anticipated overpressure.
12¼” (311 mm) hole 9⅝” (244 mm) intermediate/ production casing	The 12¼” hole section will be drilled from the 13⅜” casing shoe to the 9⅝” casing point towards the base of the Aquitaine formation.
8 ½” (216 mm) hole to TD 7” (178 mm) production liner	The 8½” hole section will be drilled from the 9⅝” casing shoe to planned well TD of 5,090 mRT (metres below rotary table) with a +/-200 m depth uncertainty. In a success case, a 7” production liner with a +/- 100 m liner lap is planned to facilitate DST operations. Pip tags may be included in the casing as a reference point for the TCP string.
Contingency: 6” (154 mm) hole 4½” (114 mm) production liner	In the event the 9⅝” casing is set early and the 7” liner is set as a drilling liner above the Sunbird Formation, the well will then be drilled to TD in 6” hole. In a success case, a 4½” production liner will be run to facilitate DST operations. A 6” contingency will also enable drilling to planned TD to evaluate the Tanmurra secondary target if it evidently becomes beneficial to set the 7” liner shallower.

2.7.1. Drilling Contingencies

Should drilling difficulties be experienced meaning the well cannot progress, a contingency option exists to cement up the existing hole above the trouble zone and side-track drill the well around the problem. Side-track drilling would only be exercised should drilling difficulties be experienced; this is not considered a new stage of the petroleum activity. A contingency liner is planned to mitigate some possible downhole problems should the need arise.

These activities may require an increase in the excavated rock volume (i.e., cuttings), drilling fluids and cement consumed.

2.7.2. Drilling Fluids and Cuttings

Drilling fluids (also referred to as drill muds) will be used during the drilling program to provide a range of functions, including:

- Control of formation pressures (i.e., providing hydrostatic head to prevent influxes and providing wellbore stability);
- Transport of drill cuttings out of the hole to the MODU;

- Maintenance of drill bit and assembly (i.e., lubrication, cooling and support); and
- Sealing of permeable formations to prevent formation invasion.

Drilling Fluid Program

Only water-based mud (WBM) will be used for the well.

The conductor hole section will be drilled using seawater and pre-hydrated gel (PHG) sweeps to clean the hole, and hole displaced to PHG to provide stability for running the conductor. This fluid will exit the well at the seabed while drilling the hole and installing the conductor casing. As with the drilling fluids, cuttings for the conductor hole section will exit the wellbore at the seabed.

Once the conductor casing is installed, and a closed circulating system is established, the remainder of the well will be drilled with WBM systems, as outlined in Table 2.5. WBM will be discharged from the MODU at the sea surface.

Cuttings for the remaining hole sections to TD will be discharged at sea level after being removed from the WBM system through the solids control system. The solids control system comprises shale shakers, and if required to remove ultra-fine solids in the recovered drilling fluid, centrifuges.

Aqueous-based lost circulation material (LCM) will be available to pump should downhole losses occur.

The selection of drilling fluids to be used during the drilling program is undertaken through an evaluation of the technical, safety and environmental attributes. A well-specific Drilling Fluid Program will be prepared by the drilling fluids contractor and endorsed by LPM and EOG prior to spud.

The Drilling Fluid Program will contain details of the well data, drilling fluid-related risk assessment, load out list, logistics plan, execution plan and procedures. This Drilling Fluid Program will be implemented by the wellsite mud engineers (24 hr coverage).

The calculated volumes of drill cuttings to be generated and drilling and completion fluid solids discharged are outlined in Table 2.5.

Drill Fluid Additives

Seawater or drill water is the primary constituent of drilling fluids. Inert drilling fluid additives are added to the seawater or drill water to form a WBM. The WBM additives (by name/brand and volume) likely to be used in the drilling program, and their toxicity ratings, are not available at this stage. However, the key additives used in WBM are xanthum gum (viscosifier), bentonite (viscosifier) and barite (weighting agent), which are all inert substances (they have no toxicity, see 'Drill Fluid Toxicity' section).

Drill Fluid Toxicity

In the absence of Australian standards (AS) regarding the suitability of drilling mud chemical additives, the Offshore Chemical Notification Scheme (OCNS) is used as a basis for selecting environmentally acceptable chemicals in the Australian offshore petroleum industry. The OCNS manages chemical use and discharge by the United Kingdom (UK) and Netherlands offshore petroleum industries. The scheme is regulated in the UK by the Department of Energy and Climate Change using scientific and environmental advice from the UK's Centres for Environment, Fisheries and Aquaculture Science (CEFAS) and Marine Scotland.

Table 2.5. Estimated drilling cuttings and mud solids discharge volumes for Beehive-1

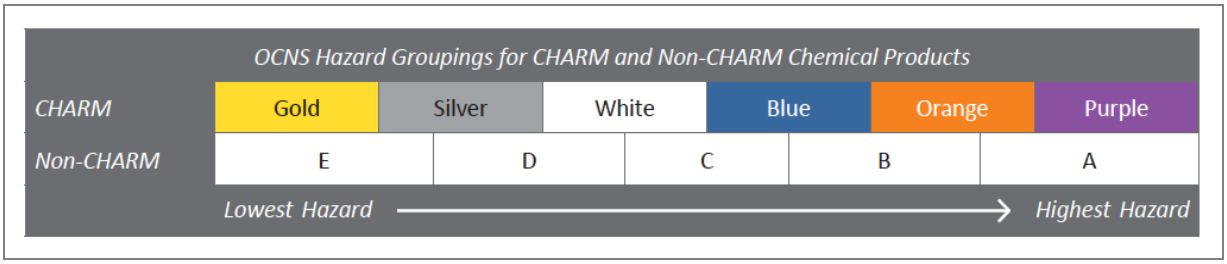
Bore diameter (inches)	Well interval	Cuttings	Mud solids		Discharge duration (days)
		Volume discharged (m^3)	Type	Volume discharged (m^3)	
36”	Conductor hole	80.4	Seawater & sweeps	19.5	0.2
26”	Surface hole	360.1	Gel/polymer WBM	75.0	1.2
17½”	Intermediate hole	322.9	Potassium chloride (KCl) WBM	81.3	2.4
12¼”	Production hole	172.3	High performance WBM	32.7	5.7
8½”	Production liner	29.7		8.8	3.1
	Mud solids discharged at sea surface at well completion			53.9	0.2
	Total	**965.4**		**271.2**	**12.8**

The OCNS uses the Harmonised Mandatory Control Scheme (HMCS) developed through the Oslo-Paris (OSPAR) Convention 1992. This ranks chemical products according to Hazard Quotient (HQ), calculated using the Chemical Hazard and Risk Management (CHARM) model. The CHARM model requires the biodegradation, bioaccumulation and toxicity data of the product to be provided.

Under the OSPAR Convention, organic-based compounds used in production, completion and workovers, drilling and cementing are subject to the CHARM model. The CHARM model calculates the ratio of the ‘Predicted Effect Concentration’ (PEC) against the ‘No Effect Concentration’ (NOEC) expressed as a Hazard Quotient (HQ), which is then used to rank the product. The HQ is converted to a colour banding to denote its environmental hazard, which is then published on the Definitive Ranked Lists of Approved Products (by the OCNS on its website). Gold has the lowest hazard, followed by silver, white, blue, orange and purple (having the highest hazard).

Products not applicable to the CHARM model (i.e., inorganic substances, synthetic-based muds (SBM), hydraulic fluids or chemicals used only in pipelines) are assigned an OCNS grouping A – E, with ‘A’ having the greatest potential environmental hazard and ‘E’ having the least. Products that only contain substances termed PLONORs (Pose Little or No Risk to the environment) are given the OCNS ‘E’ grouping (Figure 2.4). Data used for the assessment includes toxicity, biodegradation and bioaccumulation.

EOG will specify in the drilling fluid tender that only chemicals highly ranked under the OCNS rating system (i.e., ‘Gold’ or ‘Silver’ [CHARM] and ‘E’ or ‘D’ [non-CHARM], or equivalent) may be used in the drilling fluid design. Where a chemical has not been ranked under OCNS, the drilling fluids contractor will conduct a ‘pseudo rating’ using toxicity and environmental data for the individual substances of a product. The rating is conducted following the hazard assessment process outlined by CEFAS for the OCNS scheme (link). This will aim to understand the potential environmental impacts that may occur from discharge of the chemical. EOG will provide final approval for use of chemicals with those that have been risk assessed by the contractor.



Source: NOPSEMA (2015)

Figure 2.4. Illustration of hazard ranking bands for chemical products classified under the OCNS

Chemical Substitution

Chemicals that are hazardous to the marine environment are subject to substitution warnings under the HMCS. The UK follows and applies the OSPAR harmonised pre-screening scheme and complies with registration, evaluation and authorisation of chemicals (REACH) recommendation to replace chemical substances identified as candidates for substitution. These substances are flagged with a substitution warning on the product template.

CEFAS recommends that during the selection of chemical products, operators consider the magnitude of their Risk Quotient (RQ) and the presence of hazardous substances and encourages operators to select products without a substitution warning. Chemicals that have a substitution warning will only be used if a justification for their use is provided, along with an assessment of the environmental impact from the chemical. EOG will provide final approval for use of chemicals with a substitution warning.

Chemical review process

LPM and EOG will review all chemicals nominated by the drilling fluids contractor against the Definitive Ranked Lists of Approved Products (current at the time) to ensure that only 'Gold' or 'Silver' [CHARM] and 'E' or 'D' [non-CHARM] rated chemicals are nominated and that none of the chemicals nominated have a substitution warning.

Where for technical reasons a chemical does not meet the requirements regarding its hazard rating or has a substitution warning in place, LPM and EOG will review and assess the chemical proposed to ensure environmental risks are reduced to ALARP and acceptable levels. This will be managed using LPM's Change Control Process (described in Section 9.8). The risk assessment will consider the chemical's end fate, volumes, concentrations and environmental impacts.

Fluids Disposal

Where applicable, drilling fluids will be recycled between sections. Between the 17½" and the 12¼" hole sections, mud will be transferred from one section to the next.

At the end of the drilling program, any drilling fluid (mud and brine) remaining in the mud tanks will be discharged overboard. This volume will be minimised through careful mud management. Any dry, unopened sacks of chemicals left over at the end of drilling will be left on board for the next operator to use or returned to shore. The decision on the end fate of leftover materials will be documented to ensure the final decision is environmentally acceptable. The decision list in order of preference is provided in Table 2.6.

Table 2.6. End fate of unused brines, powders and bulks

Order of preference	End Fate	Justification
1	**Retain for use by EOG** The stock may be transferred to a vessel for storage until it can be used by LPM/EOG on a subsequent well as the MODU is planned to go to another operator at the end of this activity.	This will depend on the ability to transfer the material(s) to a vessel. For example, piping may not be adequate for transferring of some materials and powder may be difficult to transfer if it has been dispensed into holding tanks on board to MODU already.
2	**Sell to next operator** If the stock cannot be used by EOG, then it may remain on board the MODU for use by the next operator.	The implementation of this option is dependent on demand and commercial agreements.
3	**Transfer to another MODU** If the stock cannot be used by the next operator on the MODU, then it may be transferred to another operator for use on a different MODU.	The implementation of this option is dependent on demand and commercial agreements, and the feasibility of transfer of the materials into a suitable transfer vessel for transport elsewhere.
4	**Transfer to shore for use by supplier or onshore disposal** Stock may be returned to shore for use by the supplier or for disposal.	This will depend on the ability to transfer the material(s) to a vessel. For example, piping may not be adequate for transferring of some materials and powder may be difficult to transfer if it has been dispensed into holding tanks on board to MODU already.
5	**Overboard disposal** Powder would be discharged as a slurry, brines would be discharged as is.	Under normal circumstances, the remaining materials will be minimal (<100 m^3 of cement/barite/bentonite). The toxicity of the chemicals over boarded is low due to the chemical selection process adopted. Transport and transfers of dry bulks back to shore introduce costly technical requirements and significant additional HSE concerns and risks. The costs and risks are considered grossly disproportionate to the environmental benefit.

2.7.3. Cement Program

Cementing operations will be undertaken to provide zonal isolation between different formations as required, maintain well integrity, provide structural support of the casing and to set a temporary suspension plug or P&A plugs to abandon the well. Cement will provide the main barrier for isolation of the wellbore from reservoir conditions whether the well is P&A or temporarily suspended. The final cement plan will be confirmed once a cement service provider has been selected, though it is currently planned that the first three sections of the well will use Class G or high-temperature blend (HTB) cement, while the lower two sections will use a HTB cement.

The notional cement program is outlined below:

- 30” conductor – the conductor will be cemented to the seabed with any returns discharged directly to the seabed. It is planned to pump 100-200% excess while cementing the conductor in

place, however efforts will be made to reduce this by stopping the cement pumping operations once cement returns are observed at the seabed.

- 20” surface casing – the surface casing is planned to be cemented at least 300 m above the casing shoe, with returns monitored at surface. It is planned that 50-100% excess cement will be pumped during this cement job to account for hole washout and losses that may occur during the cementation job.
- 13⅜" intermediate casing – the 13⅜" casing is planned to be cemented to ±550 m MSL, with returns monitored at surface. It is planned that 50% excess cement will be pumped during this cement job to account for hole washout and losses that may occur during the cementation job.
- 9⅝” intermediate/production casing – the 9⅝” casing is planned to be cemented back to ±550 m MSL, with returns monitored at surface. Top of cement for this casing string may change through the well design phase. It is planned that 10-25% excess cement will be pumped during this cement job to account for hole washout and losses that may occur during the cementation job.
- 7” production liner – if run, the production liner will be cemented to the top of the liner for zonal isolation for the DST. Although a caliper log will be run, it is planned that 10% or more excess cement will be pumped during this cement job to account for losses that may occur during the cementation job.

Abandonment cement plugs will be set as required to safely temporarily suspend or P&A the well. The final abandonment program will ensure moveable hydrocarbons (if identified while drilling) are isolated in line with a NOPSEMA-accepted Beehive-1 Well Operations Management Plan (WOMP).

During cementing operations, surface cementing equipment and lines will need to be flushed, washed and cleaned with water to prevent hard setting. The residual cement and wash water will be discharged to sea after each cement job (see Section 7.7).

Cement spacer in well returns and residual surface tank volumes will also be discharged to sea during cementing operations.

Cement Disposal

Cement will be discharged overboard as part of the cement program, with only required cement mixed to ensure minimal wastage. There will be some excess cement discharged directly at the seabed during the cementing of the conductor casing string. Although cementing details are yet to be finalised, planning 100-200% excess is common for the conductor casing cement job to account for losses and over-gauge hole conditions. Once quality cement returns are detected at the seabed, cement mixing will cease and displacement will commence, with a minimal quantity of cement being deposited at the seabed during the displacement. Table 2.7 presents the estimated discharge volumes associated with the cement program.

At the end of the drilling program, and assuming the MODU moves directly to another operator, remaining dry cement will be retained on board for the next operator. Failing that, the cement will be discharged overboard as a slurry.

Table 2.7. Estimated cement discharge volumes

Cementing activity	bbl	m^3
Discharge of cement slurry during system testing.	50	8
Dry cement from the bulk tanks that may be blown overboard during windy conditions in preparation for the cement job.	30-60	5-10
Washing the cement unit and flushing cement hoses to prevent curing (for each of the five cementing operations). This is usually done with seawater or compressed air after every cementing operation (5 x casing strings, 3 x cement plugs).	20 for each cementing operation, total of 160	3 each (total of 24)
Cement overspill at the seabed during cementing of the top hole (30") cement job.	220	35
Total	**460-490**	**72-77**

2.7.4. Well Evaluation

Well evaluation involves the collection of data on the well and surrounding formation. Downhole formation evaluation will be carried out via Logging While Drilling (LWD)/Measurement While Drilling (MWD) and wireline logging, which may include VSP. No conventional coring is planned. Formation evaluation involving DST operations will include flaring at surface.

Radioactive sources used in downhole tools for logging purposes will be managed in accordance with the MODU Safety Case so that occupational health and safety risks to people are managed to an acceptable and ALARP level.

Further details on these well evaluation activities are provided herein.

Measure/Logging While Drilling

As part of the drilling operation, the drilling bottom hole assembly (BHA) will incorporate MWD and LWD sensors. The MWD tools will provide a directional survey log of the wellbore, plus key drilling dynamics parameters while drilling.

The LWD tools will be utilised to gather key geological parameters while drilling to inform progress and anticipate upcoming intervals for logging operations.

MWD/LWD logs may include, but are not limited to:

- Direction survey;
- Pressure, temperature and vibration;
- Resistivity, gamma ray;
- Neutron and density; and
- Sonic response.

Wireline Logging

Conventional wireline logging operations will be conducted in both the 12¼" and 8½" holes if feasible. The objective of the wireline logging is to gather more detailed reservoir information than is available via LWD, carry out sampling of the Sunbird target, improve depth control of seismic and prove up rates of various lithologies for the potential drilling of a future Beehive-2 well. A well test program will be prepared.

Wireline logs may include, but are not limited to:

- Quad combo (resistivity, gamma ray, neutron, density);
- Image Log and Dipole sonic;
- Formation pressure testing and fluid sampling;
- Nuclear magnetic resonance;
- Rotary and percussion sidewall cores; and
- Cased hole - cement evaluation.

The primary objective of the cased hole logging program will be to acquire cement bond logs to confirm wellbore isolation and cement integrity. As a contingency, further logs may be conducted in the cased hole sections resulting from tool failures in the open hole logging operations.

Vertical Seismic Profiling

As a subset of the wireline logging operation, EOG intends to conduct zero offset VSP. The VSP will enable a high-resolution 2D image of the well and surrounding area to be obtained and improve tie-in to seismic survey data for the area. The sound source will be held over the side of the MODU by the crane. The notional VSP details are as outlined in Table 2.8.

Table 2.8. Notional VSP details

Parameter	Details
Number of airguns	4
Sound source volume	150 cubic inches (cui) (for a total of 600 cui)
Pressure	2,000 psi
Number of shots	150
Source effort	13.8 Bar-m
Duration	4 hours active acquisition time within the total VSP program
Depth below sea level	4 m

DST Operations

In a success case, a well clean up flow and well production test(s) will be conducted after running the DST string. Each well test is expected to take approximately 3-5 days, with all flaring operations via high efficiency well effluent burner heads. Multiple zones may be tested, but the decision on which zones to test cannot be made until after logs are evaluated.

The well clean up flow will not be continuous during this period, as there will be shut-ins between the flows. An example of a single zone DST schedule would be less than 1 day flaring, followed by a half-day shut-in. This would then be followed by the longest period of flaring (approximately 1.5 days), and a longer shut-in, with another short (<0.25 day) period at the end. These periods may be adjusted as the data is analysed in real time.

Due to the carbonate formation, it may be necessary to perform a matrix acid stimulation of the perforated intervals. The acid stimulation treatments include acid, solvent and chemical treatments to improve the permeability of the near-wellbore formation, enhancing the productivity of a well. Acid

stimulation is a process of injecting a fluid into the formation, either an acid or solvent at pressures below the fracturing pressure, to improve the production or injection flow capacity of a well. In carbonates, acid stimulation creates new, highly conductive channels (wormholes) that bypass damage.

2.8. Plug and Abandonment

At the completion of drilling, the well will be P&A. This isolates the well and mitigates the risk of a potential release of hydrocarbons (assuming a success case) to the environment. The P&A operations involve setting a series of cement plugs within the well, including above and between any hydrocarbon bearing intervals. LPM's standards for P&A align with the *Well Decommissioning Guidelines* (Oil & Gas UK, 2018).

The possible final P&A condition of the well is as per the schematic in Figure 2.5 (in the case of a dry hole, where a production liner is not run).

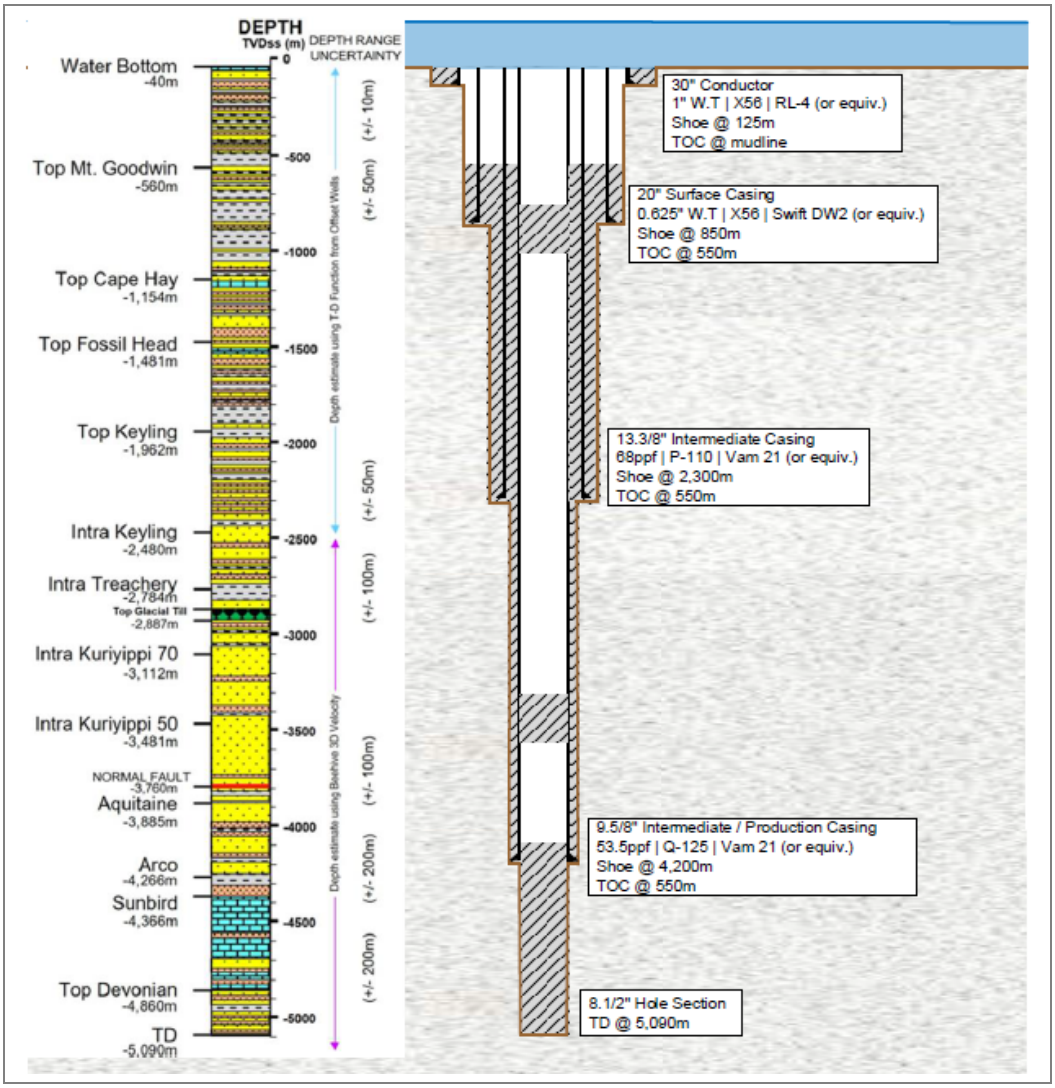


Figure 2.5. Conceptual P&A schematic (dry hole case)

The final abandonment plan will be confirmed once the well has been drilled and logged to ensure that the barriers are located at the necessary depths. The casing strings will be cut 1-3 m below the mudline and pulled back to surface and the depth of the cut will be measured. In so doing, all

infrastructure and equipment will be removed from the seabed such that nothing is left behind when the MODU departs the location. This meets the requirements of Section 572 ('Maintenance and removal of property etc. by titleholder') of the OPGGS Act.

2.9. Well Control

Well control is the process implemented to prevent a blowout from occurring. Primary well control is provided by the hydrostatic pressure of the drilling fluid having sufficient density to overcome any bottom hole pressure. Many steps are taken to ensure proper density of the drilling fluid is always maintained. Constant monitoring of the mud returns and pit levels help ensure that in the event the bottom hole pressure ever exceeds the hydrostatic pressure of the mud and the well tries to flow formation fluids (kick) into the wellbore, the drilling crew will shut in the BOPs (the secondary control). By shutting in the BOPs, the well flow stops and steps are taken to increase the mud density to overcome the bottom hole pressure.

In addition to well control procedures implemented by the drilling crew, front end engineering design with input from EOG's geological team will design the well such that sufficient kick tolerance is managed from top to bottom of the hole while drilling. This is to ensure maximum anticipated surface pressure is known ahead of time and that properly designed surface equipment is used for the well construction.

2.9.1. Blowout Preventer

A BOP is a mechanical device designed to seal off a well at surface when required. The system is made up of a number of different types of closing mechanisms consisting of:

- Rams (opposing pistons that move horizontally across the top of the well, creating a seal around the drill string, casing or completion tubing);
- Blind shear rams that are capable of shearing drill pipe and sealing the wellbore; and
- Annular preventers (which deploy an elastomer donut-like device) can also be used to close off the well around various sizes of pipe.

A BOP rated to the maximum anticipated wellhead pressure will be installed, and pressure tested prior to deployment and upon initial latch-up with the wellhead.

Response to the Loss of Well Control

The following outlines the steps that would initially be taken in response to a well kick:

- If secondary controls are required, an annular preventer or pipe ram is closed to prevent any further influx from the reservoir into the well if there is pipe in the hole (otherwise blind/shear rams are closed if there is no pipe in the hole).
- If there is pipe in the hole, the pipe rams will be closed (there are three for redundancy).
- Lastly, the blind shear rams can shear the drill pipe (if required) and seal the well completely.

The BOP will only be removed once suitable barriers are in place and are tested. This will occur:

- After setting the cements plugs in the well, if the well is abandoned; and
- For any unplanned BOP maintenance or weather suspension reasons.

The BOP design is based on API standards, best practice and anticipated formation pressures. This is discussed in detail in the WOMP.

2.10. Response to a Loss of Well Control

The nature of the Loss of Well Control (LoWC) leading to a hydrocarbon release will determine the type of source control activities required and the duration of the response. Source control activities evaluated for Beehive-1 include:

- Containment; and
- Relief well drilling.

In the event of a blowout during drilling, reservoir modelling indicates that the worst-case discharge would be released through the 8½" (216 mm) open hole (no obstruction in the well) from a net pay zone of 330 m with zero mechanical skin factor for a period of 77 days (the time required to source a MODU, drill a relief well and kill the well). The oil and gas flow rates are provided in Table 2.9. The flow rates and volumes have been calculated by EOG based on the following guidance:

- SPE Technical Report Calculation of Worst-Case Discharge (WCD) (SPE-174705-TR, 2016);
- NOPSEMA Information Paper Source control planning and procedures (N-04750-IP1979, June 2021c); and
- NOPSEMA Guidance Note Oil Pollution Risk Management (N-04750-GN1488, July 2021b).

The global upstream petroleum industry has developed and continues to advance innovative technologies to respond to a well blowout.

Table 2.9. Predicted worst-case flow rates and volumes

Flow rates and release volumes	Release volume
Oil	
Initial oil flow rate (bbl/day) (m^3/day)	72,572 (11,539)
77-day oil average oil flow rate (bbl/day) (m^3/day)	64,270 (10,219)
77-day oil cumulative release volume (MMbbl) (m^3)	4.9 (786,858)
Gas	
Initial gas flow rate (mmcf/day)	131
77-day average gas flow rate (mmcf/day)	116
77-day gas cumulative release volume (Bcf)	8.9
Water	
Initial water flow rate	N/A
77-day average water flow rate (bbl/day)	N/A

EOG has a contract in place with a well control service provider (Wild Well Control) that allows it to access personnel and equipment to respond to a well control response anywhere in the world. EOG has also a contract in place with Oil Spill Response Limited (OSRL) (which will include coverage for Australia) and has in place a contract with the Australian Marine Oil Spill Centre (AMOSC) for hydrocarbon spill response resources that allows EOG to access personnel and equipment to respond to a hydrocarbon spill.

2.10.1. Capping and Containment

A capping stack is a piece of equipment that can be placed over a blown out well and act as a cap. The purpose is to prevent the flow of hydrocarbons to the environment and thus establish a barrier to the flow of hydrocarbons to the ocean.

For this activity, a capping and containment approach is not feasible because these systems are designed for subsea wellhead applications and therefore not suitable for jack-up MODU surface stack systems (which will be used for Beehive-1).

2.10.2. Relief Well

A relief well is a longer-term response option to stop uncontrolled flow from a well (i.e., 'kill' a well) and to permanently abandon the well. A relief well is drilled to intersect the well that is flowing out of control to provide a conduit to pump high density fluid into the well, and thus stop well flow. EOG will execute its Relief Well Plan (RWP).

Relief Well Planning

A relief well requires the mobilisation of a suitable MODU and the drilling of an interception well through which the failed well can be killed and made safe.

The scope of activities involved with drilling a relief well is the same as drilling a standard well, though it would be a highly deviated well due to the need to drill from outside a safety zone. LPM is preparing a RWP as part of the Source Control Emergency Plan (SCERP) for Beehive-1. This plan:

- Describes industry guidelines relevant to relief well drilling;
- Describes the process in place to monitor for and rapidly source a suitable MODU; and
- Provides a relief well drilling program and schedule.

Further details on the RWP are provided herein.

Rig Specification & Provision for Procurement

The selection of a suitable MODU to undertake relief well activities will be based on the closest available unit that meets the criteria listed in Table 2.10. Given the water depth in the vicinity of the Beehive-1 location (~40 m), it is assumed only jack-up MODUs would be capable of undertaking the activities. Suitable jack-up MODUs working within the region (primarily in Australian waters) will be identified prior to the planned drilling window for Beehive-1.

Any relief well schedule will be driven largely by the rig mobilisation period. It is assumed that the most likely location of the jack-up MODU not contracted to drill Beehive-1 would be from the North West Shelf area, which is approximately 10-14 days mobilisation time away from the Beehive-1 location. It is expected that any ongoing operations can be safely suspended and the relief well MODU can be mobilised to the Beehive-1 location within the timeframe for the Safety Case Revision to be developed and accepted by NOPSEMA, assumed to be 24 days. The availability of suitable MODUs will continue to be monitored and their status updated within the RWP on a monthly basis to ensure any assumptions on the timely execution of relief well remain valid.

Table 2.10. Relief well rig specification

Parameter	Details
MODU type	Jack-up
Water depth	~40 m
Drilling depth rating	Minimum 6,000 m
Well control equipment rating	10,000 psi
Pumping capability	7,500 psi circulating system
Regulatory requirements	Australian Safety Case in place

Relief Well Construction and Long-lead Requirements

As per Beehive-1, a minimum 10,000 psi rating surface wellhead system configured for a 30" x 20" x 13⅜" x 9⅝" casing program and standard Oil Country Tubular Goods (OCTG) weights and grades (well loads expected to be very similar to Beehive-1) would be required for the purposes of executing a relief well. The relief well design is consistent with the original Beehive-1 well design setting 30" conductor, 20" surface casing and 13⅜" intermediate casing at the same TVDs. The final 9⅝" casing string will be set as deep as possible (~30 m above the intercept point) to provide the maximum formation fracture gradient for containing the dynamic kill whilst still also facilitating a positive alignment for penetrating into the target well.

The availability of standard long-lead equipment for the construction of the relief well has been identified as likely from local operator and/or vendor inventory and will be confirmed closer to the planned drilling window as planning for Beehive-1 progresses. High-level specification and means of provision of long lead and drilling equipment for executing a relief well for Beehive-1 is outlined in the RWP. Prior to spudding of Beehive-1, EOG will have in place access agreements to other operators' relief well contingency equipment (e.g., OCTG and wellheads) as required to ensure any assumptions on the timely execution of a relief well remain valid.

Relief Well Location and Trajectory

The relief well design assumes the surface location for a relief well would be approximately 1 km northeast/east/southeast from the primary Beehive-1 well location as shallow hazards appear to be present to the west based on data collected from the geophysical survey in 2022. Therefore, the preferred relief well location is currently eastward of the Beehive-1 well location. This will be confirmed/adjusted based on the information that will be obtained from the geotechnical investigations performed prior to the start of Beehive-1 drilling.

For the most likely scenario of a well blowout (i.e., in the 8½" hole) for the worst-case scenario (drill pipe above deepest casing shoe), the relief well is designed to set 9⅝" casing ~30 m prior to intersecting the Beehive-1 wellbore at the 9⅝" casing shoe at 4,250 m TVDRT. The relief well design is based on kicking off below the 13⅜" casing shoe at ~1,200 m TVDRT building at 2.0°/30 m to a maximum inclination of ~23°, allowing for wireline ranging tools to be run. Once the relief well is within ~50 m (centre to centre) from the target wellbore ~670 m (MD) above the planned interception point (start of locating phase), active ranging can begin to detect the target wellbore. After initial ranging, the tool will then be pulled out of the hole and directional drilling will continue until the next planned proximity ranging point, where again the ranging tool would measure the distance and direction to the original well. This process would continue with separation maintained so as to avoid intercepting the target well shallower than planned. The relief well trajectory during the tracking

phase is designed to drop at 2.0°/30 m, bypassing the target wellbore ~490 m TVD above the planned interception point. The relief well will continue to be drilled alongside the target wellbore maintaining a separation of ~10 m with ranging performed as required and the relief well turned to align with the blowout well intercept point. Once the relief well and the target wellbores are aligned ~30 m above the desired intercept point at the Beehive-1 9⅝" casing shoe, 9⅝" casing would be set before the relief well intercepts the blowout well with a closure angle of ~4.6°. The relief well trajectory is shown in Figure 2.6.

Relief Well Project Schedule

The RWP indicates it would take 77 days (11 weeks) to perform the well kill (including MODU mobilisation), as detailed in Table 2.11. The time estimate for drilling the relief well and well kill is 53 days.

AEP Mutual Assistance Agreement

The Australian Energy Producers (AEP) developed the Memorandum of Understanding for Mutual Assistance (known as the Mutual Assistance Agreement, MAA) that facilitates the transfer of a MODU between operations in the event of a drilling emergency that requires a relief well to be drilled.

EOG has signed up to the MAA.

2.11. Drilling Summary

The key drilling activity parameters are summarised in Table 2.12.

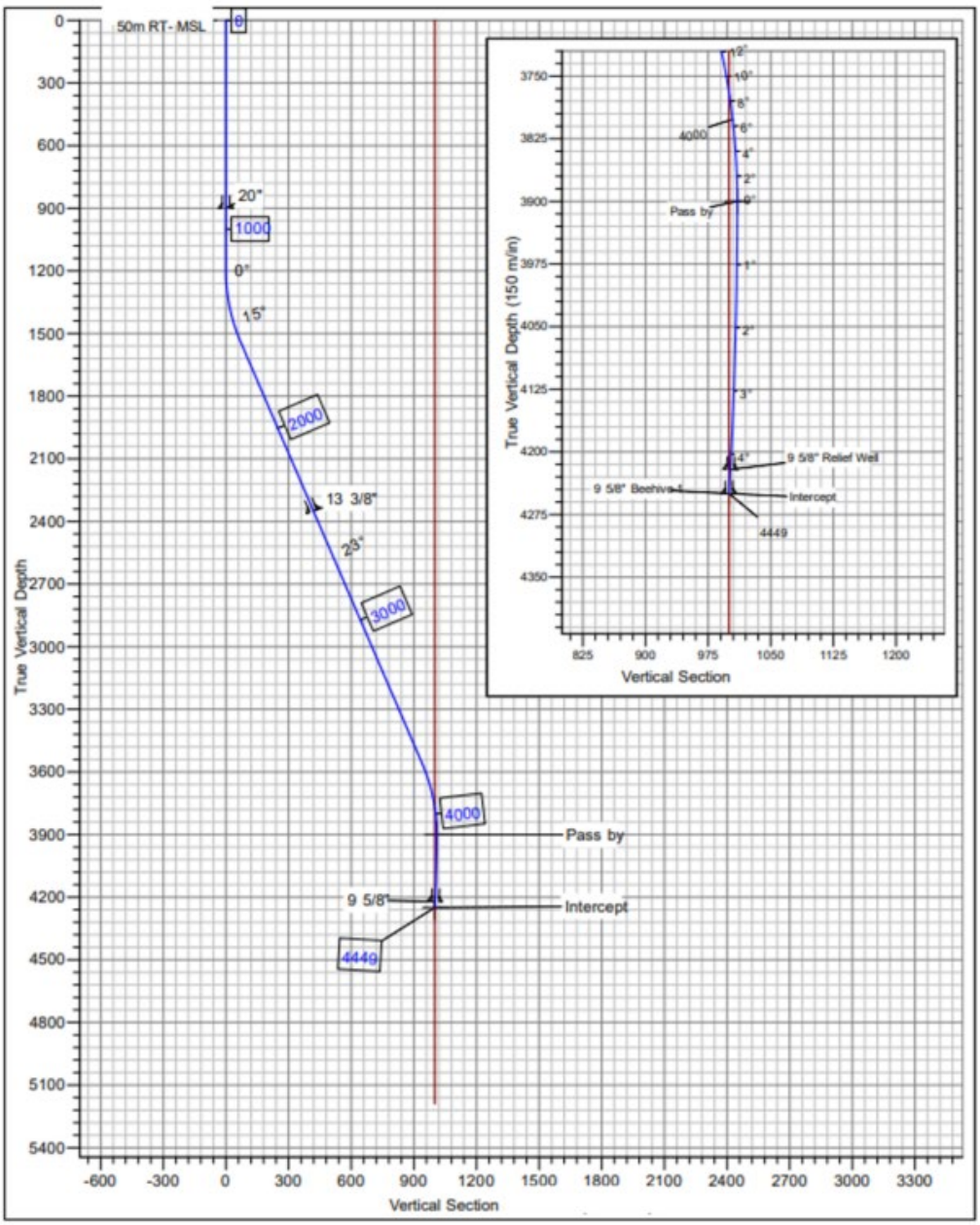


Figure 2.6. Relief well trajectory

Table 2.11. Relief well schedule

Activity	Duration (days)	Comments
Planning (prior to Beehive-1 drilling)		
Initial relief well planning	>3 months prior to spud	Relief well complexity assessment. Relief well location identification and initial design. MODU and long-lead equipment specification and identification. Signatory to AEP Memorandum of Understanding (MoU) and Operators equipment access agreements in place as required. Prepare RWP. Regional rig status update (monthly).
Execution (post-blowout)		
Suitable MODU identified	0-1	Provision for relief well aid is confirmed. Detailed relief well design is initiated.
Develop SCR	1-2	Meet NOPSEMA to discuss imminent SCR.
SCR submitted to NOPSEMA	2-16	
SCR review process	16-23	Dialogue with NOPSEMA to optimise assessment process.
MODU mobilised	20-23	Spud equipment loaded onto MODU. Specialised equipment mobilised.
SCR accepted by NOPSEMA	24	
Relief well drilling	24-77	Blowout is killed.
Total	**77**	

Table 2.12. Key drilling parameters

Parameter	Details
Location and timing	
Exploration permit	WA-488-P
Operational area	500 m radius PSZ around the MODU
Water depth	40 m
Start date (earliest)	1st of January 2024 (earliest), completed no later than 31st of December 2025
Duration of activity	Approximately 55-100 days
MODU and support services	
MODU	Jack-up, yet to be contracted
Support vessels	Two, yet to be contracted
Marine base	Yet to be decided, most likely from Darwin
Aviation support	Yet to be contracted
Drilling details	
Well depth	5,090 (+/- 200 m) MD/TVD-MSL
Drill cuttings volume (est)	965 m^3
Drilling fluid	WBM
Mud solids discharge volume (est)	271 m^3
Cement discharge volume (est)	72-77 m^3
Well evaluation	LWD, mud logging, electric line logging (including VSP), potential well test