APPENDIX E

Lessons Learned from Deepwater Horizon Oil Spill

On April 20, 2010, a well control event allowed hydrocarbons to escape from the Macondo well in the Gulf of Mexico onto the Transocean Deepwater Horizon MODU, resulting in explosion and fire on the MODU and the loss of 11 lives. BP Exploration and Production Inc. was the lease operator of the well. Hydrocarbons flowed from the reservoir through the wellbore and the BOP for 87 days, causing a spill of national significance. In January 2015, the United States District Court for the Eastern District of Louisiana found that 3.19 million barrels of oil were discharged into the Gulf of Mexico.

A BP priority is to prevent any similar oil spill from taking place. BP's 2010 internal investigation into the Macondo well blowout incident concluded that no single cause was responsible for the incident. A complex, inter-linked series of mechanical failures, human judgments, engineering design, operational implementation, and team interfaces (involving several companies including BP), contributed to the incident.

BP's internal investigation, which culminated in the Bly Report, involved a team of over 50 internal and external specialists from a variety of fields, including safety, operations, subsea, drilling, well control, cementing, well flow dynamic modelling, BOP systems, and process hazard analysis. Eight key findings relating to the causal chain of events were made, with 26 associated recommendations to enable the prevention of a similar accident and aimed at further reducing risk across BP's global drilling activities.

Key Findings from the Macondo Well Blowout Incident

Table E.1 outlines the eight key findings related to the cause of the Macondo well blowout incident, as outlined in the Bly Report (BP 2010). It also addresses how these lessons are applied to this Project in order to prevent a reoccurrence of the incident.

Incorporating Lessons Learned

Every official investigation report released to date, including those from the Presidential Commission, the US Coast Guard, the Bureau of Ocean Energy Management (Regulation and Enforcement), and the National Academy of Engineering / National Research Council, reinforces the Bly Report's core conclusion that this was a complex accident with multiple causes involving multiple parties.

The Bly Report recommended a number of measures to strengthen BP's operational practices, and these are being addressed through the implementation of enhanced drilling requirements. Key requirements that have been captured in guidance documents and engineering technical practices are described below.

Table E.1 Key Findings from the Macondo Well Blowout Incident and Application to the Newfoundland Orphan Basin Exploration Drilling Program

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. BPs zonal isolation objectives, within the Practice, are designed to prevent unintended movement of fluids between distinct permeable zones, flow to surface or seabed, development of sustained casing pressure during well operations due to communications between distinct permeable zones and the surface or seabed, and contamination of potable-water aquifers. BP established a comprehensive set of cementing documents to provide clear engineering guidance to BP Engineers when designing cement jobs to achieve zonal isolation requirements. BP established a global Cementing Engineering Team to enhance cementing discipline capability, to provide increased assurance of cement designs, and to fulfill the cement job design review requirements outlined in the Zonal Isolation Practice. 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 API that updated the industry recommended practice for the preparation and testing of foamed cement slurries.

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Finding	Summary Description	Investigation Conclusion	Application to this Project
2. The shoe track barriers did not isolate the hydrocarbons.	Having entered the wellbore annulus, hydrocarbons passed down the wellbore and entered the 9 ⅞" 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 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.	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 track cement and the float collar allowed hydrocarbon ingress into the production casing.	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 (a primary and a secondary) are required between energy sources and the surface. This BP practice applies to 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; cement verified with a length and compressive strength required in BP's zonal isolation practice; and successfully passed both a positive test and a negative test as outlined in BP's pressure testing practice.

Table E.1 Key Findings from the Macondo Well Blowout Incident and Application to the Newfoundland Orphan Basin Exploration Drilling Program

Finding	Summary Description	Investigation Conclusion	Application to this Project
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 program for rig teams. The integrated rig teams -- including individuals from BP, drilling 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.

Table E.1 Key Findings from the Macondo Well Blowout Incident and Application to the Newfoundland Orphan Basin Exploration Drilling Program

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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 past 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 Deepwater Horizon 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 enhanced, scenario-based training for rig crews.

Table E.1 Key Findings from the Macondo Well Blowout Incident and Application to the Newfoundland Orphan Basin Exploration Drilling Program

Finding	Summary Description	Investigation Conclusion	Application to this Project
Critical factor: Hydrocarbons ignited on Deepwater Horizon			
6. Diversion to the MGS resulted 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. This 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 reducing major accident hazards at source and preventing those that remain from becoming major accidents. This may include equipment and design modification before the MODU begins a drilling program. For example, BP design requirements for MGSs have been changed in order to divert gas overboard and not near equipment or personnel. In addition, BP conducts hazard and operability reviews 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 team inspects new MODUs before well operations begin and all MODUS on a periodic basis.
7. The fire and gas system did not prevent hydrocarbon ignition.	Hydrocarbons migrated beyond areas on Deepwater Horizon that were electrically classified to areas where the potential for ignition was higher.	The heating, venting and air conditioning system probably transferred a gas-rich mixture into the engine rooms, causing at least one engine to overspeed, creating a potential source of ignition.	

Table E.1 Key Findings from the Macondo Well Blowout Incident and Application to the Newfoundland Orphan Basin Exploration Drilling Program

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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 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.
		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 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 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 conditions.
			Also, BP maintains dedicated subsea BOP reliability personnel with a global remit to support all offshore BP drilling activities and can be called upon to assist with BOP related issues. BP's subsea BOP reliability personnel work with its drilling contractors and their OEMs to monitor BOP performance and further enhance BOP system reliability through oversight of maintenance and testing.

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	• ROV intervention to initiate the autoshear function, another emergency method of operating the BOP, likely resulted in closing the BOP's blind shear ram 33 hours after the explosions, but the blind shear ram failed to seal the well.		Also, BP and others in industry have advanced industry standards for BOP equipment through the API. In addition, efforts through API, the IOGP, the International Association of Drilling Contractors and other industry groups is focused on sharing information on BOP performance.

Cementing or zonal isolation

BP issued revised mandatory zonal isolation requirements and nine associated engineering guidance documents covering key cementing activities. BP established a global Cementing Engineering team to increase cementing discipline capability and provide increased technical and operational assurance for cementing operations.

Integrating process safety concepts into the management of wells

BP produced a technical practice specifying minimum requirements for well barrier management to manage the movement of fluids and gas during the life cycle of the well.

Well casing design

BP updated its design manual for well casing and tubing to include new requirements for pressure tests and revised technical practices. BP issued a revised technical practice on well control, defining and documenting requirements for subsea BOP configurations. BP requires two sets of blind shear ram and a casing shear ram for all subsea BOPs used on deep-water DP MODUs. BP also requires that third-party verification be carried out on the testing and maintenance of subsea BOPs in accordance with recommended industry practice, and that ROVs capable of operating these BOPs be available in an emergency.

Marine assurance process

BP continued the marine assurance process for MODU intake that was enhanced in 2011. BP has conducted detailed hazard and operability reviews for key fluid handling systems on all offshore MODUs contracted to BP. New MODUs contracted to BP are subject to a full independent Safety and Operational Risk Team Rig Verification assessment and ‘readiness to operate’ is verified with a detailed go / no-go process assured by the Safety and Operational Risk team. This verification process includes a checklist, which among other things, assists in assessing that the MODU conforms to applicable BP practices and industry standards and has the right technical specification, and that all actions required for start-up are completed. All MODUs are also subject to subsequent periodic Rig Verification assessments.

In addition to these technical requirements, BP has focused on: enhancement of capability and competency; verification, assurance and audit; and process safety performance management.