SUMMARY OF MARCH 1, 2012 REPORT TO THE LEGISLATURE ON OFFSHORE OIL DRILLING SAFETY AND SPILL PREVENTION (Public Resources Code §6226)

Pursuant to Public Resources Code (PRC) §6226 (AB 1112), effective January 1, 2012, the California State Lands Commission staff, in consultation with the Department of Conservation's Division of Oil, Gas and Geothermal Resources, is submitting its report on regulatory action, pending or already taken, and statutory recommendations for the Legislature to ensure maximum safety and prevention of harm during offshore oil drilling.

PRC §6108, authorized the Commission to make and enforce all reasonable and proper rules and regulations consistent with law for the purpose of carrying out the provisions of Division 6. The Commission's oil and gas operations regulations are found in the California Code of Regulations (CCR) Division 3, Chapter 1, Articles 3 through 3.6. The Commission's oil and gas regulations underwent a comprehensive update in 1980 due to the increased offshore drilling that was occurring at that time, particularly in the Santa Barbara Channel. The regulations are comprehensive and cover every phase of an oil and gas project's life cycle from inception to abandonment, and pollution prevention. Prior to approving any drilling well application on state leases, the application and drilling plan is reviewed for compliance with the Commission's regulations and policies, industry standards, and good engineering principles, including by way of example casing and cementing design, the equipment to be used, and the sufficiency of the ancillary programs for disposal of drilling fluids and other production practices.

The Commission's staff is in the process of preparing a comprehensive revision to update and clarify its current regulations. Where applicable, this includes new regulations in specific areas that have resulted from the forensic review of oilfield catastrophes (such as the Deepwater Horizon incident) to ensure that all drilling and production operations will be safer and less damaging to the environment, if an incident occurs. Among the lessons learned from the Deepwater Horizon, in addition to third party certification of blowout prevention (BOP) equipment, is that negative pressure tests be performed on all operations requiring sub-sea BOPs, that a remote shut down be available for sub-sea BOPs, and that adequacy of the cementing of casing be verified by a reliable and approved method (such as a bond log, which is already required by the Commission's regulations). The pending set of regulations continues to require the Best Achievable Technology and Best Achievable Protection standard required by the 1991 Lempert-Keene-Seastrand Oil Spill Prevention and Response Act. While the Commission's regulations have provided a safe and relatively problem-free working environment (there have been no blowouts in state waters), the update will be a significant improvement over the current regulations. Additional legislation is not considered necessary or being recommended at this time.

The Oil Spill Contingency Plans for oil and gas operations are reviewed and approved by the Administrator of the Department of Fish and Game's Office of Spill Prevention and Response (OSPR). The Commission's staff receives copies of OSPR's approved plans. In addition to approval of contingency plans the Administrator has the responsibility to respond to any spills in state waters, wherever situated, and is the best source to provide information on what has been done regarding response measures. Commission staff does review and comment on the contingency plans to determine that they are consistent with current conditions and address the specific context involving the drilling of any well.

Commission staff currently conducts Safety and Spill Prevention Audits for drilling, production, and processing facilities under the Commission's jurisdiction. This Safety and Spill Prevention Audit Program has evolved over the last two decades and will be codified in the new regulations. The program comprehensively assesses the design and condition of each platform and shore-side facility under the Commission's jurisdiction and the programs put in place by the operators to assure continued safe and pollution-free production.

This report may be accessed online at: http://www.slc.ca.gov. A hard copy can be requested by calling (916) 574-1800.

REPORT TO THE LEGISLATURE ON OFFSHORE OIL DRILLING SAFETY AND SPILL PREVENTION

Pursuant to Public Resources Code (PRC) §6226, effective January 1, 2012, the California State Lands Commission staff, in consultation with the Department of Conservation, is required to submit the following report on regulatory action, pending or already taken, and statutory recommendations for the Legislature to ensure maximum safety and prevention of harm during offshore oil drilling.

PRC 6226 (a)(1) COMPREHENSIVE SET OF REQUIREMENTS FOR OFFSHORE DRILLING

Since 1938, the California State Lands Commission (Commission) has served as manager of the State of California's (State) ungranted sovereign public trust lands, including tidelands, submerged lands, and navigable waterways. This jurisdiction is found in Division 6 of the PRC, and more specifically, in PRC §6301, which reads in part:

> "[t]he Commission has exclusive jurisdiction over all ungranted tidelands and submerged lands owned by the State, and of the beds of navigable rivers, streams, lakes, bays, estuaries, inlets, and straits, including tidelands and submerged lands or any interest therein, whether within or beyond the boundaries of the State as established by law, which have been or may be acquired by the State ... [t]he Commission shall exclusively administer and control all such lands, and may lease or otherwise dispose of such lands, as provided by law, upon such terms and for such consideration, if any, as are determined by it."

Under PRC §6108, the Legislature also authorized the Commission to make and enforce all reasonable and proper rules and regulations consistent with law for the purpose of carrying out the provisions of Division 6.

The Commission's oil and gas regulations underwent a comprehensive update in 1980 due to the increased offshore drilling that was occurring, particularly in the Santa Barbara Channel. Although the last offshore oil and gas lease was entered into in 1968, significant development from offshore platforms took place in the 1970s. The Commission's regulations are found in the California Code of Regulations (CCR) Division 3, Chapter 1, Articles 3 through 3.6. These regulations may be accessed at http://www.slc.ca.gov/Regulations/Regulations_Home_Page.html#OilGas

The regulations are comprehensive and cover every phase of an oil and gas project's life cycle from inception to abandonment, and pollution prevention during that time:

Article 3 **Oil and Gas Lease, Exploration Permits, and Operating Requirements**

Article 3.2 **Oil and Gas Drilling Regulations**

Article 3.3 **Oil and Gas Production Regulations**

Article 3.4 **Oil and gas Drilling and Production Operations: Pollution Control**

Article 3.6 **Operation Manual & Emergency Planning**

In 1990 the California Legislature enacted the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (Oil Spill Act) found in Division 7.8 of the Public Resources Code. (PRC §8755) and Title 2, Division 1, Chapter 7.4 of the Government Code (Gov. Code §§ 8670-8670.74). This act and its amendments include the requirement that the Commission's regulations provide the "Best Achievable Technology and Best Achievable Protection" (BAT/BAP). In 1993, as a result of the Oil Spill Act, Section 3.6 was added to the Commission's regulations requiring all operators to provide for Operations Manuals and Emergency Planning for all oil and gas operations that have the potential to cause a marine oil spill.

The Commission's Mineral Resources Management Division (MRMD) in Long Beach is responsible for regulating all oil and gas development on lands under the Commission's jurisdiction and maintains ongoing monthly inspections of all facilities on state offshore leases. Because of the multiple drilling and production environments, and the length of the field life, the Commission's regulations have always been considered "dynamic," and provide for improved technologies as developed under the all-encompassing definition of "good oilfield" or "good engineering" practice, and now the BAT/BAP standard. It should be noted that before any oil and/or gas well is drilled in, on or through lands under the Commission's jurisdiction, it must be approved by MRMD's multi-faceted engineering group. MRMD is staffed with engineering disciplines in petroleum, drilling, production, reservoir and civil engineering, as well as geologic, land use and facility inspection professionals.

Prior to approving any well drilling application on state leases, the application and drilling plan is reviewed for compliance with the Commission's regulations and policies, industry standards, and good engineering principles, as to, among other things, the casing and cementing design, the equipment to be used, and the sufficiency of the ancillary programs for disposal of drilling fluids and other production practices. The plans are also reviewed for the technical adequacy for the specific location and drilling objective and adequacy of the site-specific oil spill contingency and emergency plans. As discussed below, the drilling rig is required to use certified blowout prevention equipment (BOP). The engineering review does not stop at the approval. The MRMD engineering staff maintains contact and monitors day-to-day activity during the entire period for drilling the well. Engineering staff may also visit the well location to review the layout of the operation, and may witness cementing and production testing operations. Any modification to the approved drilling plan requires prior staff approval. All this ensures that the drilling plan is being carried out as approved by the Commission staff.

In addition to the review and oversight by Commission staff discussed above, the Department of Conservation's Division of Oil, Gas and Geothermal Resources (DOGGR) is involved with well drilling. Under the authority of the California Code of Regulations, Title 14, Division 2, has the right to witness testing of the BOP's on site as further defined in Chapter 4, Subchapter 1, Article 3, Section 1722.5 for onshore wells and in Chapter 4, Subchapter 1.1, Article 3, Section 1744.5 for offshore wells. These regulations may be found online at:
http://www.conservation.ca.gov/dog/pubs_stats/Pages/law_regulations.aspx
Individual written approvals are given to operators detailing the BOP inspections and tests to be witnessed.

Current Commission regulations (§ 2128 (i)) state the specific requirements for blowout prevention equipment during all drilling activities. The regulations require offshore oil drilling rigs operating in state waters to have "fully redundant" and functioning safety systems to help prevent oil spills from that activity. This includes the BOPs, integrated shut down systems on state platforms, and personnel drills and certification in well control practices. Staff must also emphasize that all of the current drilling within California waters involves low pressure (partially depleted) reservoirs and shallow water depths (<300 feet). The BOPs on a platform are also on the "surface," where it can be easily inspected and maintained (as opposed to the situation in the Gulf of Mexico in 2010 with the Deepwater Horizon "floating" drilling operation that required the BOP's to be on the seafloor, 5,000 feet below the vessel). Also, the BOPs on all offshore wells within California waters have a back-up feature that allow them to be manually operated if there is a catastrophic failure of the hydraulic pressure system that would normally open and close the equipment.

The Commission's staff also is in the process of finalizing a complete revision to update and clarify the current regulations. Where applicable, this includes new regulations in specific areas that have resulted from the forensic review of oilfield catastrophes (such as the Deepwater Horizon) to ensure that all drilling and production operations will be safer, and less damaging to the environment if an incident occurs.

Among the lessons learned from the Deepwater Horizon is the necessity to have: 1) independent Third Party Certification of BOP equipment; 2) negative pressure tests be performed on all operations requiring sub-sea BOP's; 3) a remote shut down (such as an acoustic shut down) be available for sub-sea BOP's; and, 4) the adequacy of the cementing of casing be verified by a reliable and approved method (such as a bond log, which is already required by the Commission's regulations). Long before the final federal report by the Department of the Interior on the Deepwater Horizon incident published on September 14, 2011 (Commission staff summary attached as Exhibit "A"), a number of recommendations made by Commission staff in the early fall of 2010 have been, or are in the process of being, implemented.

In response to the Deepwater Horizon, the Commission adopted the "Interim Guidelines" (attached as Exhibit "B") to have an independent third party certify that the BOP's to be used on each drilling project: 1) are designed for the specific rig and well; 2) that the equipment has not been compromised by prior use; and, 3) that the equipment will perform as designed under the conditions in which it will be used. All of the Commission's oil and gas lessees have agreed to comply with the Interim Guidelines pending their formal adoption through the regulatory process. Since March 1, 2011, Commission staff has been applying the Interim Guidelines to all offshore and uplands operations under the jurisdiction of the Commission.

In addition to adding new requirements to prevent pollution during drilling operations, the updated regulations will add other requirements for the conduct of Safety and Spill Prevention Audits for drilling, production, and processing equipment serving facilities under the Commission jurisdiction. This Safety and Spill Prevention Audit Program (Program) has evolved over the last two decades, but has yet to be codified in regulations. The Program comprehensively assesses the design and condition of each platform and shore-side facility serving facilities under the Commission's jurisdiction, and the programs put in place by the operators to assure continued safe and pollution-free production. The safety audits include verification of the safety system design to ensure that it includes all necessary alarms and controls and complies with regulations and applicable industry and government codes, and evaluation of the condition of all facility piping, vessels and tanks to ensure that they are fit for service. Company maintenance programs, operator training and qualification programs, and the Facility Operating Manual and Spill Response Plan (a document required to be prepared under the Oil Spill Act) are also reviewed in the audit. A Safety Assessment of Management Systems procedure is also conducted to assess the maturity of the organizational safety culture. This procedure consists of interviews of a cross section of lessee operators, engineers, management and contractors, and provides a measure of the human factor and organizational aspect of an operator's safety culture. In the last decade, the Program has identified over 7,500 action items needing correction on the offshore and onshore drilling, production, and processing facilities under the Commission's jurisdiction. All of the action items have been corrected by the lessees, producing a significant improvement in safety and pollution prevention.

The safety audits are currently conducted on a five-year cycle, and complement the monthly Platform Inspection Program. The monthly platform inspections ensure that platform alarm and automatic shutdown systems are functioning as required by the Commission's regulations. The inspection program provides primary verification of the reliability of platform alarm and control systems, and assures that equipment required to respond to a spill is present and in good condition. This inspection includes each well's surface and subsurface safety valves, the emergency shutdown system, toxic and combustible gas detectors, fire and smoke detection equipment, fire, abandon platform and man overboard alarms, pipeline alarms, fire pumps, deluge and fire control system, and the emergency generator. In addition, the functioning of navigational aids is checked, spill response equipment is inventoried, maintenance and calibration records of pressure relief valves, cathodic protection rectifiers, firefighting equipment, and lifesaving equipment are reviewed. Also pipeline right-of-way surveillance, spill drill, and boom deployment records are checked for compliance with required schedules. Each inspection requires two to three days to complete and includes testing of an average of 317 devices. Deficiencies found during an inspection are corrected immediately or the equipment is shut in and isolated until the malfunctioning device is repaired or replaced. For the last five decades, this program has been the primary state tool to prevent pollution from offshore platforms located in California waters.

While the Commission's current regulations have provided a safe and relatively problem-free working environment (no blowouts in state waters), Commission staff believes that the update will be a significant improvement. The staff is currently finalizing the entire package for the required public and Office of Administrative Law review.

(a)(2)(A) TECHNOLOGY AND TIMELINE TO REGAIN CONTROL OF A WELL

Each well area and geologic province has different physical attributes, which must be taken into account when discussing "blowouts" (the uncontrolled flow of formation fluids from a wellbore) and response plans. Initially it should be understood that drilling in California's offshore waters is substantially different than the drilling scenario of the Deepwater Horizon. The Gulf of Mexico incident occurred approximately 50 miles from shore in federal waters on a floating drilling platform and in a water depth of approximately 5,000 feet. The oil reservoir that was penetrated, at a depth of around 13,000 feet below the sea floor, contained oil in an "overpressured" formation of approximately 10,000 pounds per square inch. These are very extreme conditions compared to fields underlying California waters.

In California state water operations the deepest water depths are slightly more than 200 feet and most oil reservoirs are around 4,000 to 5,000 feet below the sea floor. Oil reservoir pressures are low because the fields are mature or "depleted" (having produced over many decades), and most wells require external assistance (pumps) to bring the oil to the surface (they cannot "flow" on their own). While this does not mean a blowout on a new well or in a new field could never occur, the risk is greatly reduced compared to the Deepwater Horizon. Even in the highly unlikely event of an "uncontrolled" release at the surface, the likely result would be a spill of limited amounts of oil and of short duration.

In light of the Deepwater Horizon incident, which was an uncontrolled release for several months, Executive Order #S-16-10 was issued on October 12, 2010, to require that Oil Spill Contingency Plans for offshore platforms in California waters be prepared to handle longer uncontrolled oil releases that could result from any natural or man-made incident. Specifically the order requires revised response plans for a worst case discharge scenario that includes a 30-day uncontrolled oil spill. The Reasonable Worst Case Spill Volume calculation for offshore platforms has been amended to increase the daily production volume factor in the calculation from seven (7) days to thirty (30) days. These Office of Spill Prevention and Response (OSPR) regulations were approved by the Office of Administrative Law and went into effect on April 11, 2011. These regulations may be accessed at: http://www.dfg.ca.gov/ospr/

As an example and as detailed in the Oil Spill Contingency Plan for Platform Holly in the Santa Barbara Channel, which is the most prolific drilling and production platform within California waters, the worst case scenario release from a blowout would be around 250 barrels of oil. That is not to minimize the potential environmental impact to California's coastline and coastal waters, but to contrast that to the 4.9 million barrels of oil released during the Deepwater Horizon incident. The wells in the currently developed South Ellwood Field are incapable of natural flow. The weight of the fluid is enough to overcome the formation pressure so the fluid cannot get to the surface without the help of a "lifting" mechanism. The scenario for an uncontrolled release of oil from this field, resulting from a catastrophic failure at the platform, would likely be three hours or less (to relieve the pressure in the well). The "on-water" response plan capability for this scenario is 3,000 barrels of oil, greatly exceeding the worst case scenario release. Such an uncontrolled release is within the ability of the company designated to respond as set forth in the Oil Spill Contingency Plan. This planning for incidents in excess of all likely scenarios is the case in all of the current operations under the Commission's jurisdiction. The potential to regain control in the event of an oil spill (even if the fluid could flow naturally) is greatly enhanced by such factors discussed above, but also includes the BOPs being located at the surface and the proximity to shore that allows response and replacement (or repair) equipment to rapidly reach the incident. These factors of operations under the Commission's jurisdiction stand in marked contrast to the Deepwater Horizon incident.

(a)(2)(B) DESCRIPTION OF A RESPONSE PLAN - STRATEGY, ORGANIZATION, AND RESOURCES

The Oil Spill Contingency Plans for oil and gas operations are submitted by the operator to be reviewed and approved by the Administrator of OSPR. MRMD staff does review the contingency plans to determine their being reflective of current conditions and for the specific context regarding the drilling of any well and provides comment where appropriate to the operator. The operator has the responsibility to revise the plan if needed and resubmit it to the Administrator. Once approved, OSPR posts the plans on its website so that they are available to the public. Additionally, the Commission's MRMD receives copies of approved plans. The Administrator also has the responsibility to respond to any spills in state waters, wherever situated, and is the best source to provide information on what has been done since the Deepwater Horizon regarding response measures.

All Oil Spill Contingency Plans call for a specific amount of on-site materials, such as booms, boats, absorbent materials and other spill cleanup equipment at the well sites, as well as response from one of the industry funded spill response companies located along the California coast. These companies have equipment and spill cleanup vessels at strategic sites that can respond quickly to any oil spill incident. Each plan has a specific team of company personnel responsible for specific parts of the response plan, and coordination with the state and federal agencies that may be involved, as well as contact and news dissemination to the general public.

(a)(3) BEST AVAILABLE AND SAFEST TECHNOLOGIES

The revision and update of the Commission's current regulations requires the Best Achievable Technology (BAT) and Best Achievable Protection (BAP) standard mandated by the Oil Spill Act. Pursuant to the Oil Spill Act, a subcommittee was formed made up of members of industry, state and federal regulators, environmental groups, and interested members of the public. The subcommittee was tasked with reviewing all the then current Commission regulations regarding oil and gas drilling, production and transportation. That subcommittee, in its final report ("Final Report of the BAP/BAT and Facility Breakout Subcommittee, March 4, 1996") found that the Commission regulations attained this level of protection:

> "The subcommittee found that . . . the regulations and regulatory development process of . . . SLC-MRM satisfy the BAP and BAT mandates required . . . by the Act"

The Commission's updated regulations will continue that high level of protection. Although the DOGGR is not mandated to the same standard (the Oil Spill Act was specific to the Commission's jurisdiction), the subcommittee also determined that DOGGR's "regulatory development process . . . embodies the elements of the BAP and BAT."

An additional Commission program is the Platform Structural Reassessment Program. Since the 1990s, all offshore platforms in State waters have been analyzed by the operators to American Petroleum Institute Recommended Standards 2A (API RP2A) using finite element numerical modeling programs and a non-linear time-history analysis to determine whether the platforms would withstand a 100-year return period storm event and a 1,000-year return period earthquake. These analyses have been independently verified by MRMD staff engineers. As a result of the analyses, structural strengthening projects were undertaken at several platforms. Since the initial analyses, the underwater jacket structure of each platform is inspected on a periodic basis as outlined in API RP2A guidelines and corrective measures implemented as required. Facility modification proposals made by operators that involve addition or relocation of major equipment on a platform, such that deck loads may be significantly increased or redistributed, require analysis and verification that the existing structure or additions to the structure will withstand the new loading. In addition, all new drilling projects from offshore platforms require a rigorous structural analysis and, if necessary, a complete platform requalification to ensure that the structure will withstand the additional loads imposed by the project, and any strengthening or maintenance needed to bring the structure up to current codes. Verifications of these analyses are performed by MRMD civil engineers with expertise in structural analysis.

There are inherent risks involved with oil and gas drilling and development operations. The Commission's highest priorities are public health and safety, and environmental protection. The Commission's programs, policies, and regulations, which are discussed in this report, and implemented by and through staff inspection, program reviews, and surveillance, along with the cooperative attitude and operational vigilance of the lessees, are adhered to and strictly followed. These programs and cooperation ensure that the excellent record of infrequent oil spill occurrences and safety incidences will continue.

Division of Oil, Gas and Geothermal Resources (DOGGR)

Commission staff consulted with DOGGR regarding whether they have or intend to amend their current regulations in response to the Deepwater Horizon incident. DOGGR indicated that they believe the current Division of Oil, Gas, and Geothermal Resources drilling and spill prevention requirements, along with OSPR response and preparedness requirements are adequate for the protection of life, property and the natural resources, during drilling operations in state waters. They also indicated that given the lack of major spills during state-water drilling, there is not a need for additional regulatory requirements at this time.

EXHIBIT A

COMMISSION STAFF SUMMARY OF THE UNITED STATES DEPARTMENT OF THE INTERIOR BUREAU OF OCEAN ENERGY MANAGEMENT FINAL REPORT ON THE "DEEPWATER HORIZON" BLOWOUT

After an extensive investigation conducted by the Joint Investigation Team of the Bureau of Ocean Energy Management, Regulation and Enforcement, now the Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement (BSEE), and the United States Coast Guard. The panel of investigators ("the Panel") has identified a number of causes of the Deepwater Horizon incident.

POOR CASING CEMENTING: The Panel found that a central cause of the blowout was failure of a cement barrier in the production casing string, a high-strength steel pipe set in a well to ensure well integrity and to allow future production. The failure of the cement barrier allowed hydrocarbons to flow up the wellbore, through the riser and onto the rig, resulting in the blowout. The precise reasons for the failure of the production casing cement job are not known. The Panel concluded that the failure was likely due to: (1) swapping of cement and drilling mud (referred to as "fluid inversion") in the shoe track (the section of casing near the bottom of the well); (2) contamination of the shoe track cement; or (3) pumping the cement past the target location in the well, leaving the shoe track with little or no cement (referred to as "over-displacement").

At the time of the blowout, the rig crew was engaged in "temporary abandonment" activities to secure the well after drilling was completed and before the Deepwater Horizon left the site. In the days leading up to April 20, 2010, British Petroleum (the operator and lessee, hereafter "BP") made a series of decisions that complicated cementing operations, added incremental risk, and may have contributed to the ultimate failure of the cement job. These decisions included:

- The use of only one cement barrier. BP did not set any additional cement or mechanical barriers in the well, even though various well conditions created difficulties for the production casing cement job.

- The location of the production casing. BP decided to set production casing in a location in the well that created additional risk of hydrocarbon influx.

- The decision to install a lock-down sleeve. BP's decision to include the setting of a lock-down sleeve (a piece of equipment that connects and holds the production casing to the wellhead during production) as part of the temporary abandonment procedure at Deepwater Horizon incident increased the risks associated with subsequent operations, including the displacement of mud, the negative test sequence and the setting of the surface plug.

- The production casing cement job. BP failed to perform the production casing cement job in accordance with industry-accepted recommendations.

FAILURE TO RECOGNIZE THE "KICK": There were several possible reasons why the Deepwater Horizon crew did not detect the kick:

- The rig crew had experienced problems in promptly detecting kicks. The Deepwater Horizon crew had experienced a kick on March 8, 2010, that went undetected for approximately 30 minutes. BP did not conduct an investigation into the reasons for the delayed detection of the kick. Transocean personnel admitted to BP that individuals associated with the March 8, 2010, kick had "screwed up by not catching" the kick. Ten of the 11 individuals on duty on March 8, 2010, who had well control responsibilities, were also on duty on April 20, 2010.

- Simultaneous rig operations hampered the rig crew's well monitoring abilities. The rig crew's decision to conduct simultaneous operations during the critical negative tests - including displacement of fluids to two active mud pits and cleaning the pits in preparation to move the rig ─ complicated well-monitoring efforts.

- The rig crew bypassed a critical flow meter. At approximately 9:10 p.m., the rig crew directed fluid displaced from the well overboard, which bypassed the Sperry Sun flow meter, which is a critical kick detection tool that measures outflow from the well. The Deepwater Horizon was equipped with other flow meters, but the Panel found no evidence that these meters were being monitored prior to the blowout.

LACK OF INTEGRATED ALARM SYSTEM: The Panel found evidence that the configuration of the Deepwater Horizon general alarm system and the actions of rig crew members on the bridge of the rig contributed to a delay in notifying the entire crew of the presence of very high gas levels on the rig. Transocean had configured the Deepwater Horizon's general alarm system in "inhibited" mode, which meant that the general alarm would not automatically sound when multiple gas alarms were triggered in different areas on the rig. As a result, personnel on the bridge were responsible for sounding of the general alarm. Personnel on the bridge waited approximately 12 minutes after the sounding of the initial gas alarms to sound the general alarm, even though they had been informed that a "well control problem" was occurring. During this period, there were approximately 20 alarms indicating the highest level of gas concentration in different areas on the rig.

FAILURE OF SHEAR RAM TO CUT PIPE: A forensic examination of the BOP stack revealed that elastic buckling of the drill pipe had forced the drill pipe up against the side of the wellbore and outside the cutting surface of the blind-shear ram (BSR) blades. As a result, the BSR did not completely shear the drill pipe and did not seal the well. The buckling of the drill pipe, which likely occurred at or near the time when control of the well was lost, was caused by the force of the hydrocarbons blowing out of the well; by the weight of the 5,000 feet of drill pipe located in the riser above the BOP forcing the drill pipe down into the BOP stack; or by a combination of both. As a result of the failure of the BSR to completely cut the drill pipe and seal the well, hydrocarbons continued to flow after the blowout.

VIOLATION OF FEDERAL REGULATIONS: The Panel found evidence that BP and, in some instances, its contractors violated the following federal regulations:

- 30 CFR § 250.107 – BP failed to protect health, safety, property, and the environment by (1) performing all operations in a safe and workmanlike manner; and (2) maintaining all equipment and work areas in a safe condition;

- 30 CFR § 250.300 – BP, Transocean, and Halliburton (Sperry Sun) failed to take measures to prevent the unauthorized release of hydrocarbons into the Gulf of Mexico and creating conditions that posed unreasonable risk to public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean;

- 30 CFR § 250.401 – BP, Transocean, and Halliburton (Sperry Sun) failed to take necessary precautions to keep the well under control at all times;

- 30 CFR § 250.420(a)(1) and (2) – BP and Halliburton failed to cement the well in a manner that would properly control formation pressures and fluids and prevent the release of fluids from any stratum through the wellbore into offshore waters;

- 30 CFR § 250.427(a) – BP failed to use pressure integrity test and related hole-behavior observations, such as pore pressure test results, gas-cut drilling fluid, and well kicks to adjust the drilling fluid program and the setting depth of the next casing string;

- 30 CFR § 250.446(a) – BP and Transocean failed to conduct major inspections of all BOP stack components; and

- 30 CFR § 250.1721(a) – BP failed to perform the negative test procedures detailed in an application for a permit to modify its plans.

Although the Panel found no evidence that MMS regulations in effect on April 20, 2010, were a cause of the blowout, the Panel concluded that stronger and more comprehensive federal regulations might have reduced the likelihood of the Deepwater Horizon incident. In particular, the Panel found that MMS regulations in place at the time of the blowout could be enhanced in a number of areas, including: cementing procedures and testing; BOP configuration and testing; well integrity testing; and other drilling operations. In addition, the Panel found that there were a number of ways in which the MMS drilling inspections program could be improved. For example, the Panel concluded that drilling inspections should evaluate emergency disconnect systems and/or other BOP stack secondary system functions. BOEM/BSEE has already implemented many of these improvements.

RECOMMENDATIONS

This Report concludes with the Panel's recommendations, which seek to improve the safety of offshore drilling operations in a variety of different ways:

- Well design. Improved well design techniques for wells with high flow potential, including increasing the use of mechanical and cement barriers, will decrease the chances of a blowout.

- Well integrity testing. Better well integrity test practices (e.g., negative test practices) will allow rig crews to identify possible well control problems in a timely manner.

- Kick detection and response. The use of more accurate kick detection devices and other technological improvements will help to ensure that rig crews can detect kicks early and maintain well control. Better training also will allow rig crews to identify situations where hydrocarbons should be diverted overboard.

- Rig engine configuration (air intake locations). Assessment and testing of safety devices, particularly on rigs where air intake locations create possible ignition sources, may decrease the likelihood of explosions and fatalities in the event of a blowout.

- Blowout preventers. Improvements in BOP stack configuration, operation, and testing will allow rig crews to be better able to handle well control events.

- Remotely-operated vehicles (ROVs). Standardization of ROV intervention panels and intervention capabilities will allow for improved response during a blowout.

EXHIBIT B

Minute Item # 63-1 CSLC 10/29/2010
Executive Order S-16-10

California State Lands Commission
INTERIM GUIDELINES

THIRD PARTY CERTIFICATION OF BLOWOUT PREVENTERS FOR ALL OFFSHORE AND UPLAND OPERATIONS UNDER JURISDICTION OF THE CALIFORNIA STATE LANDS COMMISSION, AND LEGISLATIVELY GRANTED LANDS

In addition to all other applicable Laws and Regulations, all Blowout Preventers (BOPs) used for well control during the drilling, redrilling or deepening of all offshore operations within state waters and upland operations under the Commission's jurisdiction shall be certified as set forth below. This includes those drilling activities being conducted into tide and submerged lands, including both state leases and legislatively granted lands, and whether from an offshore platform or upland site. BOPs used in conjunction with well service operations for reworking and abandonment of wells either in the same zone(s) or exposing additional zone(s) of offshore or upland wells where the zone(s) are capable of fluid flow to the surface also shall be certified.

For either Upland or Platform based BOPs, Lessee/Operator must utilize an independent third party to verify and certify the following:

a. The BOP stack is designed for the specific equipment on the rig and for the specific well design;
b. The BOP stack has not been compromised or damaged from any previous service; and,
c. The BOP stack will operate as designed under the conditions in which it will be used.

This certification must be performed, and documentation provided, not more than 60 (sixty) days prior to commencing operations to drill, redrill or well deepening activity. Certification documents for BOPs used in well workovers/reworks/abandonments, where the well is capable of fluid flow to the surface, shall be provided at the time the proposed well procedure is submitted to the California State Lands Commission for approval. This certification is valid for a maximum of 180 days, after which re-certification of the BOP is required. A copy of the certification must be submitted to the Division of Oil Gas and Geothermal Resources (DOGGR).

For Subsea BOP operations, the Lessee/Operator must have an independent third party conduct a detailed physical inspection and design review of the BOP. In addition to the requirements for Upland and Platform based BOPs listed above, the subsea BOP design review must certify that:

d. The BOP will operate as originally designed.
e. Any modifications or upgrades to the BOP stack after delivery have not compromised the design or operation of the BOP.
f. The Lessee/Operator must obtain independent third party certification that the blind-shear rams installed in the BOP stack are capable of shearing the drill pipe in use under maximum anticipated surface pressures.

This certification is required one time only for Subsea BOP operations, unless the BOP has been modified.

The Lessee/Operator is responsible to insure that the BOP certification is conducted by an independent third party (Certifier). A technical classification society, an American Petroleum Institute (API) licensed manufacturing/inspection/certification firm, or licensed professional engineering firm capable of furnishing the documentation required for BOP compatibility and functionality will qualify as an "Independent third party". The certifying party must demonstrate the following qualifications:

1. Such firm or its employees hold appropriate professional engineering license(s) to perform this work, the firm carries industry standard levels of professional liability insurance and has no record of violations of applicable law; and, signs the certification under penalty of perjury.

2. The firm shall provide a resume or statement of qualifications for the certifying engineer(s) performing the work.

3. The firm must submit a scope of work to be performed for the certification prior to commencing the work and a final report which includes, but is not limited to the following:

    a. BOP configuration
    b. Specification sheet
    c. Components tested
    d. Function and pressure test results
    e. Present condition of component parts
    f. If subsea, that the shear rams are capable of shearing the drill pipe in use
    g. Information on facility where the testing has been conducted

4. The firm must prepare and submit documentation that confirms the work has been completed as outlined and BOP fitness is verified.

5. Upon request, the firm shall allow staff of California State Lands Commission access in order to witness the tests and/or inspections.