Environment plan Appendix 7-4 ALARP assessment for loss of well control

Stromlo-1 exploration drilling program

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Table of contents

Page

1.0 ALARP assessment process 1
1.1 Regulatory context 1
1.2 ALARP workshops 1
2.0 Context and definitions 3
3.0 Assumptions and logistics arrangements 4
3.1 Permits for petroleum installations 4
3.2 Road transport in Australia 4
3.3 Air cargo transport to Australia 4
3.3.1 Adelaide Airport 4
3.3.2 RAAF Base Edinburgh 4
3.3.3 Sydney Airport 5
3.3.4 Melbourne Airport 5
3.4 Access to cargo aircraft 5
3.4.1 B747F 5
3.4.2 An-124 6
3.5 Customs clearance 6
3.6 Port Adelaide 6
3.7 Search and rescue (SAR) 7
3.8 Metocean conditions and impact on response timing for subsea operations 8
3.9 Debris clearance 9
3.10 SIMOPS – response time model 10
3.10.1 First 21 days of the response time model 11
3.10.2 Ship-to-ship transfer at sea 13
4.0 Control measures to reduce oil spill risk 14
4.1 Blowout preventer intervention by remotely operated vehicle 14
4.1.1 BOP intervention ALARP outcomes 15
4.1.2 BOP design and features ALARP considerations 16
4.2 Subsurface dispersant injection 18
4.2.1 Subsea dispersant injection having a contracted vessel and equipment on location (two to five days) 19
4.2.2 SSDI having a contracted vessel and equipment in Adelaide, picking up the equipment with a PSV (seven days) 20
4.2.3 Subsea dispersant injection using contracted vessel and equipment stored in Adelaide (nine days) 20
4.2.4 Subsea dispersant injection using contracted vessel and equipment by air from Singapore (nine days) 21
4.2.5 SSDI using subsea construction vessel from Singapore (23 days) 22
4.2.6 Subsea dispersant injection outcomes 23
4.3 Capping stack 26
4.3.1 WWC capping stack on rental on location (three to eight days) 26
4.3.2 WWC capping stack on rental stored in Adelaide (nine to 14 days) 27

4.3.3 WWC flyable capping stack using scheduled B747 (15 days) ... 28
4.3.4 WWC flyable capping stack from Singapore to Adelaide (21 days) ... 29
4.3.5 OSRL capping stack from Singapore by construction vessel (24 days) ... 30
4.3.6 Capping stack ALARP outcomes ... 31

4.4 Relief well ... 35
4.4.1 Rig drilling relief well in parallel with main rig at Stromlo-1 (44 days) ... 35
4.4.2 Rig on stand-by close to Stromlo-1 location (63 days) ... 36
4.4.3 Rig on stand-by east of Port Lincoln (68 days) ... 36
4.4.4 Main rig disconnects LMRP, drills relief well top-holes and relief well rig from North West Shelf (73 days) ... 37
4.4.5 Relief well rig from North West Shelf (88 days) ... 38
4.4.6 Rig from Singapore with Australian Safety Case (102 days) ... 39
4.4.7 Rig from Singapore without Australian Safety Case (149 days) ... 40
4.4.8 Relief well outcomes ... 41

4.5 Surface dispersant application ... 45
4.6 In-situ burning ... 47
4.7 Mechanical containment and recovery offshore ... 47
4.8 Nearshore containment and recovery ... 48
4.9 Shoreline response - protection and clean-up ... 49
4.9.1 Response need ... 51
4.10 Oiled wildlife response ... 53

5.0 ALARP assessment outcomes ... 56

6.0 References ... 65

Tables

Table 2.1 Cost / benefit matrix for ALARP assessment ... 3
Table 4.1 Estimated lengths of oiled shorelines accessible from land ... 49
Table 4.2 Summary extent of shoreline types and response levels for shorelines predicted to accumulate >10 g/m^2 oil over 189 days, based on the WCD129 greatest shoreline accumulation deterministic run ... 50
Table 4.3 Accumulation of weathered oil (in m^3) across shoreline types and response levels, based on the WCD129 greatest shoreline accumulation deterministic model run ... 50
Table 4.4 Evaluation of spill response strategies (ex. source control) ... 54
Table 5.1 Cost / benefit outcomes – spill response control ... 56

Figures

Figure 3.1 P50 and P90 values for time needed to perform operations limited by Hs of 3, 4 and 5 m and requiring a continuous weather window for 38 hours. Based on GROW12 hindcast data within the period 1979–2013. Duration is the sum of the actual time required to do the work and time waiting on weather ... 8
Figure 3.2 SIMOPS – response time model without debris clearance prior to capping ... 11
Figure 3.3 Response time model for the first 21 days – no debris clearance required ... 11

Figure 3.4 Response time model for the first 21 days – debris clearance required 13
Figure 3.5 Response time model for the first 21 days – platform support vessel picking up subsea dispersant injection equipment in Adelaide and debris clearance required prior to capping stack installation.....13
Figure 4.1 Blowout preventer Intervention by remotely operated vehicle ALARP evaluation 17
Figure 4.2 Subsea dispersant injection using contracted vessel and SSDI equipment stored on location (five days).....19
Figure 4.3 SSDI using a contracted vessel and equipment in Adelaide, picking up the equipment with a PSV (seven days).....20
Figure 4.4 Subsea dispersant injection using contracted vessel and SSDI equipment stored in Adelaide (nine days) 21
Figure 4.5 Subsea dispersant injection using contracted vessel and SSDI equipment by air from Singapore (nine days).....22
Figure 4.6 Subsea dispersant injection using subsea construction vessel from Singapore (23 days) 23
Figure 4.7 Subsea dispersant injection ALARP evaluation 25
Figure 4.8 WWC capping stack on rental stored on location (eight days).....27
Figure 4.9 WWC capping stack on rental stored in Adelaide (14 days) 28
Figure 4.10 WWC flyable capping stack using scheduled B747F (15 days) 29
Figure 4.11 WWC flyable capping stack from Singapore to Adelaide (21 days) 30
Figure 4.12 OSRL capping stack from Singapore by construction vessel (24 days).....31
Figure 4.13 Detailed analysis of the cost of each of the pre-emptive capping stack deployment option 33
Figure 4.14 Well capping ALARP evaluation 34
Figure 4.15 Relief well rig drilling relief well in parallel with main rig at Stromlo-1 (44 days) 36
Figure 4.16 Relief well rig on stand-by close to Stromlo-1 location (63 days).....36
Figure 4.17 Relief well rig on stand-by east of Port Lincoln (68 days).....37
Figure 4.18 Main rig disconnects LMRP, drills relief well top-holes and relief well rig from North West Shelf (73 days).....38
Figure 4.19 Relief well rig from North West Shelf (88 days).....39
Figure 4.20 Relief well rig from Singapore with Australian Safety Case (102 days) 40
Figure 4.21 Relief well rig from Singapore without Australian Safety Case (149 days) 41
Figure 4.22 Relief well ALARP evaluation 44
Figure 4.23 Unmitigated WCD Stochastic modelling (100 runs) showing zone of potential fresh oil exposure at the sea surface. Moderate levels of exposure (10 µm) and above would be potentially suitable for surface dispersant application 47
Figure 4.24 Shoreline response need and capacity, based on maximum oil volume ashore (cumulative bulked oil), planned minimum scaling of workforce (cumulative personnel days) and maximum workforce scaling through training (cumulative trained days).....53

1.0 ALARP assessment process

This appendix documents the assessment of alternative and additional control measures that have arisen in development of the Environment Plan (EP) including through stakeholder consultation, as having potential to further reduce the risks associated with an oil spill resulting from a loss of well control (LOWC) to as low as reasonably practicable (ALARP). The assessment herein relates to the risks detailed in Section 7.7 of the EP. It also documents Equinor Australia B.V.'s assessment of ALARP in selecting the oil spill response strategies adopted in the Oil Pollution Emergency Plan (OPEP). The ALARP assessment of spill prevention control measures (barriers to loss of well control) will be detailed in the Safety Case and Well Operations Management Plan (WOMP) for the activity.

Recognising the nature and scale of the risk associated with a loss of well control, Equinor Australia B.V. conducted this detailed assessment of potential new controls and ways to improve responsiveness and effectiveness of standard control measures, to reach ALARP. Alternative control measures were adopted where the cost of implementing them was not disproportionate to the environmental benefit gained.

The ALARP assessment for planned impacts and other unplanned risks are described in Sections 6.0, 7.0 and 8.0 of the EP.

1.1 Regulatory context

The Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations (OPGGS (E) Regulations) require documentation of the ALARP process and the specific places in which ALARP requirements of the regulations are addressed within this EP are listed below:

Regulation	Brief description	Location in EP
10(A)	Demonstrate impacts and risks have been reduced to ALARP	This document
13(5)(c)	Detail the control measures to reduce to be implemented to reduce impacts and risks to ALARP	Sections 6.0–8.0
14(3)(a) 14(3)(b)	Describe the specific measures to be implemented to continue to reduce impacts and risks to ALARP for the duration of the petroleum activity	Section 9.0

1.2 ALARP workshops

Workshops were run to examine the environmental impacts and risks associated with the Stromlo-1 exploration drilling activity, to demonstrate that residual impacts and risks have been, or will be, reduced to ALARP, by:

- identifying, evaluating and selecting potential treatment options following the hierarchy of control measures
- undertaking qualitative assessments of the practicality and the costs and benefits of each control measure
- preparing and implementing management plans (e.g. for source control and spill response)
- assessing the residual risk to determine if ALARP has been reached.

The workshops were attended by:

- Equinor Australia B.V. representatives, including subject matter experts (SME) in oilfield operations, drilling, noise, spill risk assessment and with detailed knowledge of Equinor Australia B.V.'s internal standards and international practices
- Equinor Australia B.V. representatives with detailed knowledge of the Stromlo-1 exploration drilling activity, e.g. the Drilling Manager
- environmental scientists from RPS Australia West Pty Ltd (RPS) with experience in the region and in-depth knowledge of the modelling and assessment of environmental impacts and risks from the drilling and operational activities.

Additional ALARP considerations have been raised and considered as the project planning developed and these have been captured in this document and newly adopted controls have been included in the main EP as appropriate.

Equinor Australia B.V.'s senior management reviewed the suite of control measures described within the EP to mitigate impacts and risks and considered alternative and additional solutions that may be able to further reduce the environmental impacts and risks in the context of the process of ALARP demonstration. ALARP workshops also considered whether the residual impacts and risks following the demonstration of ALARP for each assessment were acceptably low.

Four ALARP workshops were held between August 2017 and May 2018:

- ALARP Workshop 1 (27 September 2017) covered the following aspects
  - Assessment technique "Good Practice" – evaluated hazards identified in ENVID and application of industry standards and practice, assessed additional controls if relevant
- ALARP Workshop 2 (10 October 2017) covered the following aspects
  - Assessment technique "Engineering Risk Assessment" and "Precautionary Approach" – evaluated hazards identified in ENVID and application of sound engineering and scientific principles and methods, assessed additional controls if relevant
- ALARP Workshop 3 (7 March 2018) covered the following aspects
  - Source Control – evaluated source control strategies and alternatives
- ALARP Workshop 4 (16 April,15 May, June 27 and July 16, 2018) covered the following aspects
  - Spill Response – evaluated spill response strategies and alternatives.

2.0 Context and definitions

The definitions of the types of control measures considered are included below.

Type of control measure	Description
Eliminate	Completely remove the hazard
Substitute	Replace the material or process with a less hazardous one
Engineering / Isolation	Provide engineering solutions to control the hazard / isolate the hazard from the environment
Administration	Use administrative procedures to control the hazard
Protective	Use appropriate protective equipment, (including emergency response and contingency planning), when other control measures are not practical or have not totally removed the hazard

The definitions of the environmental benefits are included below.

Scale	Environmental benefit
Negligible	Control measure reduces the environmental effect by <1%
Minor	Control measure reduces the environmental effect by 1–3%
Moderate	Control measure reduces the environmental effect by 3–10%
Significant	Control measure reduces the environmental effect by 10–50%
Major	Control measure reduces the environmental effect by >50%

In the event of an oil spill, the environmental advantage to be obtained from each control measure was assessed in terms of the percentage reduction in the amount of spilled oil it would achieve, based on oil spill modelling and professional judgement. The environmental benefits of each method in countering the oil spill were based on the reduction in the number of days of hydrocarbon release, achieved by implementing the control measure, as a percentage of the full 102-day worst credible case discharge (WCCD) spill scenario. For example, a reduction in days of loss of well control of >51 days equates to a >50% environmental benefit.

The environmental benefit and the cost of implementing the control measure were evaluated using the matrix presented in Table 2.1. The costs were estimated based on extensive experience in delivering offshore drilling programs. In the ALARP assessments, the costs and environmental benefits for each step of the ALARP process are related to the incremental change from the previous adopted control measure.

Table 2.1 Cost / benefit matrix for ALARP assessment

Environmental benefit	Cost (~% of total drilling program cost)				
	>10%	5–10%	2–5%	0.5–2%	<0.5%
Negligible (<1%)					
Minor (1–3%)					
Moderate (3–10%)					
Significant (10–50%)					
Major (>50%)					

Definitions

Not adopted
Potentially adopted if cost not prohibitive
Adopted

3.0 Assumptions and logistics arrangements

3.1 Permits for petroleum installations

To drill a relief well the mobile offshore drilling unit (MODU) will require an approved Australian Safety Case for that task. For a mobile offshore drilling unit with a valid Australian Safety Case, a safety case revision is required. For the cases where the mobile offshore drilling unit location is at the North West Shelf (NWS) or beyond, it is assumed that this can be arranged during the transport of the mobile offshore drilling unit to the location (>2 weeks). For the cases where the mobile offshore drilling unit is held close to the location, the assumption is that the safety case for drilling the relief well has been arranged before the operations start. For cases where the assumptions deviate from this, it will be explicitly stated.

For the subsea construction vessel (SCV) that may do blowout preventer (BOP) intervention, subsea dispersant injection (SSDI) and/or capping of the well, a valid Australian Safety Case is required and will be in place prior to the petroleum activity on Stromlo-1. Additional vessels that will be involved with subsea dispersant injection will also have a valid Australian Safety Case prior to start of operations.

3.2 Road transport in Australia

There is ample heavy truck capacity in Australia, and lead time and capacity to carry the heaviest items (three items around 25 tons for capping and heavy debris clearance) will not be a bottleneck for any of the cases. Neither are roads, bridges, tunnels and overhead obstructions for transport of heavy items from Sydney Airport, Melbourne Airport, Adelaide Airport and Perth to Port Adelaide.

3.3 Air cargo transport to Australia

3.3.1 Adelaide Airport

The worst-case event will require air cargo capacity that exceeds the capacity of Adelaide Airport. The Adelaide Airport operates a curfew on all flights between 11.00 pm and 6.00 am (which would be lifted in the event of an emergency – *Adelaide Airport Curfew Act 2000*). The following are also observations:

- Two × 14 tonnes main deck loaders (MDL). There are several items in the capping stack / debris clearance kits that exceed this limitation and hence cannot be offloaded from a B747F.
- The airport can receive both B747F and An-124 aircrafts, with refuelling options.
- Simultaneous discharge is possible for a maximum of two freighter class aircraft at the same time. There is also limited parking space for aircraft at the airport.

The limitation caused by the main deck loaders limited capacity could be corrected by flying in a higher capacity MDL using an An124 aircraft. This solution would not improve the time line for the early response (subsea dispersant injection and capping) as sourcing the An-124 and MDL, and subsequent transport to Adelaide, would take more than two weeks. Increasing the main deck loaders and ground handling capacity of Adelaide Airport would also have limited value for a prolonged response, since the general capacity and space constraints of the airport. The airport will be at capacity during the time of the response, flying in general equipment and dispersant fluid. Both Melbourne and Sydney airports will be used to alleviate the general capacity and allow for items as heavy as 35 tonnes to be carried on a B747F.

3.3.2 RAAF Base Edinburgh

RAAF Base Edinburgh (YPED) potentially offers additional capacity for the discharge of An-124 aircraft, but this option will require a formal approach to the Australian Defence Force and therefore has not been included in the logistic plans.

3.3.3 Sydney Airport

The capacity of Sydney Airport is significant and is also the most significant freight hub in Australia, with seven cargo terminals. The airport handles about 500,000 tonnes of international air freight annually. This airport alone would be able to handle all equipment and material for a worst-case response (<2% of annual capacity or <8% of daily capacity for 100 days assuming 100 tonnes imported daily). The airport is also equipped with main deck loaders with capacity that significantly exceed the requirements for the heaviest items in the capping and debris clearance subsea toolkits.

No river wide enough

Qantas Freight's newest piece of ground handling equipment had to overcome several hurdles before making its way from the manufacturing warehouse in Germany to our Sydney international freight terminal late last year.

The spectacular Trepel Champ 350 main deck loader (MDL) was being transported by road to the German sea port of Bremerhaven when road works on a passing bridge meant the truck was sent back to the factory. Then three weeks later the MDL took its place on a ship heading for Port Kembla in New South Wales when, off the west coast of South Africa, bad weather struck causing containers to fall and puncture the ship. This caused the engine to flood and forced the ship to dock in Durban.

Still, nothing was going to stop the state-of-the-art MDL from reaching our Sydney terminal. It arrived almost 10 weeks later than planned but it was certainly worth the wait.

The largest of Trepel's main deck loaders, the 350 is capable of loading and unloading oversized pieces from the main deck weighing up to 35 tonnes.

The Trepel 350 model was chosen for being reliable, easy-to-use and compatible with the Qantas Freight business model. And importantly for us, the MDL boasts a number of safety features including distance sensors, cut-offs and a cage lift.

Qantas Freight is Australia's leading ground handler, and this investment gives you confidence that we can handle whatever you send our way.

LOCAL FEATURE 05

dnata's 35 tonne MDL at work loading a Rolls Royce Trent 900 engine.

Cargo Logistics Tracking System

dnata Singapore is not only highly effective in warehousing, but also in the capturing and transmission of real time information that feed to the customers' demand for real time information on shipment. A new initiative launched at the dnata warehouse at Changi Airport, called the Cargo Logistics Tracking System, is designed to address to the requests of customers.

The movement of cargo is now better tracked, as drivers use the handheld scanners mounted on their tractors to capture live timings and details of the cargo they are towing. This affords higher accountability on the movement of cargo and reduces administrative paperwork and human errors in reporting. The accuracy of such information captured means a peace of mind for customers that their cargo is in good hands.

35 tonne Main Deck Loader (MDL)

The success of dnata's operations in Singapore is only as robust as the forward planning that is done to ensure that there is always a fleet of equipment that meets the specific needs of our customers, providing them with timely and quality service.

In today's ramp environment, it is no longer about maintaining a large fleet of diversified equipment to get the job done. dnata believes that having the right equipment is key and the outcome is twofold - getting the job done efficiently and most importantly, safely.

In the past year, the dnata team in Singapore has been challenged on many occasions in managing larger, heavier and odd-sized cargo coming through on airfreight. In the past, we have had to rely on a mix of supersized cranes, forklifts and a number of main deck loaders to get the cargo on and off an aircraft.

These oversized cargo will continue to put pressure on the dnata's current fleet of ground support equipment. Today, action has been taken to simplify and increase the efficiency of ramp operations by the acquisition of a 35 tonne MDL. The new heavyweight MDL has shown its capability through the handling of Rolls Royce Trent engines on many occasions.

dnata remains the only ground handler in Singapore in possession of such an equipment that is able to safely and efficiently load an oversized cargo directly into a cargo hold.

As a trusted partner to our airline customers, investments are viewed not just as expenditure but also a consideration of improving service delivery to customers. Mark Edwards, CEO of dnata Singapore says "These efforts are for the long term and will reap its rewards in the years to come. It shows of our commitment to being an active player and contributor to Changi and a reliable and relevant partner to our airline customers. Most of all, embracing these new ideas will help us change and evolve as a company to keep up with the times."

Page extract from Changi Cargo Insight June14 Issue 05

3.3.4 Melbourne Airport

Melbourne Airport handles more than 30% of Australia's international air freight. It lacks the heavy-duty main deck loaders (maximum 12 tonnes), but due to general capacity and shorter drive to Adelaide, this airport adds flexibility and overall capacity to an emergency response.

3.4 Access to cargo aircraft

3.4.1 B747F

The Boeing 747 freighter configuration is one of the most used and available large freighter aircrafts. Several companies operate daily flights to Australia, from many destinations. The maximum cargo capacity (revenue payload) of this aircraft is 113 to 139 tonnes depending on model and configuration. The B747F requires a main deck loader (MDL) to unload, or load, the cargo to and from its elevated main cargo deck, and the access to a main deck loader with sufficient high weight rating is often a limiting factor for subsea response equipment. Some of the most frequent scheduled B747F routes are from Singapore to Sydney and Melbourne.

Singapore Airlines Cargo (SIA Cargo), operates B747F to SYD/MEL six days per week. Singapore Airlines Cargo in Singapore confirms that Equinor Australia B.V. will get space and capacity on those flights with less than 24 hours' notice given that the premium rate is accepted, and that documentation, paperwork, and custom clearance can be arranged in time. Singapore Airlines Cargo can also set up additional new B747F charter routes to SYD/MEL after five working days' notice.

3.4.2 An-124

The Antonov An-124 is a large freighter aircraft with limited availability. This aircraft has a unique feature that allows it to load and unload the cargo directly to the tarmac. The aircraft is hence ideal for remote locations or places with limited infrastructure, and for this reason the An-124 has been used several times in the last decade to carry large equipment from overseas to Adelaide (energy sector and military hardware). The drawback is the limited number of aircraft and operators, making it sometimes hard to access quickly. Another drawback is the limited range when loaded, with the need for frequent refuelling, making route planning with many stops challenging since overflying rights need to be secured. Flights from Singapore to Adelaide require one refuelling stop (Darwin), and flights from Europe require five or six refuelling stops – and potentially stopovers, as the crew runs out of hours. A documented case of heavy oilfield equipment that urgently needed to be moved from Aberdeen to Adelaide required 14 days from when the need arose until the An124 arrived in Adelaide. A common assumption is that seven days should be assumed from the time an An124 is called upon until it arrives at the loading location (worldwide).

3.5 Customs clearance

Information from Australian Border Force:

> All goods imported into Australia must be reported to the Department of Home Affairs and risk-assessed. This risk assessment relates to information that cannot be pre-determined before we know exactly what items will be sent, on which date, from which place and using what methods and companies. All of these factors would be considered together, based on the reports provided in the Integrated Cargo System (ICS). As the ICS is available 24/7, it would be sufficient to lodge import declarations (along with other necessary reports) once the need arises and arrangements have been made for the equipment to be transported to Australia. Where the required cargo reports and import declarations are submitted prior to arrival in Australia, the majority of goods are cleared before their arrival, pending payment of any applicable duties and taxes and where no impediments are placed on the equipment following border agencies risk assessment. Where the importation is related to an emergency situation, there may be scope for requesting an 'urgent cargo clearance' as outlined on the Department of Home Affairs website. https://www.homeaffairs.gov.au/busi/carg/contact-cargo-support
>
> Our customs broker confirms that there is no need to lodge anything into the Integrated Cargo System pre-emptively, and it is not possible before the need arises and the date and flight are known. There are certain steps that can and will be taken to reduce risks for delays:
>
> - All goods that are imported into Australia are assessed for biosecurity risk by the Department of Agriculture and Water Resources (DAWR). For certain departure locations this biosecurity risk can be assessed and verified at the origin before departure. Singapore Changi Airport is a location where this pre-departure assessment can be done. Equinor Australia B.V. will plan and implement this to ensure no delays due to the Department of Agriculture and Water Resources when the equipment arrives in Australia.

- All the invoices and paperwork required for customs clearance will be prepared in advance to ensure that there are no delays in securing access for departure on the next scheduled B747F from Changi to SYD/MEL. This pre-prepared paperwork will also allow a timely lodging of import declaration in the Integrated Cargo System and the request for "urgent cargo clearance". This will ensure no delays due to the Australian Border Force when the equipment arrives in Australia.

3.6 Port Adelaide

Port Adelaide has several areas providing adequate facilities for loading operations. In addition to Berth-25 that is leased for exclusive use by Equinor Australia B.V. during the operations, the following public berths can be made available:

Berth	Berth length	Berth width	Depth	Wharf height	Axle load
18	178 m	30 m	10 m*	4.6 m	64 T†
19	168 m	3 0m	10 m*	4.6 m	64 T†
20	163 m	30 m	10 m*	4.6 m	64 T†

* Depth indicated are declared depths
† Axle loads are for single axles only weights for multi axles will vary

There are cranes available in the area or can be provided by Flinders Logistics, that meet the requirements for up-stacking of the capping-stack and loading or unloading from trucks. The capping stack will be stacked-up and tested at the berth and will be accessible to the subsea construction vessel's crane for loading directly onto the vessel.

3.7 Search and rescue (SAR)

The priorities for the response after a loss of well control are:

1. Search and rescue.
2. Source control.
3. Mitigate the spill impact.

All our vessels, including the mobile offshore drilling unit itself, will have effective search and rescue functionality.

To ensure that the subsea construction vessel will be able to perform blowout preventer intervention tasks in accordance with the specified first strike response time of attempting blowout preventer closure within 24 hours, and not be redirected to search and rescue (SAR) tasks for longer than 12 hours, additional search and rescue resources will be made available. To ensure that a search and rescue mission will not compromise the source control mission, we will implement the following:

- The subsea construction vessel will be the stand-by vessel on site and its primary role will initially be search and rescue to ensure human lives are saved if necessary. It will then be relieved within 12 hours and be able to attempt blowout preventer closure to achieve well control. The subsea construction vessel will be available and ready to attempt to close blowout preventer to stop the flow of oil and thereby reduce the potential effects from the incident. There will be sufficient search and rescue support on site within 12 hours of the loss of well control to free the subsea construction vessel to perform its first strike blowout preventer intervention tasks and attempt closure of the blowout preventer emergency response sequence within 24 hours using a remotely operated vehicle.
- The schedule of the two platform support vessels during the time the reservoir is exposed will be managed such that one of them is at most 12 hours away taking into account safe travel time and forecasted weather.
- The Stromlo location is close to the Perth to Adelaide shipping route. Real-time satellite data indicate that there are normally several ships on this route and less than 12 hours travel distance from Stromlo. In an emergency event Australian Maritime Safety Authority (AMSA) will be notified and assistance from commercial shipping vessels in the vicinity will be provided – or will be commandeered by Australian Maritime Safety Authority (under the international Safety of Life at Sea (SOLAS) convention).
- In the event that either personnel are missing or there is a loss of well control situation, then the stand-by vessel will launch the GPS tracking buoys into the sea. Equinor Australia B.V. will furnish Australian Maritime Safety Authority and potentially directly guide vessels with this tracking information to allow for a more effective search and rescue.
- Real-time modelling of the spill will also inform the search and rescue operations and will be ground-truthed from the tracking buoy data.
- The Australian Maritime Safety Authority search and rescue aeroplanes will be requested and can be at the scene within four hours (day and night).
- Helicopter support will be requested from Ceduna and may be able to participate in search and rescue. Due to flying distance, they will have limited effective search and rescue time on location (half to one hour).
- Additional aviation resources will be available for search and spill monitoring in less than 24 hours.

3.8 Metocean conditions and impact on response timing for subsea operations

The safe drilling of the relief well and emergency response measures are feasible throughout the year, but winter weather conditions will result in more waiting on weather (WOW) downtime. The time estimates for all operations use P90 estimates and have waiting on weather contingencies included. The blowout preventer interventions and subsea dispersant injection operations are not very sensitive to metocean conditions, while capping stack operations are. A vessel specified for capping stack installation will also be suitable for blowout preventer intervention and subsea dispersant injection, and potential debris clearance. Capping stack operations have been evaluated for each month – see charts below.

Marine operations which must be completed without break are called critical. Otherwise they are termed non-critical. Installation of a capping stack is critical and needs a 38-hour time window. The limiting metocean condition in the Great Australian Bight (GAB) is the waves.

An operational analysis (using Equinor Australia B.V. software DurOpX) of the outcomes for Stromlo-1 location is shown. This software simulates start of an operation at each time step in a time series and compares the actual weather conditions with the operational limits. If a parameter exceeds an operational limit, it means that the operation would have to wait at least one time-step before it could be started. By doing this, the software provides an operation duration for each time step in the data set and can from this provide statistics such as expected duration and P90 duration of an operation

The chart in Figure 3.1 shows similar characteristic durations but with different operational limits, to perform critical operations in up to 3 m Hs, 4 m Hs and 5 m Hs.

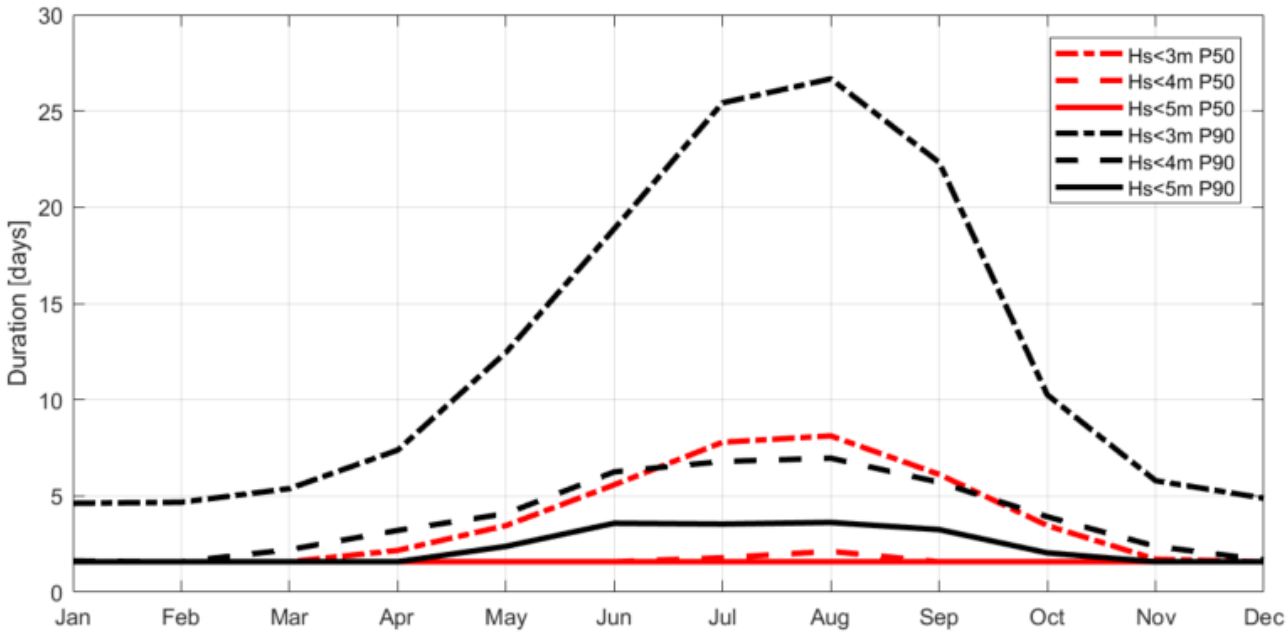


Figure 3.1 P50 and P90 values for time needed to perform operations limited by Hs of 3, 4 and 5 m and requiring a continuous weather window for 38 hours. Based on GROW12 hindcast data within the period 1979–2013. Duration is the sum of the actual time required to do the work and time waiting on weather

Having a subsea construction vessel with an active heave-compensated (AHC) crane that can operate in up to 4 m Hs would allow for the capping stack to be installed within a 38-hour time window, in a P50 case for April. Should the subsea construction vessel and active heave compensation crane have an operating limit of 3 m Hs, the capping stack could be installed within a 2.5-day time window, and with a significantly longer waiting on weather component in a P90 event. A crane with 5 m operational limit will give no improvement in the P50 case, and a modest improvement for P90. For example, in April which will be the worst-case weather scenario during the operating window:

- 5m Hs AHC:
  - P50 – 38 hrs (0 day WoW)
  - P90 – 2.3 days (~ 0.5 days WoW)

- 4 m Hs AHC
  - P50 – 38 hrs (0 day WoW)
  - P90 – 3.9 days (~2 days WoW)
- 3 m Hs AHC
  - P50 – about 2.5 days (~1 day WoW)
  - P90 – about seven days, (~5 days WoW).

The P10, P50, and P90 values have been used directly by month, and are hence part of the total Monte Carlo simulations for the total P90 time for capping of the well. The durations in the charts above can be regarded as conservative as they assume that the entire time window for capping stack installation is sensitive to weather. In fact, the weather conditions are only critical for two short discrete periods; the first is the lowering of the capping stack from the vessel trough the splash zone, and the second is the landing of the capping stack on top of the blowout preventer (or wellhead).

Based on the outcome of this analysis it was found that a subsea construction vessel, with an active heave compensation crane that can operate in a condition with at least 4 m Hs and the associated wave periods would be a more robust specification and would reduce risks to ALARP by reducing capping stack installation time under a wider range of conditions. Further increase in Hs specification would have insignificant impact on timing, at a higher cost and contracting risk. Lowering the specification to Hs 3 m would significantly worsen the environmental performance standard (environmental performance standard) for installing the capping for all months as P90 times are used for time estimation in this document.

Refer to Section 4.3 of this document for considerations around capping stack ALARP assessment. The April month was used for the time schedule in these as this would give a robust estimate over the planned drilling window, and since a spill commencing in April would cause the largest impact over the activity period.

3.9 Debris clearance

Debris clearance might be required if the rig has not disconnected the lower marine riser package (LMRP) after a loss of well control event. A remotely operated vehicle survey will be conducted as soon as practical to determine the presence of debris over and around the well centre. If debris is located, a detailed record of the locations and types of debris will be made for planning purposes. A database of blowout preventer, lower marine riser package, and riser components will be referenced to ensure that proper tooling is used. Equinor Australia B.V. holds contracts worldwide with Wild Well Control (WWC) and Oil Spill Response Limited (OSRL) on emergency response equipment. Availability of heavy-duty debris clearance equipment is very limited and there is currently no rental option for this equipment in Equinor Australia B.V.`s contracts with Oil Spill Response Limited or Wild Well Control, nor any other contract Equinor Australia B.V. holds. These packages are mobilised when and if needed. The Wild Well Control debris clearance package in Singapore will be mobilised immediately after a loss of well control incident regardless of any survey, to allow for the fastest possible arrival of debris clearance equipment in case needed. The subsea construction vessel will have a work remotely operated vehicle that will be able to utilise the debris clearance equipment that is mobilised in a loss of well control incident.

However, the most likely case is that the lower marine riser package has successfully disconnected and the rig moved away. The ALARP time estimates for source control assumes this most likely case, and additional time will be required if the actual situation is different. Examples of situations and additional time required:

- Scenario 1: Lower marine riser package has been disconnected – base-case and no additional time required for debris clearance.
- Scenario 2: Lower marine riser package with riser broken off on top of flex-joint – estimated additional two days for debris clearance.
- Scenario 3: Lower marine riser package with bent riser connected - estimated additional three or four days for debris clearance.

Scenario 3 would be the most time-consuming because it could require cutting the riser at two locations, then disconnecting the lower marine riser package and lifting it off. Scenario 2 and 3, in addition to potential drill pipe through blowout preventer may need debris to be cleared prior to successful installation of capping stack onto the primary blowout preventer; this would require heavy duty debris clearance equipment run on the subsea construction vessels subsea crane, assisted by a remotely operated vehicle.

As opposed to the capping stack installation, it is highly unlikely that debris clearance will be required prior to blowout preventer intervention and subsea dispersant injection operation as there will be no equipment subsea that could become a source of debris besides riser joints and lower marine riser package. There are no subsea cables associated with the mobile offshore drilling unit because it is a dynamic positioned vessel and will not be anchoring. Riser joints and the lower marine riser package will not be removable by remotely operated vehicle but are of a nature that they would not completely obstruct the blowout preventer panel nor block access to the plume of oil for subsea dispersant injection. In a worst-case situation where lower marine riser package did not disconnect and the riser is bent or broken, even in the direction of the remotely operated vehicle intervention panel which is on the side of the blowout preventer, the height and space below a bent riser will allow for panel access by remotely operated vehicle. The subsea dispersant injection point will be directed towards the source of flow, even if from the blowout preventer (or wellhead) or from a hole in the riser.

First strike debris clearance tasks undertaken by the support vessel and its remotely operated vehicle will be to analyse the remotely operated vehicle images during the first two days of blowout preventer intervention, to make a debris clearance plan for subsequent missions should a capping stack become necessary. The work-class remotely operated vehicle will have basic manipulator functions but will not have specialised debris clearance tooling unless it is selected as part of the mobile offshore drilling unit/remotely operated vehicle contracting process. The ALARP assessment did not support adoption of a control measure to mandate debris clearance tooling on the remotely operated vehicle on location on the support vessel. This will be re-assessed during the mobile offshore drilling unit/remotely operated vehicle technical evaluation process and if a plausible scenario can be identified whereby remotely operated vehicle debris clearance functions may be of benefit, available remotely operated vehicle debris clearance tooling will be re-assessed under ongoing ALARP assessment.

The Wild Well Control debris clearance package will be available for the subsea construction vessel on its first port-call in Adelaide to pick up the subsea dispersant injection equipment. This means that the debris clearance equipment can be available on the Stromlo-1 location on day 7 after the loss of well control incident. Refer to Section 3.10 of this document for more considerations regarding SIMOPS and vessel allocation. Early debris removal will potentially result in higher temporary flow-rates, as choke-points and friction for the flow will be removed or reduced. It is hence intended, and best practice, to do heavy-duty debris clearance operations ahead of the capping operation to avoid worsening the environmental impact. However, the equipment will available on site and a debris clearance plan prepared.

There is also debris clearance equipment in Perth. The Australian Marine Oil Spill Centre (AMOSC) has a Subsea First Response Toolkit (SFRT) and if required, the option of using this equipment is available. The use and availability of this Subsea First Response Toolkit as a back-up to the Wild Well Control equipment is considered ALARP, and the equipment can be available in Adelaide for the subsea construction vessel on its first port-call in Adelaide if required, similar to the debris clearance package from Wild Well Control.

The ALARP cases for capping stack do not include time for debris clearance as the most likely case is that it will not be required. However, should it be required, the time estimated for capping stack will be extended by the debris clearance time as this activity and the capping stack deployment will be sequential operations using the same subsea construction vessel.

3.10 SIMOPS – response time model

The main limitation for response timing is vessel allocation and capabilities. The ALARP demonstrations include arguments around vessel capabilities and how each vessel will be used for the different missions. Some of the vessels will be used for multiple missions, and the actual scenario and priorities will impact the actual time line. This section is intended to give an overview of this; how the many roles of each vessel are managed in a loss of well control scenario and the environmental performance standard for each mission is achieved. Refer to Section 4.0 of this document for more ALARP considerations around each individual mission.

Figure 3.3 presents the response time model (response time model) with full vessel allocation overview for a loss of well control incident on Stromlo-1 and showing nominal ramp-up of additional support vessels as required.

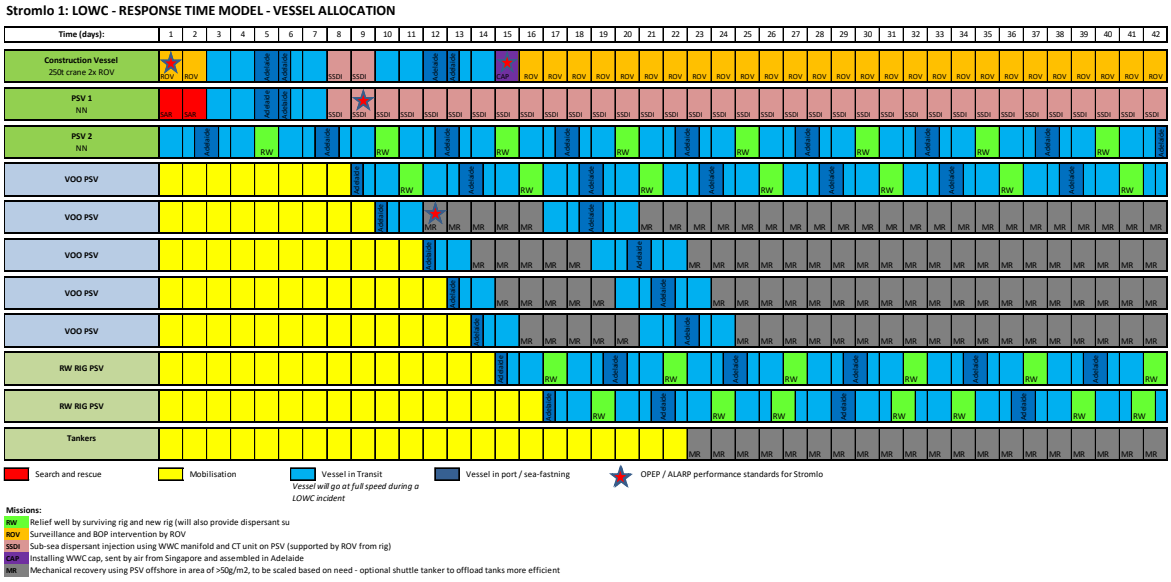


Figure 3.2 SIMOPS – response time model without debris clearance prior to capping

3.10.1 First 21 days of the response time model

Equinor Australia B.V. plans to use a fleet of three support vessels, including a subsea construction vessel (SCV). The subsea construction vessel will be the stand-by vessel on site and will have valid Australian Safety Cases for all missions prior to commencement of the petroleum activity on Stromlo-1. Having a subsea construction vessel on site during drilling of an exploration well is not considered standard for exploration drilling operations and is included to meet the environmental performance standard of closure of the blowout preventer by remotely operated vehicle intervention within 24 hours. The subsea construction vessel will also significantly reduce the time and uncertainty for subsea dispersant injection and capping stack installation. Figure 3.3 shows the response time model with vessel allocation for the three vessels in the primary fleet.

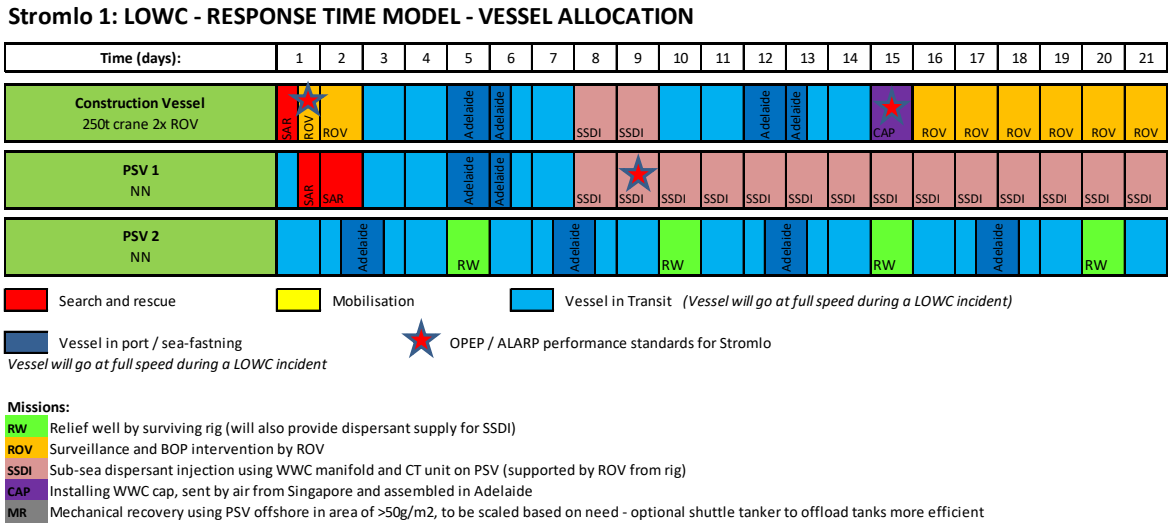


Figure 3.3 Response time model for the first 21 days – no debris clearance required

This response time model assumes P90 times and that the rig is non-operational, meaning that the time line is conservative. Most likely the rig will be operational and can assist with remotely operated vehicle operations and search and rescue.

During the first two days after the loss of well control incident, Equinor Australia B.V., Wild Well Control, Oil Spill Response Limited and Australian authorities are notified immediately after the incident. The first two days (48 hours) will be dedicated to search and rescue and blowout preventer intervention. After 48 hours from the

loss of well control incident – with high flow – the probability of using the blowout preventer as the means to stop the flow is greatly diminished, and if an acoustic system is available the accumulator capacity will have been spent.

The subsea construction vessel will prioritise search and rescue activities until one of the platform support vessels has returned to location. Referring to Section 3.7 of this document, the environmental performance standard is that at least one platform support vessel will always be less than 12 hours away from the Stromlo-1 location while drilling the reservoir section. Once a platform support vessel has returned to location, the subsea construction vessel will prioritise blowout preventer intervention to meet the environmental performance standard of closing the blowout preventer within 24 hours from the loss of well control incident. Refer to Section 4.1 of this document for considerations around blowout preventer intervention ALARP assessment. Depending on the amount of time the subsea construction vessel will spend on search and rescue activities (0–12 hours), blowout preventer interventions and remotely operated vehicle surveys will be undertaken for 36–48 hours. PSV1 will return to site and continue the search and rescue activities for the first two days, while PSV2 will transit to Adelaide to pick up equipment for a relief well top hole (assuming the main rig is operational) and dispersants for subsea dispersant injection. PSV2 will continue this mission to supply necessary equipment and dispersants for the remainder of the response time model. Transit assumes 12 knots over the 410 nautical miles – ~35 hours between the Stromlo-1 location and Adelaide.

Days 3–7 after the loss of well control incident: The subsea construction vessel may transit to Adelaide to pick up subsea dispersant injection equipment and debris clearance equipment that has been flown in from Wild Well Control in Singapore to Adelaide. PSV1 will transit to Adelaide to pick up the coiled tubing equipment and deployment frame that has been transported by truck from Perth. This equipment will then be on location on day 7.

Days 8–9 after the loss of well control incident: The subsea construction vessel and PSV1 will install subsea dispersant injection equipment to meet the environmental performance standard of having subsea dispersant injection operation on day 9 after the loss of well control incident. From this point, PSV1 will the platform for subsea dispersant injection and dedicated to this mission, with PSV2 delivering supplies of dispersants from Adelaide. Refer to Section 4.2 of this document for considerations around subsea dispersant injection ALARP assessment.

Days 10–17 after the loss of well control incident: The subsea construction vessel will transit to Adelaide to pick up the capping stack before returning to location. The capping stack installation will commence immediately to meet the environmental performance standard of capping the blowing well on day 15. Should debris clearance need to be performed prior to installing the capping stack, this will be done ahead of the capping operation. Refer to Section 3.9 of this document for details around debris clearance. Figure 3.5 shows a response time model with vessel allocation for the first 21 days including debris clearance prior to capping stack. Refer to Section 4.3 of this document for considerations around capping stack ALARP assessment.

After day 17 after the loss of well control incident: The subsea construction vessel will monitor with remotely operated vehicle and perform the work that is required to maintain the ongoing source control missions. PSV1 will continue as the subsea dispersant injection platform, and PSV2 will transit between Adelaide and location to pick up equipment for drilling of a relief well and dispersant fluids. If the main rig is operational, it will start drilling a top hole as soon as the equipment starts arriving while waiting for a relief well rig to arrive. If the rig is non-operational, a rig will be mobilised from Bass Strait, New South Wales or other locations in South-East Asia. Refer to Section 4.4 of this document for considerations around relief well ALARP assessment.

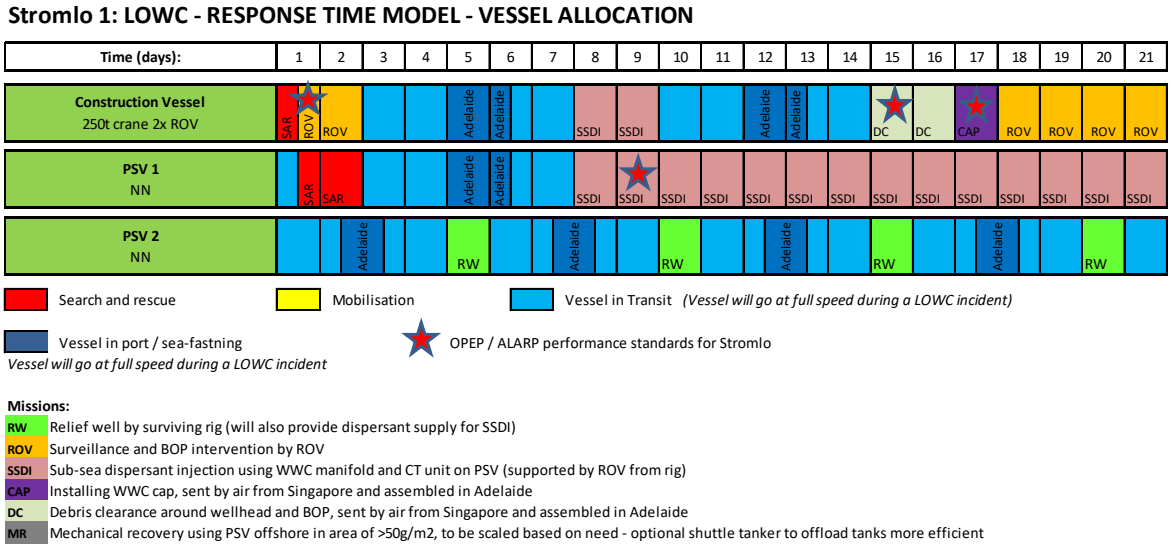


Figure 3.4 Response time model for the first 21 days – debris clearance required

3.10.2 Ship-to-ship transfer at sea

The response time for several tasks could have been improved if ship to ship transfer of equipment could have been assumed. The transfer of fluids between dynamic positioned vessels is a standard operation at sea by using flexible hoses. The transfer of cargo, using cranes, is a far more challenging task and poses significant risk to personnel on both vessels as sea-fastening must be removed from the heavy cargo. This operation requires good weather conditions and an environmental performance standard depending on a ship-to-ship transfer of heavy equipment cannot be reasonable assumed with a P90 time confidence, and such options have not been included.

The option to do ship-to-ship transfer will be explored after contracting vessels, and there are potential improvements for some missions. Figure 3.5 shows a response time model with vessel allocation for the first 21 days where a platform support vessel picks up the subsea dispersant injection equipment from Adelaide while the subsea construction vessel remains on site and continues the ongoing work with the remotely operated vehicle. This option is considered in section 4.2.2. The solution in Figure 3 6 would also allow for a faster SSDI implementation in a situation where there is no need for SAR and the PSV could transit to Adelaide immediately to pick up all SSDI equipment.

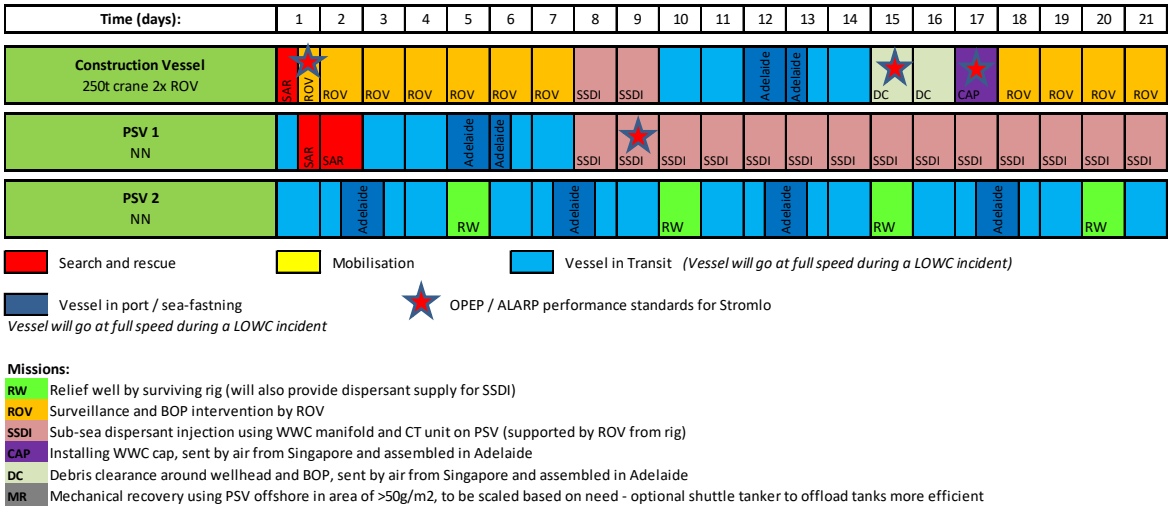


Figure 3.5 Response time model for the first 21 days – platform support vessel picking up subsea dispersant injection equipment in Adelaide and debris clearance required prior to capping stack installation

4.0 Control measures to reduce oil spill risk

The ALARP assessment of alternative or additional control measures for mitigating oil spill risks has been conducted with due consideration of the nature and scale of the risks and the local context. The contextual background includes consideration of the:

- remoteness of the southern Australian drilling location, particularly regarding mobilisation times and existing spill response capabilities in the region
- logistical challenges facing offshore drilling in a remote area, particularly the water depth and offshore conditions requiring larger vessels and constraints on aircraft operating >370 km offshore
- extended time until spilled oil would contact shorelines; fastest contact with the South Australian coastline is in the order of three weeks
- predicted very low levels of exposure of coastal waters and shorelines to fresh oil
- requirements for some specialised pieces of equipment, e.g. capping stack, to remain in a central regional location where they are available for response activities across the region.

The implementation times used in assessing the control measures were based on the P90 estimates (covers 90% of circumstances and situations) from logistical planning undertaken by Equinor Australia B.V.'s drilling experts, based on professional judgement, times achieved in other responses, e.g. Montara and Macondo, and experience from other drilling programs. This is considered appropriate because it is consistent with industry practice and the conservative engineering approach to high risk projects.

The cost/benefit evaluation was based on the:

- cost of the control or mitigation measure as a percentage of the total drilling campaign project cost, based on professional judgement
- environmental benefit; derived from how much the control measure will reduce the amount of oil getting into the ocean (reduction in number of days of discharge) or reduce the adverse effects of the spill (reduction in shoreline loading or reduction in amount of oil surfacing).

The flow charts in this section show the incremental benefit of each additional control with the associated incremental increase in costs and environmental benefits.

4.1 Blowout preventer intervention by remotely operated vehicle

The operation of the blowout preventer (BOP) is a highly-effective barrier in maintaining control of the well and is described in the WOMP for the petroleum activity. The BOP also provides source control capabilities and there are several methods by which the blind shear ram can be closed, including by remotely operated vehicle (ROV) intervention if the automatic systems on the mobile offshore drilling unit (MODU) fail. ROV intervention has the potential to completely shut off the flow soon after the incident by initiating blowout preventer closure. In the event that the blowout preventer intervention does not shut off the flow, it would most likely be because the blowout preventer is filled with bottom hole assembly (BHA) pieces or other debris. Nevertheless, it is likely that the closure attempt could further partially restrict the borehole and temporary reduce the flowrate. To maintain a conservative approach to risk assessment, Equinor does not take this potential partial restriction into account in any of the flow scenarios.

For the ROV-assisted BOP intervention to succeed, the ROV must be available and there must therefore be a suitable vessel for it to be deployed from. Generally, the ROV could be deployed from the MODU; however, for planning purposes we assume conservatively that the MODU is disabled. The following BOP intervention options have been evaluated for closing the BOP:

- Option 1: Have a subsea construction vessel (SCV) with ROV capabilities on contract and available on location – BOP closed after one day.
- Option 2: Mobilise a SCV with ROV capabilities from the North West Shelf (NWS) in the event that the automated blowout preventer systems fail – BOP closed after 10 days.
- Option 3: Mobilise a SCV with ROV capabilities from Singapore in the event that the automated blowout preventer systems fail – BOP closed after 23 days.

The availability of a ROV is the critical factor and this assessment looks at options for minimising mobilisation time for a vessel with ROV capabilities.

4.1.1 BOP intervention ALARP outcomes

Having the ROV on location reduces the time required for BOP closure to one day, as opposed to 10 days if it were mobilised from the NWS. An early deployment of ROV will also give important insight on the actual situation, debris, and flowrate, which will be required for planning further missions as SSDI and capping. The value of stopping the flow 10 days earlier, and the surveillance capabilities, outweigh the additional cost having ROV on a vessel at the location and is considered ALARP.

The ROV vessel will have a valid safety case for BOP intervention prior to the petroleum activity on Stromlo-1. The BOP intervention is not very sensitive to metocean conditions. Refer to section 3.8 of this document for details around metocean conditions on location.

In addition to having a vessel with ROV capabilities following measures will be adopted to ensure successful BOP intervention within one day from the LOWC incident:

- Equinor will ensure that competent offshore personnel, able to operate the remote BOP operating systems, are present on the vessel during reservoir intersection with clear and specific procedures for BOP intervention tasks.
- The vessel will have internet connections that allow video feeds directly to onshore operation support teams, where the surveys will be monitored, and specialist support provided as required.
- Interface compatibility between ROV and the BOP's secondary control system will be verified prior to the petroleum activity on Stromlo-1.
- A documented operational review of BOP intervention procedures and equipment to be carried out prior to the petroleum activity on Stromlo-1.

Equinor Australia B.V. commits to meeting American Petroleum Institute Standard 53 requirements for blowout preventers. The details will be provided in the Safety Cases for the mobile offshore drilling unit and the relief well rig. For the purpose of demonstrating appropriate risk reduction in the environment plan, the environment performance standard lists the key applicable provisions of American Petroleum Institute Standard 53 considered necessary to reduce risks to As Low As Reasonably Practicable. These are:

- Autoshear (emergency system)
- Deadman system (emergency system)
- Emergency Disconnect Sequence (EDS)
- Redundant control stations
- Blow out preventer real-time pressure monitoring system (pressure/temperature gauge on blow out preventer)
- A secondary control system for use in an emergency response

In the unlikely event of automated system failure, the BOP rams would be closed manually by either the ROV-based or the acoustic secondary control system, depending on what is available on the selected MODU. Secondary control systems shall be able to execute critical functions (sealing shear ram close and lock, each non-sealing shear close, one pipe ram close and lock, and LMRP connector unlatch). The BOP stack will have ROV intervention equipment that can operate critical emergency response functions using hydraulic fluid from accumulators integrated into the BOP stack's emergency response accumulators, or fluid from an ROV with a BOP intervention skid, (as per American Petroleum Institute Standard 17H); allowing for BOP operating functions within American Petroleum Institute Standard 53 specified closing times.

- BOP intervention tasks for an ROV-based secondary control system would be the ROV stabbing into the BOP ROV control panel (conforming to American Petroleum Institute Standard 17H hot stab) to operate critical functions. Hydraulic fluid will be supplied by an ROV with a BOP intervention skid mounted below the ROV. The skid has a hydraulic fluid reservoir and pump.
- For an acoustic secondary control system, it will be to operate critical functions from a remote panel on board a lifeboat, or stand-by vessel, from DP operator station at bridge if the MODU if not disabled, or from a transponder mounted on the ROV. This system will have dedicated accumulators in the BOP lower stack.

Equinor has contracts with OSRL and WWC that both can provide ROV BOP intervention skids compatible with most work-class ROVs. The preferred arrangement is that the provider of the ROV (the vessel contractor) supply a BOP intervention skid, or source a BOP skid to suit the ROV on board the vessel. This BOP intervention skid will be available on location onboard the SCV during operation if an acoustic secondary control system is not available on the selected MODU. This is considered ALARP and is adopted.

In developing the Safety Case for the MODU and drilling activity, Equinor will assess all available source control barriers and select accordingly to reduce risks of uncontrolled blowout to ALARP. Equinor will revise the ALARP assessment once the MODU has been selected to assess any further requirements of the MODU contractor that can reasonably be made and document the outcomes of the assessment.

The decision diagram to determine the additional capability that could be implemented for improving blowout preventer intervention responsiveness by increasing ROV capacity is provided in Figure 4.1. The cost/benefit analysis of all the additional controls that have been considered for improving access to ROV to initiate early blowout preventer closure, including the environmental benefits, financial, environmental and safety costs, and the outcome is presented in Table 5.1.

4.1.2 BOP design and features ALARP considerations

The option of making pipe-centring blind shear ram capability a mandatory feature during rig contracting was considered but not adopted. It is recognised that this may assist in improving the reliability of the BOP successfully shearing tubulars; however, they are not standard practice or a requirement, not available on all rigs, and the cost of retrofitting is high. The design of BOP blind shear rams is specific to the BOP on the selected mobile offshore drilling unit and they cannot be retrofit without significant cost. There is a very low probability of the drill pipe buckling and becoming off-centre.

Equinor Australia B.V. will implement mandatory parts of American Petroleum Institute Standard 53, which requires subsea BOPs to be equipped with two shear rams where one shall be a sealing ram (BSR). It is likely but not certain that the mobile offshore drilling units under consideration will have V-shear rams, the design of which acts to centre the pipe within the ram during shearing. The most common configuration available on mobile offshore drilling units will be a casing shear ram (CSR) and a blind shear ram (BSR). The CSR is used as the primary ram for shearing tubulars, not for sealing the well. The BSR is designed to shear tubular and seal the well. Most CSRs, and the latest BSRs are of V-shear design.

Some of the mobile offshore drilling units under consideration at the time of contracting (post-EP acceptance) may have pipe-centring capabilities. If V-shear rams are available on the mobile offshore drilling units under consideration, they will be given preference in the technical evaluation as it would give a minor reduction in risk; however, given the significant costs of retrofitting BOP systems to mobile offshore drilling units, it is not As Low As Reasonably Practicable to fit them if they are not available.

In developing the safety case for the mobile offshore drilling unit and drilling activity, Equinor Australia B.V. will assess all available source control barriers and select accordingly to reduce risks of uncontrolled blowout to As Low As Reasonably Practicable. Equinor Australia B.V. will revise the As Low As Reasonably Practicable assessment once the mobile offshore drilling unit has been selected to assess any further requirements of the mobile offshore drilling unit contractor that can reasonably be made and document the outcomes of the assessment.

American Petroleum Institute Standard 53 states that it is a requirement to have a remotely operated vehicle-based secondary control system, but not an acoustic secondary control system. Equinor Australia B.V. will therefore not tender for a rig with a requirement for having an acoustic secondary control system; however, the availability of an acoustic secondary control system will be considered an advantage in the technical evaluation of potential rigs. The planned remotely operated vehicle-based configuration is considered As Low As Reasonably Practicable because the remotely operated vehicle-based system is adequate and compliant with American Petroleum Institute Standard 53, while the acoustic system may offer minor benefit, the costs of retro-fitting the mobile offshore drilling units are disproportionately high and it would unnecessarily restrict the number of mobile offshore drilling units to select from.

Further optional provisions of American Petroleum Institute Standard 53 will be considered during mobile offshore drilling unit contracting and will be detailed in the safety cases for the contracted rigs.

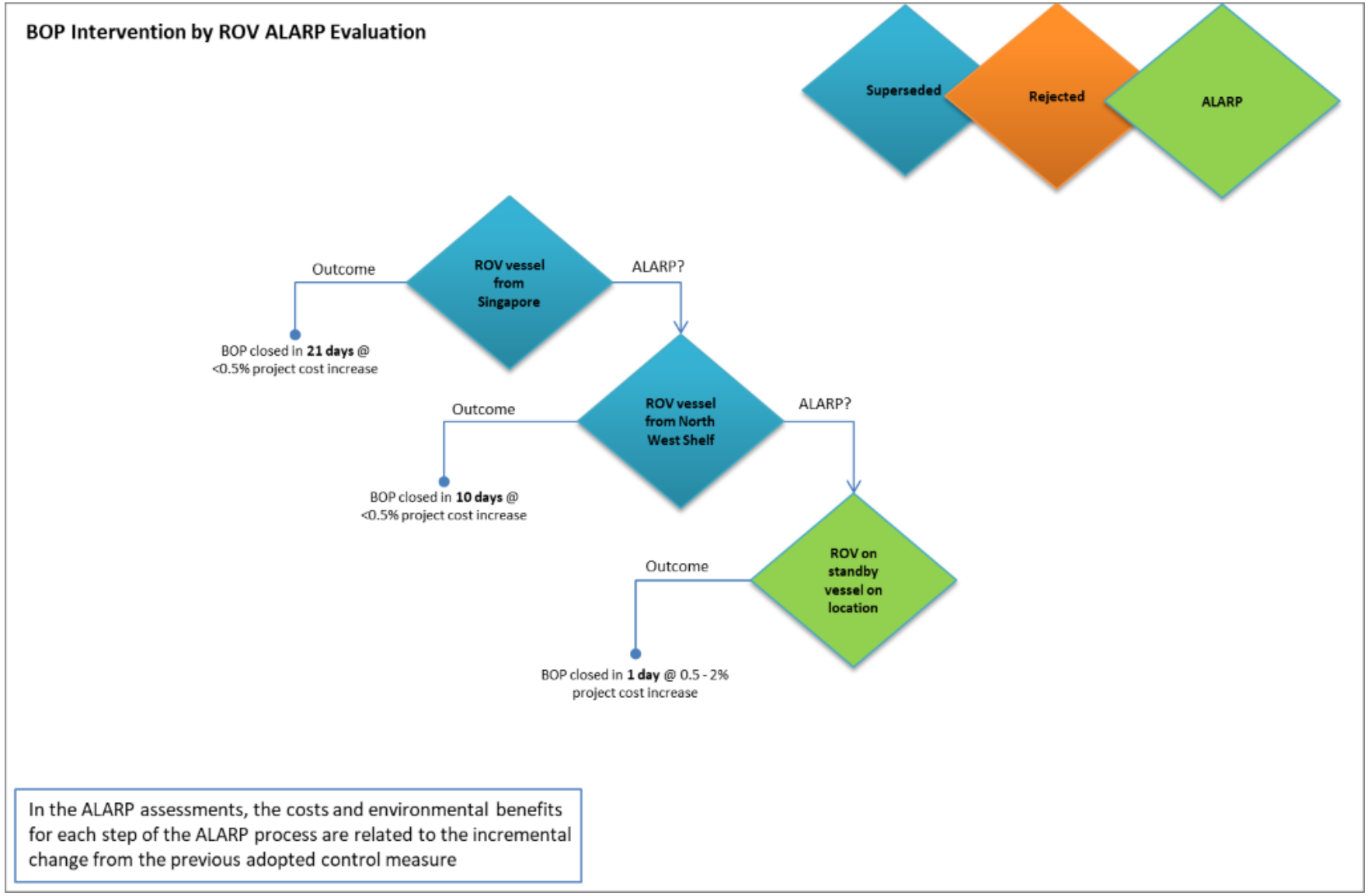


Figure 4.1 Blowout preventer Intervention by remotely operated vehicle ALARP evaluation

4.2 Subsurface dispersant injection

Subsurface dispersant injection (SSDI) was successfully used for the first time during the Deepwater Horizon incident in 2010 and has many advantages over the strategy of responding to the released oil only after it reaches the sea surface (IPIECA 2016). For example, subsea dispersant injection:

- treats oil released at the point of release and therefore maximises the encounter rate
- requires less dispersant compared to surface oil treatment due to more efficient application
- reduces the exposure of responders to the health and safety hazards of volatile chemicals and oil
- can be conducted continuously, day and night and in practically any weather conditions
- can be used in combination with surface dispersant applications (aerial and vessel).

Subsea dispersant injection is expected to be highly effective in the event of a loss of well control at Stromlo-1 and is a primary component of Equinor Australia B.V.'s Source Control Plan for responding to a loss of well control. Significant improvements in spill mitigation effectiveness are expected if the time to commence subsea dispersant injection can be reduced. Options for improving the timeliness of this response measure were considered to ensure risks are reduced to ALARP. The decision diagram illustrating the ALARP assessment of the options for additional capability that could be implemented for subsea dispersant injection is provided in Figure 4.7. The following subsea dispersant injection options have been evaluated with the time to start the injection at the point of release:

- Option 1: SSDI having a contracted vessel and equipment on location – SSDI operational after five days.
- Option 2: SSDI having a contracted vessel on location and equipment in Adelaide, picking up the equipment with a PSV – SSDI operation after seven days.
- Option 3: SSDI having a contracted vessel on location and equipment in Adelaide – SSDI operational after nine days.
- Option 4: SSDI having a contracted vessel on location and equipment in Singapore or Perth – SSDI operational after nine days.
- Option 5: SSDI using a vessel from Singapore – SSDI operational after 23 days.

To implement subsea dispersant injection timeously, the logistics and contracting processes for the following items need to be optimised:

- subsea dispersant injection equipment, including dispersant delivery systems such as the coiled tubing unit
- suitable dynamically-positioned subsea construction vessel.

Subsea dispersant injection equipment is available to Equinor Australia B.V. through its contractual arrangements with Oil Spill Response Limited (OSRL) and Wild Well Control (WWC) and can be sourced and mobilised rapidly. The subsea dispersant injection equipment is in Singapore where it is central to the region in which these response specialists provide support; allowing for equitable risk mitigation across the oil and gas fields of South-east Asia. Subsea dispersant injection equipment could also be sourced from the Australian Marine Oil Spill Centre (AMOSC) in Perth and trucked to Adelaide for deployment together with the subsea dispersant injection equipment from Wild Well Control/Oil Spill Response Limited.

Subsea dispersant injection deployment requires a vessel with a suitably rated crane and enough size and heave compensation to work safely in the metocean conditions in the Great Australian Bight (GAB). The required vessel type is a subsea construction vessel.

Since such a vessel may have many roles during an incident, some of those with higher priority than subsea dispersant injection, such as search and rescue (SAR) and blowout preventer intervention, a credible time line must include those tasks before the vessel is ready for subsea dispersant injection installation. Having the subsea dispersant injection equipment in Adelaide, or elsewhere in Australia, is not the time-limiting factor for any of the scenarios, due to the assumption of having at most one subsea construction vessel on contract.

A platform support vessel will be used as the subsea dispersant injection surface platform with dispersant stock and coil tubing unit. The subsea construction vessel will deploy the system where a dispersant manifold needs to be positioned on the sea floor and coiled tubing must then be deployed and moved into position using remotely operated vehicles. For optimal control of the injection two remotely operated vehicles should be used for this operation. One controls the dispersant injection wand into the oil release point, and the second supplies lighting and videography. Once deployed and connected, the system is designed to operate continuously.

The availability of the subsea construction vessel is the critical factor and this assessment looks at options for minimising mobilisation time for the subsea construction vessel, coordinating with the subsea dispersant injection equipment availability and transit to the Stromlo-1 location.

4.2.1 Subsea dispersant injection having a contracted vessel and equipment on location (two to five days)

The subsea dispersant injection can be operational in five days (P90), having subsea construction vessel SCV and SSDI equipment on location, while considering the following assumptions:

- Equipment and additional dispersant and materials for SSDI are available exclusively for this project and stand-by in Adelaide.
  - Coiled tubing unit and deployment stand-by in Adelaide
  - 200–300 m^3 of dispersants on stored on IBC and ISO tanks in Adelaide for timely transfer to PSV tanks
  - SSDI subsea equipment stored in Adelaide.
- A SCV with a suitably rated crane and enough deck space is on contract and on location. This vessel will be the stand-by vessel and BOP intervention tasks takes priority before the vessel can start the SSDI mission.

The PSV closest to port will return to port and take on SSDI equipment, coiled-tubing equipment, sea-fasten the equipment, and fill dispersant on its tanks from pre-filled ISO tanks (or ISO tanks being concurrent decanted from IBC). It will then steam to the location where the SSDI equipment will be transferred ship-to-ship to the SCV for deployment to the seabed and hook-up to the coiled tubing.

Further improvements to this option are considered:

- Vessels dedicated to SSDI installation (no SAR or BOP intervention) – SSDI can be operational in two days (P90).
  - This option would require another vessel with ROV on contract and available on location to perform SAR and BOP intervention while SCV is installing SSDI. The vessel would have to be contracted in advance to allow for getting a valid safety case.

Figure 4.2 presents the estimated schedule for having a contracted vessel and a full subsea dispersant injection system on location during drilling. It includes allowance for factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead and vessel availability.

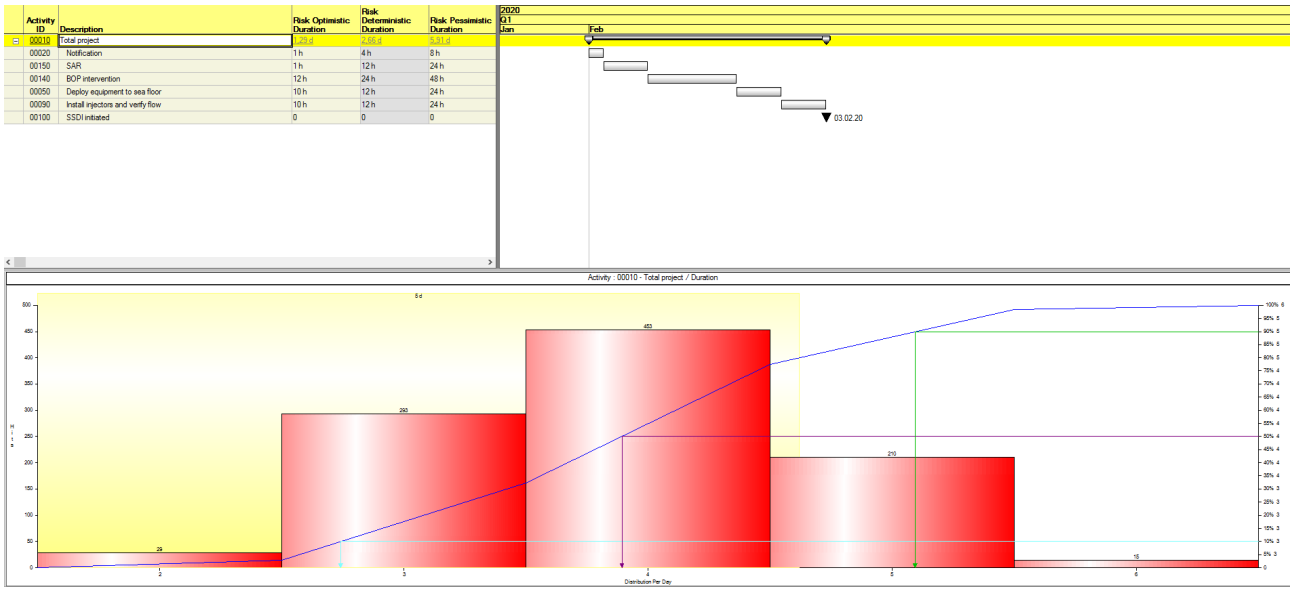


Figure 4.2 Subsea dispersant injection using contracted vessel and SSDI equipment stored on location (five days)

4.2.2 SSDI having a contracted vessel and equipment in Adelaide, picking up the equipment with a PSV (seven days)

The subsea dispersant injection can be operational in seven days (P90), having subsea construction vessel on location and SSDI equipment in Adelaide that is picked up by a PSV, while considering the following assumptions:

- Crew would be mobilised while the PSV is in transit to Adelaide and would not cause any delays. Equipment and materials for SSDI are available exclusively for this project and on location.
  - Coiled tubing unit and deployment frame
  - >200 m^3 of dispersants mobilised to Adelaide and stored or transferred to ISO tanks prior to the operation – combined with just-in-time IBC tanks from other dispersant stockpiles after LOWC
  - SSDI kit.
- Transferring of dispersants between ISO tanks and the PSV internal tanks, and decanting from IBC to ISO tanks, can be completed while loading the coiled tubing unit, deployment frame and SSDI kit.
- A SCV with a suitably rated crane and enough deck space is on contract and on location. This vessel will be the stand-by vessel and BOP intervention tasks take priority before the vessel can start the SSDI mission.
- The PSV closest to port will return to port and take on SSDI equipment, coiled-tubing equipment, sea-fasten the equipment, and fill dispersant on its tanks from pre-filled ISO tanks. It will then steam to the location where the SSDI equipment will be transferred ship-to-ship to the SCV for deployment to the seabed and hook-up to the coiled tubing. Refer to Section 3.10.2 for more details around this.

Figure 4.3 presents the estimated schedule for having a contracted vessel and a full subsea dispersant injection system in Adelaide during the petroleum activity on Stromlo-1. The equipment is picked up by a PSV while the SCV is performing SAR and BOP intervention. SSDI kit is transferred from PSV to SCV at sea. It includes allowance for factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead and vessel availability.

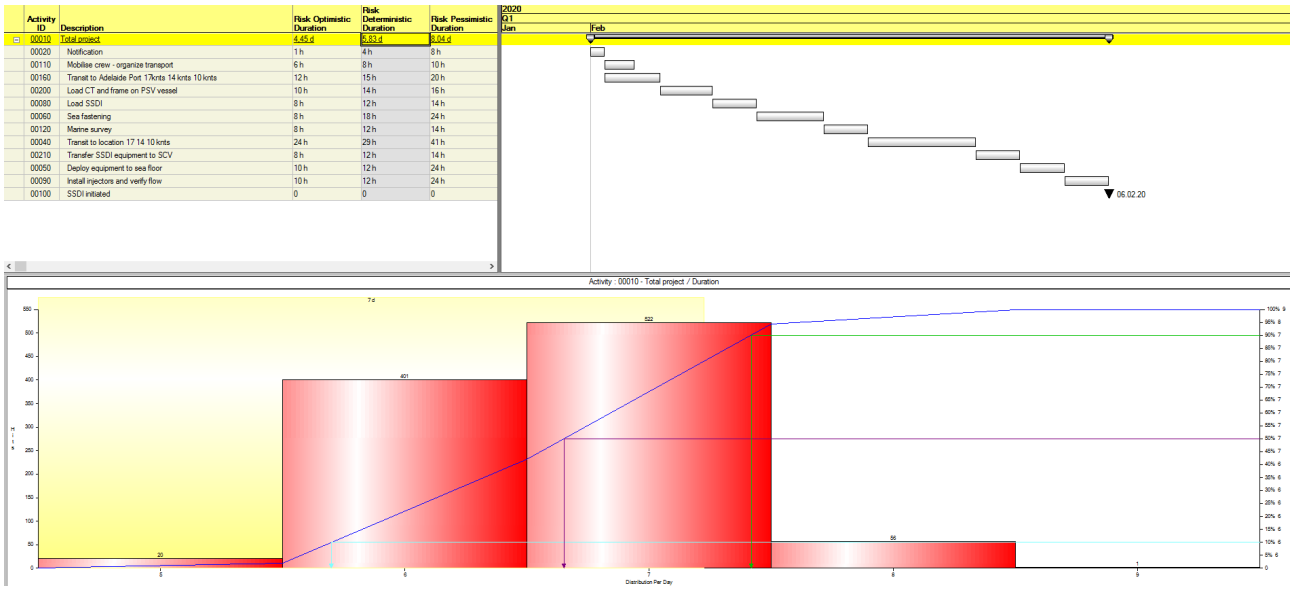


Figure 4.3 SSDI using a contracted vessel and equipment in Adelaide, picking up the equipment with a PSV (seven days)

4.2.3 Subsea dispersant injection using contracted vessel and equipment stored in Adelaide (nine days)

The subsea dispersant injection can be operational in nine days (P90), having subsea construction vessel on location and SSDI equipment in Adelaide, while considering the following assumptions:

- Equipment for SSDI is available exclusively for this project.
- Coil tubing unit and deployment frame on rental and ready in Perth (storing them in Adelaide does not reduce mobilisation time because they can be trucked to Adelaide while the SCV is completing initial site tasks)
- A SCV with a suitably rated crane and enough deck space is on contract and on location. This vessel will be the stand-by vessel offshore with its ROV at the time of an incident, this option allows the PSV to depart with >500m^3 of dispersant in its internal tanks from existing dispersant stocks in Australia.

Figure 4.4 presents the estimated schedule for storing a subsea dispersant injection kit in Adelaide, trucking a coiled tubing unit from Perth to Adelaide and using subsea construction vessel and PSV to load all subsea dispersant injection equipment in Adelaide and transit to site to commence subsea dispersant injection action. It includes allowance for factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead and vessel availability.

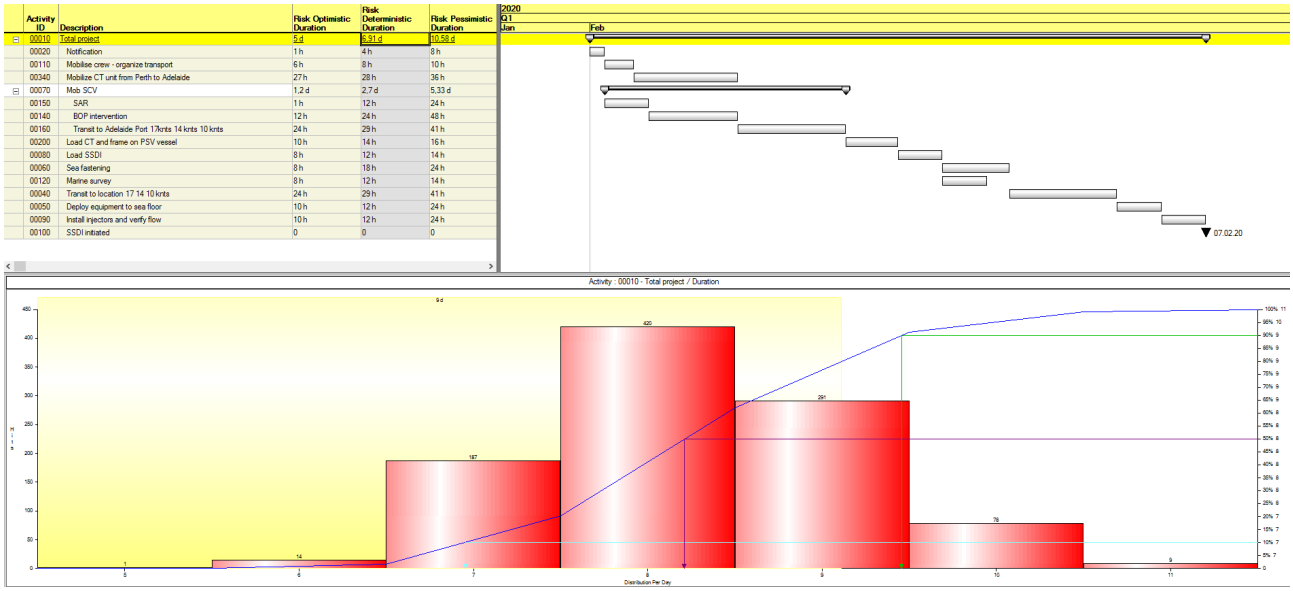


Figure 4.4 Subsea dispersant injection using contracted vessel and SSDI equipment stored in Adelaide (nine days)

4.2.4 Subsea dispersant injection using contracted vessel and equipment by air from Singapore (nine days)

The subsea dispersant injection can be operational in nine days (P90), mobilising SSDI equipment by air from Singapore, while considering the following assumptions:

- Coil tubing unit and deployment frame on rental and ready in Perth (storing them in Adelaide does not reduce mobilisation time because they can be trucked to Adelaide while the subsea construction vessel is completing initial site tasks)
- A SCV with a suitably rated crane and enough deck space is on contract and on location. This vessel will be the stand-by vessel offshore with its ROV at the time of an incident.
- There are frequent B747Fs scheduled to Sydney and Melbourne, and currently few to Adelaide; however, if there will be scheduled B747F flights to Adelaide in the future, then it will be used and may save 1–2 days,
- This option allows the PSV to be loaded and depart from Adelaide with >500m^3 of dispersant in its internal tanks from existing dispersant stocks in Australia.

The SSDI kit can also be mobilised from Perth at no additional cost or environmental benefit but adds contingency value in case of logistical issues with transport from Singapore.

Figure 4.5 presents the estimated schedule for mobilising a subsea dispersant injection kit by air from Singapore, trucking a coiled tubing unit from Perth to Adelaide and using subsea construction vessel and PSV to load all subsea dispersant injection equipment in Adelaide and transit to site to commence subsea dispersant injection action. It includes allowance for factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead and vessel availability.

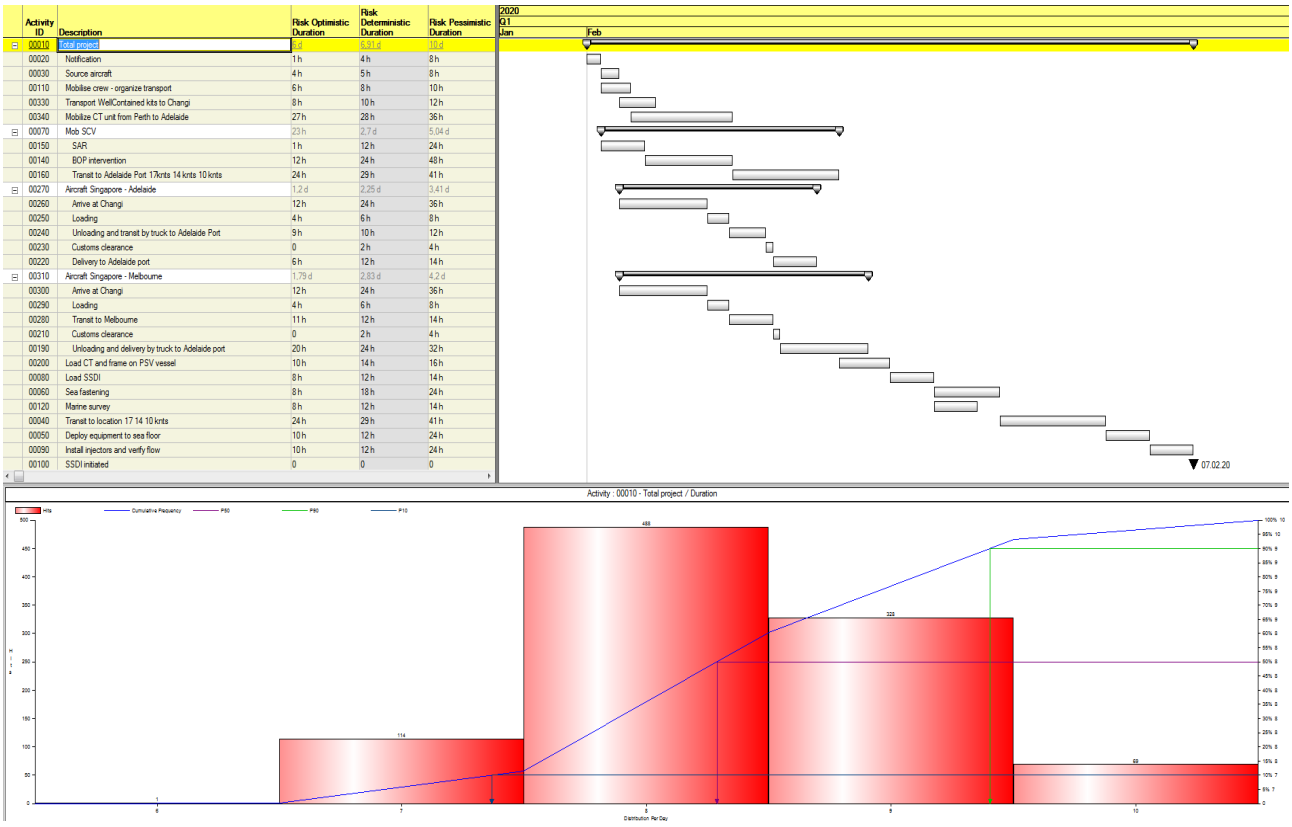


Figure 4.5 Subsea dispersant injection using contracted vessel and SSDI equipment by air from Singapore (nine days)

4.2.5 SSDI using subsea construction vessel from Singapore (23 days)

The subsea dispersant injection can be operational in 23 days (P90) when sourcing a subsea construction vessel in Singapore, transporting the SSDI equipment by sea on the SCV and loading a coil tubing unit and frame in Perth, while considering the following assumptions:

- The SCV will be contracted in or around Singapore as a vessel of opportunity, and the vessel will have an existing Australian Safety Case which will be amended for the SSDI operations.
- The SCV brings the SSDI components to Australia.
- There is no need to have a coil tubing unit on rental as there will be about two weeks mobilisation time during which it can be sourced from Perth and picked up by a PSV.

Figure 4.6 presents the estimated schedule for mobilising a subsea dispersant injection system using a subsea construction vessel and PSV from Singapore, transit to Perth to load coiled tubing and frame, and further transit to site to commence subsea dispersant injection action. It includes allowance for factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead and vessel availability.

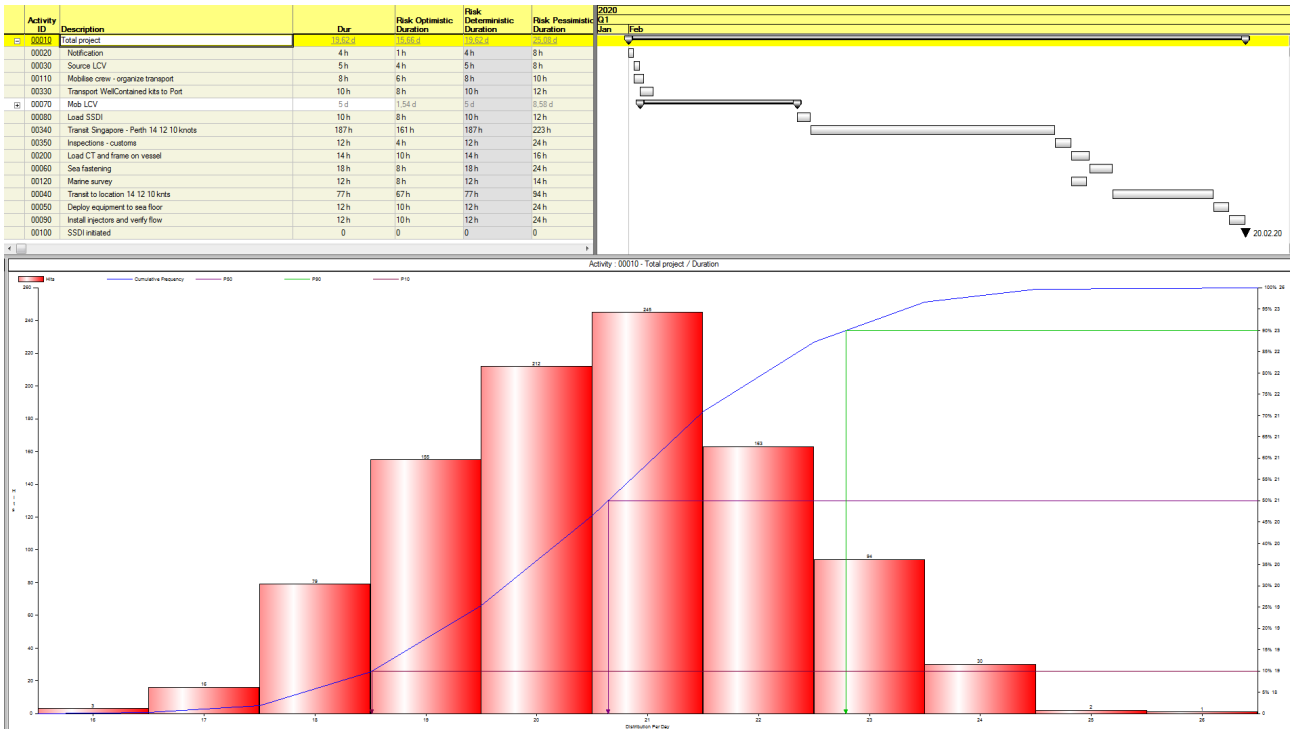


Figure 4.6 Subsea dispersant injection using subsea construction vessel from Singapore (23 days)

4.2.6 Subsea dispersant injection outcomes

Timely implementation of subsea dispersant injection will result in significant mitigation and will reduce shoreline loading and surface hydrocarbon expression. This would reduce the overall environmental risk because most of the key sensitivities and values of the area are associated with the nearshore waters, coastline and surface of the sea.

Equinor has adopted the option of having a suitably rated SCV on contract and on location during the petroleum activity on Stromlo-1. The PSV that will be the SSDI platform, will have the overall technical and functional requirements to function as a PSV in the GAB (DP, tank volumes, metocean etc). It will also have the requirement that a coiled tubing unit can be installed, using a frame, or another dispersant conduit system. It shall also have the requirement to transfer fuel and dispersant fluids at sea from another PSV, given the metocean conditions at the location. The SSDI installation is not very sensitive to metocean conditions. Refer to Section 3.8 of this document for more considerations around this SCV and metocean conditions on location. The vessels involved with SSDI will have a valid Australian Safety Case prior to the petroleum activity in Stromlo-1.

The main improvement in response time for SSDI is found in having this SCV on contract and on location, compared to mobilising vessel from Singapore. This measure allows for the subsea dispersant injection to commence on day nine as opposed to day 23. Applying dispersants directly to the subsea plume 14 days earlier is a significant environmental benefit because it will significantly reduce the volume of oil reaching the sea surface and therefore ultimately reduce shoreline loadings later.

The SSDI kits are available to Equinor through its contractual arrangements with Oil Spill Response Limited (OSRL) and Wild Well Control (WWC) and can be sourced and mobilised rapidly. This arrangement does not include the coiled tubing unit and deployment frame. To have timely access to this equipment, separate arrangements are required. Equinor will commit to having coiled tubing unit on retainer and have access to a deployment frame compatible with most PSVs. This will ensure that the equipment is available when and if required. The equipment will be mobilised from Perth by truck after the LOWC incident, similar to the SSDI kit located in Singapore which will be transported to Adelaide by flight. All this equipment will be mobilised while the SCV is undertaking SAR, BOP intervention and transiting to Adelaide, and will be available at the port at the time the SCV arrives in Adelaide on Day 5 (P90) after the LOWC incident.

To have more flexibility with the ROVs, Equinor will get manufactured clips for injection nozzles that will allow the injection points to be fixed on the BOP, allowing for continuous dispersant injection without ROV active support. This injection may then also occur without continuous surveillance. In the most likely situation, the rig will disconnect and be operational after LOWC. In this case the rig can be used both as a SSDI platform and its ROVs can be used to direct and observe the injection.

While the main bottleneck is vessel availability, followed by the conductor from vessel to seabed manifold, the second bottle-neck will be the dispersant supply-chain. For the initial deployment it would for a WCCD discharge situation be desirable to have in the range 300 to 500 m^3 dispersant fluid on the PSV internal tanks. The options of having this amount already on a PSV tanks, or pre-loaded on the liquid mud plant (LMP) has been considered and not adopted. Storing this amount of dispersant in Port Adelaide has also been considered and not adopted. The supply chain allowing for dispersant transport from a number of origins (Freemantle / Melbourne / Singapore) and the process of pumping dispersant in stages from IBC tanks, to ISO tanks, to LMP tanks, and finally to PSV internal tanks, would not allow for a P90 time line faster than five days without significant cost associated with pre-filling those larger tanks from 1 m^3 IBC containers.

In a scenario where all equipment and materials needed for SSDI, together with a competent crew and the vessel availability offshore, SSDI could be operational after two days if the vessels are dedicated to SSDI, and another vessel with ROV is available for SAR and BOP intervention. The cost of these options exceeds 10% of the project cost, with a mitigation minor impact (<3%) vs day 9 option. This is not industry standard and is neither considered ALARP.

The scenario equipment and materials needed for SSDI is stored ready in Adelaide and a PSV loads all equipment and supplies including 200–400 m^3 dispersant pre-loaded on larger tanks, while the SCV stays at location, could achieve an EPS of SSDI deployment day 5 or 6. The cost of these options exceeds 5% of the project cost, with a mitigation minor impact (<1%) vs day 9 option. Some of the options also relies on ship-to-ship transfer of heavy equipment and the P90 EPS is not robust. This is not industry standard and is neither considered ALARP.

The cost/benefit analysis of the additional controls that could be implemented for improving SSDI implementation efficiency, including the environmental benefits; financial, environmental and safety costs and the outcomes is presented in Table 5.1 of this document.

The decision diagram to assess the options for additional capability that could be implemented for SSDI is provided in Figure 4.7.

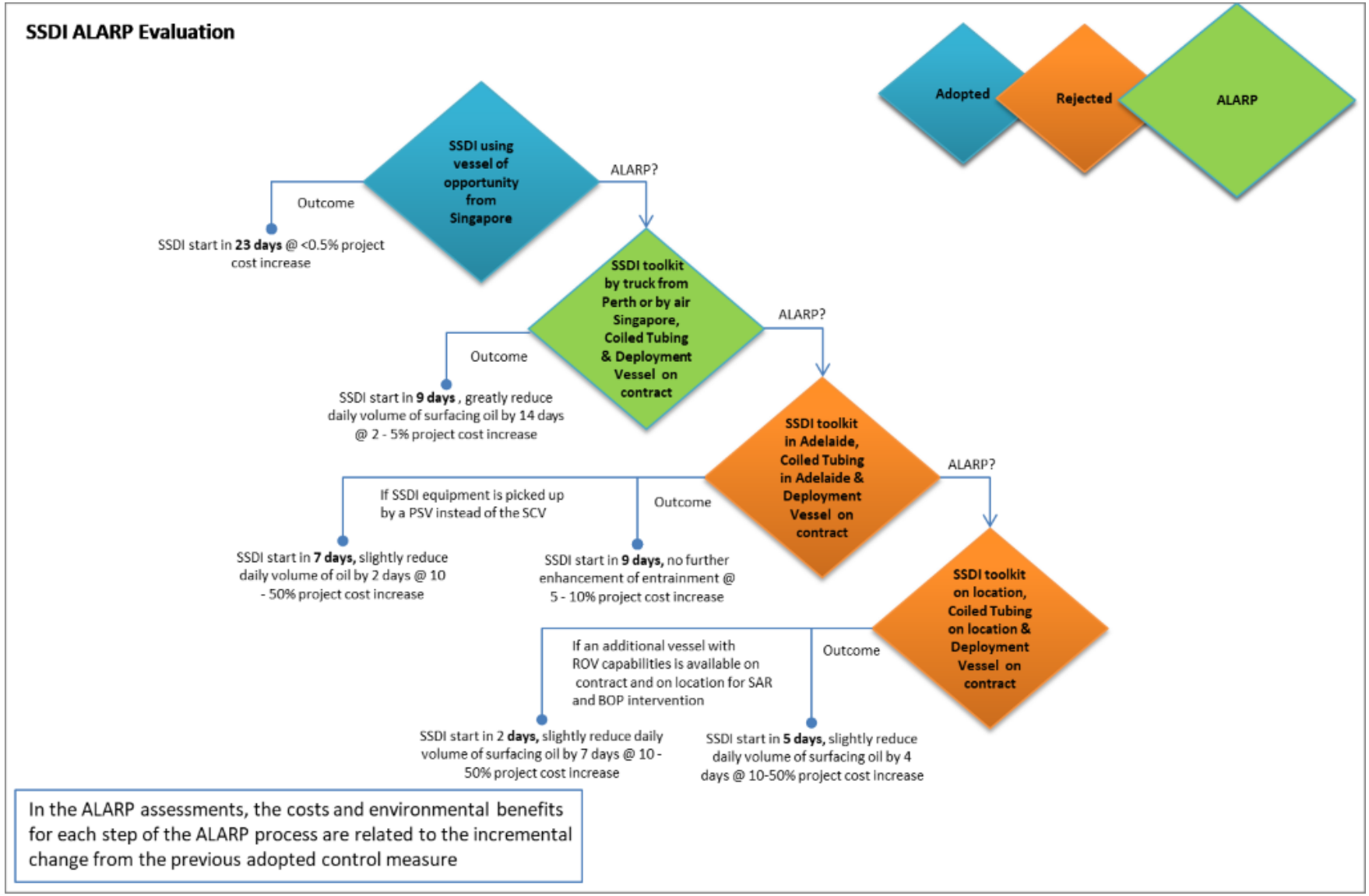


Figure 4.7 Subsea dispersant injection ALARP evaluation

4.3 Capping stack

Well capping requires the availability of an assembled, tested and verified well cap and other accessory capping equipment to be deployed by a construction vessel with a suitably rated crane. The capping plan assumes that the remotely operated vehicle has attempted to close the blowout preventer but has failed.

Equinor Australia B.V. has access to many capping stacks (CS) through subscription to Oil Spill Response Limited (OSRL) and Wild Well Control (WWC), which both provide access to a full subsea intervention capability, including dispersants and capping and containment equipment. These capping stacks must be centrally located because they support response plans across the whole industry. They are maintained ready for immediate use and onward transportation by sea or air in the event of an incident.

Logistics studies have demonstrated that the capping equipment can be delivered to the Stromlo-1 well site concurrently with the operations underway for blowout preventer intervention. The following capping stack options have been evaluated with the time to completely turn off the flow and stop the pollution:

- Option 1: WWC capping stack on rental stored on location – well capped in 8 days
- Option 2: WWC capping stack on rental stored in Adelaide – well capped in 14 days
- Option 3: WWC flyable capping stack using scheduled B747F to Sydney, Melbourne and Adelaide – well capped in 15 days
- Option 4: WWC flyable capping stack from Singapore to Adelaide using Antonov – well capped in 21 days
- Option 5: OSRL capping stack from Singapore by construction vessel – well capped in 24 days.

Many general steps which underpin all the capping stack options considered have been taken to reduce the number of days required to prepare for, plan and deploy a capping and containment solution. These are:

- Equinor holds subscriptions to response providers including OSRL and WWC, which enable immediate engagement and redundant access, including access to several concurrent capping stacks being mobilised to a single incident.
- Equinor has undertaken extensive logistics planning to identify the supply chain and logistical challenges facing capping stack deployment or deployment of other required equipment and vessels.
- Equinor will make a SCV with a suitably rated crane and approved Safety Case available in Australia during the drilling.
- The ROV vessel will be able to intervene on the blowout preventer within 24 hours, including surveying the scene making detailed capping plans feasible.

The capping plan assumes the most likely scenario where the Lower Marine Riser Package (LMRP) has disconnected from the blowout preventer as the rig disconnected either through the EDS or Deadman features of the BOP that we have committed to. Debris removal scenarios will be sequential and additional operations described in the RTM and debris removal chapter 3.

4.3.1 WWC capping stack on rental on location (three to eight days)

The capping stack can be in place in eight days (P90) if a suitable capping stack ready for operations were to be stored offshore, while considering the following assumptions:

- The capping stack would have to be stacked-up and tested in Adelaide by a competent crew and transferred to a vessel, assuming a crew is available at the time stack-up is required.
- Capping stack is available for rent in the time period set for Stromlo-1 petroleum activity.
- There is no debris to remove and the LMRP disconnected. If debris must be removed the SCV might need to return to Adelaide to take on this heavy equipment. This roundtrip plus sea-fastening will take 5 days. Debris removal may hence add 6 to 8 days in such a scenario. The only way to guarantee an EPS is to also rent the heavy-duty debris clearance equipment, significantly increasing the cost of this option.

Further improvements to this option are considered:

- Competent crew on stand-by together with the capping stack offshore – capping stack could be in place in six days (P90).
- Another vessel with ROV capabilities on contract for SAR and BOP intervention in addition to a competent crew on stand-by together with the capping stack offshore – capping stack could in theory be in place in three days (P90).

Figure 4.8 resents the estimated schedule for the well capping operation using a WWC capping stack stored on location. It includes allowance for factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead and vessel availability.

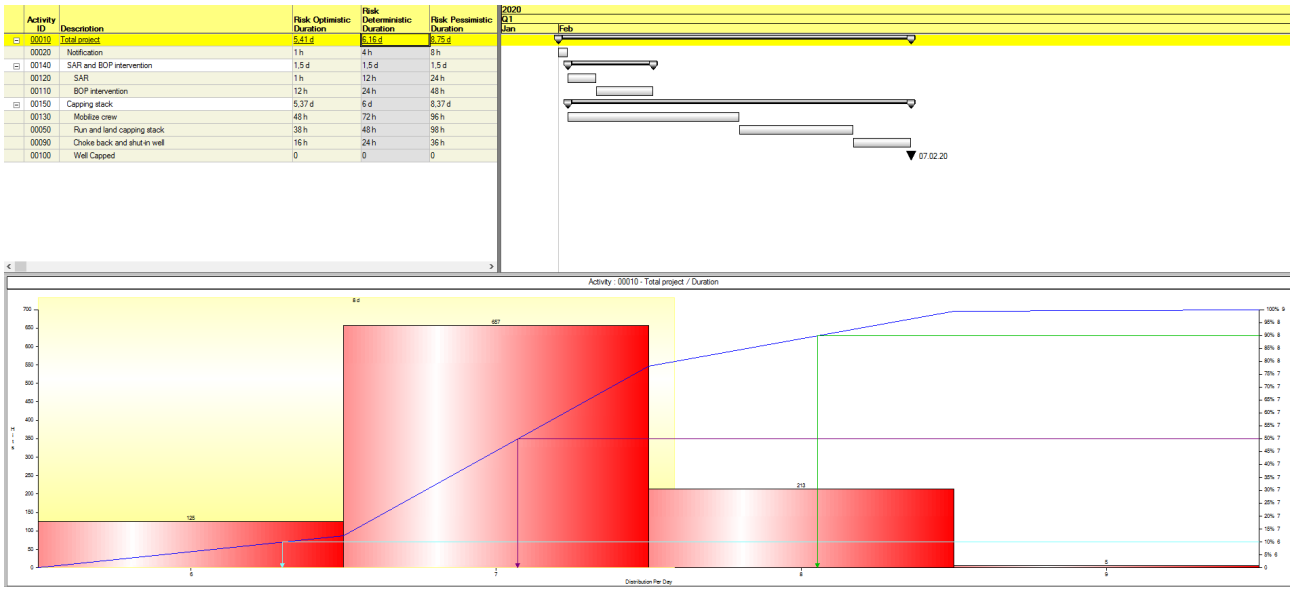


Figure 4.8 WWC capping stack on rental stored on location (eight days)

4.3.2 WWC capping stack on rental stored in Adelaide (nine to 14 days)

The capping stack can be in place in 14 days (P90) if a suitable capping stack is stored in Adelaide, while considering the following assumptions:

- The capping stack is stored in the port in Adelaide in the containers it was shipped in, only stacked-up and tested in the event of a LOWC incident.
- Capping stack is available for rent in the time period set for Stromlo-1 petroleum activity.
- There is no debris to remove and the LMRP disconnected. Debris removal kit will be mobilised by air and will arrive in Adelaide day 6. Debris removal will not need to wait on equipment, and only add 1 to 3 days depending on the scenario.

Further improvements to this option are considered:

- Competent crew on stand-by together with the capping stack. Capping stack stacked-up and tested – capping stack could be in place in 11 days (P90).
  - The capping stack would then be stacked-up, tested and stored at the berth as there is currently no suitable storage hangar and transport options of a pre-assembled capping stack to the quay in Port Adelaide. It would be stored on the quay so that it is within reach of the SCVs crane.
- Another vessel with ROV capabilities on contract for SAR and BOP intervention. Competent crew is on stand-by together with the capping stack in Adelaide. Capping stack stacked-up and test – capping stack could in theory be in place in nine days (P90).

Figure 4.9 resents the estimated schedule for the well capping operation using a WWC capping stack stored in Adelaide. It includes allowance for factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead and vessel availability.

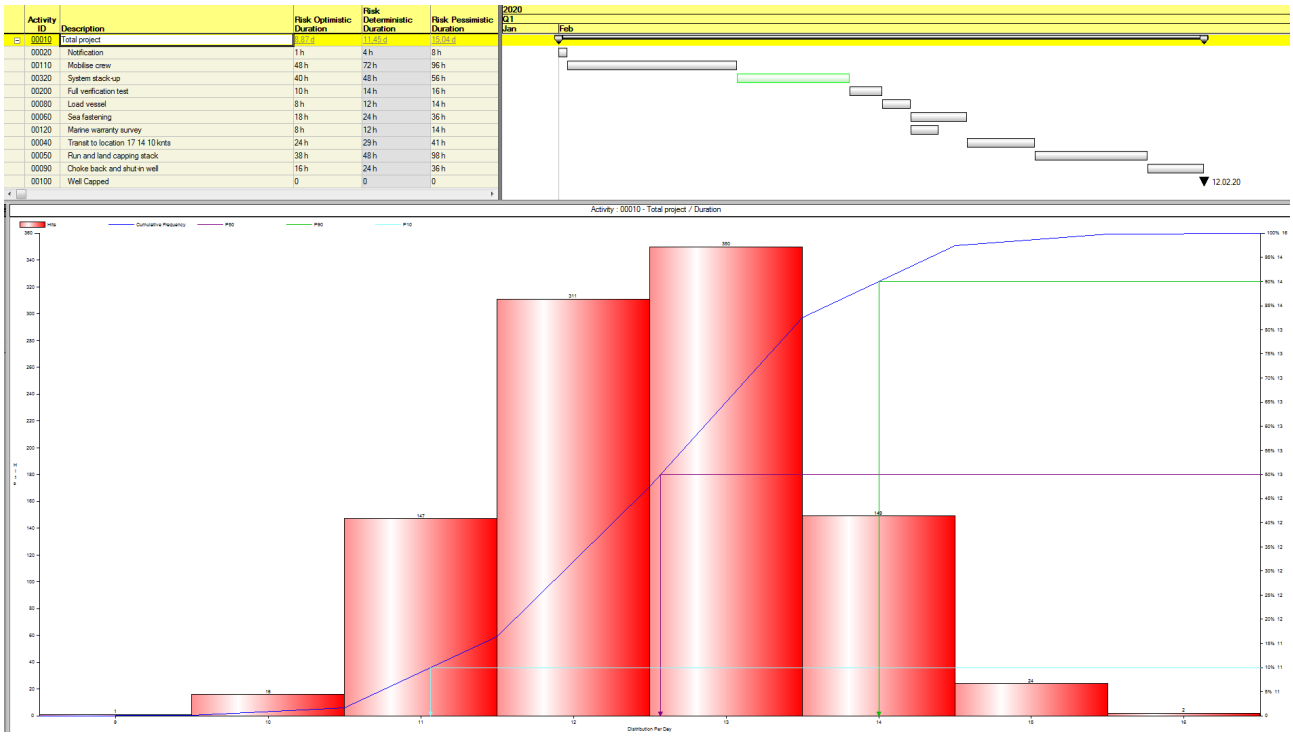


Figure 4.9 WWC capping stack on rental stored in Adelaide (14 days)

4.3.3 WWC flyable capping stack using scheduled B747 (15 days)

Using scheduled Boeing 747 flights from Singapore to three different airports in Australia and then sending the items by road to Adelaide would reduce mobilisation time and eliminate the limitation of the main deck loader, since Sydney airport has 35 t capacity for offloading. This schedule also addresses airport general freight handling capacity, airport curfew (Adelaide), and the fact that there are many scheduled Singapore Airline B747F flights to Sydney and Melbourne each week. Refer to Section 3.0 for more details around logistical arrangements.

The WWC flyable capping stack can be flown from Singapore as scheduled B747F airfreight and in place in 15 days (P90), while considering the following assumptions:

- Equinor will get priority on the scheduled B747F freighters already scheduled for Sydney and Melbourne.
- Customs clearance procedures have been checked and verified with the operation group of Australian Border Force and our freight forwarding and custom clearance broker. By using correct procedures for emergency material and biological verification before departure in Singapore, customs hold-ups will be at most two hours (24/7).
- Heavy truck transport capacity is readily available within the time frame and this is not considered a critical part of the time line. The transport route to Adelaide Port has been assessed and no choke points have been identified.

Figure 4.10 presents the estimated schedule for the well capping operation using a WWC flyable capping stack using scheduled B747F flights. It includes allowance for factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead and vessel availability.

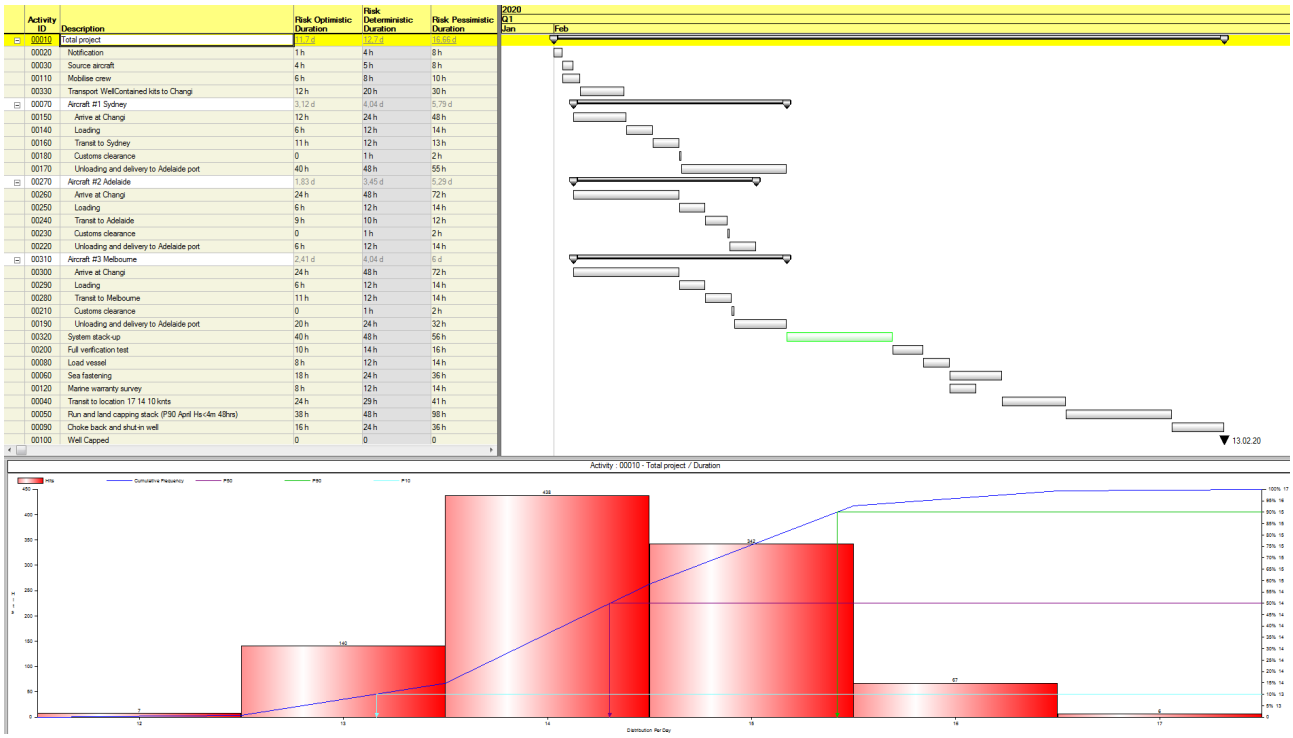


Figure 4.10 WWC flyable capping stack using scheduled B747F (15 days)

4.3.4 WWC flyable capping stack from Singapore to Adelaide (21 days)

The Wild Well Control capping stack in Singapore is in containers ready to be flown. Due to the weight of some of the items and the limited equipment available at Adelaide airport for offloading heavy equipment from transport aircrafts main deck, an Antonov must be used.

The capping stack can be in place in 21 days (P90) using WWC flyable capping stack from Singapore to Adelaide, while considering the following assumptions:

- The average time to charter the Antonov aircraft is seven days.

Figure 4.11 presents the estimated schedule for the well capping operation using a WWC capping stack flown from Singapore to Adelaide, including factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead, and subsea construction vessel availability.

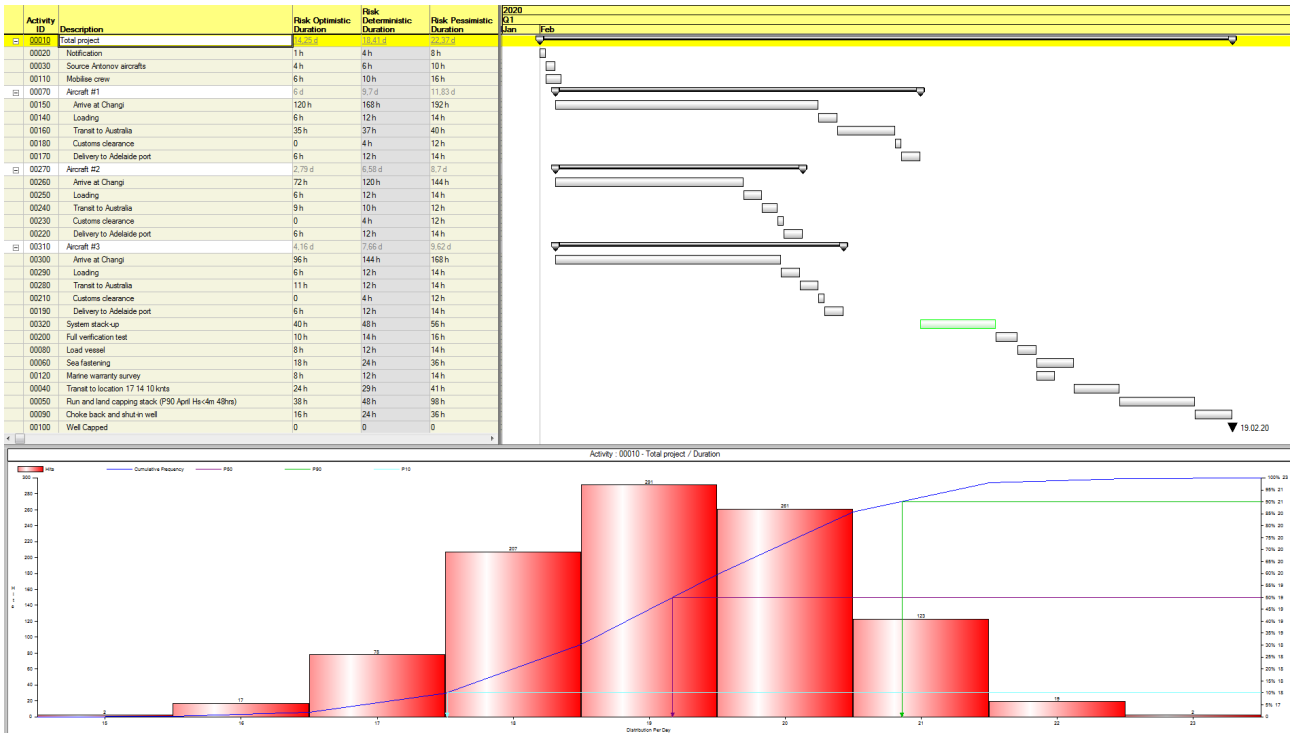


Figure 4.11 WWC flyable capping stack from Singapore to Adelaide (21 days)

4.3.5 OSRL capping stack from Singapore by construction vessel (24 days)

This solution uses the OSRL capping stack that is on stand-by (ready, assembled and tested) in Singapore. It will be transported to the quay and installed directly onto a construction vessel that will sail it to the well location and install it. One of the uncertainties will be the availability of a suitable offshore construction vessel. The capping stack can be in place in 24 days using the OSRL capping stack from Singapore by construction vessel, while considering the following assumptions:

- The construction vessel can be sourced and mobilised to Singapore in five days (P90). This uncertainty can be managed by several mechanisms such as a “first right of refusal” contract.
- The SCV already has an Australian Safety Case that can be amended for the capping activity while transiting from Singapore.
- There is no need to remove the LMRP, either because it was disconnected by the Emergency Disconnect Sequence (EDS), or because it has been removed ahead of time by using another vessel. If there is a need to remove the LMRP then three days should be added.
- The construction vessels are typically 100–150 m long and cruise at approximately 14 to 16 knots; however, a P90 cruising speed of 10 knots is used to take into consideration unfavourable weather, wind, current and sea state in travelling from Singapore to the Great Australian Bight.

Figure 4.12 presents the estimated schedule for the well capping operation using an OSRL capping stack from Singapore, including factors such as metocean conditions, accessibility to the area of the blowout preventer and wellhead, and vessel availability. The P90 time for deploying the capping stack is 24 days.

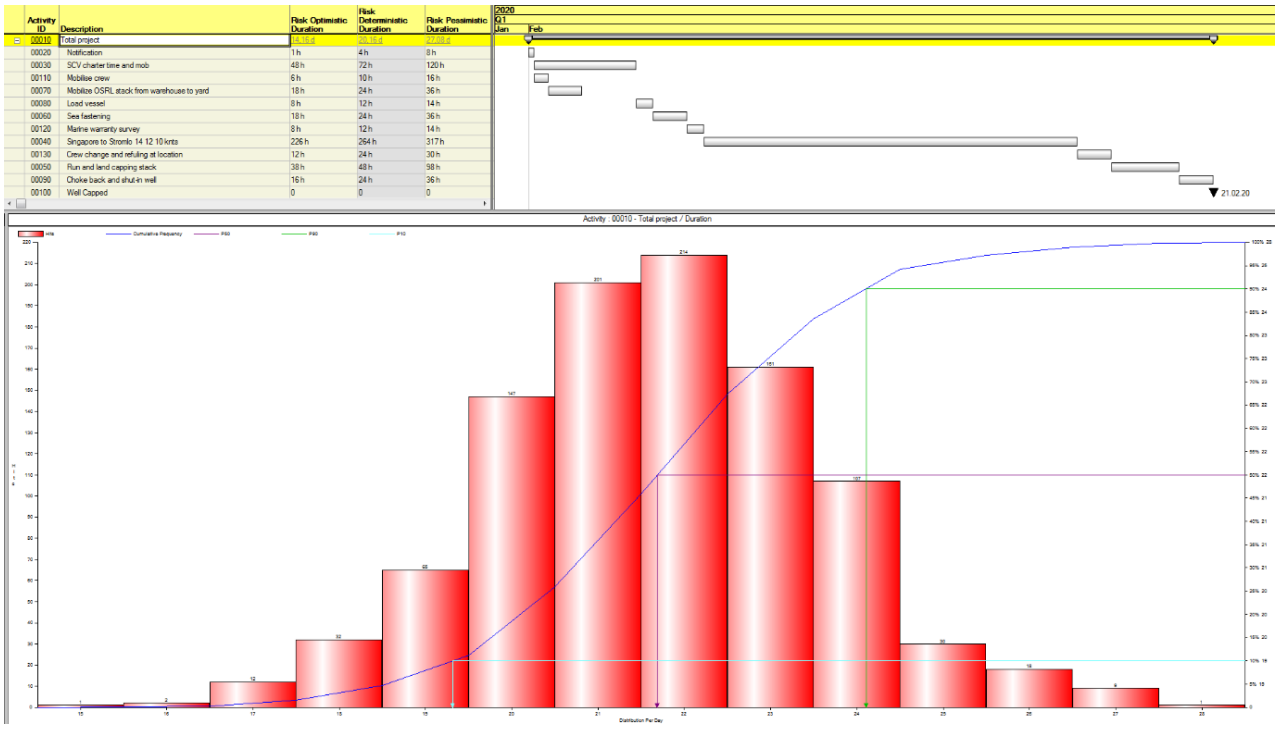


Figure 4.12 OSRL capping stack from Singapore by construction vessel (24 days)

4.3.6 Capping stack ALARP outcomes

The key improvement in the ALARP assessment cases for capping stack is found in having this SCV on contract and on location with a valid safety case for the capping stack operations, compared to mobilising one from Singapore together with the capping stack. Refer to Section 3.8 of this document for more considerations around this SCV and metocean conditions on location. The measure of having the SCV on site and flying in the WWC capping stack from Singapore allows for the capping stack to be in place on day 15 as opposed to day 24. Singapore should be regarded as being in the region, and the logistical facilities (airport, loading equipment, and flight schedules) in Singapore allows for fast response. Capping the well nine days earlier is a significant environmental benefit because it will significantly reduce the volume of oil reaching the sea surface and therefore ultimately reduce shoreline loadings later. This is considered ALARP and is adopted.

To improve the time line of capping the well earlier than day 15, the capping stack would have to be rented or purchased exclusively for this project and stored in Adelaide or on location. There is no guarantee that a capping stack is available for rent during the petroleum activity on Stromlo-1, and the time required for manufacturing a capping stack is ~24 months. The benefit of between 1% to 5% reduction of oil lost (depending on what option is adopted) is disproportionate compared to the major cost it will incur (>10% of project cost). Given the small incremental improvement in time line, and that such arrangements are not industry practice, these options of storing a capping stack at location or in Adelaide is not considered ALARP and is not adopted.

A light-weight capping stack from the USA was evaluated as a rental but not adopted as it is not feasible for a high case of flowrate and GOR for Stromlo-1. Lift forces have been analysed for a well with similar worst case discharge (WCD) as Stromlo, using a 7 1/8” 10 k psi capping stack. The analysis showed that a 7 1/8” capping stack, similar to OSRLs capping stack in Singapore, would require an additional force of 14 000N to avoid lateral translation on the capping stack above the wellhead or BOP. The analysis used 100 000 barrels of oil per day (BOPD) with 2000 gas oil ratio (GOR). The median case for Stromlo is 300 GOR and high case of 1500, while the flowrates are of the same order 11,900 m^3/day (75 000 BOPD). The lightweight capping stack from the USA weighs almost half of the 7 1/8” 10k psi capping stack used in the analysis mentioned above, and so the high case of flowrate and GOR for Stromlo-1 will result in negative buoyancy, and the capping stack cannot be landed on the flowing well. In the GAB environment with persistent swells, a heavier stack will also aid in the heave compensation making the landing process more robust. The advantage of needing a lighter construction vessel (with lesser specification on the crane and heave compensation), is not that relevant in the GAB as persistent heave makes it important to have high specification on the crane heave compensation. The option of a light-weight capping stack from the USA is not feasible or considered ALARP and is not pursued any further.

Having a competent crew in Adelaide or on location has also been considered as an improvement for the time line of capping the well earlier than day 15. Equinor will get immediate access to this crew when notified, and they can be mobilised without delay while the capping stack is mobilised from Singapore. This option is not adopted as there will no additional benefit of this option if the capping stack is not pre-emptively mobilised. A mobilisation plan for the crew will be prepared in advance to ensure that they are mobilised as rapidly as possible.

Equinor has also considered storing the capping stack, and potential crew, in other places than in Adelaide and on location:

- ports – Perth and Port Lincoln
  - Perth: There will no time benefit in storing the capping in a port in Perth compared to Adelaide port and transporting to location by vessel. The logistical facilities (airport, loading equipment, and flight schedules) in Singapore allows for faster response to the eastern part of Australia due to limitations in Perth airport (making only road or sea transport viable)
  - Port Lincoln has no wharf with the capacity and infrastructure needed (weight and hoists), and follow-up logistics would be via truck to/from Adelaide, which makes it less reliable in the event that additional equipment is needed (debris removal, etc.)
- having the capping stack on a vessel in the port, or in a suitable anchorage, ready for transport to location: This option would require a dedicated vessel and would not give any value to the project unless a LOWC incident. The option has a greater cost than storing the capping stack on the SCV on location and gives less time benefit.

These options are superseded by the alternatives. The option of storing at a port in either Adelaide or Port Lincoln, would reduce the mission by one day compared to mobilising the regional capping stack from Singapore when and if required, and with significant added cost. The cost of renting a capping stack exclusively is very high. If Equinor were to adopt this cost, the capping stack would rather be stored on the SCV on location instead of in a port or on a dedicated vessel in a suitable anchorage. Storing the capping stack on site would cost the roughly same as storing the capping stack in a port, and with 7-12 days reduction of days with lost oil, depending on if a crew is on stand-by or not.

When considering the potential benefit of renting or purchasing a capping stack, debris clearance must also be considered and may be required prior to installing the capping stack. Time for debris clearance is not included in the time estimates for the different options as the most likely case is that the LMRP has successfully disconnected. Debris clearance will have negative impact on time benefit for all options where a capping stack is mobilised after LOWC incident or on stand-by in Adelaide. The delay will not only be the time the debris clearance takes as sequential operations before the capping, but for some options with the capping stack on location the vessel may need to return to Adelaide to take on this equipment. Debris clearance equipment may be too heavy to be transferred ship-to-ship safely from a PSV at sea. Referring to Section 3.9 of this document for more details around debris clearance, and Section 3.10.2 for more details around at-sea transfer.

The capping stack in Singapore and other places worldwide are regional resources, including the crew on stand-by duty. This crew is part of a global pool with limited number of professionals for capping stack deployment. The need for them to be available for other incidents world-wide might cause a stand-by crew in Adelaide to potentially have negative impact on response at an industry level if a major accident was to happen elsewhere.

The capping stacks are located in locations with support infrastructure (storage, maintenance, testing) and also logistical response infrastructure (harbour, vessel capacity, cranes, transport, airports). The contracts with WWC and OSRL are intended for use in an emergency response only and will secure that the resources are available to those that might need it, when they need it. The contract with OSRL and WWC also ensures access to a second capping stack. Based upon the scale and the actual LOWC situation, it is the intention of Equinor to have a robust response. A robust response includes back-up and fall-back options. For the capping option it is the intention to mobilise a second capping stack from one of several locations based upon the actual logistic situation at the time. This can be OSRL in Singapore, on a second construction vessel contracted when the situation arises or flying in a second capping stack from Europe if a suitable deployment vessel happens to be in the region (for example around Perth). It is reasonable to make arrangements for such redundant back-up operations, after the LOWC has occurred, and the scale and nature is clear, since the primary response effort will be exhausted before the redundant option is needed.

The cost/benefit analysis of the additional controls that could be implemented for improving capping stack implementation efficiency, including the environmental benefits; financial, environmental and safety costs and the outcomes is presented in Table 5.1.

The decision diagram to determine the additional capability that could be implemented for well capping is provided in Figure 4.14. The option of flying the capping stack to Adelaide (Option 4) is not included in this diagram to avoid confusion. Equinor has adopted the optimal flight solution of sending the capping stack to Sydney or Melbourne by B747F, rather than slower solution of using the Antonov An-124 to Adelaide.

Summary of resources and costs for the pre-emptive capping stack deployment option are shown in Figure 4.13. Figure 3.1 The equipment and personnel assumed for the option assessment are:

- capping stack, 10K, 18¾" full-bore, H4 connectors
- subsea construction vessel with 250 t heave compensated crane and ROV
- Light Intervention Kit (Subsea First Responder Toolkit), for minor debris removal
- heavy-duty debris removal kit, for cutting 21" riser elements and remove LMRP
- crane at Adelaide port to allow for stack-up
- on-shore crew: 3–5 competent capping / subsea crew that can stack-up the capping stack, perform pressure testing and maintenance
- off-shore deployment crew: 4–6 competent crew and supervisor that can prepare the stack offshore for deployment, execute optional debris removal operations, deploy the stack, and shut-in the well
- the fastest capping options would not make the SSDI mission redundant as this option and its EPS would remain, this requires an additional vessel (a light intervention vessel), with a lesser crane requirement (70–100 t) compared to the about 250 t crane vessel.

Capping Stack Options	Option 1 (MUSD) ON LOCATION			Option 2 (MUSD) IN ADELAIDE			Option 3 (MUSD) Flyable from SIN and SCV on contract
Sub-Options / Resources & Costs	Capping stack and crew on dedicated SCV	Capping stack and crew on SCV	Capping stack on SCV	Capping stack and crew in Adelaide. Dedicated vessel	Capping stack and crew in Adelaide	Capping stack in Adelaide	
	3 days	6 days	8 days	9 days	11 days	14 days	15 days
Regional shared capping stack - WWC/OSRL	V	V	V	V	V	V	V
SCV in Great Australian Bight	V	V	V	V	V	V	V
Rent of capping stack	V	V	V	V	V	V	-
Extra subsea crane vessel	V	-	-	V	-	-	-
Mobilize	V	V	V	V	V	V	-
Crew - onshore	V	V	V	V	V	-	-
Crew - offshore	V	V	-	-	-	-	-
Stack-up	V	V	V	V	V	-	-
Light-duty debris clearance	V	V	V	-	-	-	-
Heavy-duty debris clearance	V	V	V	V	V	-	-
Rig down and demobilize	V	V	V	V	V	-	-
Post-maintenance	V	V	V				-
Total cost estimate	**25.8**	**20.8**	**20.6**	**25.25**	**20.25**	**19.1**	**9**

Figure 4.13 Detailed analysis of the cost of each of the pre-emptive capping stack deployment option

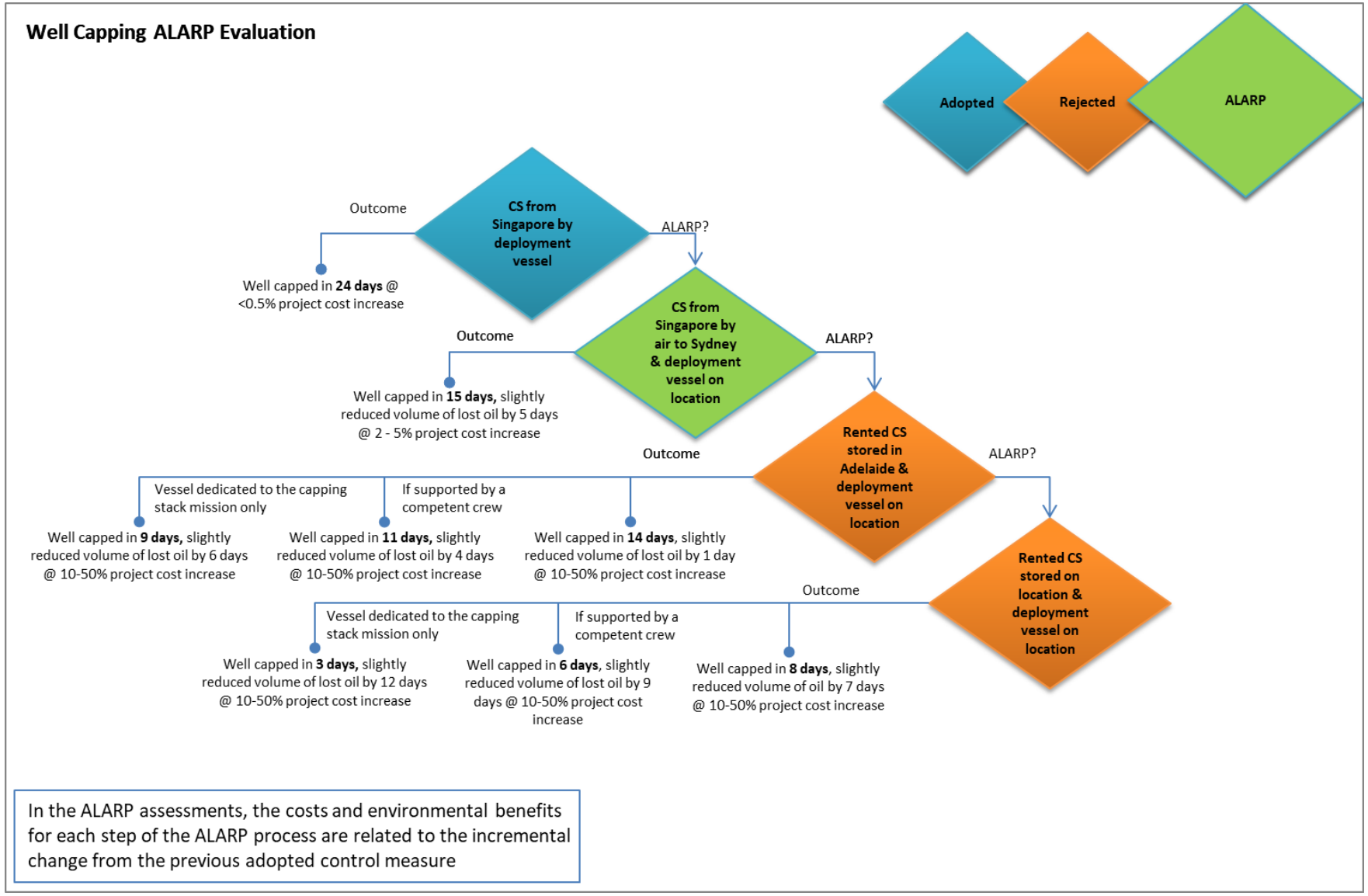


Figure 4.14 Well capping ALARP evaluation

4.4 Relief well

The relief well (RW) is considered a highly reliable and effective method of stopping a spill from a subsea loss of well control. A replacement rig might be needed; however, the most likely scenario would be that the main rig would have successfully executed an EDS and be able to start drilling the top sections of the relief well within a few days. The times until the well could be killed and the oil leak stopped have been studied in detail for the following relief well rig alternatives:

- Option 1: Relief well rig drilling relief well in parallel with main rig at Stromlo-1 – relief well drilled in 44 days.
- Option 2: Relief well rig on stand-by close to Stromlo-1 location – relief well drilled in 63 days.
- Option 3: Relief well rig on stand-by in the Great Australian Bight – relief well drilled in 68 days.
- Option 4: Main rig disconnects and can drill the relief well top-holes, then relief well rig from North West Shelf completes relief well – relief well drilled in 73 days.
- Option 5: Relief well rig from North West Shelf in Australia – relief well drilled in 88 days.
- Option 6: Relief well rig from Singapore with Australian Safety Case – relief well drilled in 102 days.
- Option 7: Relief well rig from South-East Asia without Australian Safety Case – relief well drilled in 149 days.

For the Stromlo-1 exploration drilling program, the well equipment required to commence a relief well will be stored at Port Adelaide. Additional equipment will be mobilised concurrently with MODU mobilisation and is therefore not a critical element of the relief well time frame.

Additional information regarding relief well design and plan is addressed within the WOMP.

The availability of the rig is the critical factor and this assessment looks at options for minimising mobilisation time for getting rig and equipment to location and options for having it available on location the rig during the petroleum activity on Stromlo-1.

4.4.1 Rig drilling relief well in parallel with main rig at Stromlo-1 (44 days)

Equinor evaluated drilling of a relief well in parallel with the petroleum activity at Stromlo-1. The relief well is then assumed to be completed until the end of the 16” section, meaning that the 13 5/8” casing is installed and cemented in place. Drilling of the 12 ¼” and installing 9 7/8” liner is not recommended based on the following risks:

- In case of any contingencies (re-spud, contingency sections and/or adjustment of reservoir depth) the relief well could end up being sub-optimal if completed down to and including the 9 7/8” liner. In a worst case this could require time-consuming side-tracking operations from the 9 7/8” liner or 13 5/8” casing. The 9 7/8” liner in the relief well would then create large magnetic interference when ranging towards the 9 7/8” liner shoe in the flowing well (Stromlo-1).
- Risk of unplanned collision with Stromlo-1 caused by uncertainties and/or incorrect sensors.

A relief well can be completed in 44 days (P90) using a relief well rig drilling a relief well in parallel with the petroleum activity on Stromlo-1, while considering the following:

- The estimated time for drilling to the end of the 12¼ inch section is based upon Equinor’s extensive experience in drilling wells.
- The rest of the assumptions, including ranging, interception and killing of the well, are based upon Wild Well Control’s analysis for this specific well, using their experience and reference data.

Figure 4.15 presents the estimated schedule for drilling a relief well in parallel with the petroleum activity on Stromlo-1.

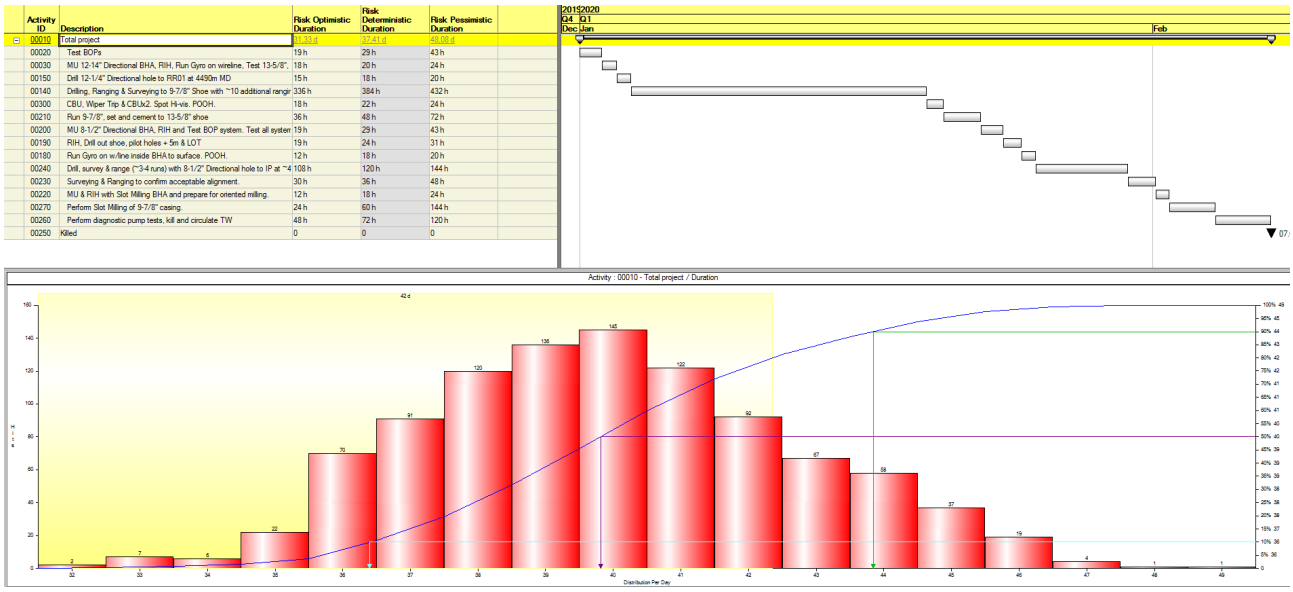


Figure 4.15 Relief well rig drilling relief well in parallel with main rig at Stromlo-1 (44 days)

4.4.2 Rig on stand-by close to Stromlo-1 location (63 days)

A relief well can be completed in 63 days (P90) using a relief well rig on stand-by close to Stromlo-1 location during the petroleum activity. A stand-by rig on location is generally only a consideration in parts of the world where the sea freezes and it is not possible to access the drilling location in winter. The rig would then be on stand-by with full crew, in addition to two support vessels for supply and helicopter for crew change.

Figure 4.16 presents the estimated schedule for drilling a relief well using a relief well rig on stand-by close to Stromlo-1 location.

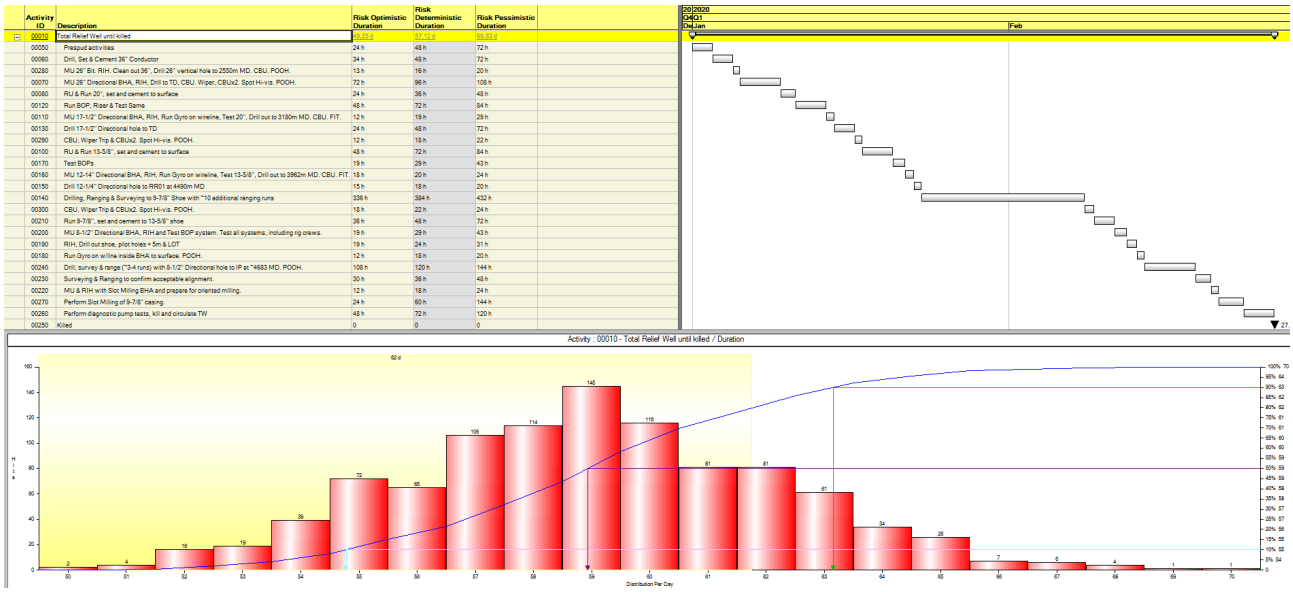


Figure 4.16 Relief well rig on stand-by close to Stromlo-1 location (63 days)

4.4.3 Rig on stand-by east of Port Lincoln (68 days)

Equinor have also evaluated having a dedicated relief well rig on stand-by in South Australia during the petroleum activity. There are few options for stationing a suitable rig in South Australian waters, and it would probably need to be held near Port Lincoln based on the following assessment:

- Port Lincoln is the closest, suitable and safe anchorage for the relief rig within the immediate area. It can be held in a sheltered, low-risk location, anchored (not on DP) to reduce fuel use (cost and emissions reduction) and can have reduced crew. It is also close to an airport for flying in personnel.

A relief well can be completed in 68 days (P90) using a relief well rig on stand-by east of Port Lincoln, while considering the following assumptions:

- If the rig is on stand-by, the decision to mobilise it is 0.8 days (P90).
- The rig would need three days (P90) to take on supplies and personnel before departure.
  - The three-day period is mainly needed for getting the right personnel mobilised. The warm rig would probably be manned by a skeleton crew. There are limited options to fly large numbers of personnel offshore from Ceduna (6–8 on a hot day, 8–12 on a normal day). The manning up of the rig to some degree must happen before departure, and provisioning, will happen after an incident. The P90 assumption of 72 hours is based on up-manning, provisioning, and removing anchors, and is a reasonable worst-case assumption. The P10 assumption in the time-planner for this process is 24 hours, and the expected time is 48 hours.
- The rig would need three to six days (P90) to transit to the site and complete pre-spud activities.

Figure 4.17 presents the estimated schedule for drilling a relief well using a relief well rig on stand-by east of Port Lincoln, including factors such as metocean conditions.

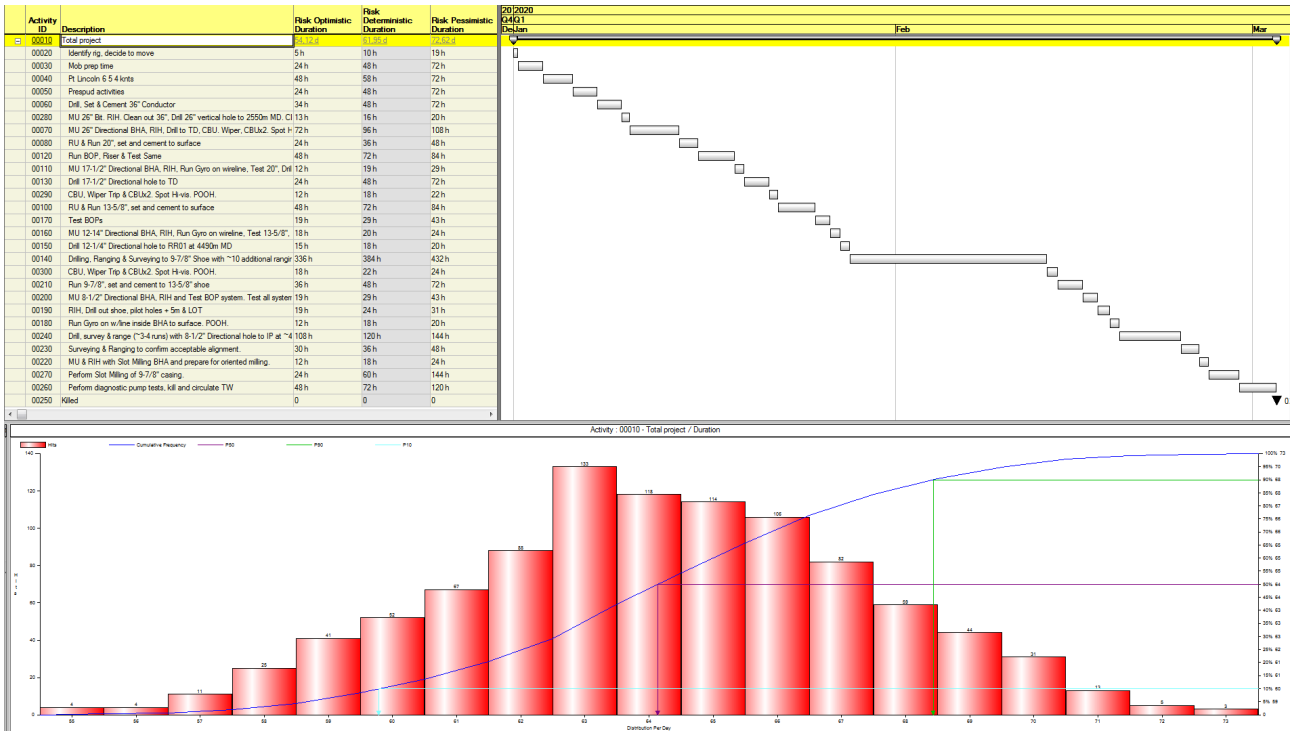


Figure 4.17 Relief well rig on stand-by east of Port Lincoln (68 days)

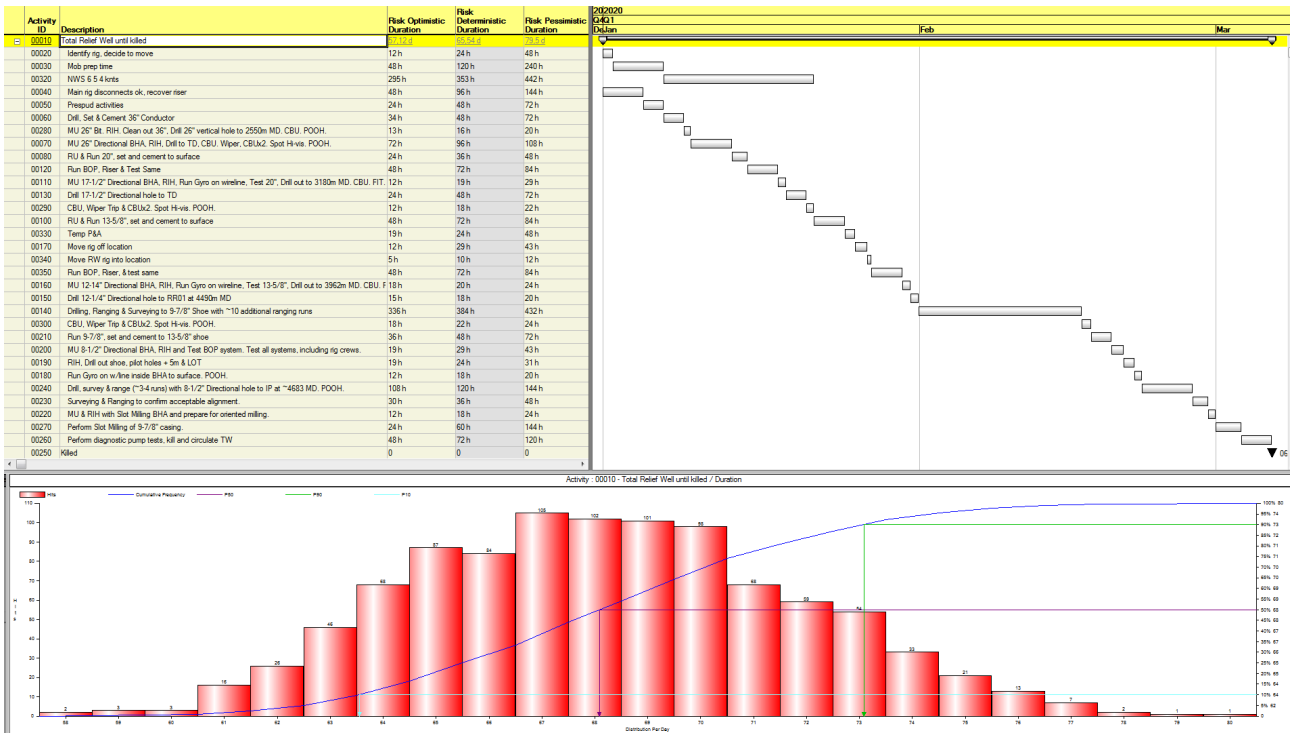
4.4.4 Main rig disconnects LMRP, drills relief well top-holes and relief well rig from North West Shelf (73 days)

The EDS would disconnect the LMRP from the Blow-out Preventer (BOP) if there were to be a loss of well control situation and the blowout preventer did not work. The rig could then recover the riser and start drilling the top sections (riser-less) while waiting for a new rig to arrive.

A relief well can be completed in 73 days (P90) using the main rig to drill the relief well top-holes while a relief well rig is mobilised from the North West Shelf, while considering the following assumption:

- The pre-spud activities have been set to six days, and this assumes that there is a set of wellhead and surface casing available in Adelaide.

Figure 4.18 presents the estimated time schedule for drilling a relief well using a main rig and relief well rig from the North West Shelf, including factors such as metocean conditions.



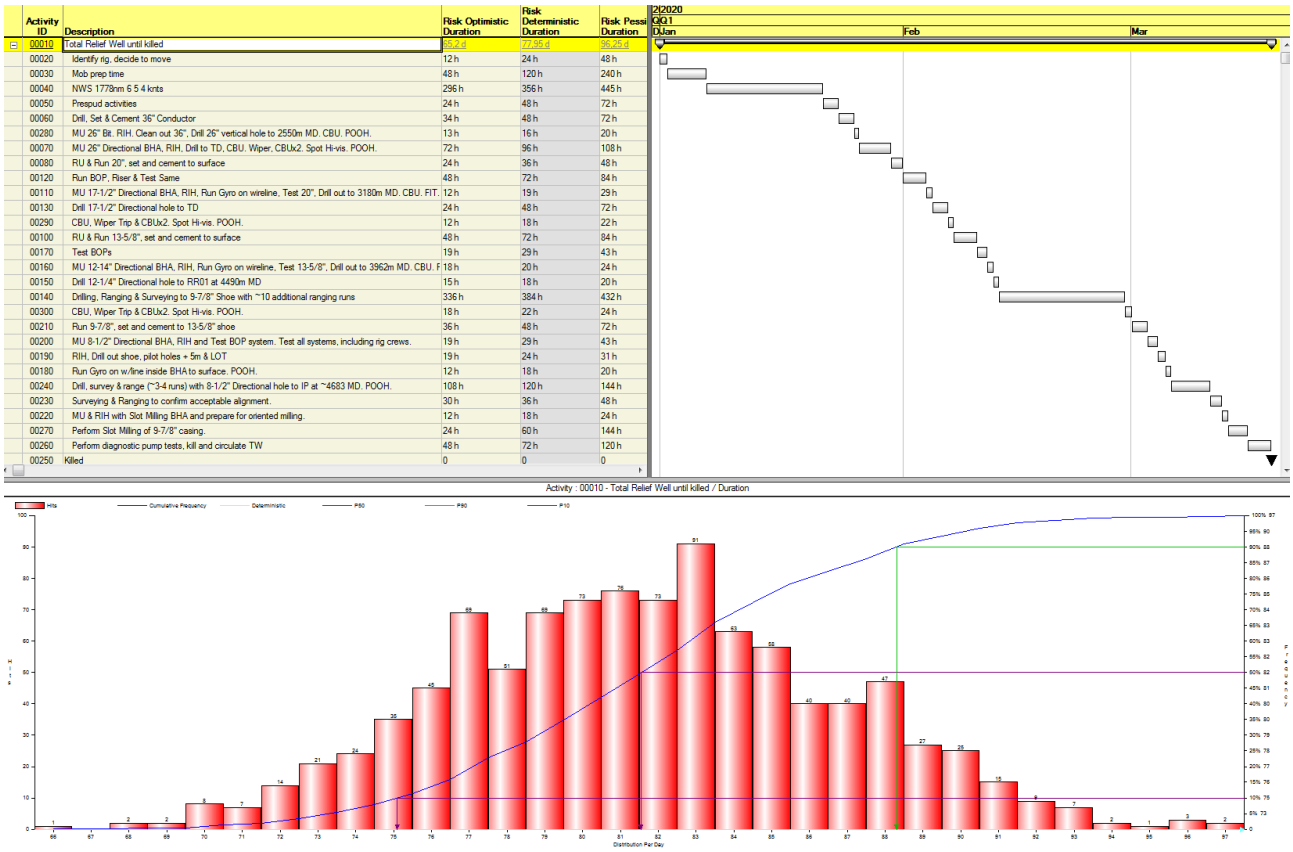
Activity ID	Description	Risk Optimistic Duration	Risk Deterministic Duration	Risk Pessimistic Duration
00010	Total Relief Well until killed	1512 d	1824 d	2112 d
00020	Identify rig, decide to move	12 h	24 h	48 h
00030	Mob prep time	48 h	120 h	240 h
00320	NWS 6 5 4 knts	295 h	353 h	442 h
00040	Main rig disconnects ok, recover riser	48 h	96 h	144 h
00050	Prespud activities	24 h	48 h	72 h
00060	Drill, Set & Cement 36" Conductor	34 h	48 h	72 h
00280	MU 26" Bit, RIH. Clean out 36", Drill 26" vertical hole to 2550m MD. CBU. POOH.	13 h	16 h	20 h
00070	MU 26" Directional BHA, RIH, Drill to TD, CBU. Wiper, CBUx2. Spot Hi-vis. POOH.	72 h	96 h	108 h
00080	RU & Run 20", set and cement to surface	24 h	36 h	48 h
00120	Run BOP, Riser & Test Same	48 h	72 h	84 h
00110	MU 17-1/2" Directional BHA, RIH, Run Gyro on wireline, Test 20", Drill out to 3180m MD. CBU. FIT.	12 h	19 h	29 h
00130	Drill 17-1/2" Directional hole to TD	24 h	48 h	72 h
00290	CBU, Wiper Trip & CBUx2. Spot Hi-vis. POOH.	12 h	18 h	22 h
00100	RU & Run 13-5/8", set and cement to surface	48 h	72 h	84 h
00330	Temp P&A	19 h	24 h	48 h
00170	Move rig off location	12 h	29 h	43 h
00340	Move RW rig into location	5 h	10 h	12 h
00350	Run BOP, Riser, & test same	48 h	72 h	84 h
00160	MU 12-14" Directional BHA, RIH, Run Gyro on wireline, Test 13-5/8", Drill out to 3962m MD. CBU. F	18 h	20 h	24 h
00150	Drill 12-1/4" Directional hole to RR01 at 4490m MD	15 h	18 h	20 h
00140	Drilling, Ranging & Surveying to 9-7/8" Shoe with ~10 additional ranging runs	336 h	384 h	432 h
00300	CBU, Wiper Trip & CBUx2. Spot Hi-vis. POOH.	18 h	22 h	24 h
00210	Run 9-7/8", set and cement to 13-5/8" shoe	36 h	48 h	72 h
00200	MU 8-1/2" Directional BHA, RIH and Test BOP system. Test all systems, including rig crews.	19 h	29 h	43 h
00190	RIH, Drill out shoe, pilot holes + 5m & LOT	19 h	24 h	31 h
00180	Run Gyro on w/line inside BHA to surface. POOH.	12 h	18 h	20 h
00240	Drill, survey & range (~3-4 runs) with 8-1/2" Directional hole to IP at ~4683 MD. POOH.	108 h	120 h	144 h
00230	Surveying & Ranging to confirm acceptable alignment.	30 h	36 h	48 h
00220	MU & RIH with Slot Milling BHA and prepare for oriented milling.	12 h	18 h	24 h
00270	Perform Slot Milling of 9-7/8" casing.	24 h	60 h	144 h
00260	Perform diagnostic pump tests, kill and circulate TW	48 h	72 h	120 h
00250	Killed	0	0	0

Figure 4.18 Main rig disconnects LMRP, drills relief well top-holes and relief well rig from North West Shelf (73 days)

4.4.5 Relief well rig from North West Shelf (88 days)

A relief well can be completed in 88 days (P90) using a rig operating on the North West Shelf. The only difference in mobilisation time compared to the Singapore case above is that the rig would have a shorter sailing time, shortening the P90 case by 14 days.

Figure 4.19 presents the estimated time schedule for drilling a relief well using a relief well rig from North West Shelf, including factors such as metocean conditions.



Activity ID	Description	Risk Optimistic Duration	Risk Deterministic Duration	Risk Pessi Duration
00010	Total Relief Well until killed	66.2 d	77.95 d	96.25 d
00020	Identify rig, decide to move	12 h	24 h	48 h
00030	Mob prep time	48 h	120 h	240 h
00040	NWS 1778nm 6 5 4 knts	296 h	356 h	445 h
00050	Prespud activities	24 h	48 h	72 h
00060	Drill, Set & Cement 36" Conductor	34 h	48 h	72 h
00280	MU 26" Bit, RIH. Clean out 36", Drill 26" vertical hole to 2550m MD. CBU. POOH.	13 h	16 h	20 h
00070	MU 26" Directional BHA, RIH, Drill to TD, CBU. Wiper, CBUx2. Spot Hi-vis. POOH.	72 h	96 h	108 h
00080	RU & Run 20", set and cement to surface	24 h	36 h	48 h
00120	Run BOP, Riser & Test Same	48 h	72 h	84 h
00110	MU 17-1/2" Directional BHA, RIH, Run Gyro on wireline, Test 20", Drill out to 3180m MD. CBU. FIT.	12 h	19 h	29 h
00130	Drill 17-1/2" Directional hole to TD	24 h	48 h	72 h
00290	CBU, Wiper Trip & CBUx2. Spot Hi-vis. POOH.	12 h	18 h	22 h
00100	RU & Run 13-5/8", set and cement to surface	48 h	72 h	84 h
00170	Test BOPs	19 h	29 h	43 h
00160	MU 12-14" Directional BHA, RIH, Run Gyro on wireline, Test 13-5/8", Drill out to 3962m MD. CBU. F	18 h	20 h	24 h
00150	Drill 12-1/4" Directional hole to RR01 at 4490m MD	15 h	18 h	20 h
00140	Drilling, Ranging & Surveying to 9-7/8" Shoe with ~10 additional ranging runs	336 h	384 h	432 h
00300	CBU, Wiper Trip & CBUx2. Spot Hi-vis. POOH.	18 h	22 h	24 h
00210	Run 9-7/8", set and cement to 13-5/8" shoe	36 h	48 h	72 h
00200	MU 8-1/2" Directional BHA, RIH and Test BOP system. Test all systems, including rig crews.	19 h	29 h	43 h
00190	RIH, Drill out shoe, pilot holes + 5m & LOT	19 h	24 h	31 h
00180	Run Gyro on w/line inside BHA to surface. POOH.	12 h	18 h	20 h
00240	Drill, survey & range (~3-4 runs) with 8-1/2" Directional hole to IP at ~4683 MD. POOH.	108 h	120 h	144 h
00230	Surveying & Ranging to confirm acceptable alignment.	30 h	36 h	48 h
00220	MU & RIH with Slot Milling BHA and prepare for oriented milling.	12 h	18 h	24 h
00270	Perform Slot Milling of 9-7/8" casing.	24 h	60 h	144 h
00260	Perform diagnostic pump tests, kill and circulate TW	48 h	72 h	120 h
00250	Killed	0	0	0

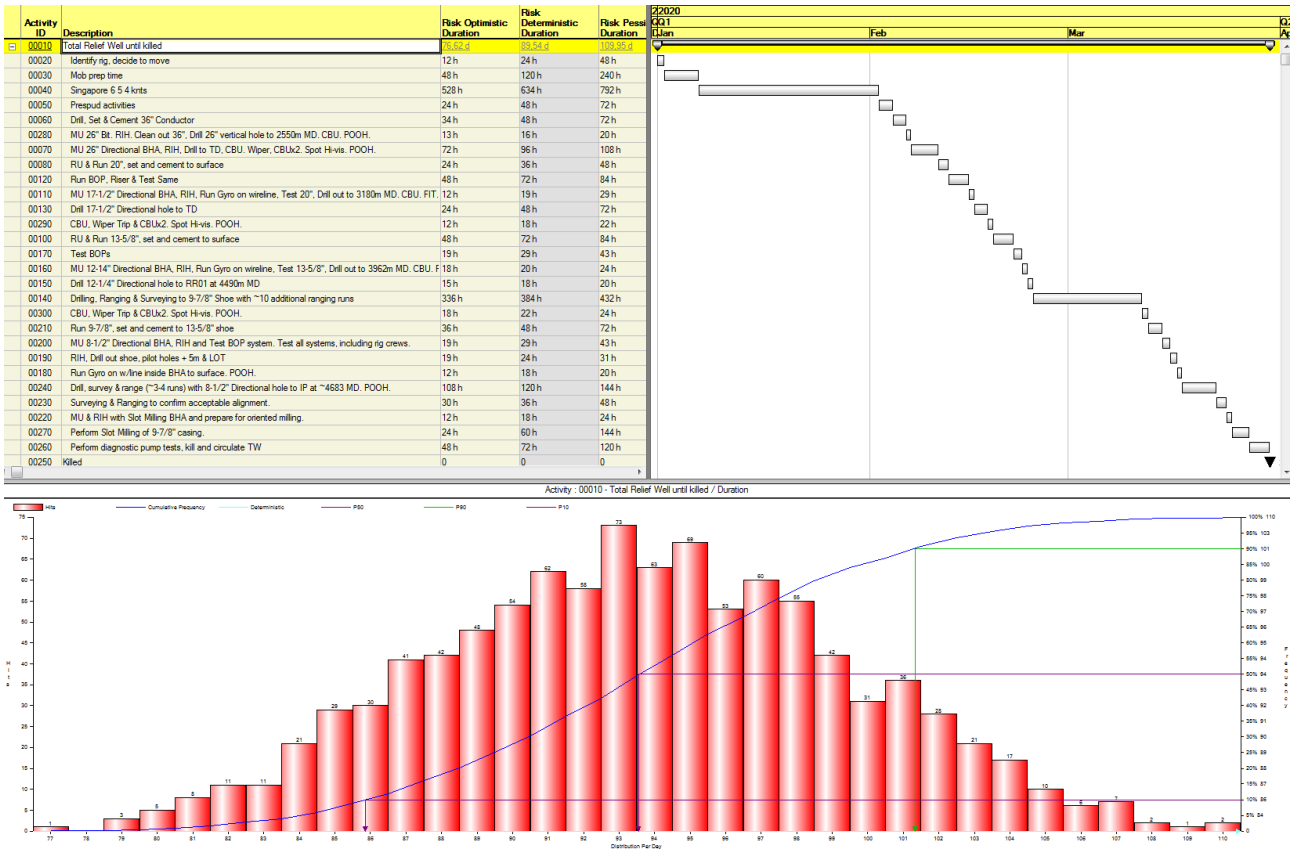
Figure 4.19 Relief well rig from North West Shelf (88 days)

4.4.6 Rig from Singapore with Australian Safety Case (102 days)

A relief well can be completed in 102 days (P90) using a relief well rig from Singapore, while considering the following assumptions:

- There is at least one warm stacked rig (i.e. idle and readily deployable) with all equipment specifications needed, and a valid Australian Safety Case close to Singapore, and that the time for amending this for the Stromlo-1 relief well would take less than the rig move.
- Time to select suitable MODU: Two days as evident from real incidents such as Macondo and Montara.
- Mobilisation preparation time: a working rig will need 10 days to safely terminate current activity, and a warm stacked rig will require time to take on personnel and arrange for departure.
- Sailing time: although MODU can be towed at six knots or more, we assume an average tow speed of four knots to allow for bad weather. This compares to Montara rig mobilisation of 5.1 knots, mobilisation of Transocean's GSF Development Driller 1 rig to Australia at 4.5 knots, and general advice from operators of towing vessels that conservative speeds will be 4–5 knots in the Great Australian Bight.
- Pre-spud activities after arriving at location, including loading of equipment and materials, change of crew, refuelling, etc. will take three days.

Figure 4.20 presents the estimated time schedule for drilling a relief well using a relief well rig from Singapore, including factors such as metocean conditions.



Activity ID	Description	Risk Optimistic Duration	Risk Deterministic Duration	Risk Pessi Duration
00010	Total Relief Well until killed	76.52 d	89.54 d	109.95 d
00020	Identify rig, decide to move	12 h	24 h	48 h
00030	Mob prep time	48 h	120 h	240 h
00040	Singapore 6 5 4 knts	528 h	634 h	792 h
00050	Prespud activities	24 h	48 h	72 h
00060	Drill, Set & Cement 36" Conductor	34 h	48 h	72 h
00280	MU 26" Bit. RIH. Clean out 36", Drill 26" vertical hole to 2550m MD. CBU. POOH.	13 h	16 h	20 h
00070	MU 26" Directional BHA, RIH, Drill to TD, CBU. Wiper, CBUx2. Spot Hi-vis. POOH.	72 h	96 h	108 h
00080	RU & Run 20", set and cement to surface	24 h	36 h	48 h
00120	Run BOP, Riser & Test Same	48 h	72 h	84 h
00110	MU 17-1/2" Directional BHA, RIH, Run Gyro on wireline, Test 20", Drill out to 3180m MD. CBU. FIT.	12 h	19 h	29 h
00130	Drill 17-1/2" Directional hole to TD	24 h	48 h	72 h
00290	CBU, Wiper Trip & CBUx2. Spot Hi-vis. POOH.	12 h	18 h	22 h
00100	RU & Run 13-5/8", set and cement to surface	48 h	72 h	84 h
00170	Test BOPs	19 h	29 h	43 h
00160	MU 12-14" Directional BHA, RIH, Run Gyro on wireline, Test 13-5/8", Drill out to 3962m MD. CBU. F	18 h	20 h	24 h
00150	Drill 12-1/4" Directional hole to RR01 at 4490m MD	15 h	18 h	20 h
00140	Drilling, Ranging & Surveying to 9-7/8" Shoe with ~10 additional ranging runs	336 h	384 h	432 h
00300	CBU, Wiper Trip & CBUx2. Spot Hi-vis. POOH.	18 h	22 h	24 h
00210	Run 9-7/8", set and cement to 13-5/8" shoe	36 h	48 h	72 h
00200	MU 8-1/2" Directional BHA, RIH and Test BOP system. Test all systems, including rig crews.	19 h	29 h	43 h
00190	RIH, Drill out shoe, pilot holes + 5m & LOT	19 h	24 h	31 h
00180	Run Gyro on w/line inside BHA to surface. POOH.	12 h	18 h	20 h
00240	Drill, survey & range (~3-4 runs) with 8-1/2" Directional hole to IP at ~4683 MD. POOH.	108 h	120 h	144 h
00230	Surveying & Ranging to confirm acceptable alignment.	30 h	36 h	48 h
00220	MU & RIH with Slot Milling BHA and prepare for oriented milling.	12 h	18 h	24 h
00270	Perform Slot Milling of 9-7/8" casing.	24 h	60 h	144 h
00260	Perform diagnostic pump tests, kill and circulate TW	48 h	72 h	120 h
00250	Killed	0	0	0

Figure 4.20 Relief well rig from Singapore with Australian Safety Case (102 days)

The assumption that a warm-stacked rig with an Australian Safety Case will be available near Singapore is still true but no longer relevant to the response planning. Since this time, it has become evident that several suitable rigs will be working in Australian waters at the time of drilling Stromlo-1 and these would be given preference due to their shorter mobilisation time.

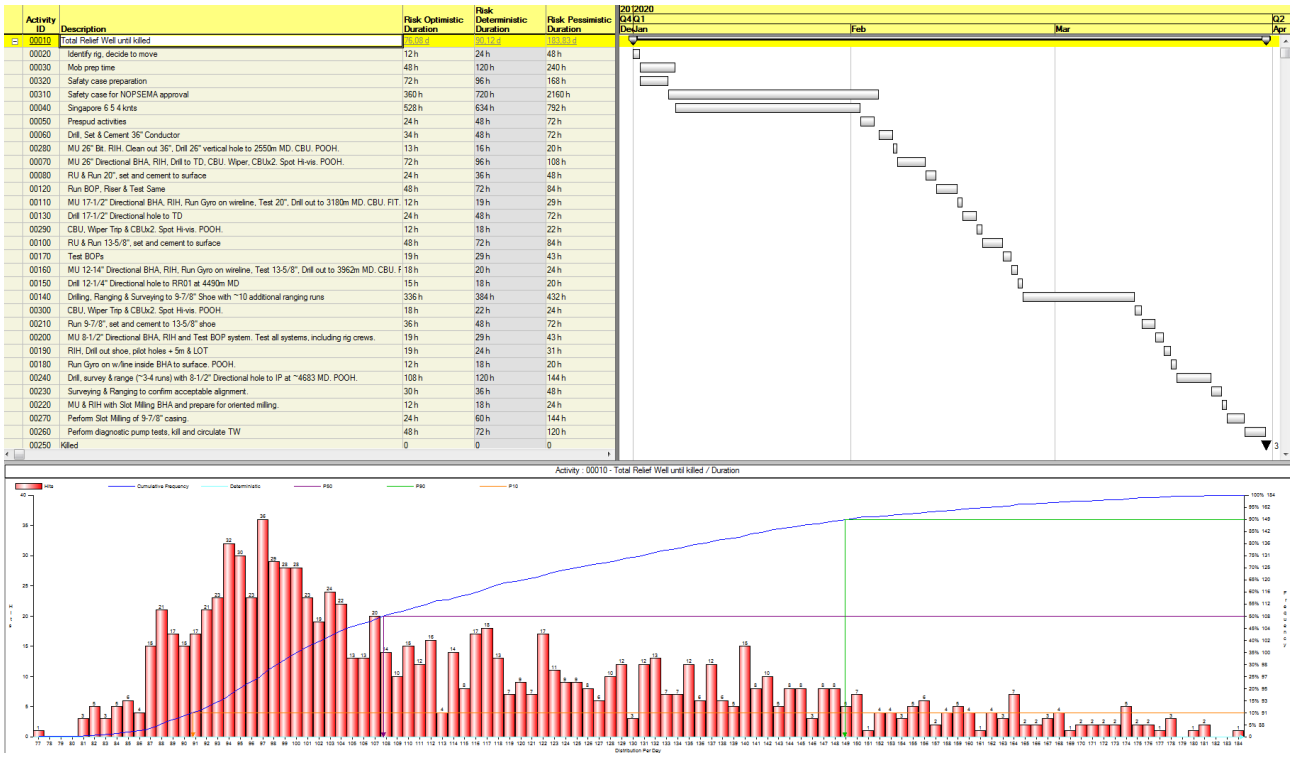
4.4.7 Rig from Singapore without Australian Safety Case (149 days)

This case assumes that no rigs with Australian Safety Case can be identified in the region, and NOPSEMA approval of the Safety Case would be needed before well operations can commence. A relief well can be completed in 149 days (P90) using a relief well rig from Singapore without Australian Safety Case, while considering the following assumptions:

- Development and approval of the Safety Case by NOPSEMA can be done concurrently with mobilisation of the rig to Australia – to be completed prior to spud.
- Preparation of a Safety Case can be done in three days P10 to seven days P90.
- NOPSEMA approval time would take 15 days (P10) to 90 days (P90).

There are drilling rigs close to Singapore and in Australia with all required specifications and requirements for Stromlo-1 and with valid Australian Safety Cases. While it cannot be assumed that the same rigs will be available at the time of drilling Stromlo-1, it confirms this is a realistic scenario.

Figure 4.21 presents the estimated time schedule for drilling a relief well using a relief well rig from Singapore without Australian Safety Case, including factors such as metocean conditions.



Activity ID	Description	Risk Optimistic Duration	Risk Deterministic Duration	Risk Pessimistic Duration
00010	Total Relief Well until killed	76.06 d	90.12 d	183.83 d
00020	Identify rig, decide to move	12 h	24 h	48 h
00030	Mob prep time	48 h	120 h	240 h
00320	Safety case preparation	72 h	96 h	168 h
00310	Safety case for NOPSEMA approval	360 h	720 h	2160 h
00040	Singapore 6.5-4 knts	528 h	634 h	792 h
00050	Prespud activities	24 h	48 h	72 h
00060	Drill, Set & Cement 36" Conductor	34 h	48 h	72 h
00280	MU 26" Bit, RIH. Clean out 36", Drill 26" vertical hole to 2550m MD. CBU. POOH.	13 h	16 h	20 h
00070	MU 26" Directional BHA, RIH, Drill to TD, CBU. Wiper, CBUx2. Spot Hi-vis. POOH.	72 h	96 h	108 h
00080	RU & Run 20", set and cement to surface	24 h	36 h	48 h
00120	Run BOP, Riser & Test Same	48 h	72 h	84 h
00110	MU 17-1/2" Directional BHA, RIH, Run Gyro on wireline, Test 20", Drill out to 3180m MD. CBU. FIT.	12 h	19 h	29 h
00130	Drill 17-1/2" Directional hole to TD	24 h	48 h	72 h
00290	CBU, Wiper Trip & CBUx2. Spot Hi-vis. POOH.	12 h	18 h	22 h
00100	RU & Run 13-5/8", set and cement to surface	48 h	72 h	84 h
00170	Test BOPs	19 h	29 h	43 h
00160	MU 12-14" Directional BHA, RIH, Run Gyro on wireline, Test 13-5/8", Drill out to 3962m MD. CBU. F	18 h	20 h	24 h
00150	Drill 12-1/4" Directional hole to RR01 at 4490m MD	15 h	18 h	20 h
00140	Drilling, Ranging & Surveying to 9-7/8" Shoe with ~10 additional ranging runs	336 h	384 h	432 h
00300	CBU, Wiper Trip & CBUx2. Spot Hi-vis. POOH.	18 h	22 h	24 h
00210	Run 9-7/8", set and cement to 13-5/8" shoe	36 h	48 h	72 h
00200	MU 8-1/2" Directional BHA, RIH and Test BOP system. Test all systems, including rig crews.	19 h	29 h	43 h
00190	RIH, Drill out shoe, pilot holes + 5m & LOT	19 h	24 h	31 h
00180	Run Gyro on w/line inside BHA to surface. POOH.	12 h	18 h	20 h
00240	Drill, survey & range (~3-4 runs) with 8-1/2" Directional hole to IP at ~4683 MD. POOH.	108 h	120 h	144 h
00230	Surveying & Ranging to confirm acceptable alignment.	30 h	36 h	48 h
00220	MU & RIH with Slot Milling BHA and prepare for oriented milling.	12 h	18 h	24 h
00270	Perform Slot Milling of 9-7/8" casing.	24 h	60 h	144 h
00260	Perform diagnostic pump tests, kill and circulate TW	48 h	72 h	120 h
00250	Killed	0	0	0

Figure 4.21 Relief well rig from Singapore without Australian Safety Case (149 days)

4.4.8 Relief well outcomes

Relief well planning is a critical safety measure, ensuring readiness and rapid response in the event of a well control incident out of control that may cause harm to humans and the environment. A relief well is an effective way of stopping a blowout, but also the most time-consuming option. Therefore, is it important during the planning phase to evaluate ways to increase the chance of success and to decrease the time required for drilling a relief well as much as reasonably possible.

The main improvement in response time for a relief well is found in availability of an appropriate rig. Rigs can only be held on exclusive stand-by if they are on charter and the costs of this are grossly disproportionate to the minor reduction in risk in sourcing a relief well rig earlier because Equinor has committed to having a relief well rig identified with an Australian safety case identified and in the region before drilling into the reservoir. Preference would be given to rigs in the Great Australian Bight or adjacent areas, or on the North West Shelf, if it can be shown to reduce mobilisation times at the time of the event. There is no risk of a LOWC until the drill string intersects the potential oil-bearing strata and this intersection is considered a more reasonable time by which to have secondary response plans confirmed.

The improvement in response time from sourcing a rig from Singapore compared to a rig from NWS with a valid Australian Safety case, that the well can be killed on day 88 as opposed to day 102. The improvement in response time from having a rig on contract in Port Lincoln compared to mobilising a rig from the NWS, is that the well can be killed on day 68 as opposed to day 88. In addition, further improvements are evaluated for the last two options.

- contracting a relief well rig when and if required
  - if a rig is available at a location closer than North West Shelf, for example in the Bass Strait, the well could be killed on day 73 as opposed to day 88. However, it is unlikely that a DP rig will be available in the Bass Strait, or Great Australian Bight during the petroleum activity on Stromlo-1
- having a relief well rig on contract
  - if the rig is on stand-by on location instead of Port Lincoln, the well could be killed on day 63 as opposed to day 68
  - if the rig were to drill a relief well in parallel with the petroleum activity on Stromlo-1, the well could be killed on day 44 as opposed to day 63.

Equinor has assessed the option of contractually ensuring that a suitable mobile drilling unit is present in the GAB with a Stromlo-1 safety case, and it appears unlikely and should not be assumed. Equinor believes it is highly unlikely that there will be another environment plan accepted for drilling in the GAB until Stromlo has been finished. If the situation changes, this will be re-assessed as an option for the relief well.

The improvements must be evaluated against the negative impact on cost and the environment if a relief well eventually is not needed. If a relief well rig is on stand-by on location or drilling a relief well in parallel, it will have to be supported by two support vessels for supply and helicopter for crew change. The cost and environmental impact would be similar to that of Stromlo-1, potential doubling the well cost and impact on:

- exclusion of other marine users
- underwater sound from drilling, thrusters and engines
- artificial lighting on MODU and vessels for navigational and operational safety
- fuel combustion by MODU, helicopter and vessel engines
- discharge of cooling and brine water from MODU and support vessel
- discharge of sewage, grey water and putrescible wastewater from MODU and support vessels
- discharge of deck and bilge waters from MODU and support vessels.

Drilling of a relief well in parallel would have additional impact on the environment:

- underwater sound from intermittent or impulsive sources
- discharge of drilling fluids (SBM) and cuttings
- discharge of cement
- BOP fluid discharge during BOP installation and function testing.

There would be some impacts associated with the storage in Port Lincoln also, including about 30–50 m^3 MGO fuel use per day for the rig and the supply vessels, waste discharges (in accordance with MARPOL) and possible interference with maritime operations in the area. To have a rig warm-stacked in the Port Lincoln would have about the same cost as the main rig, since it would need to be similarly equipped and ready to operate on short notice. To be a fast and credible relief well option, the rig needs to be supported by two anchor-handling tugs, to be able to move her to the location swiftly if the need arises. The rig also needs to be mobilized and demobilised after the single exploration well. The costs would be grossly disproportionate to the environmental benefit gained in terms of reducing risks associated with a LOWC by reducing the amount of oil spilled. The option of having a relief well rig on contract in a port, suitable anchorage or on location is not considered ALARP and is not adopted.

In November 2020, it can be confirmed that there will be several ultra-deep DP rigs on contract in Australian waters in Q4 2020–Q1 2021, at the time when Stromlo-1 is planned to be drilled. The contractors of these rigs are all AMOSC associate or member companies which gives them (and Equinor) access to the industry mutual aid arrangements under AMOSPlan and they also agree to assist in emergencies under APPEA's Mutual Aid Memorandum of Understanding. It is considered reasonable to assume that at least one of these rigs could be contracted under emergency aid service agreements and mobilise to the GAB and drill the relief well in 88 days.

The rig would need to have the same functional requirements as the main rig, to be able to operate safely in the metocean conditions at the location, in addition to technical requirements to be able to successfully kill the blowing well (Stromlo-1). Equinor will assess all the options available before operations start and make plans for timely use of any relief well rig that may be useful for a relief well effort. Equinor will gap the equipment and reasonable arrangements, including Australian Safety Case, so that a mobilisation of a relief well effort will not be unnecessarily delayed. It has already been identified that the potential relief well rigs in Australia are not outfitted with sufficient riser to be used in 2240 m water, and that this gap needs to be closed. Equinor have committed to a solution for this before spud, that will not impact negatively the response time lines stated in this environmental plan. We will otherwise have all Long Lead Items (LLI) for a timely spud, including all hardware for spudding and completing the top-hole of the relief well in Adelaide. These arrangements will allow for a rig to be available within reasonable time and with no additional cost or impact on the environment if a relief well is never required. This option is considered ALARP and is adopted.

The long lead equipment for relief well will be available in Adelaide, included any potential equipment required for the relief well rig to drill the relief well. All logistical plans and arrangements can be done in advance. The pre-spud activities reduce the mobilisation time.

The most likely case is that the main rig will remain operational and able to drill a top hole for a relief well while mobilising a rig from the NWS. This option allows for drilling of a relief well within reasonable time, 73 days (P90), and with no additional impact on cost or the environment if a relief well is never required. This option is considered ALARP and is adopted.

The cost/benefit analysis of the additional controls that could be implemented for improving relief well drilling efficiency, including the environmental benefits; financial, environmental and safety costs and the outcomes is presented in Table 5.1.

The decision diagram to determine the additional capability that could be implemented for relief well is provided in Figure 4.22.

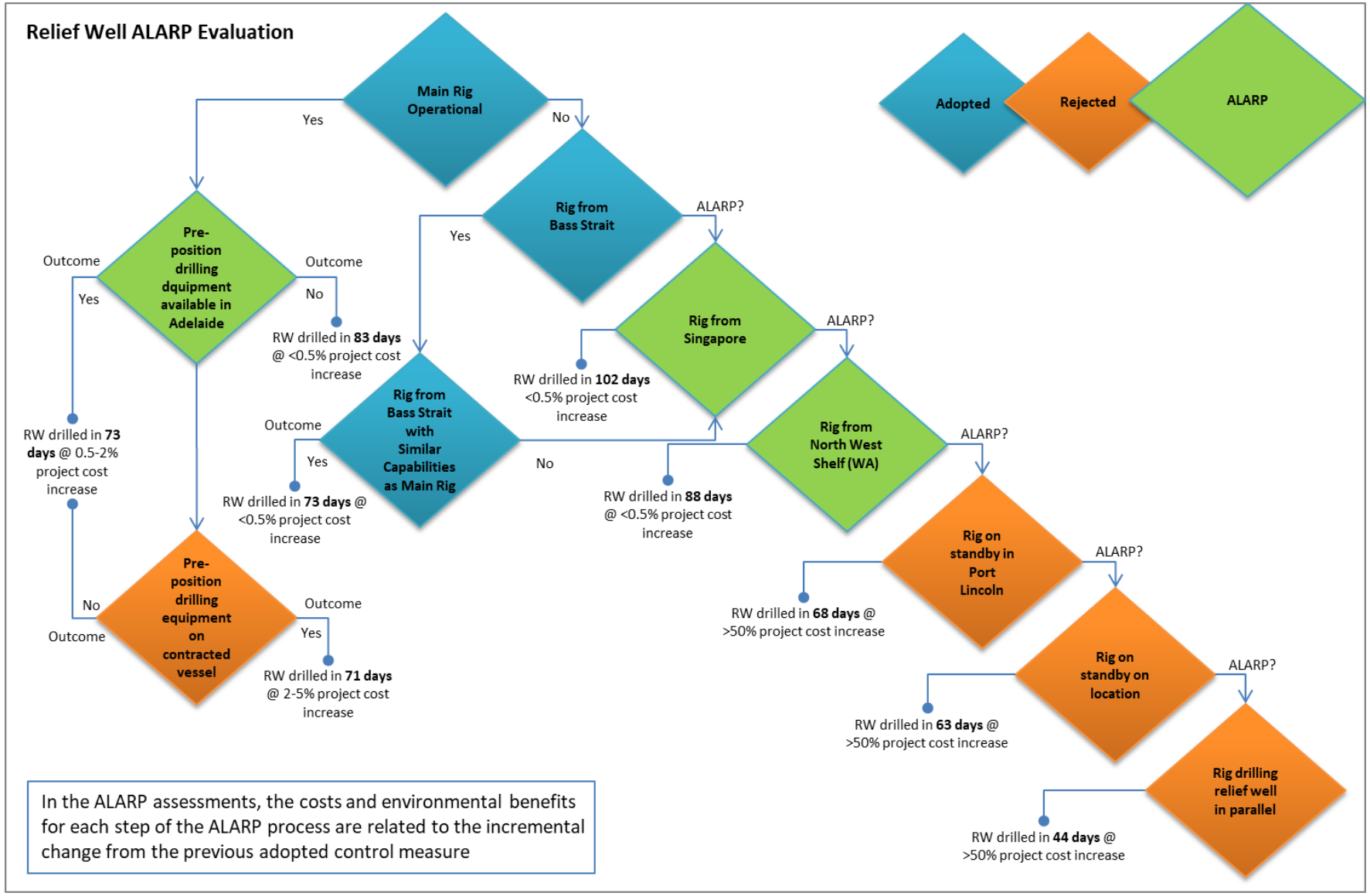


Figure 4.22 Relief well ALARP evaluation

4.5 Surface dispersant application

During a subsurface loss of well control incident, large quantities of fresh oil accumulating on the sea surface within 1–2 days of the release. Left untreated, this would create an environmental hazard to both ecological and socio-economic values from direct contact with surface oil, gaseous volatile organic compounds (VOCs) or stranded oil on shorelines (see Section 7 of the EP).

The application of chemical dispersants from vessels or aircraft potentially reduces hydrocarbon loading at the sea surface, reducing risk of impacts from oil to sensitive surface and shoreline receptors. A potential reduction in human health and safety risk to responders from VOCs may also be gained. Chemical entrainment also means that no waste is generated and is relatively less labour-intensive than other response strategies.

Potential drawbacks of this strategy include potential impacts from toxicity of dispersed oil on subsurface receptors and impacts to socio-economic receptors such as fisheries and aquaculture. Dispersants also don't remove hydrocarbons from the environment, but redistribute it into the water column via entrainment. A summary of the advantages, disadvantages, feasibility and potential for environmental risk reduction is presented in Table 4.1.

Surface dispersant application using airplanes has relevant advantages for spill mitigation in a remote location. It allows fast response, can be scaled rapidly, and equipment is readily available. In addition to aircraft, there will be support vessels with capabilities to spray dispersant on the sea surface.

The following options have been assessed based on the WCD (129 day) scenario:

- Option 1: Opportunistic vessel dispersant spraying (PSVs) from day 1
- Option 2: Vessel dispersant spraying (PSVs) from day 1 for 129 days
- Option 3: Opportunistic vessel dispersant spraying (PSVs) plus scaling up of aerial response from day 2–4, with full aerial response from day 4 to day 20 (following assessment of the efficacy of SSDI)
- Option 4: Opportunistic vessel dispersant spraying (PSVs) from day 1 plus scaling up of aerial response from day 2–4, with full aerial response from day 4 to day 20 (following assessment of the efficacy of SSDI)
- Option 5: Opportunistic vessel dispersant spraying (PSVs) from day 1 plus scaling up of aerial response from day 2–4, with full aerial response from day 4 to day 129.

ALARP assessment of the five options above considered a range of environmental risks (benefits/disbenefits) and operational aspects with regards to the response need (daily surface hydrocarbon loading with and without SSDI), potential efficacy in metocean conditions of the GAB, practical limitations of response (in a remote offshore environment) and other critical aspects such as the logistics supply chain. To summarise:

Vessel dispersant spraying: this approach is spatially limited in its effect, as the response is limited to the effective range of the spray units, the dispersant: oil ratio, the dispersant spray rate and the vessel speed (to transit between areas of actionable oil. The maximum volume of oil a single vessel could potentially entrain per day is 62.4 m^3/day, assuming a 0.5 m^3/hr spray rate over 12 hours, a 1:20 dispersant to oil ratio and 52% dispersant efficacy. This treatable volume is likely to be unachievable under GAB metocean conditions and due to the requirement to transit between areas of actionable oil. This approach would also require dedicated vessel to transport dispersants from Port Adelaide or Port Lincoln to the offshore dispersant application area to maintain the response. These considerations resulted in vessel dispersant application being classified as an opportunistic response, though it was considered that equipping PSVs with dispersant equipment would support reduction of risk to ALARP.

Aerial dispersant application: Due to the location of air tractors around the country (FWADC and Aerotech 1st Response) or internationally (OSRL 727 and C-130A Hercules), a staged increase in response from day 2 to day 4 was identified. The smallest aircraft (air tractors) could theoretically treat a maximum of 62.4 m^3 per day (assuming 2 sorties per day, 52% dispersant efficacy, fresh oil and 100% encounter rate), and the largest aircraft 312 m^3/day (OSRL 727, 2 sorties per day). The maximum theoretical daily surface oil treated would be 1,144 m^3/day, which equates to 12.8% of the average daily release rate for the WCD scenario (assuming nine air tractors, 1 × 727 and 1 × C-130A; two sorties per day). Achieving or maintaining this treatment rate is unlikely under GAB metocean conditions. These considerations resulted in aerial dispersant application being identified as an appropriate response, subject to NEBA, dispersant testing and monitoring outcomes. However, should there be a limitation in the dispersant logistics supply chain, it was considered that prioritising SSDI response over aerial dispersant application would support reduction of risk to ALARP, due to the greater oil treatment potential (as SSDI is likely to demonstrate to be effective). Pre-mobilising dispersant stockpiles have been considered and accepted, though relocating large stockpiles is not considered ALARP as the relatively short mobilisation times from existing stockpiles mean that the response need can be met during ramp-up of the aerial response.

The key components of the surface dispersant plan are:

- To store 6 m^3 of dispersant for aerial application in Ceduna. From day 2 onwards, further dispersant supplies can be sourced from Geelong or elsewhere (in Australia there is a confirmed capacity for at least 20 days of aerial dispersant application).
- To store local stockpile of up to 50 m^3 of dispersant for initial application either by airplanes or vessels. With this quantity on stand-by there will be enough time for additional stock to be sourced from Geelong (where there is over 100 m^3 of mutual aid supply) or elsewhere.
- Two offshore PSVs will be equipped with dispersant application capability. The vessels will have an initial dispersant supply on board and can refill dispersant stocks from Port Adelaide.
- The fixed-wing dispersant aircrafts (FWDA) on contract for the Australian Maritime Safety Authority (AMSA) are maintained in strategic locations to respond to oil spills on a 24/7 basis and can operate up to 200 NM from the coast. They need to remain at their point of origin to be available across the industry.
- The large aircraft that are on contract via OSRL and as regional resources on non-exclusive contract must remain at their point of origin.
- To inform efficient aerial dispersant application, Equinor will deploy a spotter plane within 24 hours following a loss of well control event.
- A minimum of nine air tractors and two large aircraft are on contracts dedicated to oil spill response.
- An organised airborne dispersant campaign with multiple aircraft using spotter aircraft in accordance with AMSA guidelines will start on day 2.

However, surface dispersant application is far less efficient than subsea dispersant injection (SSDI), which maximises potential encounter rate by injecting dispersants straight into the released fresh oil plume. This is because the effectiveness of surface dispersant application strategies is affected by:

- the degree of weathering of surface oil; dispersants are considered potentially effective on fresh oil
- oil type; surface dispersant application is not considered effective for light oils (e.g. condensates, marine diesels) as natural weathering (e.g. evaporation) is likely to remove the oil from the environment more rapidly
- surface oil thickness; dispersants can “punch through” surface slicks if they are too thin (<25 µm), with little or no entrainment of the oil
- weather conditions/sea state; wind can affect the distribution of oil on the surface (e.g. “windrows”), which means that dispersants can encounter only open water (rather than surface oil). Additionally, poor weather and high winds can interfere with or curtail dispersant operations (e.g. health and safety risk) and high-energy wave action can naturally entrain surface hydrocarbons and reduce encounter rates
- response limitations, e.g. highly localised for vessel-based dispersants, and larger area but reduced period of response for aerial dispersant. Resource availability (e.g. aircraft) may also be a limiting factor. For vessel-based dispersant application, the supply chain of dispersants in a remote offshore area (around 40 hours from Port Adelaide) is also a potential limiting factor
- the availability of dispersants and opportunity cost. If there is a limited supply of dispersants, the allocation of dispersant from available sources will be prioritised based on the likely effectiveness of the response strategy. Surface dispersant activity would therefore be evaluated for further use once the subsea dispersant injection has been assembled on the seabed and turned on, and the effect on actionable surface hydrocarbons determined from surveillance and monitoring activities.

To maximise potential dispersant efficacy and minimise environmental risk to benthic (seabed), nearshore and shoreline receptors, dispersant application will be targeted at fresh oil. Modelling indicates that surface fresh oil is likely to be found up to ~130 km from the well location, therefore the outer limit of the dispersant application zone is likely to be around 200 km or more from the nearest shoreline (see Figure 4.22).

No improvements to the oil spill response control measures were identified.

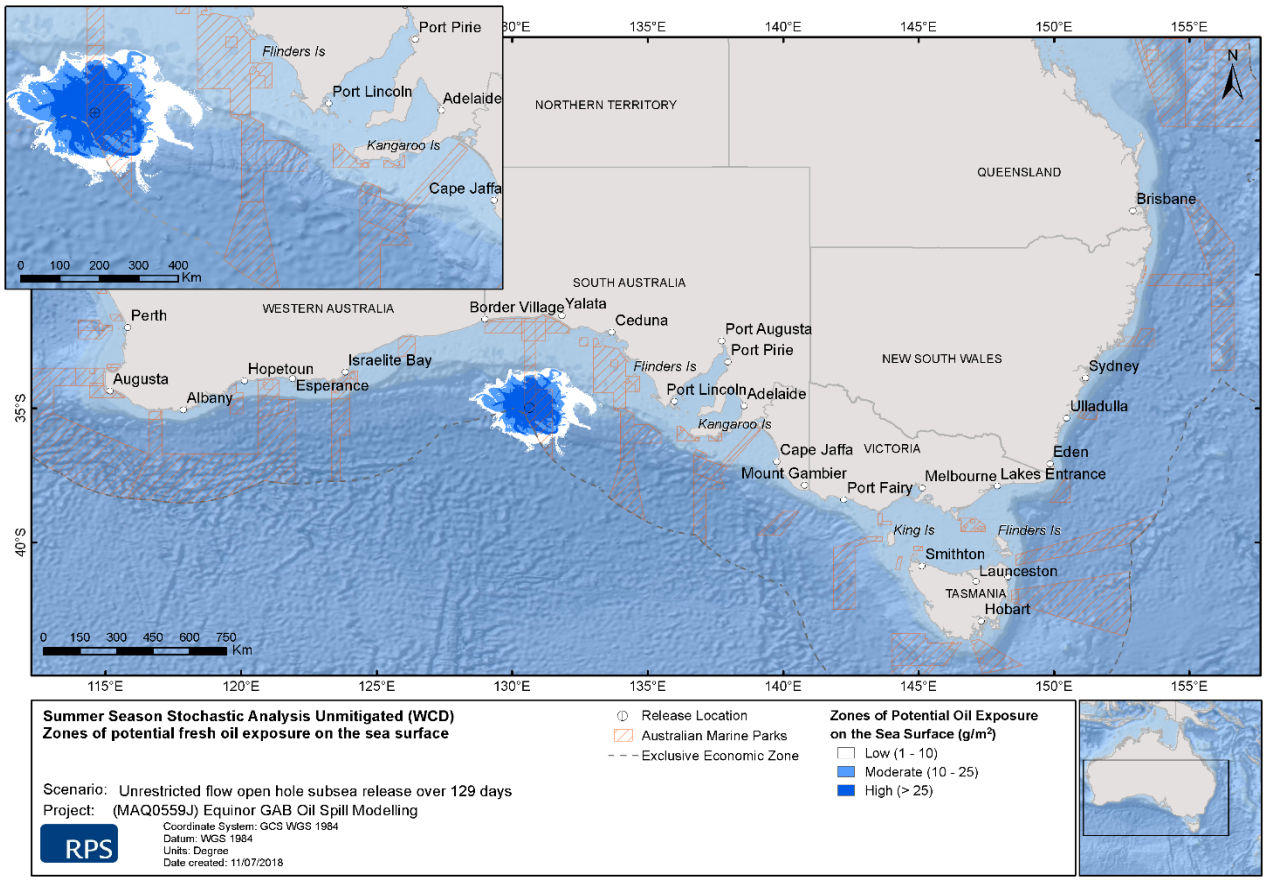


Figure 4.23 Unmitigated WCD Stochastic modelling (100 runs) showing zone of potential fresh oil exposure at the sea surface. Moderate levels of exposure (10 µm) and above would be potentially suitable for surface dispersant application

4.6 In-situ burning

In-situ burning (ISB) was used during the Macondo incident (>300 in-situ burns). The oil was concentrated using booms and it became ignitable. About 4% of the total oil was burned at sea. A summary of the advantages, disadvantages, feasibility and potential for environmental risk reduction is presented in Table 4.1.

In-situ burning in the Great Australian Bight is not adopted offshore because the wave height is always beyond the limitation for this method (limit between one and two metres). Oil that drifts to coastal and sheltered areas might be too weathered to enable ignition.

However, if necessary, Equinor's response contractors (OSRL) have suitable equipment and ISB-trained responders available.

4.7 Mechanical containment and recovery offshore

Mechanical containment and recovery (C&R) techniques potentially reduces surface hydrocarbons in offshore and nearshore areas. In doing so, it may also reduce the probability of exposure to or magnitude of shoreline loading.

The efficiency of mechanical recovery depends on many factors (oil thickness, encounter rate, operating hours, type of boom used) and is sensitive to weather and sea state. Theoretical capacities have generally not been achieved in actual incidents. Depending on oil thickness, one vessel and one system (single vessel system) can contain and recover 59 to 453 m^3 per day (AllMaritim recovery capacity calculator for NOFI Current Buster 6 – daylight only operations, 3–5 knots, 50–200 µm oil thickness). A more detailed assessment is provided in the relevant tactical response plan, which also details the arrangements and capability to meet the response

need. Containment and recovery as a response has a potential effective recovery rate of up to 5–10% when an encounter rate of 25–50% is achieved for discontinuous or continuous true oil (thickness of >50 µm; BAOAC 4 and 5).

However, when the oil rises through the 2300 m water column it will disperse and the resulting surface slick can cover a spatially large area. The water depth in combination with subsea dispersant injection will cause the surface oil thickness to be thinner, with the result that mechanical recovery capacity will be at the lower end of the mentioned recovery ranges. Therefore, the need to transit between areas of actionable oil may also have negative time and efficiency effects. The effectiveness achieved for this strategy using many different C&R systems during the Macondo (Deepwater Horizon) spill was considered to be more in the region of 3–5% overall. However, this was after more than half the collected oil was in-situ burned (ISB). If all the skimmed oil had been recovered, the total may have been closer to approximately 8%. A summary of the advantages, disadvantages, feasibility and potential for environmental risk reduction is presented in Table 4.1.

With an average yearly wave height of 3 m in the Great Australian Bight and 2.6 m during summer months, it is likely that mechanical systems offshore will have lower efficiency than that modelled and observed in areas closer to the shore elsewhere in the world. Efficiencies up to around 70% of the theoretical capacity have been achieved in exercises (NOFO Oil on water exercise 2014) but efficiencies in the offshore Great Australian Bight are expected to be lower.

There are always benefits to the environment by mechanically removing oil and this option will be implemented as soon as suitable vessels are available. Preparedness planning based on estimated recovery rates in the dispersant and offshore containment and recovery tactical response plan indicated that 11 offshore strike teams would be required to response to surface hydrocarbons when SSDI is active. The waste management plan describes the offloading of recovered oil between dynamic positioned (DP) vessels, including a tanker, that will allow for minimal interruptions of the recovery operation.

Due to the distances and conditions in the Great Australian Bight, effective operations offshore require large PSV-type vessels with internal tanks for oil storage (OILREC) that can operate large mechanical recovery systems. This type of vessel may initially be tasked to source control activities in the initial response (as controlling the release will be the priority response), depending on the availability and location of Vessels of Opportunity, and time required to mobilised to the well location. For the purposes of ALARP assessment, it has been considered that a delay in the implementation of offshore containment and recovery operations is potentially realistic. However, this response is subject to a continuous ALARP process, and therefore should it be feasible to mobilise the response more rapidly, or should it be identified that additional strike teams are required to reduce environmental risk to ALARP (based on the nature and scale of the actual incident), then further teams will be sourced and tasked to the response. This spill response measure can also be scaled up over time by mobilising additional vessels from the North West Shelf or Singapore, and equipment through AMSA and OSRL.

Considered improvements to the oil spill response control measures are identified in Table 5.1. These include:

- faster mobilisation times
- additional trained personnel
- improved equipment.

4.8 Nearshore containment and recovery

Any oil that is not successfully dispersed or recovered close to the source will continue to weather and move under the influence of currents and prevailing winds. The time for highly weathered oil to reach the coast ranges from weeks to months depending on the metocean conditions (Appendix 7-1). The nature of the oil on the water will vary from patches or “streamers” of weathered and emulsified oil and residues, through to oily sheens with very low concentrations of hydrocarbons. A summary of the advantages, disadvantages, feasibility and potential for environmental risk reduction is presented in Table 4.1.

Modelling (Appendix 7-1) indicates that there are potentially large sections of the coast that could be affected. The exact shoreline sections and loadings will depend on factors such as the weather and prevailing currents. Any weathered oil washing ashore will have lost all the volatile and more toxic aromatic hydrocarbon components through evaporation and natural degradation and would be emulsified and increasingly solid as time goes by after release.

Nearshore containment and recovery will be implemented when oil is present on surface waters adjacent to sensitive and priority protection areas, under the direction of relevant state control agencies. Eleven nearshore strike teams will consist of vessels of opportunity (VOO) with equipment capable of containing up to approximately 5–50 m^3 of oil per day. Stochastic modelling indicated that the fastest time to shoreline exposure was likely to be 21 days for South Australia. Therefore, it has been considered that reducing response mobilisation times to less than 15 days is not likely to result in a further reduction in environmental risk. This level of response is subject to a continuous ALARP process, and therefore should it be identified that additional strike teams are required to reduce environmental risk to ALARP (based on the nature and scale of the actual incident), then further teams will be sourced and tasked to the response.

Considered improvements to the oil spill response control measures are identified in Table 5.1. These include:

- faster mobilisation times
- additional trained personnel.

4.9 Shoreline response - protection and clean-up

A summary of the advantages, disadvantages, feasibility and potential for environmental risk reduction is presented in Table 4.4. Additional oil spill shoreline protection and clean-up control measures that were considered in the ALARP assessment are described in Table 5.1.

The following assessment was based on the WCD_{129} unmitigated greatest accumulation onshore deterministic model run to identify the greatest potential 'response need' to determine the upper level of scaling for response planning.

Accessibility to the shoreline is limited in some areas by the lack of access roads and tracks, or very steep terrain. Of the total oiled shoreline length, 1497 km (34%) was considered accessible by vehicle from the landward side using existing roads or 4 × 4 tracks and 2858 km (66%) potentially inaccessible by vehicle from the landward side (foot access only, cliffs and small offshore islands). The lengths of shoreline accessible from the landward side by different methods are summarised in Table 4.1.

Table 4.1 Estimated lengths of oiled shorelines accessible from land

	Vehicle access		No vehicle access	
	via blacktop road then 4x4 track	via 4x4 track	foot access only	no access from land
Accessibility (km)	43	1454	519	2339
%	1	33	12	54

The response needs on oiled shorelines vary according to level of oiling and accessibility. Shorelines which are inaccessible by vehicle or receive <100 g/m^2 oil require surveillance. Some shorelines where oil may accumulate at 100 to 1000 g/m^2 require assessment during a spill response to confirm accessibility for potential response. Accessible shorelines which may accumulate enough oil to be respondable (1000 to 10,000 g/m^2) require manual clean-up response. Accessible shorelines with higher loadings (>10,000 g/m^2) require manual or mechanical clean-up response.

The lengths of oiled shorelines where each of these response levels would be required are shown in Table 4.2 . approximately 4355 km of shoreline may be exposed to accumulations of weathered oil at >10 g/m^2. Of the 4355 km, approximately 1994 km (46%) is sandy beach, 1377 km (32%) is rocky shore, 28 km is artificial infrastructure (<1%), 947 km (22%) is cliff and 9 km (<1%) is estuary.

Table 4.2 Summary extent of shoreline types and response levels for shorelines predicted to accumulate >10 g/m² oil over 189 days, based on the WCD129 greatest shoreline accumulation deterministic run

	Surveillance (km)	Requires assessment (km)	Manual (km)	Manual or mechanical (km)	Total (km)
Sandy beach	764 (18%)	540 (12%)	428 (10%)	262 (6%)	1994 (46%)
Rocky shore	1135 (26%)	70 (2%)	95 (2%)	76 (2%)	1377 (32%)
Artificial	4 (<1%)	10 (<1%)	6 (<1%)	8 (<1%)	28 (1%)
Cliff	898 (21%)	17 (<1%)	17 (<1%)	15 (<1%)	947 (22%)
Estuary	6 (<1%)	1 (<1%)	1 (<1%)	1 (<1%)	9 (<1%)
Total length (km)	2807 (64%)	638 (15%)	547 (13%)	362 (8%)	**4355** (100%)

The total volumes of oil predicted to accumulate at >10 g/m² on each type of shoreline is shown in Table 4.3. For conservatism, accumulation on shoreline types that are not considered safe for response (e.g. cliffs) was included in the total volumes for response as it was assumed that oil would not necessarily accumulate at these locations, but would drift onto nearby shorelines where clean-up would then be feasible. The volumes in Table 4.3 are particularly conservative as they are based on modelled levels of accumulation onshore, and have not taken accessibility into account. It was also assumed that state IMTs would require 100% of the shorelines classified as "requires assessment" to be cleaned up, though the actual percentage would be dependent on site conditions and the outcomes of NEBA.

Table 4.3 Accumulation of weathered oil (in m³) across shoreline types and response levels, based on the WCD129 greatest shoreline accumulation deterministic model run

	Surveillance (m³)	Requires assessment (m³)	Manual (m³)	Manual or mechanical (m³)	Total (m³)
Sandy beach	10,819	429	2826	46,276	60,350
Rocky shore	54,669	59	704	11,119	66,551
Artificial infrastructure	88	6	79	2163	2337
Cliff	112,879	15	135	2013	115,042
Estuary	1	0	2	182	186
Total	178,456	510	3747	61,754	**244,466**

Of the modelled 244,466 m³ accumulating on shore, 178,456 m³ would not be actionable and would be subject to surveillance, and 66,010 m³ was classified as potentially actionable for preparedness planning purposes (pooling assessment, manual, mechanical clean-up response). A maximum bulking factor (increase volume due to entrainment of other substances) of 10 was applied to determine the potential volume of bulked waste requiring shoreline clean up. This bulking factor for waste is a conservative maximum and the waste volume could be reduced through in situ waste processing methods such as sieving (POSOW 2013, ITOPF 2013, IPIECA 2014).

Modelled minimum time to shoreline contact (generally for islands in state waters rather than mainland) for each state from the WCD_{129} unmitigated stochastic modelling (100 runs) was:

- Western Australia – 56 days
- South Australia – 21 days
- Victoria – 44 days
- Tasmania – 55 days
- New South Wales – 105 days.

Although first shoreline contact was identified as being 21 days from the fastest shoreline contact deterministic run, the earliest day at which shoreline accumulation was considered sufficient to be potentially actionable from the WCD_{129} greatest shoreline accumulation deterministic run was day 44. It was considered that response teams would be on site (shorelines) two days prior to response, and hence for the purposes of demonstrating preparedness for the WCD_{129} greatest shoreline accumulation scenario the following assessment demonstrates shoreline response from day 42. However, although this is not presented here, the conservative response planning allows for response to commence on day 14, ahead of modelled first shoreline contact by oil on day 21.

The long period of weathering at sea was considered in the modelling, which indicated that up to 99% of oil ashore was likely to be highly weathered (e.g. like tar balls), with only 1% likely to be liquid oil. The environmental implications to shoreline clean-up are that common shoreline strategies such as absorbent booms or flushing/washing are likely to be inefficient or ineffective.

This evaluation has been made based on the characteristics of the analogue hydrocarbon (Statfjord C) used for the risk assessment, and in the modelling. It is therefore based on the same assumptions as inherent throughout the risk assessment. This evaluation has been used to determine the upper range of scaling of response requirement, based on the worst-case discharge 129-day scenario. Classification of shorelines and potential accessibility were made by an environmental subject matter expert (SME) for each individual 2 × 2 km square predicted to be exposed to hydrocarbons. Through ongoing ALARP assessment of successful well kill time frames, the spill duration was subsequently reduced to 88 days, and hence the volumes upon which the evaluation is based are considered conservative.

As no oil is predicted to reach shore during the first three weeks after a loss of well control, this provides time for assessing the behaviour of the spill and updating the relevant Tactical Response Plans (TRP).

Shoreline response and clean-up is generally staged:

- Stage 1 – oiled wildlife care (see Section 4.10)
- Stage 2 – bulk oil is removed from the shore to prevent re-mobilisation
- Stage 3 – removal of stranded oil and oiled shoreline material which is often the most protracted part of shoreline clean-up
- Stage 4 – final clean-up of light contamination and removal of stains, if required.

Considerations for evaluating ALARP in shoreline clean-up planning include:

- staffing and training of enough personnel within the fastest time line for oil to reach shore and through all the stages until final clean-up
- effective clean-up operations will need to be supported by facilities and resources such as PPE, accommodation, catering, toilets, transport, access to medical facilities and mental care, tools, waste management and training
- oil may continue coming ashore and, in some cases, it is better to wait until most of the oil has beached before implementing clean-up activities, to avoid repeated ground disturbance and subsequently increased environmental impacts
- Equinor is working closely with state government agencies and will support any shoreline clean-up program as directed by the states.

Staffing and training is a key potential limiting factor for effective shoreline response and has been further investigated below to ensure risk is reduced to ALARP.

4.9.1 Response need

The cumulative response need was determined from the modelled WCD_{129} greatest shoreline oil accumulation over the full 189 day period modelled. The total volume of actionable oil washed ashore over the 189 days was calculated as 66,010 m^3 and after applying the bulking factor of 10x, this was estimated at 660,100 m^3 of weathered oil, oiled sand and debris requiring clean-up. The volume of actionable oil washed ashore represents approximately 27% of the total volume reaching all shorelines.

To determine response capability, it was assumed that one person could remove 1 m^3 of bulked oil from a shoreline each day. Mechanical clean-up measures would remove far more than this amount each day. The number of person-days, over the course of the response action is linked to the total volume of actionable oil ashore; therefore 660,100 person-days are required to remove 100% of the bulked oil from shorelines.

To ensure adequate preparedness, the minimum number of untrained personnel required to meet the response need was calculated. The following assumptions were used in the calculations:

- personnel would be contracted weekly from multiple locations (in South Australia, Victoria and the rest of Australia/internationally)
- a 5% weekly level of attrition (personnel turnover) was applied to cover people leaving for personal reasons
- it was assumed that only 50% of the total work force (after attrition) would be available for response on a given day based on a FIFO-style shift rotation to manage fatigue
- personnel would be available to clean more than 1 km of shoreline each over the period of the response
- existing trained personnel (e.g. IMT advisors, Equinor's GIMAT, AMOSC's core group, trained specialists such as vehicle operators) have not been included in the response team calculations.

A scalable response starting with 330 contracted personnel by the end of week 1, adding an additional 350 by the end of week two and 520 each subsequent week to week 27 (i.e. day 189), would comprise a total of 13,680 trained shoreline response personnel, able to undertake 660,523 person-days of shoreline clean-up between day 44 (first actionable bulked oil ashore) and day 189. The clean-up of oiled shorelines would probably persist over several years, so the demands on individual responders is much lower than calculated, and the number of personnel required to clean-up the total volume is much lower than 13,680.

Both AMOSC and OSRL would be contracted to train response trainers, who would then lead and train contracted response personnel. RPS would act as a contingency source of response trainers. An assessment has been undertaken to determine the maximum number of shoreline response personnel that could be trained during the WCD_{129} greatest shoreline accumulation scenario, to determine the upper level of scaling required. AMOSC would be able to provide eight trainers by week 2, who could then train 50–60 trainers per week from week 3. These trainers could then train 10–20 personnel each per week. OSRL could provide 10 trainers by week 4 (subject to visa approval), who would train 75 personnel per week as trainers. These could then train 10 people each per week.

Based on this assessment, a total of 42,150 shoreline response personnel (trained following the release) would be able to undertake 1,744,461 person-days between day 42 (just prior to first actionable bulked oil) and day 189.

The outcomes of these assessments have been plotted in Figure 4.24, and define:

- the "response need" (cumulative bulked oil accumulation on shore – the purple line/circle marker)
- minimum response capability (minimum personnel requirements – green line, square marker)
- maximum response capability (maximum potential personnel trained – light blue line, diamond marker).

Together, the minimum and maximum response capability demonstrate the 'capability envelope', and the potential for scaling on any given day. Figure 4.24 demonstrates that response capability exceeds the defined response need and incorporates potential for scaling.

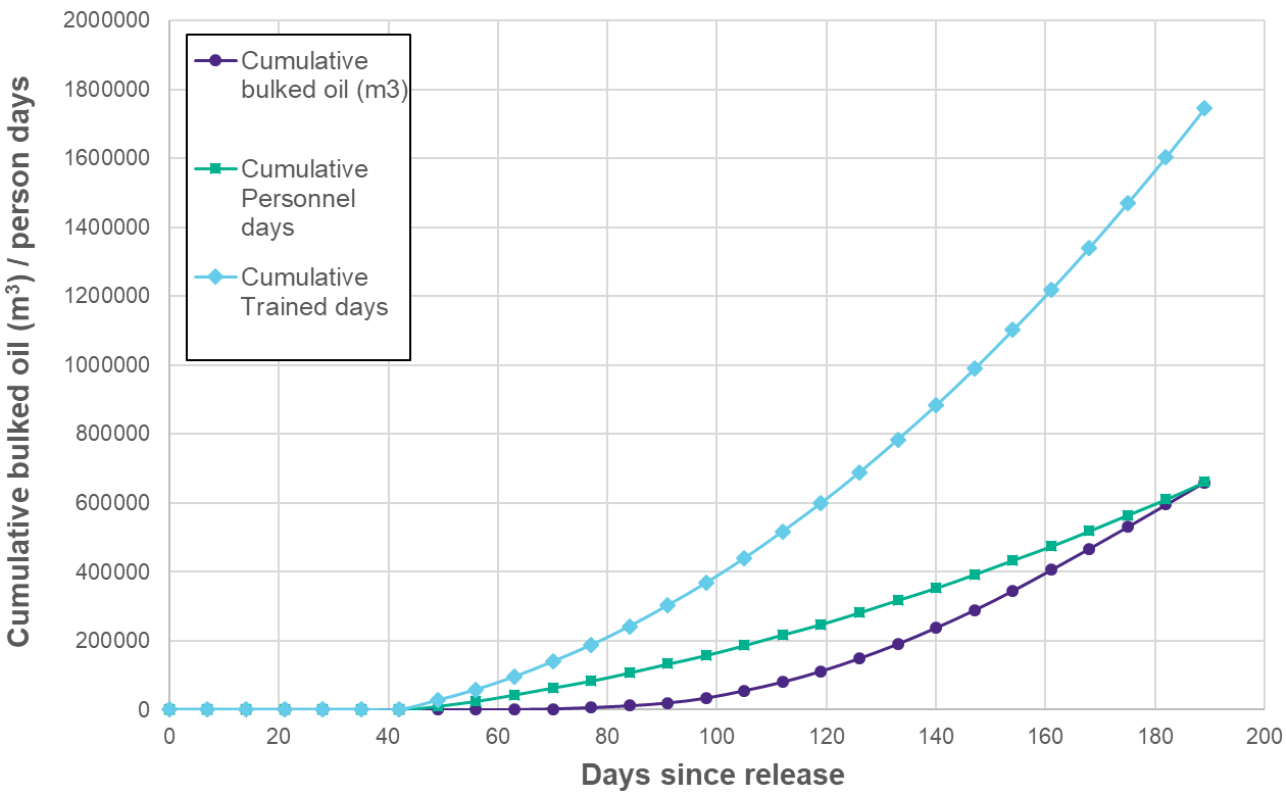


Figure 4.24 Shoreline response need and capacity, based on maximum oil volume ashore (cumulative bulked oil), planned minimum scaling of workforce (cumulative personnel days) and maximum workforce scaling through training (cumulative trained days)

4.10 Oiled wildlife response

The following statements are key parameters upon which the response need is based:

- As surface oil approaches the shorelines the potential for wildlife to suffer oiling increases.
- No oil is predicted to reach shore during the first three weeks after a loss of well control.
- The total extent of oil ashore, and therefore oiled wildlife, in the case of loss of well control will take many months to occur.
- The estimated total need is based on the ability to respond in a first strike capacity to the initial need followed by the ability to rapidly scale-up trained personnel and resources as the extent of oiled wildlife increases to a level that is not possible to predict.

A summary of the advantages, disadvantages, feasibility and potential for environmental risk reduction is presented in Table 4.4.

Equinor has the capability to initially deploy staffing, training and equipping teams capable of responding to two simultaneous Level-6 OWR incidents (as defined in the Western Australian OWRP) and the ability to rapidly scale up capability if state agencies are not involved in the response. If state agencies are involved or direct the oiled wildlife response, their resources will be in addition to those supplied by Equinor.

In Table 5.1 the controls considered in addition to those adopted to meet the initial oiled wildlife response need to demonstrate ALARP include:

- additional wildlife treatment systems and equipment
- additional trained wildlife responders
- improved mobilisation time for wildlife response

Alternatives to wildlife response have not been considered as there are no credible alternatives available for dealing with oiled wildlife.

Table 4.4 Evaluation of spill response strategies (ex. source control)

Response strategy	Advantages	Disadvantages	Suitability, feasibility and practicability	Potential for risk reduction
Surface dispersant application - Vessels	Some localised reduction of oil on surface. Some potential localised reduction in VOCs.	Very limited potential for treatment relative to the daily release volume, due to spraying period (daylight hours only), limited spray and encounter rates, and potential dispersant efficacy (e.g. ~52% for Dasic Slickgone). May slow down natural weathering and degradation processes. Dispersant application may be limited by metocean (e.g. wind/wave) conditions, as it requires calm conditions to be administered effectively. Dispersant application has value only where surface hydrocarbon slicks are sufficiently thick (>10 um) and fresh for dispersants to be effective. Requires dedicated logistics chain, as around 40 hr transit from Port Adelaide; requires multiple vessels to transfer dispersants. Risk of reducing availability of dispersants for other, potentially more effective, dispersant application strategies. Potentially low encounter rate due to distribution of hydrocarbons on surface and herding of the oil due to dispersants in the upper water column. Does not remove oil from the environment, redistributes it into the water column where it may impact on subsurface sensitive receptors. Chemically-dispersed oil has a higher level of toxicity than undispersed hydrocarbons (e.g. due to increased Water Accommodated Fraction (WAF)).	Due to the low efficacy and volume of surface hydrocarbons treatable relative to the daily release volume, this strategy is likely to be unsuitable (relatively ineffective) for this scenario. It is not considered practicable or sustainable to maintain a vessel dispersant application strategy due to the opportunity cost to other response strategies (e.g. vessel and dispersant requirements).	The logistical challenges, opportunity cost and very limited potential benefit do not support implementation as a primary strategy. However, this strategy may reduce risk when used as an opportunistic response, subject to NEBA, dispersant efficacy testing and OSMP data.
Surface dispersant application - Aerial dispersant application	Beneficial in managing surface hydrocarbons – greater active response area. Dispersants and aerial dispersant application aircraft are available in Australia and Internationally, with full mobilisation potentially achievable in 4 days. Some reduction in VOCs at the surface in dispersant application areas, resulting in some potential reduction in human health risk from VOCs.	Limited potential for treatment relative to the daily release volume, due to spraying period (daylight hours only), and encounter rates, and potential dispersant efficacy (e.g. ~52% for Dasic Slickgone). May slow down natural weathering and degradation processes. Dispersant application may be limited by metocean (e.g. wind/wave) conditions, as it requires calm conditions to be administered effectively. Risk of reducing availability of dispersants for other, potentially more effective, dispersant application strategies (e.g. SSDI). Potentially low encounter rate due to distribution of hydrocarbons on surface (e.g. windrows, insufficient surface thickness), potential “punching through” and herding of the oil due to dispersants in the upper water column. Does not remove oil from the environment, redistributes it into the water column where it may impact on subsurface sensitive receptors. Chemically-dispersed oil has a higher level of toxicity than undispersed hydrocarbons (e.g. due to increased Water Accommodated Fraction (WAF)). Fixed wing aerial dispersal capability (FWADC) would require aircraft to be mobilised to Ceduna Airport from across Australia, in addition to Aerotech 1st Response planes (up to 21 in state). OSRL planes from Singapore and UK would require mobilising to Adelaide Airport. There is a substantial cost involved in mobilising and utilising the FWADC, Aerotech and OSRL planes.	The potential aerial dispersant application zone is within range of FWADC. Unlikely to be effective against light oils (e.g. condensate, diesel) and therefore in-situ efficacy testing is a requirement prior to implementation. Increased entrainment of hydrocarbon droplets in surface waters (e.g. upper 20 m) resulting from dispersant application is likely to result in greater bioavailability and exposure to surface water receptors (e.g. diving birds, air-breathing animals, plankton). Due to the potential volume treated of surface hydrocarbons relative to the daily release volume, this strategy is likely to be of low overall effectiveness during a LOWC event.	Based on the modelled distribution of fresh surface hydrocarbons of >10 µm thickness, aerial dispersant application will occur at a minimum of around 200 kms offshore, reducing risk to nearshore and intertidal sensitivities. Modelling (based on Statfjord C crude oil) suggests that aerial dispersant application will have only a small effect on surface hydrocarbon volumes. This strategy would need to be implemented as part of a broader response strategy, subject to NEBA, dispersant efficacy testing and OSMP data.
In-situ burning	May reduce surface hydrocarbons including VOCs. No need to dispose of oily water or transport recovered oil to shore for disposal, therefore there is a potential reduction in carbon emission and risk of accidental re-release.	Requires specialised equipment and trained resources that are potentially unavailable in Australia within practical time frames. Requires offshore metocean conditions to be suitable for containment so that there is enough thickness/quantity to burn. There are health and safety risks to responders when burning the oil. Burning will result in a localised reduction in air quality due to the release of carbon dioxide and other airborne contaminants. Burning may not remove 100% of contained hydrocarbons, with some residues potentially remaining. Does not work on highly weathered oil or very thin sheens. Only feasible in winds <~18 kn, Ignitable only if <~25% evaporated and thicker than 2–3 mm, uncertainty in burnability-stable emulsions are difficult to ignite.	Considerable logistical issues. Currently not adopted in Australia and therefore lack of specialist equipment and trained and experienced personnel in-country.	The period of the activity is extremely short; therefore, it is unlikely that there will be enough change in the national level of preparedness and approvals to consider that this strategy could reduce risk.

Response strategy	Advantages	Disadvantages	Suitability, feasibility and practicability	Potential for risk reduction
Containment and recovery (C&R) - Offshore and nearshore	Reduces volume of surface hydrocarbons (slicks). Potential to contain and remove more weathered hydrocarbons near priority protection sites in coastal areas. Reducing the spread and thickness of surface hydrocarbons will reduce potential exposure and impacts.	Limited by metocean conditions (wind speed, surface current speeds and sea state). For example, unless offshore rated, containment boom is not suited to strong currents (>0.8 knots), winds (>15 knots) or high sea state (Beaufort scale >3 to 4). Booms and skimmers are also limited in their efficacy by hydrocarbon type. For example, absorbent boom will not be effective at containing/recovering highly-weathered hydrocarbons (e.g. tar balls). There are health and safety risks of containment and recovery of volatile hydrocarbons. Containment of weathered hydrocarbons is of low efficacy. Contaminated booms and recovered hydrocarbons must be disposed of appropriately. A robust waste disposal logistics chain must be in place. Localised response.	Boom located at various on-shore stockpiles will take >3-4 days to mobilise to site (minimum), if appropriate vessels are not prioritised for source control activities. Near-shore containment boom deployment (e.g. 600 mm or 800 mm fence boom) could be feasible if waste storage facilities are available. Reduced spill spread will minimise impact. Containment boom could be practical depending on sea state. Boom deployment may not be possible in high sea states/strong currents. Requires a well-developed waste management logistics chain with enough shore disposal facilities. C&R operations may not be possible in high sea states/strong wind or currents and if vessels of opportunity are unavailable for this response activity.	Near-shore C&R may reduce risk to intertidal priority protection areas. Near-shore boom deployment will lower risk of oil spill contact with emergent and shoreline sensitive receptors, and values/attributes that interact with the sea surface (e.g. intertidal reefs, shorelines). This strategy may be employed where feasible to reduce potential environmental impacts (i.e. near-shore) or to protect particular assets. (e.g. fishing vessels, SBT cages/pens, etc.). Offshore C&R will be implemented using appropriate offshore-rated skimmers, though recovery rates are likely to be variable depending on boom types and metocean conditions. Implementation will be subject to ongoing NEBA and OSMP data. Potential for risk reduction related to resource availability.
Shoreline response - protection and deflection	Protects sensitive shorelines and priority protection areas from accumulation of hydrocarbons.	Requires specialist booms and equipment. Only a relatively small area can be boomed due to site/ environmental (incl. weather) conditions and resources required – limited response. Deflection booms and curtains are not effective in sea current speeds of >0.7 knots. Deployment is difficult and/or unsafe in heavy sea states and/or high winds. Anchoring may cause damage to benthic habitats (e.g. seagrass beds). This strategy potentially increases environmental risk to adjacent shorelines, and "sacrificial" shorelines may be identified.	Oil spill modelling for a level three release demonstrates the need to consider protection of vulnerable shorelines/priority protection areas. Shoreline Tactical Response Plans (TRPs) developed for WA and SA include planning for deployment of protection and deflection booms. Additional TRPs (e.g. for VIC/TAS/ NSW) will be developed as required based on stochastic modelling and real-time situational awareness; these will be developed in conjunction with relevant state control agencies.	Requires an understanding of the local deployment environment to minimise implementation risk to responders and sensitive receptors. Operational monitoring will provide information on the efficacy and potential impacts of the response. This strategy will be implemented in line with location-specific tactical response plans (TRPs) and likely focussed on identified priority protection areas, subject to NEBA and OSMP data.
Shoreline response - shoreline clean-up	Reduces some environmental risks and visual impacts of oil accumulation on shorelines.	Significant equipment and personnel resources are required. Significant support infrastructure, resources and logistics also required. Access may be limited in remote areas. Health and safety risks can be significant and must be carefully considered. Shoreline clean-up has the potential to cause greater impacts than the stranded oil itself.	Robust logistical planning and support will be required to support this response. Infrastructure and PPE will be provided. Requires specialist training for responders. Shoreline TRPs for Priority Protection Areas (PPAs) pre-prepared in South Australia. As most operations will be in state jurisdictions, close engagement with state IMTs will be required, and working under state direction. Response will be subject to NEBA, especially for shorelines with sensitive or retentive shallow water/intertidal habitats and where there is potential for long-term negative impacts.	Planning will be based on shoreline TRPs, SCAT, situational awareness and modelling. Relatively long time-to-contact periods (minimum of 21 days) allow additional time for planning and logistical management. Prolonged weathering will also affect the hydrocarbon characteristics, including potentially reducing the toxicity of hydrocarbons accumulating on shores. Considered only where effective clean-up may be possible without significant long-term impacts (based on NEBA, OSMP data and SCAT outcomes, and in line with location-specific TRPs). Operational monitoring will inform potential risks and impacts of shoreline clean-up to minimise risk. Waste management plans and logistics chain required.
Oiled wildlife response (OWR)	Removal of animals from the source of risk. Cleaning of oil from animals, rehabilitation and release of survivors. Potential to treat animals suffering from secondary health issues resulting from oil exposure (e.g. infections/ disease resulting from stress reduced immune system function).	Potential to increase stress in affected (or at risk) animals. Animals relocated from "at risk" sites may return to still contaminated sites. Historically high mortality rate of cleaned animals. Potential for long periods of rehabilitation before release back into the wild.	Requires specialist resources, equipment and infrastructure over a potentially very large spatial area and long period. Requires specialist training for responders. Requires robust oil wildlife response planning. As most operations will be in state jurisdictions, close engagement with state IMTs will be required, and working under state direction.	Equinor will work closely with state IMTs and AMOSC to support OWR. Equinor will arrange for two Category 6 teams to be trained across the response area, drawing on local resources (at Equinor's expense). Equinor has OWR branch directors available in their Global Incident Management Assist Team (GIMAT) that may be mobilised to coordinate OWR with states and OSRAs.

5.0 ALARP assessment outcomes

A summary of the additional spill response options that were assessed and their environmental benefits, costs and outcomes is presented in Table 5.1. In the ALARP assessments, the costs and environmental benefits for each step of the ALARP process are related to the incremental change from the previous step. Options marked as "superseded" were adopted, but then an improvement was identified, and the improved option was adopted in its place.

Table 5.1 Cost / benefit outcomes – spill response control

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
A	Blowout preventer						
A1	ROV vessel from Singapore	Protective	Enables intervention by ROV (in the event that main and backup systems fail). Well shut-in in 21 days, would reduce the worst credible case discharge (WCCD) hydrocarbon release time by 81 days, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Major (>50%)	<0.5% of project cost	Standard practice.	Superseded
A2	ROV vessel from North West Shelf (WA)	Protective	Enables intervention by ROV (in the event that main and backup systems fail). Well shut-in in 10 days, would reduce the worst credible case discharge hydrocarbon release time by a further 11 days, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Significant (10-50%)	<0.5% of project cost	Standard practice.	Superseded
A3	Subsea intervention by ROV on stand-by vessel on location	Protective	Enables intervention by ROV (in the event that main and backup systems fail). Well shut-in in one day, would reduce the worst credible case discharge hydrocarbon release time by a further nine days, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Moderate (3–10%)	0.5–2% of project cost	Highly effective control and ROV capability also useful for surveillance. Not normal to be on stand-by, however the great distances in Great Australian Bight makes this reasonable to implement. Will be able to close the Blind Shear Ram and other BOP functions using the accumulator pressure already on the seabed or using an ROV BOP intervention skid. The BOP will close and seal unless there are large obstructions inside the BOP.	Adopted (EP Section 7.7.13.4)
A4	Subsea intervention by ROV on stand-by vessel and BOP intervention skid/kit on rental	Protective	Well shut-in in one day, would not lead to a further reduction in hydrocarbon release, but will increase robustness if BOP secondary accumulator system is not available.	Negligible (<1%)	<0.5% of project cost	These kits are part of emergency response equipment that normally shared between operators. They are not normally mobilised on location before an incident. Such kit will allow an increased pump-rate that will allow for closure of the Blind Shear Ram if there is no secondary subsea BOP accumulator (acoustic secondary system). The benefits of this control outweigh the cost and is therefore adopted if the BOP is not equipped with an acoustic secondary control system.	Adopted (EP Section 7.7.13.4)
A5	Acoustic secondary BOP closure equipment on site as mandatory MODU specification	Protective	Well shut-in in one day with ROV-operated BOP closure equipment, no further reduction in hydrocarbon release. Could be selected if available on selected rig but will not increase robustness of ROV solution.	Negligible (<1%)	0.5–2% of project cost	The cost of retrofitting the MODU is grossly disproportionate to the risk of adverse effects. This control measure will be given preference in the technical evaluation of the MODU, but will not be a requirement.	Not adopted
A6	V-shear rams included in mandatory MODU specifications	Protective	Reduces risk that BOP may fail to effectively cut or seal drill string due to non-centred pipe string. Could be selected if available on selected rig but risk is already very low and further reduction adds negligible benefit.	Negligible (<1%)	0.5–2% of project cost	The cost of retrofitting the MODU is grossly disproportionate to the small reduction in risk of adverse effects. This control measure will be given preference in the technical evaluation of the MODU, but will not be a requirement.	Not adopted
A7	Additional SAR capability within 12 hours during hydrocarbon zone penetration, to enable SCV to attempt BOP closure timeously	Administrative	Additional SAR capability will enable SCV to close BOP within 12 – 24 hours of a LOWC. This could reduce the volume of spilled oil and hence reduce environmental effects	Negligible (<1%)	<0.5% of project cost	The costs of ensuring other support vessels are capable of SAR activities and that one of the support vessels is always within 12 hours of the well-site during hydrocarbon zone penetration do not outweigh the benefit of meeting commitment to timely response and reduction in environmental risk.	Adopted (EP Section 7.7.13.4)
B	Subsurface dispersant injection (SSDI)						
B1	SSDI using subsea construction vessel (SCV) of opportunity from Singapore	Protective	SSDI deployed on day 23 would reduce the duration of undispersed hydrocarbon release by 79 days, with resultant reduction in shoreline loading and nearshore environmental impact	Major (>50%)	<0.5% of project cost	Sourcing a SCV in Singapore, loading the SSDI equipment and then installing a coiled tubing unit in Perth and mobilising to Stromlo-1 location is considered standard practice.	Superseded
B2	SSDI using contracted SCV in GAB and SSDI by air from Singapore, Coiled Tubing Unit from Perth	Protective	SSDI deployed on day 9, would reduce the duration of undispersed hydrocarbon release by 14 days, with resultant reduction in shoreline loading and nearshore environmental impact	Significant (10 - 50%)	2–5% of project cost	Cost of SCV vessel is offset by other purposes including CS capabilities and not disproportionate to reduction in environmental risk.	Adopted (OPEP Section 13.1)
B3	Subsea dispersant toolkit from AMOSC in Perth and Coiled Tubing unit in Perth, deployment SCV on contract	Protective	SSDI deployed on day 9, no further resultant reduction in shoreline loading and nearshore environmental impact	Negligible (<1%)	< 0.5% of project cost	No additional cost or environmental benefit but adds contingency value in case of logistical issues with transport from Singapore.	Adopted (OPEP Section 13.1)

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
B4	Subsea dispersant toolkit held locally in Adelaide	Protective	SSDI deployed on day 9, no further resultant reduction in shoreline loading and nearshore environmental impact	Negligible (<1%)	5-10% of project cost	Not normally done, because the SSDI toolkits are held on non-exclusive contracts and delivery time for new ones is 2 years and adding this capability locally would not further reduce the response time. Implementation brings significant costs in terms of buying or renting response kit throughout activity, but with negligible benefit. The cost outweighs the benefits of this control and is therefore not adopted for any of the rental options.	Not adopted
B5	Subsea dispersant toolkit held locally in Adelaide picked up by a PSV while SCV is performing SAR and BOP intervention.	Protective	SSDI deployed on day 76, would further reduce the duration of undispersed hydrocarbon release by 2 3 days, with resultant reduction in shoreline loading and nearshore environmental impact resultant reduction in shoreline loading and nearshore environmental impact	Minor (1-3%)	10-50% of project cost	The same rationale from B4 is applicable. This option would also require a significant volume (>200 m^3) of dispersant to be stored and potentially pre-filled on ISO tanks in Adelaide to allow for sufficient and timely loading of dispersant to the PSV – combined with just-in-time IBC tanks from other dispersant stockpiles. At-sea transfer of SSDI kit over to SCV would be required and there could be potential WOW involved if rough conditions, not allowing the transfer to be done safely. The absolute reduction in time from B4, B3 and B2 is significant, but evaluating the efficiency of the SSDI over the time period required for drilling a relief well the total benefit of 2 days from ALARP B2/B3 is minor.	Not adopted
B6	Subsea dispersant toolkit held on location	Protective	SSDI deployed on day 5, would further reduce the duration of undispersed hydrocarbon release by 4 days, with resultant reduction in shoreline loading and nearshore environmental impact	Moderate (3-10%)	10-50% of project cost	The same rationale from B4 is applicable. This option would also require a significant volume (>400 m^3) of dispersant to be already stored onboard PSV tanks to allow for enough autonomy for about a week. The absolute reduction in time from B4, B3 and B2 is significant, but evaluating the efficiency of the SSDI over the time period required for drilling a relief well the total benefit of 4 days from ALARP B2/B3 is negligible.	Not adopted
B7	Subsea dispersant toolkit held on location with vessels dedicated for SSDI.	Protective	SSDI deployed on day 2, would further reduce the duration of undispersed hydrocarbon release by 72 days, with resultant reduction in shoreline loading and nearshore environmental impact resultant reduction in shoreline loading and nearshore environmental impact	Moderate (3-10%)	10-50% of project cost	The same rationale from B4 and B6 is applicable. This would require an additional vessel with ROV capability to be able to perform SAR and BOP interventions simultaneously while installing SSDI. The cost outweighs the benefits of this control and is therefore not adopted. The absolute reduction in time from B4, B3 and B2 is significant, but evaluating the efficiency of the SSDI over the time period required for drilling a relief well, the total benefit of 7 days from ALARP B2/B3 is negligible.	Not adopted
B8	Further Ecotoxicity testing of OSCA-registered dispersants for on local species	Protective	Improve the knowledge of specific dispersants toxicity toon local species and improve NEBA process; however, negligible benefit given the relevant ecotoxicity data already available.	Negligible (<1%)	0.5–2% of project cost	Equinor's selected dispersants are approved on the OSCA-register, which means that they have been tested on relevant Australian species and this testing is considered adequate for a priori selection of dispersants. The test results supporting the chemicals' OSCA approval indicate that 12 of the 13 test species are likely to occur in the GAB region and therefore are directly relevant. Further testing will not reduce the risks any further.	Not adopted
B9	Dispersant selection process for transitional and/or non-OSCA registered dispersants	Protective	Improve NEBA outcomes and risk reduction of response by enabling preferential selection of dispersants which are effective, low toxicity and biodegradable. Screen out chemical with higher risk of unacceptable impact on environment.	Negligible (<1%)	< 0.5 of project cost	The potential environmental risk of transitional and non-OSCA registered dispersants must be understood. Outcomes must meet or be equivalent to AMSA acceptability standards for OSCA registered dispersants to ensure reduction of risk to ALARP. Low cost given process only needed if OSCA-registered dispersant supply exhausted and this is not predicted.	Not adopted as not required per Appendix 6 (OPEP Appendix 9.1)
C	Well capping stack (CS)						
C1	Capping using OSRL capping stack (CS) from Singapore transported on construction vessel from Singapore to GAB	Protective	Well capped in 24 days, would reduce the hydrocarbon release time by 81 days, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Major (>50%)	<0.5% of project cost	Standard practice as part of the OSRL contract, but its success is dependent on availability of a suitable construction vessel in Singapore with Australian Safety Case. Is considered standard practice.	Superseded
C2	Capping using WWC flyable CS from Singapore to Adelaide by Antonov and SCV on contract in the region, with the ability to handle source control equipment (CS)	Protective	Well capped in 21 days, would reduce the hydrocarbon release time by a further three days, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Minor (1-3%)	2–5% of project cost	Cost associated contracting the SCV. The cost is high compared to environmental benefit of reducing spill duration by four days. This is plan is not adopted but superseded by ALARP C3 which has a more optimal and robust flight solution without any additional impact.	Superseded
C3	Capping using WWC flyable CS from Singapore to Adelaide by B747 and SCV on contract in the region, with the ability to handle source control equipment (CS)	Protective	Well capped in 15 days, would reduce the hydrocarbon release time by nine days compared to using a vessel from Singapore, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Moderate (3-10%)	2–5% of project cost	Cost associated with contracting SCV and additional logistics planning is reasonable compared to environmental benefit of reducing spill duration by nine extra days. B747 on regular schedule to Sydney and Melbourne from Singapore. Sydney Airport has B747 main deck unloader with capacity for the heaviest in the capping (and debris removal) packages.	Adopted (OPEP Section 13.1)
C4	Capping using CS on rental stored in Adelaide and deployment vessel available on location	Protective	Well capped in 14 days, would reduce the hydrocarbon release time by a further one day, with resultant reduction in environmental impacts associated with less exposure to entrained, dissolved and floating hydrocarbons	Negligible (<1%)	10–50% of project cost	Would improve capping speed by one day vs alternative in ALARP C3. Not normal practice, because capping stacks are on non-exclusive contracts and delivery time for new ones is ~two years. There are a few options for renting capping stacks, and the estimated cost for this arrangement is grossly disproportionate to the benefit in improved response timing, and is therefore not adopted.	Not adopted

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
C5	Capping using CS on rental stored and assembled in Adelaide, with specialised personnel available on exclusive stand-by in Adelaide and deployment vessel available on location	Protective	Well capped in 11 days, would reduce the hydrocarbon release time by further four days, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Moderate (3-10%)	10–50% of project cost	This solution would require the complete crew to be on stand-by in Adelaide during the project, in addition to the having the capping stack on exclusive rental in Adelaide. There are a few options for renting capping stacks, and the estimated cost for this arrangement is grossly disproportionate to the benefit in improved response timing, with moderate benefits compared to ALARP C3, and is not adopted. The measure of having specialised personnel available on exclusive stand-by in Adelaide, or on location will only improve the time line if the CS is pre-emptively mobilised.	Not adopted
C6	Capping using CS on rental stored and assembled in Adelaide, with specialised personnel available on exclusive stand-by in Adelaide and dedicated deployment vessel available on location	Protective	Well capped in 9 days, would reduce the hydrocarbon release time by further six days, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Moderate (3-10%)	10–50% of project cost	This solution would require the complete crew to be on stand-by in Adelaide during the project, in addition to the having the capping stack, and heavy debris clearance equipment, on exclusive rental and the infrastructure (hangar, lifting and transfer) setup in Adelaide. Implementing this solution has very high cost, long lead-times, with moderate benefits compared to ALARP C3, and is not adopted.	Not adopted
C7	Capping using CS on rental stored on location and deployment vessel available on location	Protective	Well capped in 8 days, would reduce the hydrocarbon release time by a further seven days (compared to storage in Adelaide – C4), with resultant reduction in environmental impacts associated with less exposure to entrained, dissolved and floating hydrocarbons	Moderate (3-10%)	10–50% of project cost	This solution would require the capping stack, and heavy debris clearance equipment, on exclusive rental. In addition, a competent crew would have to be mobilised for system stack up and transferring to a vessel. Implementing this solution has very high cost, long lead-times, with moderate benefits compared to ALARP C3, and is not adopted.	Not adopted
C8	Capping using CS on rental stored on location, with specialised personnel available on exclusive stand-by on location and deployment vessel available on location (shared with BOP intervention mission)	Protective	Well capped in 6 days, would reduce the hydrocarbon release time by a further nine days, with resultant reduction in environmental impacts associated with less exposure to entrained, dissolved and floating hydrocarbons	Moderate (3-10%)	10–50% of project cost	This solution would include the rental of both the capping and heavy debris clearance equipment, and a SCV on contract and at location with all equipment and crew. Implementing this solution has very high cost, long lead-times, with moderate benefits compared to ALARP C3, and is not adopted.	Not adopted
C9	Capping using CS on rental stored on location, with specialised personnel available on exclusive stand-by on location and dedicated deployment vessel available on location	Protective	Well capped in 3 days, would reduce the hydrocarbon release time by a further 12 days, with resultant reduction in environmental impacts associated with less exposure to entrained, dissolved and floating hydrocarbons	Significant (10-50%)	10–50% of project cost	This solution would include the rental of both the capping and heavy debris clearance equipment, and a SCV on contract and at location with all equipment and crew. Implementing this solution has very high cost, long lead-times, and is not adopted even with the significant benefits compared to ALARP C3.	Not adopted
C10	Verification of mobilisation plan and logistical assumptions by desktop CS deployment exercise.	Administrative	Reduce potential uncertainties and check the capping plan can be further improved to less than 15 days.	Negligible (<1%)	< 0.5 of project cost	Verify assumptions and identify potential logistical bottlenecks for capping mobilisation. Check if other options have become available.	Adopted (OPEP Section 13.1)
C11	Capping stack (CS) and active heave compensation crane – operability specifications	Protective	An active heave compensation crane (AHC) crane on the subsea construction vessel (SCV) that can safely operate in a broader range of metocean conditions will potentially reduce the capping stack installation period, thereby reducing the volume of oil released into the environment.	Moderate (3–10%)	0.5–2% of project cost	Having a SCV with an AHC crane that can operate in up to 4 m Hs would allow for the capping stack to be installed within a 38-hour time window, in a P50 case for April. Should the SCV and AHC crane have an operating limit of 3 m Hs, the capping stack could be installed within a 2.5-day time window, and with a significantly longer installation period in a P90 event (installation period of 3.5 days and 7 days for operating in up to 4 m Hs and 3 m Hs, respectively). Increasing the AHC specification to 5 m Hs shows no improvement in the P50 case, and minor improvements for the P90 case, The benefit of reducing the volume of oil released through earlier capping stack installation outweighs the cost differential of an up to 4 m Hs versus a 3 m AHC crane, and therefore this control measure is considered as reducing risk to ALARP.	Adopted (EP Section 7.7.13.4)
D	Relief well (RW)						
D1	Relief well assuming rig mobilised from South-East Asia after loss of well control (LOWC); Australian Safety Case is not assumed and must be approved during mobilisation	Protective	Well killed in 149 days stopping the flow of hydrocarbons to the marine environment.	None	<0.5% of project cost	Standard practice. This assumes using any rig within the technical specifications either warm-stacked or operating in South-East Asia. A Safety Case for Australia will be needed.	Adopted and superseded
D2	Relief well assuming rig mobilised from Singapore after LOWC; Australian Safety Case revision/bridging documentation developed in mobilisation period	Protective	Well killed in 102 days stopping the flow of hydrocarbons to the marine environment.	Significant (10-50%)	<0.5% of project cost	Standard practice to use warm-stacked or operating MODU sourced from Singapore (or in the area) as the key regional centre. The costs of bringing in a relief well and drilling the RW are high, but not disproportionate to the environmental consequences associated with an LOWC. Upfront cost of relying on RW in Singapore is low.	Adopted (EP Section 7.7.13.4)
D3	Relief well assuming rig mobilised from North West Shelf (WA) including access to enough riser length for 2239 m water depth	Protective	Well killed in 88 days, would reduce the hydrocarbon release time by 14 days. A RW rig may also be available from closer areas in Australia, e.g. Bass Strait, which would further improve response time and reduce hydrocarbon release time, with resultant reduction in environmental impacts.	Significant (10-50%)	0.5–2% of project cost	Standard practice through Memorandum of Understanding (MOU) on mutual aid. Due to shorter RW rig sailing time and availability of marine riser package the RW drilling can start earlier and kill the well earlier. The 14-day reduction in flow represents a significant environmental benefit, which is not outweighed by the cost. Upfront cost of relying on RW on North West Shelf will include moving and storing additional riser elements in the region. This control is adopted and will be confirmed and planned for in the WOMP.	Adopted (to be included in the WOMP)

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
D4	Have drilling equipment available in Adelaide to start RW if the main rig remains operational, drill RW top holes, RW rig from North West Shelf (WA) to bring BOP and complete well-kill	Protective	Well killed in 73 days, would reduce the hydrocarbon release time by a further 15 days, with resultant reduction in environmental impacts.	Significant (10-50%)	0.5–2% of project cost	The chance that the main rig is available after an emergency disconnect sequence which leads to an LOWC is high and the potential time saving will be ~4 weeks compared to bringing a RW rig from Singapore, or ~2 weeks compared to bringing RW rig from North West Shelf. The opportunity to start RW earlier would require that the drilling equipment is available locally and an alternative RW rig is mobilised from North West Shelf (or closer). Upfront cost due to storage of backup equipment locally during drilling program. The environmental benefit of reducing the flow by 2–4 weeks is significant and outweighs the costs associated with pre-mobilising additional well equipment. This control is adopted in principle and will be confirmed and planned for in the WOMP.	Adopted in principle (to be included in the WOMP)
D5	Have drilling equipment available on a contracted vessel locally to start RW immediately if the main rig remains operational, drill RW top holes, RW rig from North West Shelf (WA) to bring BOP and complete well-kill	Protective	Well killed in 71 days, would reduce the hydrocarbon release time by a further two days, with resultant reduction in environmental impacts.	Minor (1-3%)	2–5% of project cost	Holding the spare drilling equipment on a vessel locally would enable the main rig to start the RW two days earlier due to faster mobilisation. Upfront cost is high due to charter of extra vessel and storage of equipment during drilling program. The environmental benefit of reducing the flow by two days is outweighed by the disproportionately high costs, for a very low probability event and is therefore not adopted.	Not adopted
D6	Relief well rig on stand-by east of Port Lincoln throughout drilling program	Protective	Well killed in 68 days, would reduce only five days assuming the most likely scenario where the main rig did EDS and can start the RW, with resultant reduction in environmental impacts.	Moderate (3-10%)	>50% of project cost	Not normally done in areas accessible year-round and engenders a disproportionately high cost for a very low probability event. The improvement is only five days to the ALARP D4 and is therefore not adopted.	Not adopted
D7	Pre-drill top section of relief well	Protective	Pre-drill the top sections of the RW with the aim to shorten the time line to complete a RW after a LOWC. Depending on the scenario, the time saving may only be in the order of five days (ref ALARP D5, as the main rig will most likely execute EDS and can start the RW while waiting for the RW rig.	Moderate (3-10%)	10–50% of project cost	Detailed plans for a RW will always be redone and revised based on the actual situation after a LOWC. There will be several locations for the RW identified before an incident, and the optimal location is chosen after a LOWC incident. A pre-drilled RW top-section might render a sub-optimal RW design and location. It is not industry practice, and such a top-hole RW will significantly increase the planned activity, with the associated cost and environmental impacts.	Not adopted
D8	Relief well rig on stand-by on location throughout drilling program	Protective	Well killed in 63 days, would reduce with 10 days assuming the most likely scenario where the main rig did EDS and can start the RW, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Moderate (3-10%)	>50% of project cost	Not normally done in areas accessible year-round and engenders a disproportionately high cost for a very low probability event. The improvement is 10 days to the ALARP D5 and is therefore not adopted.	Not adopted
D9	Relief well rig drilling relief well in parallel with the petroleum activity on Stromlo-1.	Protective	Well killed in 44 days, would reduce with 29 days assuming the most likely scenario where the main rig did EDS and can start the RW, with resultant reduction in environmental impacts associated with exposure to entrained, dissolved and floating hydrocarbons	Significant (10-50%)	>50% of project cost	Detailed plans for a RW will always be redone and revised based on the actual situation after a LOWC. There will be several locations for the RW identified before an incident, and the optimal location is chosen after a LOWC incident. A pre-drilled RW might render a sub-optimal RW design and location. It is not industry practice, and such a RW will significantly increase the planned activity, with the associated cost and environmental impacts.	Not adopted
E	Dispersant supply chain						
E1	Pre-store approximately 8 m^3 of dispersant at Port Adelaide to enable vessel application response within first few days	Protective	Starting vessel dispersant application within the first few days of the LOWC after the vessels are cleared for dispersant activities will enable dispersion of oil from the sea surface adjacent the MODU and prior to the main SSDI intervention being in place. This will reduce the overall volume of surface oil and reduce contributions to accumulated surface slick, with resultant reduction in shoreline loading and nearshore environmental impact.	Negligible (<1%)	<0.5% of project cost	A dispersant stock of 8 m^3 (at Port Adelaide) allows enough volume to support the first few days' activities; allowing time for additional stock to be sourced from alternative dispersant resources. The cost of purchase and probably disposal of 8 m^3 is not disproportionate to the benefit of early application of dispersants, particularly for a small spill where it will only be "actionable" for a short time.	Superseded
E2	Pre-store approximately 50 m^3 of dispersant across multiple sites including Port Adelaide and vessels, to enable greater vessel application response within first few days	Protective	Starting vessel dispersant application within the first few days of the LOWC after the vessels are cleared for dispersant activities, will enable dispersion of oil from the sea surface adjacent the MODU and prior to the main SSDI intervention being in place. This will reduce the overall volume of surface oil and reduce contributions to accumulated surface slick, with resultant reduction in shoreline loading and nearshore environmental impact.	Negligible (<1%)	<0.5% of project cost	A dispersant stock of 50 m^3 (total volume at Port Adelaide and on vessels) allows enough volume to support the first few days' activities, allowing time for additional stock to be sourced from alternative dispersant resources. The cost of purchase and probably disposal of 50 m^3 is not disproportionate to the benefit of early application of dispersants, particularly for a small spill where it will only be "actionable" for a short time.	Adopted (EP Section 8.5.4)
E3	Supply Ceduna Airport with 6 m^3 dispersant to enable aerial application within two days	Protective	Starting aerial dispersant application within the first few days of the LOWC will enable dispersion of oil from the sea surface prior to the main SSDI intervention being in place. This will reduce the overall volume of surface oil and reduce contributions to accumulated surface slick during days 2–9, with resultant reduction in shoreline loading and nearshore environmental impact.	Negligible (<1%)	<0.5% of project cost	A dispersant stock of 6 m^3 at Ceduna Airport will enable swift aerial application. On day 2, 28 m^3 can be sourced from Geelong or elsewhere. AMOSC confirmed enough dispersant for 20 days of aerial dispersant available in Australia. The cost of purchase and probably disposal of 6 m^3 is not disproportionate to the benefit of early aerial application of dispersants.	Adopted (EP Section 8.5.4)

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
E4	Pre-fabricate more dispersant before project starts	Protective	Pre-fabrication increases assurance of dispersant supply but given the very low probability of an LOWC causing a prolonged spill, the surplus dispersant may need to be disposed at the end of the activity.	Negligible (<1%)	0.5–2% of project cost	To pre-fabricate more dispersant before the project starts would engender disproportionately high costs for fabrication, local storage and maintenance and would only bring marginal benefits, given that the supply chain would be triggered as soon as the LOWC occurred, the risk of the LOWC being very low. Even a prolonged incident with Worst Credible Case Discharge, including completion of a Relief Well, can be managed by existing stock and post-incident fabrication, with a logistical supply chain to deliver it offshore.	Not adopted
E5	Fabricate more dispersant upon LOWC event	Protective	Fabrication after an LOWC has occurred will ensure a reliable supply of dispersant and the environmental will benefit from avoiding periods where there is insufficient dispersant available to implement the response strategy	Negligible (<1%)	<0.5% of project cost	Finasol's manufacturer Total has confirmed production time frames and that volumes can be rapidly scaled up after notification of an LOWC. Equinor will make a request to OSRL to arrange manufacture of additional OSCA-registered dispersants from their suppliers in Europe. The reliability of manufacture will be dependent on market supplies of feedstocks and therefore is assessed as a backup measure only to sourcing dispersant off-the-shelf given the available national and international stockpiles. AMOSC has investigated the potential for manufacture of dispersants in Australia, but ChemeTell is not interested in JIT manufacture unless industry invests more than vocal support for the initiative. The benefit of ensuring continuity of supply outweighs the costs of producing more dispersants which may not be needed if, for example, the BOP successfully closes the well after one day and current stocks are sufficient. No upfront costs.	Adopted (OPEP Section 13.1)
E6	Equinor spotter plane within 24 hours	Protective	It will beneficial to the environment to optimise the dispersant response strategy based on improved situational awareness. The spotter plane will also enable assessment of the distribution megafauna in the spill area and feed into other response plans such as oiled wildlife response	Negligible (<1%)	<0.5% of project cost	The benefits of improved efficiency in aerial dispersant application and situational awareness to feed into other response plans, outweigh the costs of contracting the aircraft. This also enables the aerial operation to be expanded in line with AMSA guidelines.	Adopted (OPEP Section 13.1)
E7	Stockpile on MODU or SCV/PSV for vessel application	Protective	Negligible benefit because the vessels will be engaged in other activities in the first few days of the response and having dispersant in the field may not improve response times for vessel application	Negligible (<1%)	<0.5% of project cost	Even if cost to operational efficiency through reducing deck space on the offshore vessels possibly outweighs the negligible benefit of having an offshore stockpile of dispersants, it will be adopted since it will add options and robustness given the long transit times.	Adopted (OPEP Section 13.1)
E8	Stockpile and pre-fill larger ISO tanks to allow for faster SSDI start-up	Protective	Pre-loading of 200 – 400 m^3 on larger ISO tanks (20 m^3) would allow for faster initial loading of dispersants to PSV enabling sooner start of SSDI	Negligible (<1%)	2-5% of project cost	The purchase of this amount of dispersant, the rental of ISO tanks and the amount of work required to transfer them to ISO tanks ahead of an incident has a very high cost. This control and is linked to the SSDI time line, and there is a dispersant supply chain planned that will not slow down the selected SSDI solution and time line. Pre-loading of this amount of dispersant will hence not improve the response, and the significant cost outweighs the benefits.	Not adopted.
F	Aerial dispersant						
F1	Air tractors from day 2; up to nine aircraft mobilised by day 4	Protective	Starting aerial dispersant response within two days will enable dispersion of oil from the sea surface and prior to the SSDI intervention being in place. This will reduce the overall volume of surface oil and reduce contributions to the accumulated surface slick, with resultant reduction in shoreline loading and nearshore environmental impact.	Negligible (<1%)	<0.5% of project cost	The air-tractors are part of the National Plan and under contract with AMSA. Further aircraft will be added if required and if useful and feasible. More than 20 aircraft are confirmed available throughout Australia, though there is potential for some aircraft to be tasked to bush fire response if required. The benefit of the improved response capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)
F2	One Hercules ex Kuala Lumpur from day 2 (OSRL)	Protective	Additional aerial capacity in first few days will enable rapid scaling up of available dispersant volumes and increase application rates adjacent the MODU and prior to the main SSDI intervention being in place. This will reduce the overall volume of surface oil and reduce contributions to accumulated surface slick, with resultant reduction in shoreline loading and nearshore environmental impact.	Negligible (<1%)	<0.5% of project cost	Large aircraft can be mobilised from outside Australia via OSRL contract and maintaining this capability is a low cost compared to the benefit gained through enabling rapid response in aerial dispersant application.	Adopted (OPEP Section 13.1)
F3	One 727 ex UK (OSRL)	Protective	Additional aerial capacity in the first few days will enable rapid scaling up of available dispersant volumes and increase application rates to the waters adjacent the MODU and prior to the main SSDI intervention being in place. This will reduce the overall volume of surface oil and reduce contributions to accumulated surface slick, with resultant reduction in shoreline loading and nearshore environmental impact.	Negligible (<1%)	<0.5% of project cost	Large aircraft can be mobilised from outside Australia via OSRL contract and maintaining this capability is a low cost compared to the benefit gained through enabling more comprehensive response in aerial dispersant application (greater volumes).	Adopted (OPEP Section 13.1)
F4	More aircraft resources available prior to spill event	Protective	The area over which dispersant can be effectively applied prior to subsea dispersant injection is unlikely to require more aircraft than has been detailed above. Therefore, applying additional dispersant is unlikely to be effective in dispersing oil and provide additional environmental benefit.	Negligible (<1%)	0.5–2% of project cost	The additional costs include both the financial cost of contracting more aircraft and additional safety risk of operating multiple aircraft simultaneously over a restricted area.	Not adopted

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
F5	Faster mobilisation times	Protective	Earlier response would result in little environmental benefit due to the time required for dispersible volumes reaching the water surface.	Negligible <1%	0.5–2% of project cost	Due to the distances involved, the relocation of aircraft, personnel and resources to Ceduna/Adelaide, and the planning and organisation required for a safe and effective response, faster mobilisation times are not considered feasible.	Not adopted
F6	Dispersant selection process for non-OSCA registered dispersants	Protective	Improve risk reduction of response through selection of dispersants whose potential efficacy, ecotoxicology and biodegradation have been tested using methods meeting industry standards	Negligible (<1%)	< 0.5 of project cost	The potential environmental risk of non-OSCA registered dispersants must be understood. Outcomes must meet or be equivalent to AMSA acceptability standards for OSCA registered dispersants to ensure reduction of risk to ALARP.	Not adopted as not required per Appendix 6 (OPEP Appendix 9.1)
G	Vessel dispersant						
G1	Two PSVs equipped with dispersant capability	Protective	Starting vessel dispersant application within the first few days of the LOWC will enable dispersion of oil from the sea surface adjacent the MODU and prior to the main SSDI intervention being in place. This will reduce the overall volume of surface oil and reduce contributions to accumulated surface slick.	Negligible (<1%)	<0.5% of project cost	The vessels will prioritise this activity if not needed for source control activities. Due to the water depth and time it takes the non-entrained oil to reach the surface it is also unlikely that fresh oil will appear near the MODU, and hence it will be more effective to disperse from the air. Negligible benefit but cost to have the capability is low. The benefit of the improved response capability outweighs the costs of implementation.	Adopted (OPEP Section 8.5.4)
G2	Extra PSV at well location or in the region to enable dispersant application	Protective	Negligible benefit because the oil is not predicted to surface immediately, and it will need to be assessed before the response can be appropriately targeted. Having an extra vessel will only marginally improve response times for vessel application, with negligible increase in volumes of dispersed oil.	Negligible (<1%)	2%–5% of project cost	The costs associated with having a PSV and crew on stand-by offshore, in port, or tasked to supply dispersants from port to offshore response vessels are disproportionately high in comparison with the small benefit from having a vessel ready to apply dispersants in the first few days when this will not be a priority activity. There will also be increased fuel use from the vessel during the 60 days in the field and during crew changes. The cost outweighs the benefits of this control and is therefore not adopted.	Not adopted
G3	Dispersant selection process for non-OSCA registered dispersants	Protective	Improve risk reduction of response through selection of dispersants whose potential efficacy, ecotoxicology and biodegradation have been tested using methods meeting industry standards	Negligible (<1%)	< 0.5 of project cost	The potential environmental risk of non-OSCA registered dispersants must be understood. Outcomes must meet or be equivalent to AMSA acceptability standards for OSCA registered dispersants to ensure reduction of risk to ALARP.	Not adopted as not required per Appendix 6 (OPEP Appendix 9.1)
H	Mechanical containment and recovery offshore						
H1	Dedicated PSV for mechanical recovery with capacity for recovery of oil (OILREC)	Protective	Additional vessel would only enable recovery of additional small volumes of oil (Section **Error! Reference source not found.**) with negligible environmental benefit; assuming low recovery in the GAB.	Negligible (<1%)	2–5% of project cost	This may not have a material effect on the volume of oil on the surface. The costs associated with the additional vessels and crews are disproportionate to the small benefit gained by recovering potentially small volumes of oil. The cost outweighs the benefits of this control and is therefore not adopted.	Not adopted
H2	Include booms and skimmer systems on the PSVs on contract	Protective	Would allow for faster response for mechanical recovery close to rig site and be able to recover fresh oil.	Negligible (<1%)	0.5%–2% of project cost	The vessel plan for all the potential outcomes of a LOWC scenario shows that the priority will be source control, and the vessels will be fully occupied with those missions, and this measure is therefore not adopted.	Not adopted
H3	Mobilise immediately PSV for mechanical recovery from Australia without waiting for assessment of source control and dispersant effectiveness. Prepare a logistic plan that will allow vessels to be equipped and prepared for operations immediately after arrival.	Protective	Would allow for added robustness if dispersant is less effective than anticipated. Will allow for mechanical recovery of fresh oil close to PSZ in-between ongoing source control activities.	Negligible (<1%)	<0.5% of project cost	The effect of mechanical recovery is sensitive to several factors, including weather, encounter rate and oil thickness. Recovery rates during actual incidents (e.g. Montara and Macondo) were lower than the theoretical capacities. However, this capability may have value after dispersant by air and in the event of intermittent functioning of SSDI. This control is scalable, and we will mobilise all PSV on MoU (mutual assist) in Australia. The number of vessels in Australia fluctuates (currently about 40), and we can assume that 20% can be released for assistance within days. Large boom and skimmer equipment will be available from AMSA, OSRL in Singapore and Equinor (own flyable equipment) before the vessels arrive. The benefit of the improved response capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)
H4	Mobilise immediately PSV for mechanical recovery and DP tanker for oil storage from South-East Asia (day 20–30 arrival) without waiting for assessment of source control and dispersant effectiveness. Prepare a logistic plan that will allow vessels to be equipped and prepared for operations immediately after arrival.	Protective	Would allow for scaling of mechanical recovery	Negligible (<1%)	<0.5% of project cost	Many PSV vessels are available in and around Singapore. Such vessels will add capacity for mechanical recovery. The limiting factor (time) is the vessel itself and not the booms and skimmer equipment that can be flown in as part of tier-3 equipment from Europe, Singapore or the USA. The benefit of the improved response capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
H5	Faster mobilisation times: PSV (w/OILREC) and offshore C&R equipment. on contract and stand-by in Port Adelaide	Protective	Earlier response means a greater potential for recovery of hydrocarbons offshore, with potential benefits to surface, benthic and shoreline sensitivities.	Negligible <1%	0.5–2% of project cost	If a PSV with offshore containment and recovery equipment on board is on stand-by throughout the drilling activity, it could potential be at the well location within 48 hours to commence containment and recovery operations. If the oil has reached the surface at this point, aerial dispersant application (ADA) activities will have commenced. As both ADA and C&R would target the same thickness of fresh oil, the operational period of C&R would be reduced to avoid conflict with ADA. This issue is likely to be exacerbated from day 9 following commencement of SSDI. C&R success would also be affected by metocean conditions and sea state. Therefore effectiveness (and environmental benefit) is likely to be reduced under such sub-optimal conditions. Additionally, due to the nature of emergency situations, it is possible that the PSV may be re-tasked to support other aspects of response despite being contracted for the purpose of offshore C&R (therefore no additional environmental benefit from offshore C&R would be achieved). The cost of having a PSV and C&R equipment on hire in Port Adelaide for the activity period (up to 60 days) is significant, and due to the low probability of a release and the limited potential environmental benefit of a single vessel operating under sub-optimal conditions, this is not considered practicable and hence not ALARP.	Not adopted
H6	Additional trained personnel	Protective	The level of training provided to response personnel ensures efficient response and reduces human health and safety risk and secondary impacts to the environment.	Negligible <1%	<0.5% of project cost	Trained response personnel exercise regularly to maintain competency. All personnel will receive an operational briefing prior to commencing operations. Therefore, pre-mobilisation provides no further reduction in environmental risk.	Not adopted
H7	Improved equipment	Protective	Preferential selection of offshore-rated booms and skimmers to improve potential operational effectiveness	Negligible <1%	<0.5% of project cost	Increased potential oil recovery is likely to provide a reduction in environmental risk, supporting reduction of risk to ALARP	Adopted (OPEP Section 13.1)
I	Nearshore containment and recovery						
I1	Nearshore containment and recovery strike teams provided with equipment in time to allow for training.	Protective	May recover only small volumes of oil but will help protect priority environments or fauna.	Negligible <1%	0.5–2% of project cost	Contract, training and equipment for several VoO (fishing, workboats and tug vessels or similar) that will be available for nearshore containment and recovery or deflection. Deployed as prioritised through NEBA process (with focus on protected and prioritised areas) The vessels will be available at least five days before the arrival of first oil allowing for additional training and readiness with the equipment. Benefit in confirming readiness and improving responsiveness outweighs costs.	Adopted (OPEP Section 13.1)
I2	In time training (after loss of well control) to test preparedness	Administrative	Field-based training with AMOSC equipment and VoO will improve response capacity.	Negligible (<1%)	<0.5% of project cost	Verify operational assumptions. Benefit in confirming readiness outweighs costs.	Adopted (OPEP Section 13.1)
I3	Faster mobilisation times: Prepositioning of nearshore C&R vessels and equipment	Protective	Earlier response means that vessels are in place to respond as soon as spill hydrocarbons reach nearshore waters. No benefit as response time is not improved.	Negligible <1%	0.5–2% of project cost	The cost of pre-positioning vessels and equipment prior to day 15 following a LOWC incident would be significant, and provides no additional environmental benefit over item I1 as there would be no oil to contain or recover. This is considered not practicable as the response time is not improved, and therefore not ALARP.	Not adopted
I4	Potential mobilisation of more than eleven nearshore strike teams under the direction of State Control Agency/ies	Protective	Mobilisation of more strike teams in nearshore waters increases the potential to reduce shoreline loading at any additional priority protection areas identified by State jurisdictions during a response	Negligible <1%	0.5–2% of project cost	Should state control agencies identify additional priority protection areas, increasing the number of nearshore strike teams accordingly is likely to further reduce environmental risk. Therefore, should this be the case, the benefit in improving responsiveness outweighs costs.	Adopted (OPEP Section 13.1)
I5	Additional trained personnel	Protective	The level of training provided to response personnel ensures efficient response and reduces human health and safety risk and secondary impacts to the environment.	Negligible <1%	<0.5% of project cost	Trained response personnel exercise regularly to maintain competency. All personnel will receive an operational briefing prior to commencing operations. Therefore, pre-mobilisation provides no further reduction in environmental risk.	Not adopted
J	Shoreline protection clean-up						
J1	Locate booms in Adelaide	Protective	To allow for robustness in logistics some protection booms will be in Adelaide.	Negligible <1%	<0.5% of project cost	Used for in-time training pre-activity, then prioritised through NEBA if needed. Benefit in improving responsiveness confirming readiness and outweighs costs.	Adopted (OPEP Section 13.1)
J2	Response equipment: Pre-mobilise equipment from stockpiles to areas of predicted shoreline exposure	Protective	Mobilise response equipment from stockpiles/forward operating bases/logistic hubs at a minimum five days before predicted shoreline exposure for the relevant IBRA sub-region	Negligible <1%	<0.5% of project cost	Mobilising equipment from stockpiles/ forward operating bases/logistic hubs prior to the arrival of first oil allowing for additional training and readiness with the equipment. The benefit in confirming readiness and improving responsiveness outweighs costs.	Adopted (OPEP Section 13.1)
J3	Pre-mobilise response equipment to Priority Protection Areas	Protective	Pre-mobilise equipment defined in shoreline TRPs relevant to sectors in Priority Protection areas to protect shorelines	Negligible <1%	<0.5% of project cost	As predicted fastest shoreline contact in the unlikely event of a LOWC event is 21 days, there is sufficient time to mobilise equipment from stockpiles to priority protection areas, and therefore pre-mobilisation provides no further reduction in environmental risk.	Not adopted

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
J4	Faster mobilisation times: Pre-mobilise equipment to shorelines at risk prior to entering reservoir	Protective	Potential to respond earlier via more efficient logistical management	Negligible <1%	<0.5% of project cost	As predicted fastest shoreline contact in the unlikely event of a LOWC event is 21 days, there is sufficient time to mobilise resources to shorelines, and therefore the cost of pre-mobilising equipment provides no further reduction in environmental risk and is therefore not ALARP.	Not adopted
J5	Additional trained personnel	Protective	The level of training provided to response personnel ensures efficient response and reduces human health and safety risk and secondary impacts to the environment.	Negligible <1%	<0.5% of project cost	As predicted fastest shoreline contact in the unlikely event of a LOWC event is 21 days, and as the response will be staged across multiple States, additional personnel can be sourced from OSROs and local resources trained via in-time training. Trained response personnel exercise regularly to maintain competency. All personnel will receive an operational briefing prior to commencing operations. Therefore, pre-mobilisation provides no further reduction in environmental risk.	Not adopted
J6	Update of Shoreline TRPs prior to drilling	Protective	Revision of existing shoreline TRPs for South Australia and Western Australia; preparation of shoreline TRPs for Victoria, Tasmania and New South Wales	Negligible <1%	0.5–2% of project cost	Although there is some potential to reduce environmental risk, additional cost of revising the existing shoreline TRPs, and the preparation of new TRPs for Victoria, Tasmania and New South Wales is disproportionately high in comparison to the risk of a LOWC event. The revised documents may also require further revision should they be required.	Not adopted
J7	A shoreline TRP template is available prior to the OPEP desktop exercise	Protective	A shoreline TRP template will allow rapid preparation on new shoreline TRPs following SCAT for areas not currently covered by existing TRPs.	Negligible <1%	<0.5% of project cost	Availability of a shoreline TRP template prior to the OPEPE desktop exercise would allow it to be reviewed/tested, and allow a faster, more effective response with a potential reduction in secondary impacts. The costs of this approach are also low. Therefore, this control measure is considered a supporting reduction of risk to ALARP.	Adopted (OPEP Section 13.1)
J8	Additional shoreline clean-up resources	Protective	Basic set-up for two crews to be in Adelaide (standard container kits) will improve response capacity	Negligible <1%	<0.5% of project cost	Will allow for early training and familiarisation of actual equipment. Will be used as strike-1 and deployed as prioritised through NEBA process (with focus on protected areas). Benefit in improving responsiveness outweighs costs.	Adopted (OPEP Section 13.1)
J9	Pre-order PPE	Protective	Purchase PPE for early responder. Prepare supply chain for escalation. Will improve response capacity	Negligible <1%	<0.5% of project cost	Have stock of PPE for early responders that may need equipment the first 15 days. Prepare purchase orders to increase PPE levels swiftly for a prolonged response. Benefit in improving responsiveness outweighs costs.	Adopted (OPEP Section 13.1)
J10	Recruitment process in place for sourcing required workforce	Administrative	Access to a large pool of personnel will allow for shoreline clean-up within acceptable time and support ability to ramp up resources as required	Negligible <1%	<0.5% of project cost	Agreement with staffing and recruiting companies to hire and staff shoreline responders. Benefit of greater access to personnel and ability to scale-up resources outweighs any costs of arranging such agreements. The recruitment will go in tandem with revolving “in-time training” from OSRL and AMOSC. The benefit of the improved response capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)
J11	Identify camp sites, catering, sanitary location, and providers	Administrative	Prepare for protracted large response and reduce uncertainty	Negligible <1%	<0.5% of project cost	The number of options is large, and the detailed planning will likely have low value. Camps and support equipment are generally available in Australia and used by mining and oil and gas industry. Given the time line with 3–10 weeks lead time before first shoreline contact, and potential final clean-up as late as five months later, it is reasonable to identify and source the support services and equipment after the incident; therefore, this control is not adopted.	Not adopted
J12	Faster mobilisation times	Protective	Potential to respond earlier via more efficient logistical management	Negligible <1%	<0.5% of project cost	As predicted fastest shoreline contact in the unlikely event of a LOWC event is 21 days, there is sufficient time to mobilise resources to shorelines, and therefore pre-mobilisation provides no further reduction in environmental risk.	Not adopted
K	Oiled wildlife response						
K1	Prepare for staffing, training and equipping teams capable of responding to two simultaneous Level-6 OWR incidents (as defined in the Western Australian OWRP)	Administrative	Will allow for robust oiled wildlife response, especially if more than one state is impacted. Will ensure two operational teams can be mobilised rapidly.	Negligible <1%	<0.5% of project cost	The manning and equipment mobilisation plan will allow for a staged mobilisation, starting in South Australia, and expand either west or east depending on the spill behaviour. The implementation of the plan will meet the earliest arrival of weathered oil in each scenario (east or west of South Australia). The benefits associated with better preparedness to respond to oiled wildlife consequences outweigh the cost of assembling, training and equipping the teams. The benefit of the improved response capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)
K2	OWRP gap plan prepared for Victoria, Tasmania, New South Wales, South Australia and Western Australia prior to spud	Administrative	Identifying gaps in resourcing and how to resolve those to improve cooperation between response agencies and resource sharing will assist in improving the response plan.	Negligible <1%	<0.5% of project cost	The plan will identify a concurrent, multi-state, ramp-up according to fastest time lines for oil to shore include equipment, logistics, personnel, training. The benefit of the improved response capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)
K3	Pre-establish dedicated triage and rehabilitation facilities at sites determined after spill volume, fate and trajectory is known	Protective	Establishing oiled wildlife assessment and treatment facilities prior to oil reaching shore would reduce the consequences for some affected individual oiled fauna in the early days of the response.	Minor (1-3%)	<0.5% of project cost	State agencies responsible for oiled wildlife response have indicated they will manage triage and rehabilitation facilities as needed. The cost of Equinor supporting such centres is not disproportionate to the benefit to be gained once the trajectory of the oil is known and suitable sites can be identified.	Adopted (OPEP Section 13.1)

#	Additional capability / control measures	Hierarchy	Environmental benefit	Benefit%	Cost	Rationale	Outcome
K4	Unspecified nearshore VOO and mutual aid vessels – Adelaide, Port Lincoln and Melbourne available on site before a plume approaches coastal waters	Engineering	Variable depending on number of vessels required and focus of activity	Negligible <1%	<0.5% of project cost	Predicted time before first oil ashore enough to complete charter contract and mobilise personnel and equipment. Both flexible to fit event and scalable. Offshore presence not considered effective due to location and low number of likely affected wildlife.	Adopted (OPEP Section 13.1)
K5	Access to equipment through OSRL, AMOSC and AMSA including purchasing additional equipment nationally and internationally in event of a spill	Engineering	The exact resources cannot realistically be anticipated and therefore flexibility in capability to scale-up resourcing will most accurately and effectively meet the need. Thereby providing the greatest environmental benefit and improving the environmental benefit threshold at which ALARP is achieved.	Moderate (3-10%)	<0.5% of project cost	Since there will be a time lag in the oil arriving ashore and therefore the extent of OW, time is available to scale-up equipment needs. By engaging OWR providers such as OSRL and AMOSC resources can be acquired more rapidly through their existing call-down contract and through an established understanding of equipment volumes and combinations required to effectively undertake OWR. By having a scalable level of resourcing cost is reduced per unit of environmental benefit thereby achieving ALARP with greater environmental benefit.	Adopted (OPEP Section 13.1)
K6	Ability to rapidly train responders in all levels of OWR skill through existing contracts with AMOSC and OSRL in event of a spill.	Administration	The exact numbers of trained personnel cannot realistically be anticipated and therefore flexibility in capability to scale-up resourcing will most accurately and effectively meet the need. Thereby providing the greatest environmental benefit and improving the environmental benefit threshold at which ALARP is achieved.	Moderate (3-10%)	<0.5% of project cost	Since there will be a time lag in the oil arriving ashore and therefore the extent of OW, time is available to scale-up trained personnel. Engaging OWR providers such as AMOSC with existing training programs and teachers, OWR personnel can be rapidly increased. Conservative estimates provided by AMOSC include basic training to 50 unskilled people per day and OWR leader training of 30 per week. OWR leader training could also be rolled out to qualified veterinarians requiring additional training in OWR.	Adopted (OPEP Section 13.1)
K7	Mobilisation of a wildlife branch director from the Equinor GIMAT to support the Equinor IMT and liaise with state IMTs.	Administration	Whole of response' coordination/viewpoint. Improved communications with state IMTs. Improved logistical effectiveness	Negligible <1%	<0.5% of project cost	The quicker and more selective response outweighs the costs	Adopted (OPEP Section 13.1)
K8	Pre-emptive hazing or relocation of fauna, or temporary refuge in the event of a spill	Protective	Relocating fauna from the predicted effect zone ahead of an oil slick reaching a sensitive area would reduce impacts to those individuals	Minor (1-3%)	<0.5% of project cost	In the event of a spill, pre-emptive hazing or relocation of fauna is a recognised OWR response technique that prevents oiling to some individual fauna. The implementation of pre-emptive hazing and relocation would be adopted in accordance with the OWR plan.	Adopted (OPEP Section 13.1)
K9	Pre-arrange for pre-emptive relocation of fauna, or temporary refuge prior to spud	Protective	Relocating fauna from the predicted effect zone ahead of an oil slick reaching a sensitive area would reduce impacts to those individuals	Negligible <1%	<0.5% of project cost	Relocated individuals may return to the impacted area (this has been observed for little penguins) and the recipient populations/areas may be adversely affected by the influx of translocated individuals. Considering the uncertain environmental benefits and potentially deleterious consequences of this control it is not adopted. The benefit of the improved response capability outweighs the costs of implementation.	Not adopted
K10	Dedicated vessel	Engineering	Single vessel on stand-by	Negligible <1%	2–5% of project cost	May not have appropriate functionality. Limited scalability. Only need vessel(s) within approximately three weeks of spill, so cost outweighs the benefit of having vessel(s) immediately available.	Not adopted
K11	Purchase of all equipment and trained personnel on stand-by	Engineering	Immediately available	Negligible <1%	2–5% of project cost	Under Equinor control, available at all times. Maintaining in-house capability for low probability events imposes significant cost and complexity. Do not require availability for first ~3 weeks. Costs of purchase, storage and trained personnel outweighs environmental benefits.	Not adopted
K12	First strike capability greater than two simultaneous Level-6 OWER incidents (as defined in the Western Australian OWERP)	Engineering	Potentially increased first strike response capability, but this would depend on the extent of initial oiling. However, there would be little environmental benefits due to the ability of the response to scale up to meet an equivalent response before first shoreline contact.	Negligible <1%	0.5–2% of project cost	The OWR program has been designed to scale up rapidly to meet OWR need. In addition, there is anticipated to be approximately three weeks before first shoreline contact and many months where increasing levels of shorelines and coastal areas are contacted by oil. Therefore, there is sufficient time to deploy a scalable response which equally meets the OWR need.	Not adopted
L	Tracking and monitoring						
L1	IR camera on the subsea construction vessel (SCV)	Administrative	Improved monitoring to support the response activities and enable more targeted response actions. IR may also allow detection of marine mammals in the area around the vessel.	Negligible <1%	<0.5% of project cost	The benefit of the improved spill monitoring capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)
L2	Oil spill detector radar on SCV (in specifications for SCV)	Administrative	Improved monitoring to support the response activities and enable more targeted response actions.	Negligible <1%	<0.5% of project cost	The benefit of the improved spill monitoring capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)
L3	Dispersant testing kit on PSVs	Administrative	Improved monitoring to support the response activities and enable more targeted response actions.	Negligible <1%	<0.5% of project cost	The benefit of the improved spill monitoring capability outweighs the costs of implementation.	Adopted (OPEP Section 13.1)
L4	SSDI monitoring using ROV	Administrative	Improved monitoring to support the response activities and enable more targeted response actions.	Negligible <1%	<0.5% of project cost	The benefit of the improved spill monitoring capability outweighs the costs of implementation.	Adopted (EP Section 8.5.4)

6.0 References

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