bp

Claire Fitzpatrick
Managing Director Exploration & Production - Australia

BP Developments Australia Pty. Ltd.
A.B.N. 54 081 102 856
Level 8, QV.1 Building
250 St Georges Terrace
PERTH WA 6000
AUSTRALIA

P.O. Box Z5463, St. Georges Terrace, Perth
WESTERN AUSTRALIA 6831

31 March 2016

Senator Anne Urquhart
Committee Chair
Senate Environment and Communications
References Committee
By email: ec.sen@aph.gov.au

Dear Senator,

Senate Environment and Communications References Committee
Oil or Gas Production in the Great Australian Bight Inquiry

Please find attached BP Australia's (BP) submission to the above inquiry. BP also endorses submissions from the Australian Petroleum Production & Exploration Association (APPEA) and the Australian Marine Oil Spill Centre (AMOSC).

BP's submission is based on five areas including an overview of oil and gas practices, Australia's well established and regulated industry, industry and regulatory changes introduced in response to the Deepwater Horizon accident, environmental aspects of operating in the Great Australian Bight, and lastly, the economic option that future oil and gas production may bring to South Australia.

Attached to our submission are a number of key BP and Australian Government reports.

Given BP's significant interest in the Inquiry, we will closely follow its progress over the coming weeks. This may include providing a supplementary submission.

BP acknowledges the many demands on the Committee at this time, but hope that completion of this Inquiry will be prioritised appropriately given the Senate has taken the unusual step of specifically naming our company and its proposed investments in Australia.

We trust this submission addresses the Committee's areas of interest. If you have any questions please do not hesitate to contact me or David Stuart

Yours sincerely
BP Developments Australia Pty Ltd

Claire Fitzpatrick

Australian Senate Inquiry into

Oil or Gas Production in the Great Australian Bight

BP Australia, March 2016

Executive Summary

- Global oil and gas production is forecast to continue to rise over the next two decades, in order to help meet the world's demand for primary energy. The increase in energy demand is almost exclusively from outside the OECD, driven by rising populations, higher living standards, and greater economic prosperity.

- Australia has been producing oil since the 1960s. In recent years, the industry has drilled in excess of 50 wells each year in the Commonwealth Marine Area. Over previous decades, more than a dozen exploration wells and thousands of kilometres of seismic survey were conducted in the Great Australian Bight.

- Australia is a net oil importer. Its domestic oil production has been steadily declining whilst consumption has been rising. Australia is a net gas exporter, and has recently benefitted from a $200bn wave of investment in new Liquefied Natural Gas developments in Western Australia, Queensland and the Northern Territory.

- Since the recommendations of the Montara Commission of Inquiry, safety and environmental regulation of petroleum activities in the Commonwealth Marine Area has been independently managed by a single national regulator, the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA). NOPSEMA oversees an "objectives-based" regulatory regime which places the onus on the industry to identify and manage risks to levels that are as low as reasonably practicable, rather than to simply comply with a prescribed set of minimum government mandated standards.

- Since the 2010 Deepwater Horizon accident in the Gulf of Mexico, BP and the industry have advanced equipment, procedures and training/competency management in the areas of drilling safety and prevention; containment; and oil spill response. The eight key findings of the Accident Investigation Report have all been directly addressed in preventative planning for operations in the Great Australian Bight.

- Environmental issues in the Great Australian Bight include the potential interaction of underwater sound with cetaceans and other marine species, and the potential impact of seabed disturbance upon localised benthic habitat. Moreover, whilst the priority for planning is to prevent any accidents, the impact of potential unplanned events – e.g. oil spills – is modelled and prepared for in significant detail.

- Oil and gas exploration is already providing economic benefits in South Australia: jobs, and infrastructure investment in Adelaide and Ceduna. At this early stage of exploration it is not possible to quantify precisely what a future development, if any, could bring: but South Australia is adjacent to Victoria which has enjoyed the tens of thousands of jobs supported by Bass Strait oil and gas operations since the 1960s, and has also witnessed the economic benefits that Perth and Western Australia have enjoyed from the surge of investment in natural gas. These potential outcomes are the prizes that motivate both companies and governments in the pursuit of new oil and gas resources in the Great Australian Bight.

- BP has operated in Australia since 1919, when it formed a joint venture (Commonwealth Oil Refineries or C.O.R.) with the Australian Government and built the country's first oil refinery at Laverton in Victoria. Fuel continued to be sold under the C.O.R brand until the late 1950s, by which time BP had also built the Kwinana Refinery in Western Australia: today it remains the largest operating refinery in the country. In the early 1980s, BP and its fellow joint venture participants began the development of the North West Shelf gas project in WA, and in 1986 BP drilled its first well (Duntroon-1) in the Great Australian Bight. Today, BP's assets still include the North West Shelf Venture, shares in the Greater Gorgon area and the Browse Joint Venture, the Kwinana Refinery, and supply fuel to around 1,400 BP-branded service stations of which 350 are directly owned. The company employs over 6,000 employees in Australia.

1. The Oil and Gas industry explained[i]

1.1. **Petroleum** is the general term for oil and natural gas. The world's demand for primary energy, which includes petroleum, is expected to grow by 34% between 2014 and 2035 because of the growth in the world economy and the rising population. Virtually all of the additional energy is consumed in fast-growing emerging economies as their populations increase access to heat, light, electricity and transportation. Energy demand within the OECD is barely expected to grow. Renewables and natural gas are expected to be the strongest growing fuels (6.6% and 1.8% per annum respectively), with oil expected to grow at 0.9% per annum. Coal is forecast to continue to grow, but much less than in the previous twenty years as the world increasingly turns to lower carbon energy (Figure 1).

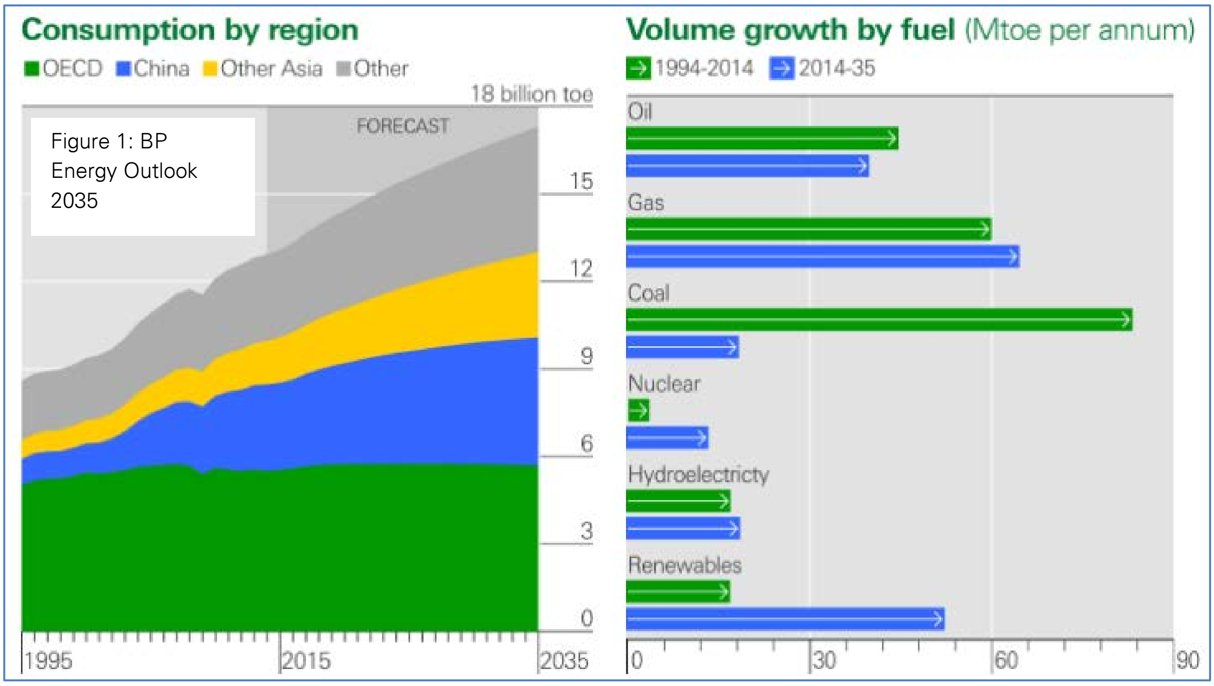

Figure 1: BP Energy Outlook 2035

1.2. **Oil and gas are formed** from the decomposition and pressurisation of algae, plankton and other organisms. This process forms hydrocarbons. These are compounds consisting entirely of hydrogen and carbon that form powerful combustible fuels. When algae, plankton and other organisms die, they sink to the bottom of the sea and lakes, as well as rivers that wash them into seas and lakes. These low-lying areas are parts of "sedimentary basins" that are filled over tens of millions of years by fragmented material that hardens into rock layers – including sandstones, shales and coal seams. Organic material (mostly plankton and algae) in these rock layers breaks down to hydrocarbons (oil and gas) that are trapped in the rocks. Australia produces most of its oil and gas from sedimentary basins in northern South Australia, inland Queensland, the Bass Strait, offshore Western Australia and the Timor Sea. There is also some production in onshore Western Australia and in NSW.

1.3. **Oil** is the world's most important fuel and underpins our high standard of living. It provides modern convenience and is crucial to transport systems. Oil refining produces transport fuels, such as petrol (gasoline), diesel and jet fuel, as well as heating oils such as kerosene. By-products from oil refining are also valuable. They are used in the production of plastics and chemicals, as well as many lubricants, waxes, tars and asphalts. Nearly all pesticides and many fertilisers are made from oil or oil byproducts. Oil has been produced commercially and refined since the 1850s. Australia has produced oil commercially since the 1960s and it is an important driver of Australia's prosperity.

1.4. **Natural Gas** is a reliable, cleaner-burning fuel. It is flexible and plentiful and underpins growing domestic and export production sectors. Natural gas primarily consists of methane. It is found in several different types of rocks, including sandstone, coal seams and shales. Gas is used to generate electricity and to power appliances such as heaters and stoves. It is also important in many industrial processes, including making fertilisers, glass, steel, plastics, paint, fabrics and many other products.

1.5. **Oil and gas exploration** begins with an examination of the local geology. Explorers assess if it is likely to have the kinds of rocks that can produce oil and gas and can form reservoirs that can hold oil and gas. They then use survey technology, such as seismic surveys, to detect whether the rocks are likely to contain oil and gas deposits and how large these deposits are likely to be. In a marine seismic survey (see Figure 2) explorers generate seismic (sound) waves and measure the time taken for the waves to travel from the source, reflect off subsurface features and be detected by receivers towed behind the survey vessel. The time taken to travel from the source to the receivers can indicate features such as rock density and the likely presence of fluids or gases. This can help build an image of the subsurface. If interpretation of survey results shows it is likely that oil and gas deposits exist in a particular area, an exploration well may be drilled. But even positive survey results do not guarantee success.

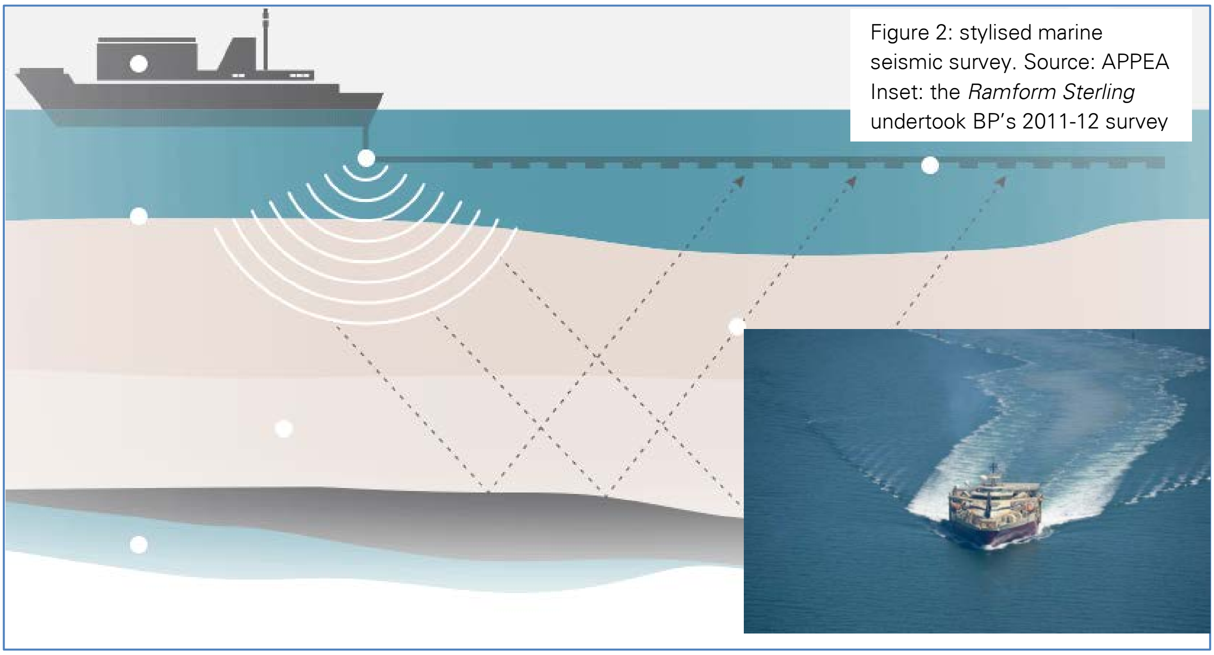

Figure 2: stylised marine seismic survey. Source: APPEA Inset: the *Ramform Sterling* undertook BP's 2011-12 survey

1.6. During and after the drilling of an **exploration well** information is acquired in various ways, including acquiring core (rock) samples, examining rock cuttings brought to the surface in the circulating drilling fluid, and lowering specialised logging tools into the wellbore. These tests give a clearer picture of whether oil or gas is present and if it can be commercially recovered. Exploration drilling stops at regular intervals so that purpose-built steel pipes – or casing – can be installed (Figure 3). The gap between the casing and borehole wall is filled with cement. The casing and the cement form a non-porous barrier that prevents cross-contamination between the petroleum-bearing rock formation and any overlying formations. The casing and cement are pressure-tested to ensure that they can tolerate higher pressures than those expected over the life of the well. A wellhead is placed on the seabed to maintain control of the well and the well is pressure-tested to ensure that it is safe. The wellhead contains barriers, valves, and seals. It allows the pressure of the well and the flow of fluids to be controlled at the surface.

Figure 3: Source Leimkuhler, J. (2010)

1.7. If sufficient volumes of oil or gas are found to support commercially viable **production**, the well must be connected to markets. Oil is generally piped or shipped to a refinery for processing into more useful products such as petrol, diesel fuel, liquefied petroleum gas (LPG), heating oil, kerosene and asphalt base. Gas can be used within Australia for electricity generation, household gas and industrial uses. It can also be sold into export markets as liquefied natural gas (LNG). LNG plants super-chill the gas to liquefy it. LNG's volume shrinks to 1/600 of the space taken by natural gas in its gaseous form, enabling export via purpose-built tankers. Australia has recently benefitted from an unprecedented wave of more than $200bn of investment in new LNG capacity which will see Australia's exports increase from 30 million tonnes per annum (in 2015) to 85 million tonnes in 2020. In addition to the giant North West Shelf Venture and the Pluto facilities (in WA) and the Darwin LNG plant (in NT), four new LNG projects have entered production since 2014 (Queensland Curtis LNG, Gladstone LNG, Australia Pacific LNG and Gorgon) and another three are still under construction (Prelude Floating LNG, Wheatstone and Ichthys).

1.8. Australia is a net importer of oil (Figure 4), with a growing gap between its consumption and its domestic production. Australia is a net exporter of natural gas, and in dollar terms the exports of gas outweighed the imports of oil for the first time in 2015 due to the growth in the LNG industry.[ii]

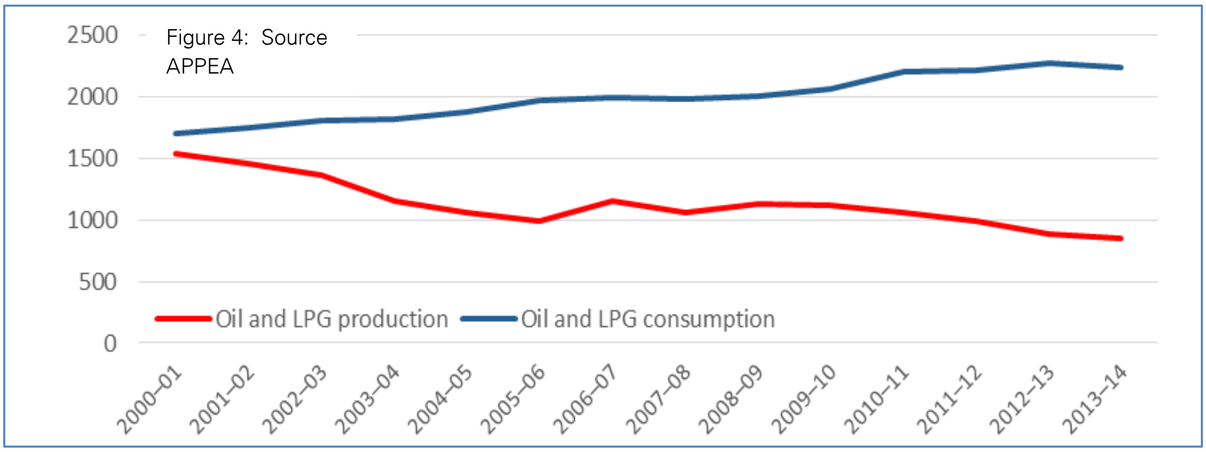

Figure 4: Source APPEA

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2. A well established, well regulated industry

2.1. Petroleum resources and activities in the Commonwealth Marine Area, including the Great Australian Bight, are administered under the *Offshore Petroleum and Greenhouse Gas Storage Act (2006)* (OPGGS Act). Under this Act significant decisions of resource management are taken by a **Joint Authority** comprising the Commonwealth Resources Minister and the Resources Minister of the adjacent State or Territory.

2.2. As Figure 5 shows, under this regime the industry has routinely drilled between 50 and 90 offshore petroleum wells in the Commonwealth Marine Area per year.[iii]

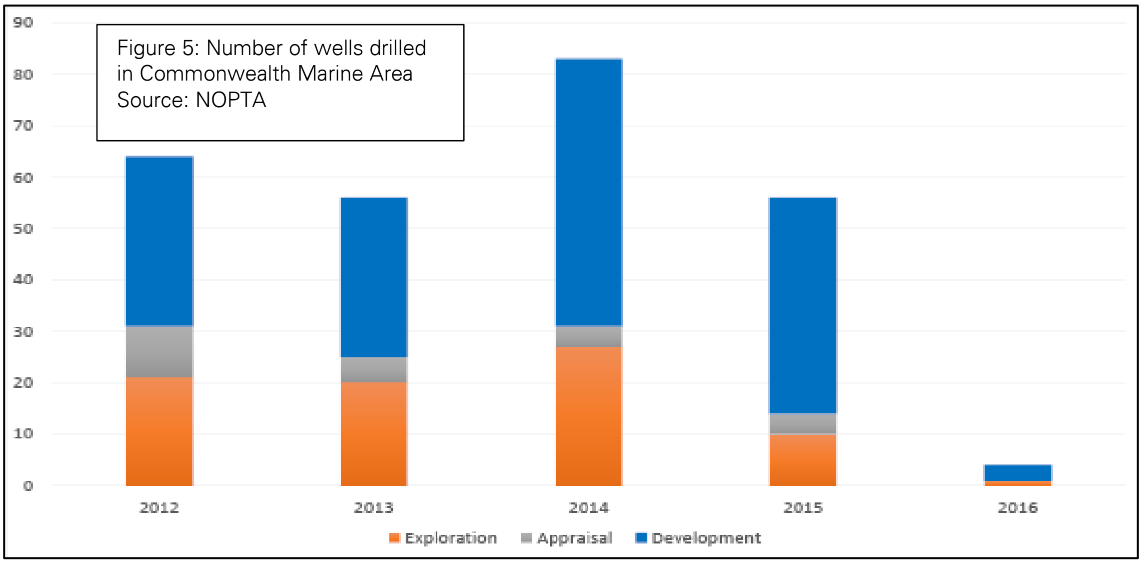

Figure 5: Number of wells drilled in Commonwealth Marine Area
Source: NOPTA

2.3. Petroleum exploration permits are released for bidding on a regular basis. Typically, oil and gas companies will bid a **work programme** and the Joint Authority will select the programme which best promises to advance the understanding of the petroleum geology of the area. The successful bidders become the **Titleholders** with an exclusive right to explore the area and, if they discover petroleum, to retain and develop it under successive forms of Title. Titles do not confer any other approval, with Titleholders still required to obtain other regulatory approvals to conduct activities.

2.4. Since 2012, the Joint Authority has been advised on resource management matters by the **National Offshore Petroleum Titles Administrator** (NOPTA), a division of the Department of Industry, Innovation and Science (the Department). Separately, environmental and safety approvals are independently regulated by the **National Offshore Petroleum Safety and Environmental Management Authority** (NOPSEMA), a statutory authority. This system of management was established following the **Borthwick Commission of Inquiry** into the Montara well blow-out in 2009, and replaced the previous system in which the Joint Authority had been supported by the adjacent State or Territory resources department. Because of the functional division, NOPSEMA does not consider investment promotion or resource development, and focusses exclusively on safety and environmental management.

2.5. NOPSEMA oversees a system of "objectives based regulation". In contrast to "prescriptive" regulation (in which the government takes responsibility for setting minimum standards), objectives based regulation places responsibility upon the Titleholder to identify risks and to manage them to a level that is both **As Low As Reasonably Practical** (ALARP) and also **Acceptable**. The use of the ALARP threshold is intended to ensure that Titleholders continuously improve their performance, for example by adopting new technologies, rather than waiting to be instructed by the regulator. It also ensures that Titleholders must adopt measures that are specific to the particular circumstances of their activity, rather than complying with a 'one size fits all' prescription.

2.6. Since February 2014, NOPSEMA has also been responsible for assessments under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act), after the Federal Environment Minister endorsed NOPSEMA's processes following a Strategic Assessment. In 2015, an independent review of NOPSEMA's compliance with this environmental management authorisation determined that NOPSEMA is meeting all of its commitments. The relevant documents are attached as an appendix.

2.7. During 2015 and 2016, NOPSEMA and the industry acknowledged a need to **improve levels of community engagement** and confidence. Industry is working through its industry association, APPEA, to establish a common methodology for undertaking stakeholder engagement for Environment Plans. The Department, in consultation with NOPSEMA, is currently reviewing the consultation and transparency requirements in place under the Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009 (the Environment Regulations). The objective of this review is to ensure the consultation and transparency requirements under the Environment Regulations meet and represent leading practice, and to address the concerns raised by stakeholders. An issues paper is available for public consultation from 22 March 2016 to 30 April 2016.

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3. Industry and regulatory changes in response to Deepwater Horizon

3.1. The 2009 Montara well blow out in Australia, and the 2010 Deepwater Horizon accident in the Gulf of Mexico, have both led to significant change in industry and regulatory processes and technology innovations.

3.2. On 24 November 2010, the Australian Government released the **Report of the Montara Commission of Inquiry** and the Commonwealth's draft response to the Report's 105 recommendations. In the draft response, the Commonwealth outlined its policy direction and draft position regarding the Commissioner's recommendations and findings. In respect of the 105 recommendations made by the Commissioner, the Commonwealth proposed accepting 92 recommendations, noting 10 and not accepting three. Amongst the recommendations was the establishment of the current regulatory regime, including NOPSEMA, to provide a single national regulator for offshore petroleum activities.

3.3. The **Deepwater Horizon accident** occurred on April 20, 2010 in the Gulf of Mexico. Eleven lives were lost. The resulting oil spill impacted the Gulf Coast communities and the environment. Deepwater Horizon was a tragic accident and there was much to learn from it that we have shared with regulators and the industry. In the immediate aftermath of the explosion, BP launched an internal investigation, drawing on expertise of more than 50 technical and other specialists from within BP and the industry. The BP internal investigation team report (the Bly Report) concluded that no single cause was responsible for the accident. The investigation instead found that the accident was the result of multiple, complex causes and the activities of multiple parties. The investigation team made 8 findings and 26 recommendations specific to drilling, which BP has implemented across our worldwide drilling activities. These recommendations cover contractor oversight and assurance, risk assessment, well monitoring and well control practices, integrity testing practices and Blow Out Preventer (BOP) system maintenance, among other issues, and their implementation has been completed. The full Bly Report is included as an appendix to this submission.

3.4. BP and industry have continued to advance capabilities and adopt changes in a number of areas as a result of the lessons learned from the Montara, Deepwater Horizon and other incidents. The first and foremost priority is **Prevention and Drilling Safety, which** is the ability to maintain control of the well from spud to abandonment. Our objective is to prevent well control incidents from occurring in the first instance. BP applies a multi-layered approach to drilling safety and spill prevention. Our approach includes using trained and competent people, using robust designs and appropriate equipment, and following the right standards and procedures with targeted review and monitoring to design and construct safe, compliant, reliable wells.

3.5. In the areas of **Equipment and Procedures**, BP is further enhancing standards. The organization works to BP's Global Wells Organization practices, based on current industry standards, which embed standardization and consistent implementation of well design and planning. Since 2011, blowout preventers (BOPs) on BP's dynamically positioned drilling rigs must have two blind shear rams and a casing shear ram (to cut through drilling pipe and seal the well), and must be capable of being operated subsea via a remotely operated vehicle (ROV). BP carries out a number of equipment and process checks for equipment used during drilling operations. This includes regular checks on the BOP and well control equipment before and during drilling operations. For example, BOP maintenance must be independently verified by a third party agency. Well control monitoring is done by the rig personnel, with advanced instrumentation and well specific training. Well monitoring, drilling fluid monitoring and subsurface tools are designed to detect the presence of hydrocarbons in the well. As do most oil industry operators, BP relies on its contractors to carry out many of its well operations. We expect our contractors to take the lead in delivering their activities safely. Drilling units brought into our fleet for drilling operations are subject to a rig intake process designed to identify and effectively manage risks for rig start-ups and verify that contracted rigs conform to specified BP practices and industry standards. Bridging documents align BP and contractor requirements applicable during operations. BP conducts formal oversight of performance against the contractor's safety and environmental management systems. Leadership, including well-site leaders and supervisors conduct regular safety inspections. BP uses a standardized tool with checklists on tablet computers to support relevant leaders across its global drilling operations to self-verify safety standards and preventative well barriers.

3.6. Prevention and drilling safety is, and should be, our highest priority. But we also continue to **plan and prepare to contain a situation**, should a loss of well control occur. BP implements a tiered approach to tactical response to subsea well incidents.

Typically, the first and likely fastest tactic to close a flowing subsea well is to close the original BOP. BP's subsea BOPs have multiple sealing rams with built-in subsea intervention panels (providing multiple options to close the BOP), and are certified by third-parties as functioning in accordance with the manufacturer's and industry standards. Each BP drilling region holds the equipment and capability to intervene on the BOP within 48 hours and to begin to activate the multiple sealing mechanisms available.

In addition to the original BOP, "Cap and containment" technology now provides the ability to minimize and stop the flow of hydrocarbons from the well by stopping or capturing the flow at the source. BP has response plans and access to associated capabilities to cap wells drilled with subsea BOPs. In Australia, BP is a founding member of the Subsea First Response Toolkit (SFRT) hosted by the Australian Marine Oil Spill Centre (AMOSC) with equipment in Geelong and Fremantle. The SFRT includes the equipment needed to prepare the site of a subsea loss of well control event for the deployment of a capping package. BP has access to a number of capping packages (see Figure 6) around the world, including the equipment hosted by Oil Spill Response Limited (OSRL) in Singapore and other international locations.

Figure 6: 'Cap and containment' technology
Source: OSRL

3.7. Other technologies have also been developed to **respond to an oil spill**, including subsea dispersant application, in-situ burn capabilities, and mechanical recovery, or skimming. In the Deepwater Horizon response, surface and subsea dispersant application were important components of oil spill response. Subsea dispersant application greatly improved the working condition in the vicinity of the well. It made it possible to work in the area by preventing heavy hydrocarbon vapors from entering the work area. We also used controlled in-situ burning on a much larger scale than was ever done before, developing and enhancing techniques that allowed us to complete approximately 400 burns and deploy approximately a dozen burn teams at one time. This was an effective capture and disposal technique. The traditional tool in near-shore response is skimming, or scooping up the oil, and for the Great Australian Bight equipment will be strategically located in South Australia whilst AMOSC is conducting detailed shoreline response planning.

3.8. The practical ways in which the eight findings of the Bly Report have been integrated into the plans to drill in the Great Australian Bight are provided in Table One below.

Table One: Key findings from the Deepwater Horizon Accident and application to the Great Australian Bight

Finding	Summary description	Investigation conclusion	Application to this project
Critical factor: Well integrity was not established, or failed			
1. The annulus cement barrier did not isolate the hydrocarbons.	The day before the accident, cement had been pumped down the production casing and up into the wellbore annulus to prevent hydrocarbons from entering the wellbore from the reservoir. The annulus cement that was placed across the main hydrocarbon zone was light, nitrified foam cement slurry. This annulus cement did not isolate the wellbore annulus from the hydrocarbon zone.	There were weaknesses in the cement design and testing, quality assurance and risk assessment.	BP's Zonal Isolation Practice was updated and clarified, establishing clear requirements for annular cement well barrier elements and verification of these barriers during well construction, temporary abandonment and permanent abandonment. Zonal isolation objectives are designed to prevent unintended movement of fluids between distinct permeable zones (DPZ), flow to surface or seabed, development of sustained casing pressure (SCP) during well operations due to communications between a DPZ and the surface or seabed, and contamination of potable-water aquifers. BP established a global Cementing Engineering Team to enhance cementing discipline capability and to provide increased assurance of cement designs. BP conducted a review of the quality of the services provided by all cementing service providers working with BP globally and new providers are reviewed before their services are contracted. BP provided leadership for a Work Group within the American Petroleum Institute (API) that updated the industry recommended practice for the preparation and testing of foamed cement slurries.
2. The shoe track barriers did not isolate the hydrocarbons.	Having entered the wellbore annulus, hydrocarbons passed down the wellbore and entered the 9 $\frac{7}{8}$" x 7" production casing through the shoe track, installed in the bottom of the casing. Flow entered into the casing rather than the casing annulus. For this to happen, both barriers in the shoe track must have failed to prevent hydrocarbon entry into the production	Hydrocarbon ingress was through the shoe track, rather than through a failure in the production casing itself or up the wellbore annulus and through the casing hanger seal assembly. Potential failure modes were identified that could explain how the shore	BP's updated Well Barrier Practice provides the requirements for the design, selection, installation, maintenance, monitoring and management of well barriers and well barrier elements throughout the full life cycle of the well. Per the practice, well barriers are generally required to isolate energy sources within the earth from each other, the surface environment, and people. Dual well barriers (primary and a secondary) are required between energy sources and the surface. This BP practice applies to

Finding	Summary description	Investigation conclusion	Application to this project
	casing. The first barrier was the cement in the shoe track, and the second was the float collar, a device at the top of the shoe track designed to prevent fluid ingress into the casing.	track cement and the float collar allowed hydrocarbon ingress into the production casing.	all wells regardless of where they are in their life cycle, including those wells under construction, actively in service, temporarily abandoned or permanently abandoned. Well barrier elements are verified to acceptance criteria in BP's Well Barrier Practice. For a cemented shoe track to be used as a well barrier element, it must have two independent floats for redundancy to prevent backflow of cement; have cement verified with a length and compressive strength required in BP's zonal isolation practice; and have successfully passed both a positive test and a negative test as outlined in BP's pressure testing practice.
Critical factor: Hydrocarbons entered the well undetected and well control was lost			
3. The negative-pressure test was accepted although well integrity had not been established.	Prior to temporarily abandoning the well, a negative pressure test was conducted to verify the integrity of the mechanical barriers (the shoe track, production casing and casing hanger seal assembly). The test involved replacing heavy drilling mud with lighter seawater to place the well in a controlled underbalanced condition. In retrospect, pressure readings and volume bled at the time of the negative pressure test were indications of flow-path communication with the reservoir, signifying that the integrity of these barriers had not been achieved.	The Transocean MODU crew and BP well site leaders reached the incorrect view that the test was successful and that well integrity had been established.	BP's practices address both the positive and negative pressure testing requirements for wells. This updated practice requires prior approval of the engineering procedures for negative testing, and also specifies the minimum criteria to be met for a successful test. The Well Site Leader interprets the results of the test against the engineered acceptance criteria. The Well Superintendent, who has an off-site supervisory role, then approves the negative pressure test. Both staff positions are classified as critical roles that undergo mandatory competency assessments. With the aim of building and maintaining competency of its staff, BP delivers in-house industry-accredited well control training with staff instructors and full-size drilling simulators in its own facilities in Houston, Sunbury, and, from 2016, in Baku. In addition, building on its Applied Deep Water Well Control course that BP developed and delivered in recent years to its entire deep water rig fleet, BP has an agreement with Maersk Training to use its state-of-the-art immersive simulation training facilities and instructors to provide an enhanced development programme for rig teams. The integrated rig teams -- including individuals from BP, drilling

Finding	Summary description	Investigation conclusion	Application to this project
			contractors and service companies -- work through simulator-based scenarios to practice procedures, roles and responsibilities in challenging drilling and completion situations before they potentially encounter those situations in actual operations.
4. Influx was not recognized until hydrocarbons were in the riser.	With the negative pressure test having been accepted, the well was returned to an overbalanced condition, preventing further influx into the wellbore. Later, as part of normal operations to temporarily abandon the well, heavy drilling mud was again replaced with seawater, under-balancing the well. Over time, this allowed hydrocarbons to flow up through the production casing and passed the BOP. Indications of influx with an increase in drill pipe pressure are discernible in real-time data from approximately 40 minutes before the rig crew took action to control the well. The rig crew's first apparent well control actions occurred after hydrocarbons were rapidly flowing to the surface.	The rig crew did not recognize the influx and did not act to control the well until hydrocarbons had passed through the BOP and into the riser.	BP's well monitoring practice lists the responsibilities and requirements for verifying and documenting that well monitoring has been properly implemented. The requirements include alarm setting and actions to be taken, fluid volume and density monitoring, flow checking, and actions to verify conformance with the practice. The BP practice requires a tailored regional wellbore monitoring procedure that is communicated to personnel with responsibilities for well monitoring, including the rig contractor and mud logger. The Well Site Leader, through BP's self-verification and oversight process, helps assure that the crew's actions conform to the wellbore monitoring procedure. As described in item 3, BP well site leaders and superintendents undergo competency assessments for their role. Relevant BP, rig contractor and well services company staff are required to receive industry-recognized well control certification. Also, BP provides enhanced, scenario-based training for rig crews.
5. Well control response actions failed to regain control of the well.	The first well control actions were to close the BOP and diverter, routing the fluids exiting the riser to the DWH mud gas separator (MGS) rather than to the overboard diverter line.	If fluids had been diverted overboard, rather than to the MGS, there may have been more time to respond, and the consequences of the accident may have been reduced.	BP's practices provide requirements and options for well control risk mitigation, response, and remediation on all BP operated activity throughout the lifecycle of a well. These practices incorporate enhanced industry standards that BP and others developed to advance capabilities across the industry following industry incidents. As described in item 3, BP well site leaders and superintendents are required to undergo competency assessments for their role. BP, rig contractor and well services company staff are required to receive industry-recognized well control certification. Also, BP provides

Finding	Summary description	Investigation conclusion	Application to this project
			enhanced, scenario-based training for rig crews.
Critical factor: Hydrocarbons ignited on Deepwater Horizon			
6. Diversion to the mud gas separator results in gas venting onto the rig.	Once diverted to the MGS, hydrocarbons were vented directly onto the rig through the 12' goosenecked vent exiting the MGS, and other flowlines also directed gas onto the rig. The increased the potential for the gas to reach an ignition source.	The design of the MGS system allowed diversion of the riser contents to the MGS vessel although the well was in a high flow condition. This overwhelmed the MGS system.	BP's practices outline the methods and tools to achieve design safety through management of hazards. Managing hazards involves eliminating or minimizing major accident hazards (MAHs) at source and preventing those that remain from becoming major accidents. This may include equipment and design modification before the MODU begins a drilling programme. For example, BP design requirements for mud gas separators have been changed in order to divert gas overboard and not near equipment or personnel. In addition, BP conducts hazard and operability reviews (HAZOPs) of surface gas and fluid systems for all BP-owned and BP-contracted drilling rigs, which include a review of hydrocarbon vent locations and design. For additional assurance, BP's Rig Engineering intake team inspects all MODUs before well operations begin.
7. The fire and gas system did not prevent hydrocarbon ignition.	Hydrocarbons migrated beyond areas on DWH that were electrically classified to areas where the potential for ignition was higher.	The heating, venting and air conditioning (HVAC) system probably transferred a gas-rich mixture into the engine rooms, causing at least one engine to overspeed, creating a potential source of ignition.	
Critical factor: The blowout preventer did not seal the well			
8. The BOP emergency mode did not seal the well.	Three methods for operating the BOP in the emergency mode were unsuccessful in sealing the well. • The explosions and fire very likely disabled the emergency disconnect sequence, the primary emergency method available to the rig personnel, which was designed to seal the wellbore and disconnect the marine riser from the well. • The condition of critical components in the yellow and blue control pods on the BOP very likely prevented activation of	There were indications of potential weaknesses in the testing regime and maintenance management system for the BOP.	BP's Well Control Practice specifies that: • all dynamically positioned (DP) rigs be equipped with subsea BOPs that have two blind shear rams and a casing shear ram; • before beginning drilling new wells, a remotely operating vehicle (ROV) demonstrates the ability to access the subsea BOP control panel to pressurize and activate the shear rams; • a third party will certify that; o the BOP has been inspected and its design reviewed in accordance with the original equipment manufacturer (OEM) specifications, o modifications to the BOP, if any, have not compromised its design or function, o testing and maintenance of BOPs are performed in

Finding	Summary description	Investigation conclusion	Application to this project
	another emergency method of well control, the automatic mode function, which was designed to seal the well without rig personnel intervention upon loss of hydraulic pressure, electric power and communications from the rig to the BOP control pods. An examination of the BOP control pods following the accident revealed that there was a fault in a critical solenoid valve in the yellow control pod and that the blue control pod AMF batteries had insufficient charge; these faults likely existed at the time of the accident. • Remotely operated vehicle intervention to initiate the autoshear function, another emergency method of operating the BOP, likely resulted in closing the BOP's blind shear ram (BSR) 33 hours after the explosions, but the BSR failed to seal the well.		accordance with OEM guidelines and API Standard 53. This practice also requires confirmation by a shear specialist that the BOP has the ability to shear drill pipe under maximum anticipated surface pressure (MASP) conditions. Also, BP has formed a dedicated subsea BOP reliability team. The team, which has a global remit, supports all offshore BP drilling activities and can be called upon to assist with BOP related issues. BP's subsea BOP reliability team works with its drilling contractors and their original equipment manufacturers (OEMs) to monitor BOP performance and further enhance BOP system reliability through oversight of maintenance and testing. Also, BP and others in industry have advanced industry standards for BOP equipment through the American Petroleum Institute (API). In addition, efforts through API, the International Association of Oil and Gas Producers (IOGP), the International Association of Drilling Contractors (IADC) and other industry groups is focused on sharing information on BOP performance.

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4. Environmental aspects of operating in the Great Australian Bight

4.1. Petroleum operations are not new to the Great Australian Bight. As Figures 7 and 8 indicate, there have been significant amounts of seismic surveying undertaken, and a number of wells have been drilled – including closer to sensitive population centres such as Port Lincoln and Kangaroo Island than the BP permits.

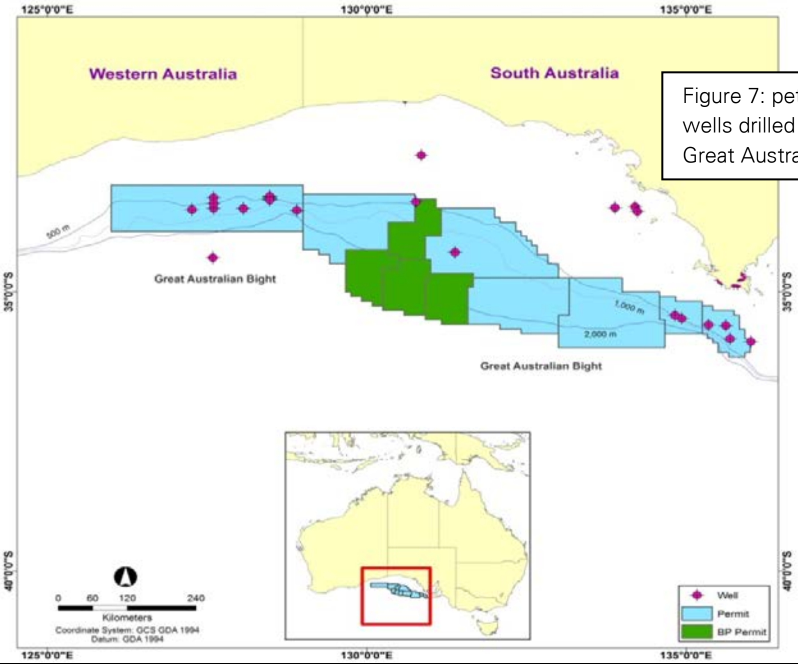


Figure 7: petroleum wells drilled in the Great Australian Bight

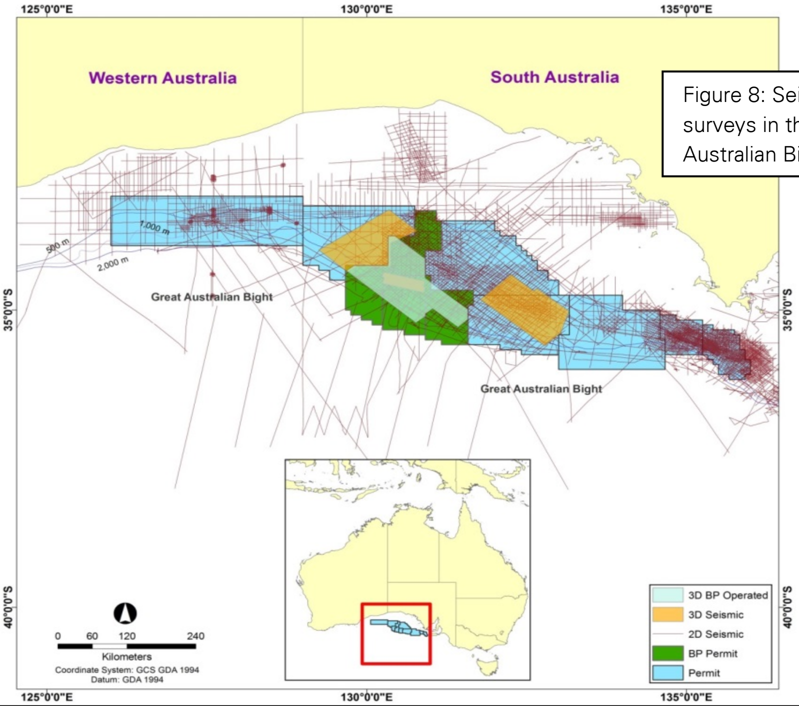


Figure 8: Seismic surveys in the Great Australian Bight

4.2. These activities demonstrate that oil and gas operations can be appropriately managed in the Great Australian Bight, and have also provided learnings about the issues to focus upon. In addition, BP continues to engage with government, industry and community groups (see Table Two) to understand their varying perspectives on the proposed operations.

4.3. The **draft summary environmental risk assessment** of environmental matters, together with the management plans for them, is detailed in Table Three below. This document was published in 2015 in order to inform consultation on the Environment Plan. In addition, a draft Environment Plan Summary which BP published in October 2015 is attached as an appendix.

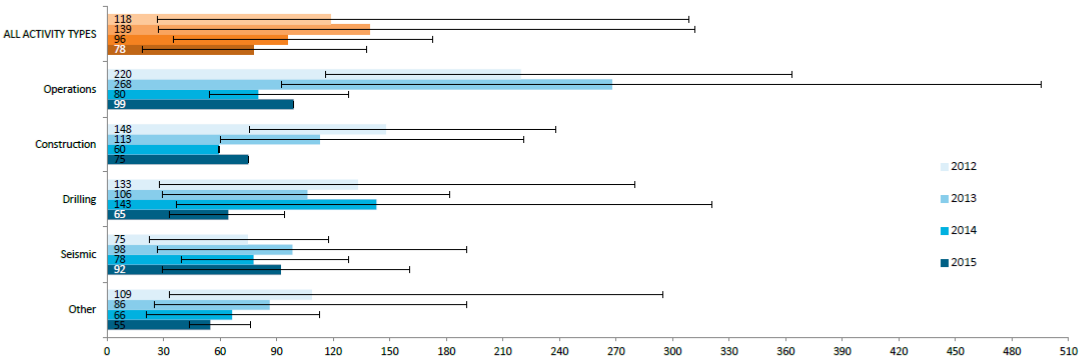
Table Two: organisations in engaged to date during Environment Plan consultation	
Commonwealth Government and elected representatives	
Australian Fisheries Management Authority	Australian Maritime Safety Authority
National Offshore Petroleum Safety and Environmental Management Authority	Department of the Environment
Rowan Ramsey, Federal Member for Grey	
South Australian Government and elected representatives	
Department of State Development	Department of Planning, Transport and Infrastructure
Department of Environment, Water and Natural Resources	Environmental Protection Agency
Department of Primary Industries and Regions	GAB Marine Park Manager
South Australia Police	Hon Ian Hunter MP, Minister for Sustainability, Environment and Conservation
Hon Geoff Brock MP, Minister for Regional Development and Local Government	Peter Treloar MP, Member for Flinders
SA Research and Development Institute	
Western Australian Government	
Department of Transport	Department of Mines and Petroleum
Department of Parks and Wildlife	
Local and Regional governments and agencies	
District Council of Ceduna	City of Port Lincoln
District Council of Streaky Bay	District Council of Lower Eyre Peninsula
District Council of Elliston	Kangaroo Island Council
Eyre Peninsula Local Government Association	Eyre Peninsula Mining and Energy Resources Community Development Taskforce
Eyre Peninsula Natural Resource Management Board	Alinytjara Wilurara Natural Resource Management Board
Regional Development Australia – Whyalla and Eyre Peninsula	
Indigenous organisations	
Far West Native Title Group	Yalata Community Inc
Business and commerce	
Australian Southern Bluefin Tuna Association	SA Oyster Growers Association
South Australian Sardines Industry Association	Spencer Gulf and West Coast Prawn Fishers Association
Abalone SA	Great Australian Bight Industry Association
Commonwealth Fisheries Association	Northern Zone Rock Lobster Fishery Association
Southern Shark Industry Alliance	South Australian Marine Scalefish Fishery
Marine Fishers Association	SA Mussel Growers Association
Sarin Group	Seafood Council SA
Wildcatch Fisheries of South Australia	WA Fishing Industry Council
Charter Boat Fisheries	Fowlers Bay Eco Tours
Non Governmental and Community Based Organisations	
Australian Conservation Foundation	Clean Bight Alliance
Conservation Council of South Australia	Friends of Scale Bay
International Fund for Animal Welfare	The Nature Conservancy
The Wilderness Society	Whale and Dolphin Conservation Society
Wild Migration Kangaroo Island	World Wildlife Fund Australia

4.4. An Environment Plan for BP's exploration drilling in the Great Australian Bight is currently being considered by NOPSEMA. In it, BP has to satisfy NOPSEMA that it has reduced risks to levels that are both *as low as reasonably practical* and *acceptable*. The Plan is not finalised until NOPSEMA accepts it, and it is normal for this to be an iterative process with Titleholders being offered successive "Opportunities to Modify and Resubmit" their Plan in the light of feedback. Figure 9, from NOPSEMA, shows typical timelines for the completion of assessment of a range of petroleum activities. Notably the chart demonstrates the regulatory rigour in the assessment process, with the assessment timeframe for some drilling activities being in excess of 300 days.

NOPSEMA

Figure 9

Environment Plans - average assessment timeframes
by activity type



Notes
Assessment time = date of submission to date of completion (decision notification date).
Assessments in progress are excluded.
'Operations' refers to operation of a facility or petroleum pipeline.
'Construction' refers to construction, installation or modification of a facility or petroleum pipeline.
'Other' refers to petroleum-related activities that do not fit in the categories of construction, seismic, production operations or drilling eg. geophysical surveys, other surveys.
Decommissioning EPs are not included in chart due to limited dataset.
Line bars (as shown by the example on the right) represent the 10th and 90th percentile range of assessment times for each dataset.
A value of 'N/A' indicates there is no data yet available for selected year.

Table Three: GAB Exploration Drilling – DRAFT Summary Environmental Risk Assessment

Potential risk	Potential consequences	Key avoidance, mitigation & management measures
Planned Events		
Seabed Disturbance	Temporary and localised seabed disturbance	Drilling will not take place within a 3 km radius of known and mapped seabed volcanic mounts (Anna's Pimple and Murray's Mount).
Underwater Noise	Temporary and localised disturbance to noise sensitive marine fauna, such as cetaceans.	Mobile offshore drilling unit (MODU) and support vessel engines and thrusters will be maintained as per planned maintenance system (PMS).
		Vertical seismic profiling (VSP) operations will be conducted in accordance with EPBC Act Policy 2.1 Part A.
		VSP crew aboard the MODU will be inducted into the EPBC Act Policy 2.1 requirements.
Light Emissions	Attractant to fauna. Temporary increase in predation rates on fauna attracted to lights.	Ensure the MODU and vessels are lit in accordance with maritime safety standards.
Atmospheric Emissions	Temporary and localised reduction in air quality. Contribution to global Greenhouse Gas effect.	No waste incineration will take place on board the MODU.
		Only low-sulphur marine diesel oil will be used to power the MODU and vessel engines and other combustion equipment.
		Combustion equipment on the MODU and vessels will be maintained in accordance with the PMS.
		Fuel use will be measured, recorded and reported.
		The MODU Heating, Venting and Air Conditioning (HVAC) system will be maintained to prevent refrigerant gas leaks.
Discharge of Drilling Cuttings and Fluids	Temporary and localised smothering of immediate seabed area around the well. Temporary and localised reduction in water quality from suspended sediments.	Drilling will not take place within a 3 km radius of known and mapped seabed volcanic mounts (Anna's Pimple and Murray's Mount).
		The MODU's bunkering procedure will be implemented during the loading and back loading of mud and associated products.
		Only low toxicity, readily biodegradable and non-bio accumulating drilling base fluids and additives will be used.
		Synthetic based mud (SBM) operations will be managed to ensure discharges contain less than 6.9% mud on cuttings.
		No bulk SBM will be disposed overboard.
		Remote Operated Vehicle (ROV) footage of the seafloor will be conducted post-drilling to determine whether a cuttings pile has formed.
Discharge of Cement	Temporary and localised reduction in water quality.	The MODU's bunkering procedure will be implemented during the loading (and possible back loading) of dry cement.

	Localised smothering of benthic habitat and fauna.	Cementing will be undertaken in accordance with the Cement Programme.
		Chemical additives used will meet technical requirements and will be of low toxicity.
		During conductor cementing operations, operations will be coordinated with the ROV Technicians to prevent excess discharges at the seabed.
Discharge of Cooling and Brine Water	Temporary and localised increase in sea water temperature, causing thermal stress to marine biota. Temporary and localised increase in sea surface salinity.	Engines and associated equipment that requires cooling by water will be maintained in accordance with the PMS so that they are operating within specified operating parameters.
		The MODU Electrolytic Marine Growth Protection System will be maintained in accordance with the PMS so it is operating within specified operating parameters.
		BP's chemical selection process will be used to ensure that only environmentally-appropriate chemicals are used in the MODU water cooling and brine systems.
Discharge of Sewage and Grey Water	Temporary and localised reduction in surface water quality (i.e., increase in the nutrient content).	A MARPOL-approved sewage treatment plant (STP) will be fitted to the MODU and support vessels.
		The STPs will be maintained in accordance with the PMS.
Discharge of Putrescible Waste	Temporary and localised increase in the content of nutrients in the surrounding surface waters. Increase in scavenging behaviour of marine fauna and seabirds	A Garbage Management Plan will be in place and implemented on the MODU and support vessels.
		A MARPOL Annex V-compliant macerator will be installed on the MODU and support vessels and used while within the Petroleum Safety Zone (PSZ).
		The galley macerators will be maintained in accordance with the PMS.
		All non-putrescible galley waste (i.e., packaging, cooking oils and grease) will be transported back to shore for recycling or disposal.
Discharge of Deck and Bilge Waters	Temporary and localised reduction of surface water quality. Acute toxicity to marine fauna through ingestion.	Overboard discharges of hydrocarbon or chemical spills will be prevented (highest priority) or controlled (priority) by a number of measures including bunding of hydrocarbon and chemical storage tanks and the use of scupper plugs on deck.
		Bilge water will be treated through an oily water system to remove hydrocarbons prior to overboard discharge (discharge water will not contain > 15 ppm hydrocarbons, in line with MARPOL Annex I).
		Chemicals will be stored in chemical storage lockers.
		Deck cleaning detergents will be biodegradable.
		Spills on deck will be rapidly cleaned up.
Discharge of Pipe Dope and Hydraulic Fluids	Temporary and localised reduction of surface water quality. Acute toxicity to marine fauna through ingestion.	Low toxicity hydraulic fluids and pipe dope will be used.
		Chemicals will be stored in chemical storage lockers.
		Spills on deck will be rapidly cleaned up.

Unplanned Events		
Accidental Disposal of Hazardous and Non-hazardous Material	Marine pollution.	A Garbage Management Plan will be in place and implemented on the MODU and vessels.
	Injury and entanglement of marine fauna and seabirds.	A procedure for MODU loading and back loading will be in place and implemented to reduce the risk of dropped objects.
	Smothering or pollution of benthic habitats	Objects dropped overboard from the MODU will be retrieved wherever possible.
Introduction of Invasive Marine Species	The survival, colonisation and spread of foreign species that may compete with native species for resources, reducing species diversity and abundance	The MODU and support vessels will have anti-fouling paint applied.
		The MODU and support vessels will be cleared to enter Australian waters by the Australian Quarantine Inspection Service (AQIS).
Interference with Other Marine Users	Collision risk	The MODU and support vessels will be readily identifiable to third-party vessels using standard anti-collision monitoring equipment.
	Temporary disruption to commercial activities around the drill rig safety zone.	The location of the MODU and support vessels will be communicated to other marine users.
		A 500-m radius PSZ will be gazetted and enforced around the MODU for the duration of the project.
Collisions with Cetaceans	Injury or death from vessel strike.	The support vessels will implement the Australian Guidelines for Whale and Dolphin Watching (2005) for sea-faring activities while in the PSZ.
Bulk Chemical, Drilling Mud and other Spills	Temporary and localised reduction of surface water quality.	A pre-acceptance inspection of the MODU will be conducted to verify all equipment is in good condition, including storage tanks, equipment, bunding and machinery spaces.
	Acute toxicity to marine fauna through ingestion.	Low toxicity chemicals (e.g., mud and cement additives, hydraulic fluids and greases) will be used.
		Aviation fuel will be stored within a bunded area.
		The dump valve/s for the SBM tanks will remain closed and locked while using SBM.
		Transfer hoses will be regularly inspected and replaced in accordance with the PMS schedule.
		The MODU bunkering procedure will be implemented for all bulk hose transfers.
		Planned maintenance will be undertaken on all MODU storage and transfer systems (eg mud tanks, bunds, hoppers, hose fittings).
		Repairs will be undertaken on all MODU storage and transfer systems that are found to be defective.
		Spills on deck will be rapidly cleaned up.
Diesel Spill	Temporary decrease in water surface and water column quality.	The MODU bunkering procedure will be implemented.
		Fuel hoses will be regularly inspected and replaced in accordance with the PMS schedule.
	Injury or death of exposed	The MODU crew will undertake spill response training in accordance with the MODU Shipboard Oil Pollution

	marine fauna. Tainting of commercial fisheries species.	Equipment Plan (SOPEP) requirements.
		Diesel spills to deck will be promptly cleaned up to avoid drainage overboard.
		A pre-spud Emergency Response desktop exercise will be conducted to test emergency responses.
		In the event of a significant diesel spill, a satellite tracking buoy will be immediately deployed in the PSZ.
		A diesel spill within the PSZ will be promptly reported internally and managed to minimise the risk of further damage to the vessel.
		A diesel spill within the PSZ will be promptly reported to external regulatory agencies.
		In the event of a significant diesel spill, operational monitoring data will be collected to support spill response and to characterise any environmental impacts.
Well Blowout/Loss of Well Control	Decrease in water surface and water column quality. Pollution of shoreline. Injury or death of exposed fauna. Tainting of commercial fisheries species.	The wells will be drilled in accordance with designs and documents prepared specifically for the project, including the Well Operations Management Plan, Safety Case, well control bridging document, drilling fluid programme, cement programme, relief well plan and BOP testing procedure.
		The wells will be drilled by qualified and experienced drillers.
		Regular well control drills will be undertaken in order to keep the drilling crew familiar with response procedures.
		It will be ensured that key BP and Diamond office- and MODU-based management personnel are familiar with their roles in a well blowout response.
		An ROV Intervention Plan will be in place to remotely operate the BOP if required.
		The wells will be plugged and abandoned in accordance with industry guidelines to prevent future hydrocarbon leaks from the wells.
		A loss of well control will be promptly reported to external agencies.
		In the event of a loss of well control, the Well Relief Plan will be implemented within 48-72 hours of the blowout.
		The extent, duration and severity of environmental impacts from a well blowout will be minimized by implementing the Oil Pollution Emergency Plan (OPEP).
		Available subsea blowout controls, such as the subsea first response toolkit and a well capping stack, will be deployed for use if deemed suitable.
		In the event of a well blowout, operational and scientific monitoring data will be collected to support spill response and to characterise environmental impacts from an unplanned Tier 2 or 3 release.

4.5. BP has included its Oil Spill Model Fate and Effects conclusions report as an appendix. Caution should be exercised when considering oil spill models for a number of reasons:

4.5.1. There are two types of model. A **deterministic** model runs just a single scenario (including of ocean currents, weather and oil spill duration) for a prediction of what an oil spill could look like. Figure 10 below is an example. **Stochastic** models combine all of the potential oil spill scenarios to create a probabilistic "area that may be affected" (AMBA). This shows the entire area that an oil spill could occur <u>within but not throughout</u> and provides a probability for any given point. This helps guide response planning, but it does not create a picture of an oil spill.

4.5.2. All oil spill models are based on <u>worst case scenarios</u> and assume that <u>no response action is taken</u> until the spill ceases. This is useful for response planning because it shows where efforts should be prioritised, but it is not a realistic prediction because of course the measures described in section 3 would be deployed as appropriate.

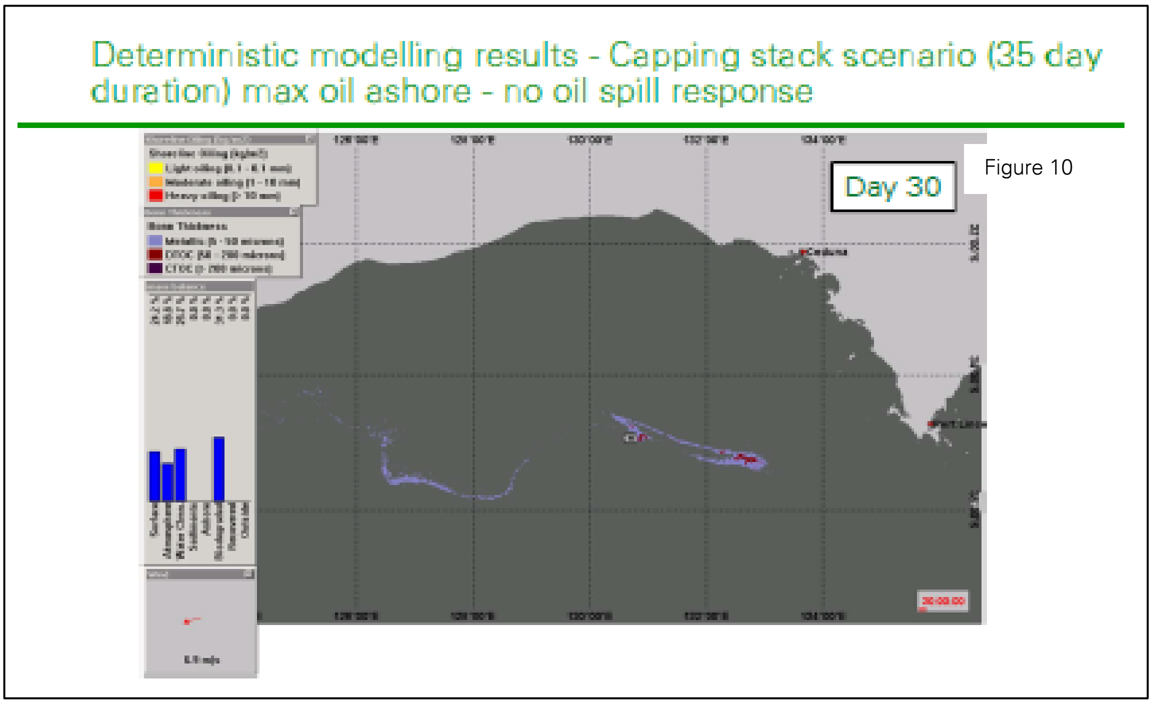
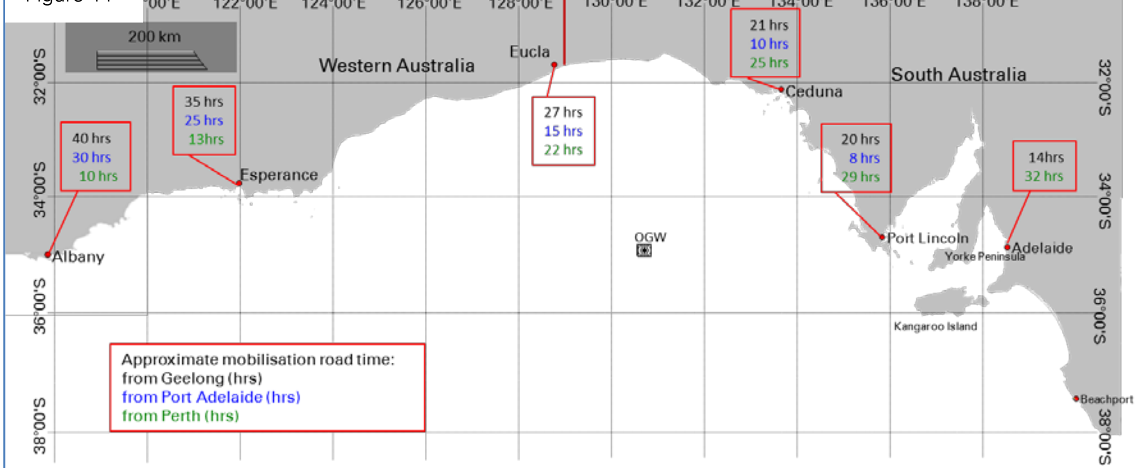


Figure 10

4.6. In the case of the Great Australian Bight, the wide variation in seasonal metocean and weather conditions means that the AMBA is large: a spill could head in any direction from Esperance to Beachport, but of course not all directions at the same time. The key to oil spill response planning is flexibility and mobility: as Figure 11 shows, BP can deploy equipment to anywhere in that zone within 3 days – whereas the earliest predicted shoreline contact is 2-3 weeks. (Whilst the BP model does not predict any shoreline contact outside of this area, others have claimed a wider area. Argument for the purposes of response planning would be superfluous: it follows that timelines for contact would be even longer and that mobilisation times would be even more robust. And as pointed out above, oil spill models have limited application as predictive tools beyond oil spill response planning.)

Figure 11



Times to mobilise equipment to various locations by road

4.7. In addition to a range of studies to ensure environmentally responsible operations in the GAB, BP is a partner in the **Great Australia Bight Research Programme (GABRP)** along with the CSIRO, the South Australian Research and Development Institute (SARDI), the University of Adelaide, and Flinders University.

This A$20 million four-year programme is one of the largest whole-of-ecosystem research programmes ever undertaken in Australian waters. It will obtain information to improve understanding of the environmental, economic, and social values of the Bight to inform future sustainable development. The programme will focus on seven major research themes including oceanography, pelagic (open water) ecosystem and environmental drivers, benthic (ocean floor) biodiversity, iconic species and apex predators, socio-economics and ecosystem modelling.

Commencing in April 2013, the programme is advised by an Independent Science Panel of internationally recognised experts. Reports are being published on the programme's website as they become available.

4.8. Whilst BP has comprehensive plans, it should be noted that oil spill response is a joint matter for various government agencies as well as industry. The Australian Maritime Safety Authority (AMSA) is responsible for the National Plan for Maritime Emergencies. It is a national integrated Government and industry organisational framework enabling effective response to marine pollution incidents and maritime casualties. AMSA manages the National Plan, working with State/Northern Territory (NT) governments, the shipping, ports, oil, salvage, exploration and chemical industries, and emergency services to maximise Australia's marine pollution response capability. The National Plan Strategic Co-ordination Committee (NPSCC) provides strategic management of the National Plan while three technical groups handle operational functions. BP's plan, which is part of its Environment Plan, is designed to interface with this National Plan.

5. An economic option for the future

5.1. Petroleum exploration in the Great Australian Bight remains at an early stage. None of the previous petroleum wells (see Figure 7) resulted in the discovery of commercially recoverable petroleum. However, from a local, national and global perspective it is an option that is worth trying to create.

5.2. Even without making a discovery, the oil and gas exploration work is creating jobs and infrastructure for South Australia. Ceduna Airport is being upgraded to handle helicopter flights. Port Adelaide is being developed to include a dedicated oil and gas marine supply base. These developments are creating jobs today, and will be lasting benefits for the future. BP has worked closely with the South Australian Industry Capability Network (ICN), with which over a thousand local businesses have registered to be kept informed of procurement opportunities.

5.3. A commercial discovery has not yet been made in the Bight, but there are analogies around Australia that can guide an understanding of the potential economic value of a development. BP's drilling area is some 700km west of Adelaide. Not much further away (900km to the east) is Victoria's Gippsland region, a home of oil and gas operations for over fifty years. Bass Strait oil and gas operations have not only provided energy to Victoria and the east coast of Australia, they have also sustained tens of thousands of jobs as well as billions of dollars in tax revenue. In Western Australia, the whole State has prospered from resource development. Just one such development, the North West Shelf Venture near Karratha, was found in 2009 to have increased GDP by $70bn and paid taxes to the State and Commonwealth of nearly $5bn (source Woodside[iv]). It is too early to say whether South Australia can emulate this success – but it is certainly a prize worth hoping for.

5.4. The whole nation will also benefit from the discovery of a new oil or gas region, and not just through tax and other macroeconomic benefits. Wood Mackenzie, an independent oil and gas analytical firm, estimates the potential resource in the GAB to be 1,900mmboe (million barrels of oil equivalent) of oil – more than twenty times the entire Australian production in 2014 (79.5mmboe, source APPEA). Australia has been a net oil importer for many years, weighing on the country's trade balance. A new oilfield development could make a material difference to the balance of payments – and to tax revenues.

5.5. Globally, the world continues to need new oil and gas supplies: they provide the fuel for our heat, power and transportation, as well as the feedstock for useful chemicals and plastics. Although economic growth is becoming steadily more energy efficient, and primary energy consumption is beginning to turn towards a less carbon intense mix, fossil fuels like oil and gas will continue to play a role for decades ahead – indeed natural gas is a key part of decarbonising the energy mix.

APPENDICES

Appendix #	Title
1	Deepwater Horizon Accident Investigation Report
2	Gulf of Mexico Environmental Recovery and Restoration Report
3	Final government response to the report of the Montara Commission of Inquiry
4	NOPSEMA strategic assessment and follow up report
5	BP Draft Environmental Plan Summary
6	Oil Spill Modelling: Fate and Effects Conclusions Report
7	History of BP in Australia

END NOTES

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[i] Section 2.2-2.8 with compliments to the Australian Petroleum Production and Exploration Association, www.appea.com and their submission to this Senate Inquiry.
[ii] http://www.energyquest.com.au/insightsandanalysis.php?id=244
[iii] National Offshore Petroleum Titles Administrator. www.nopta.gov.au
[iv] http://www.woodside.com.au/Our-Business/Producing/Documents/NWSVACILTasmanreportOct2009.pdf