CALENDAR ITEM
63

A: Statewide 10/29/10
Scott, G.
Gregory, G.
Oggins, C.
S: Statewide Bugsch, B.

CONSIDER STAFF RECOMMENDATIONS FOR OIL SPILL POLLUTION PREVENTION AND OFFSHORE OIL OPERATIONS DERIVED FROM THE AUGUST 20, 2010 "REPORT TO COMMISSIONERS - PRODUCTION AND MARINE TERMINAL OPERATIONS IN STATE WATERS AND THE CALIFORNIA STATE LANDS COMMISSION'S OIL POLLUTION PREVENTION PROGRAMS PROTECTING STATE WATERS," AND THE MEMO FROM LIEUTENANT GOVERNOR MALDONADO, "APPLYING LESSONS LEARNED FROM THE DEEPWATER HORIZON OIL SPILL."

PARTY:
California State Lands Commission

BACKGROUND:
At its June 28, 2010, California State Lands Commission (CSLC) meeting, the Chair of the Commission asked CSLC staff to review oil production operations in State waters in light of the events occurring in the Gulf of Mexico relating to the British Petroleum (BP) Deepwater Horizon oil spill, and to report its findings to the Commission at its August meeting. The Chair also asked CSLC staff to report on the CSLC's oil spill prevention activities and programs for oil production operations and marine oil terminal operations in State waters. CSLC staff prepared and submitted the report (Report), Exhibit A attached hereto, including a presentation of the Report's content to the Commissioners at the CSLC meeting on August 20, 2010, held in Sacramento, California.

The Report, and presentation, discussed CSLC's safety, pollution prevention, and resource management programs, and described individual Division responsibilities to carry out and implement those programs. The Report concluded with a discussion of the current and future challenges to the program.

It also included recommendations staff is proposing to amend current regulations, policies and practices regarding oil operations in order to further strengthen CSLC's ability to protect the state's sovereign lands and its waters and enhance the current CSLC programs.

Additionally, Lieutenant Governor Maldonado gave a presentation on his personal fact finding visit to the Gulf spill and lessons learned during that visit, and asked staff to investigate the federal recommendation regarding third-party certification of blowout prevention equipment (BOPE) and drilling operations. The Lieutenant Governor also proposed that the Commission recommend to the Administrator of the Office of Oil Spill Prevention and Response (OSPR) that the standard for oil spill response planning for an uncontrolled release be expanded from the current 7 day period to 30 days. Lieutenant Governor Maldonado also delivered this request in a written communication to the other Commissioners (Exhibit B, attached hereto), and subsequently executed, as Acting Governor, an Executive Order (E.O. S-16-10) regarding these matters. Staff has analyzed the federal recommendations regarding third-party certification of the BOPE and drilling programs, as well as the current requirements for third-party structural reviews in light of California operations. A staff report regarding third-party certification is attached as Exhibit C, and concludes that such certification would be beneficial for providing enhanced oil spill prevention capabilities involving offshore wells in state waters. Staff believes that the most expeditious way to implement the third-party certification for BOPE and new drilling programs is by requesting the lessees to voluntarily implement the certifications. Our lessees have voluntarily adopted Commission proposals in the past, and have indicated that they are amenable to this request.

Staff is also preparing an update to the Commission's current regulations and this could be added under the Commission's general authority to promulgate regulations, and under the authority of the 1991 Lempert-Keene-Seastrand Oil Spill Act. Legislation has been introduced in Congress to require certification in both state and federal waters. To become law the current bills will have to be enacted prior to the close of the current session in January. Staff is following the current federal legislation regarding these matters, and will wait to update the current regulations pending the outcome of that Federal legislation which may include state water drilling.

If any problems arise with the voluntary acceptance of the third-party inspection proposals, or updating of the Commission regulations, staff recommends seeking legislation to enact a new state statute to require this practice. Legislation is also necessary to implement certain other recommendations discussed in this report.

Staff was also asked to elicit public comment on the Report, and to present concise recommendations for the Commission to consider supporting. The Report was posted on the Commission's website and staff notified its lessees, industry, and the public for review and comment. No comments were received.

The staff reconsidered the recommendations in the Report, and reviewed the proposal for third-party certification. Based on the Report, the discussion of the Commissioners, the request of the Lieutenant Governor, and its own investigation, staff has derived the following recommendations for Commission consideration.

STAFF RECOMMENDATIONS:

1. Direct the Mineral Resources Management Division (MRMD) staff to obtain agreements from state lessees to submit third-party certification of all drilling programs, and operation of the BOPE on lessee platforms. Third-party certification would apply to all new wells submitted to CSLC for drilling approval. Certification would be performed by a registered professional engineer with applicable drilling engineering experience. These third-party certifications would be submitted to CSLC with a copy to the Division of Oil, Gas, and Geothermal Resources.

2. Send a letter on behalf of the Commission to the Administrator of the Office of Oil Spill Prevention and Response recommending revising their planning standards from the current 7 day response period to 30 days.

3. Direct MRMD staff to update oil and gas drilling and production regulations.

4. Fill at least four of the six engineering vacancies currently existing in MRMD to ensure continued program efficiency if feasible, given the current budget constraints or seek additional funding in order to do so.

5. Resubmit the reclassification of Mineral Resources Inspector series to include Inspector Specialist positions and seek adjustment of pay scale.

6. Support the creation of two (2) engineer inspector positions in Marine Facilities Division (MFD) to oversee Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS).

7. Support the creation of a Systems Safety Audit Group in MFD (as currently operating in MRMD) for Marine Terminals.

8. Support the enhancement of Environmental Impact Report (EIR) data and information gathering for modeling trajectory studies, and to make the studies available in Geographic Information Systems (GIS) format to ensure compatibility with other State information.

9. Support legislation to:

   - Give CSLC cease and desist authority over oil and gas and marine terminal operations in State waters;
   - Increase the Oil Spill Prevention Administration Fund (OSPAF) per barrel fee to cover current and increased costs of CSLC and Office of Spill Prevention and Response (OSPR) prevention and response programs including the above recommended staff increases;
   - Allow changes in bonding and insurance requirements for oil and gas leases as needs and conditions change, or review and adjust every five (5) years at a minimum, without requiring a lease amendment, including sufficient bonding for complete platform removal.
   - If necessary, due to failure of any lessee to voluntarily provide third-party certification for BOPE and/or drilling programs, or problems with updating Commission regulations requiring such certification, seek legislation to enact a new State statute to require third-party certification of BOPE and all drilling, workover, and abandonment plans and projects.

OTHER PERTINENT INFORMATION:

1. Pursuant to the Commission’s delegation of authority and the State CEQA Guidelines [Title 14, California Code of Regulations, section 15060(c)(3)], the staff has determined that this activity is not subject to the provisions of CEQA because it is not a “project” as defined by CEQA and the State CEQA Guidelines.

   Authority: Public Resources Code section 21065 and Title 14, California Code of Regulations, sections 15060(c)(3) and 15378.

EXHIBITS:

A. Report to Commissioners on the Oil Production and Marine Terminal Operations in State Waters and the California State Lands Commission’s Oil Spill Prevention Programs Protecting State Waters
B. Lieutenant Governor Maldonado’s memo to the Commission, Governor and Commission Staff
C. Staff’s report on third-party certification

PERMIT STREAMLINING ACT DEADLINE:
N/A.

RECOMMENDED ACTION:
It is recommended that the Commission:

CEQA FINDINGS:

1. Find that the activity is not subject to the requirements of CEQA pursuant to Tile 14, California Code of Regulations, section 15060(c)(3) because the activity is not a project as defined by Public Resources Code section 21065 and Tile 14, California Code of Regulations, section 15378.

AUTHORIZATION:
Direct the Staff to take the following actions:

1. Obtain agreements from state lessees to submit third-party certification of all drilling programs, and operation of the BOPE on lessee platforms. Third-party certification would apply to all new wells submitted to CSLC for drilling approval. Certification would be performed by a registered professional engineer with applicable drilling engineering experience. These third-party certifications would be submitted to CSLC with a copy to the Division of Oil, Gas, and Geothermal Resources.

2. Send a letter on behalf of the Commission to the Administrator of the Office of Oil Spill Prevention and Response recommending revising their planning standards from the current 7 day response period to 30 days.

3. Update oil and gas drilling and production regulations.

4. Fill at least four of the six engineering vacancies currently existing in MRMD to ensure continued program efficiency if feasible, given the current budget constraints or seek additional funding in order to do so.

5. Resubmit the reclassification of Mineral Resources Inspector series to include Inspector Specialist positions and seek adjustment of pay scale.

6. Seek the creation of two (2) engineer inspector positions in Marine Facilities Division (MFD) to oversee MOTEMS.

7. Seek the creation of a Systems Safety Audit Group in MFD (as currently operating in MRMD) for Marine Terminals.

8. Pursue the enhancement of EIR data and information gathering for modeling trajectory studies, and to make the studies available in GIS format to ensure compatibility with other State information.

9. Seek legislation to:
    - Give CSLC cease and desist authority over oil and gas and marine terminal operations in State waters;
    - Increase the OSPAF per barrel fee to cover current and increased costs of CSLC and OSPR prevention and response programs including the above recommended staff increases;
    - Allow changes in bonding and insurance requirements for oil and gas leases as needs and conditions change, or review and adjust every five (5) years at a minimum, without requiring a lease amendment, including sufficient bonding for complete platform removal.
    - If necessary, due to failure of any lessee to voluntarily provide third-party certification for BOPE and/or drilling programs, or problems with updating Commission regulations requiring such certification, seek legislation to enact a new State statute to require third-party certification of BOPE and all drilling, workover, and abandonment plans and projects.

Direct the Executive Officer or his designee to pursue implementation of the recommendations approved by the Commission, and to execute any documents necessary to implement the Commission's action.

EXHIBIT A

CALIFORNIA STATE LANDS COMMISSION

Report to Commissioners

Production and Marine Terminal Operations in State Waters and the California State Lands Commission's Oil Spill Prevention Programs Protecting State Waters

CSLC Staff Report

August 20, 2010

Table of Contents

I Introduction

At its June 28, 2010, California State Lands Commission (CSLC) meeting, the Chair of the Commission directed CSLC staff to review oil production operations in State waters by the August 2010 Commission meeting, in light of the events occurring in the Gulf of Mexico relating to the British Petroleum (BP) Deepwater Horizon oil spill. The Chair also directed CSLC staff to report on the CSLC's oil spill prevention activities and programs for oil production operations and marine oil terminal operations in State waters, their effectiveness, and to evaluate opportunities for improvement of these programs. CSLC staff has prepared this report to address the Commission Chair's directive.

The CSLC has served, since 1938, as manager of the State's sovereign lands, including ungranted tidelands, submerged lands, and navigable waterways. The State's jurisdiction includes the beds of navigable rivers, streams, lakes, bays, tide and submerged coastal lands extending to a distance of three (3) nautical miles. By statute, the Commission may lease these lands for the orderly development of State mineral resources. The Commission, also by statute, has jurisdictional authority for operation of marine terminals' oil spill prevention programs to ensure their safety.

Oil production and marine terminal operations in State waters are clearly defined by statute, closely regulated, and constantly monitored by the Commission staff. The CSLC administers its authority for these activities through an integrated staff structured within four operating Divisions, each with specific responsibility and duties to oversee activities in State waters. The Mineral Resources Management Division (MRMD) is responsible for carrying out the Commission's responsibilities for mineral leasing and oil production activities. The Marine Facilities Division (MFD) carries out the Commission's responsibilities for marine terminal operations in State waters. The Land Management Division (LMD) is responsible for surface management of State lands including leasing of marine oil terminals, and right-of-way for oil and gas pipelines crossing State waters. The Division of Environmental Planning and Management (DEPM) ensures the Commission's compliance with the provisions of the California Environmental Quality Act (CEQA).

The above Divisions, each with their unique abilities and expertise, jointly apply coordinated, collaborative, and supportive efforts toward CSLC management of activities in State waters. In describing the CSLC's management and pollution prevention program in this report, individual Division responsibilities will be clearly discussed.

Oil production activities, marine terminal operations, and pipeline infrastructure carry an inherent level of safety and pollution risk. The accident in the deep waters of the Gulf of Mexico is a solemn reminder of these risks. The CSLC has long recognized that these risks exist and, over many decades, has developed strong regulations, policies and practices to ensure that the highest level of protection of State waters is maintained. This report describes the physical operations of offshore facilities, and

CSLC’s authority, and provides an overview of the regulations, programs, and safeguards that ensure the maximum protection of these facilities and the environment.

Finally, this report concludes with a discussion of the current and future challenges to the CLSC’s oil spill prevention programs, and recommendations to amend current regulations, policies and practices regarding oil operations in order to further strengthen CSLC’s ability to protect State waters.

II Operations in State Waters

A. Oil Production Operations

1. CSLC Authority

Since 1938, CSLC has served as manager of the State's sovereign lands, including most historic tidelands, submerged lands, and navigable waterways. This jurisdiction is found in Division 6 of the Public Resource Code (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.

In 1990 the California Legislature passed the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act. PRC §8755, adopted as part of the Act, requires that CLSC regulations provide the “Best Achievable Technology and Best Achievable Protection” (BAT/BAP), and provides, in part, that:

> *the [State Lands] Commission [CSLC] shall adopt rules, regulations, guidelines, and commission leasing policies for reviewing the location, type, character, performance standards, size and operation of all existing and proposed marine terminals within the state, whether or not on lands leased from the commission, and all other marine facilities on lands under lease from the commission to minimize the possibility of a discharge of oil... The [CSLC] shall ensure that the rules, regulations, guidelines, and commission lease covenants provide the best achievable protection of public health and safety and the environment.*

2. Existing Oil & Gas Operations

The Mineral Resources Management Division (MRMD) oversees the leasing and operations of all mineral leases in State’s offshore tide and submerged lands along the state’s more than 1,100 miles of coastline, extending from mean high tide out to three (3) nautical miles.

Presently, eighteen (18) producing offshore oil & gas leases exist in State waters (as shown in Figures 1 & 2). The leases are developed from offshore structures and from onshore coastal facilities. Ten (10) leases produce oil from four offshore platforms, and two man-made islands. The Platforms are located in offshore Santa Barbara, Seal Beach and Huntington Beach, and one manmade island is off the coast of Ventura. Additionally, the Long Beach Unit, located within the granted tidelands of the City of Long Beach, produces from four manmade islands. Eight (8) active offshore leases produce oil from four onshore coastal sites, located in the Huntington Beach and Ventura areas.

Figure 1: Southern California (Orange-L.A. County) Oil & Gas Production Operations

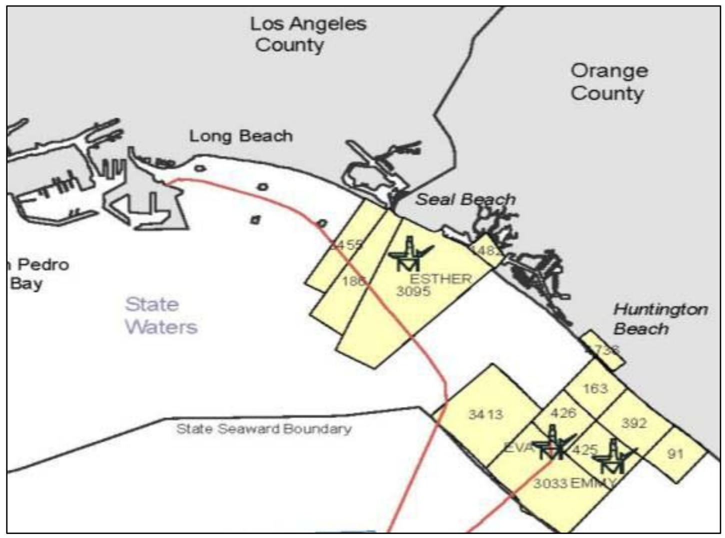
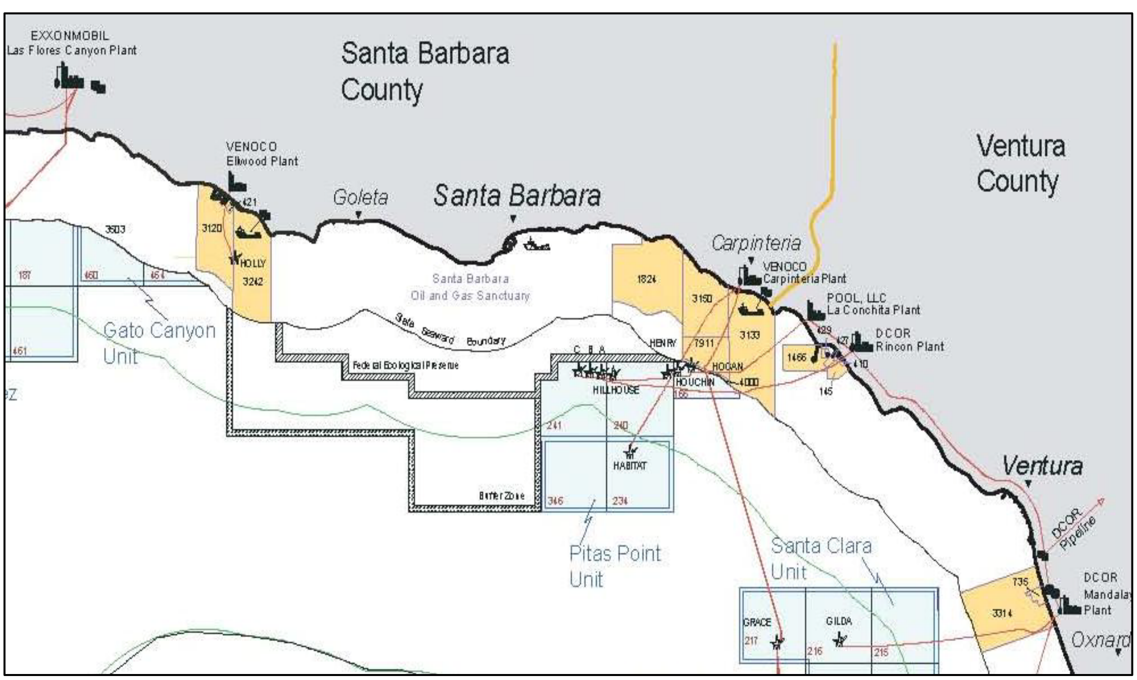
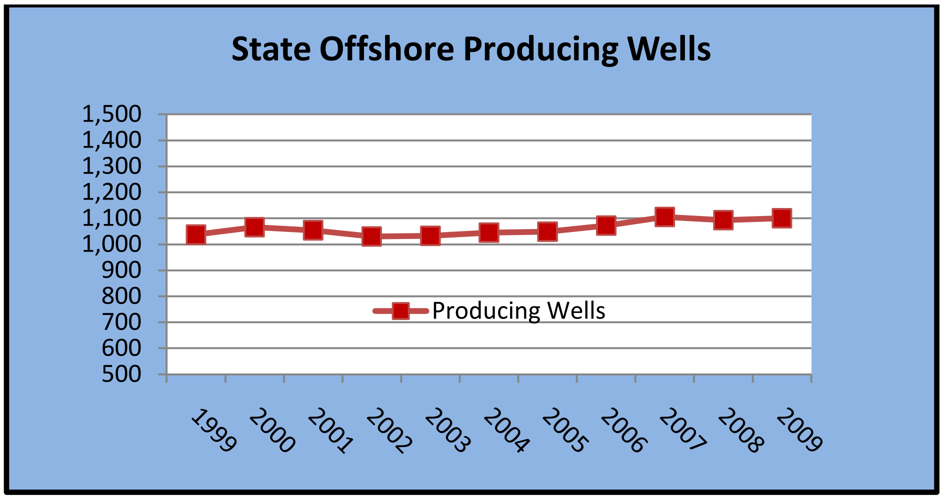


Figure 2: Southern California (Santa Barbara-Ventura County) Offshore Oil & Gas Production Operations

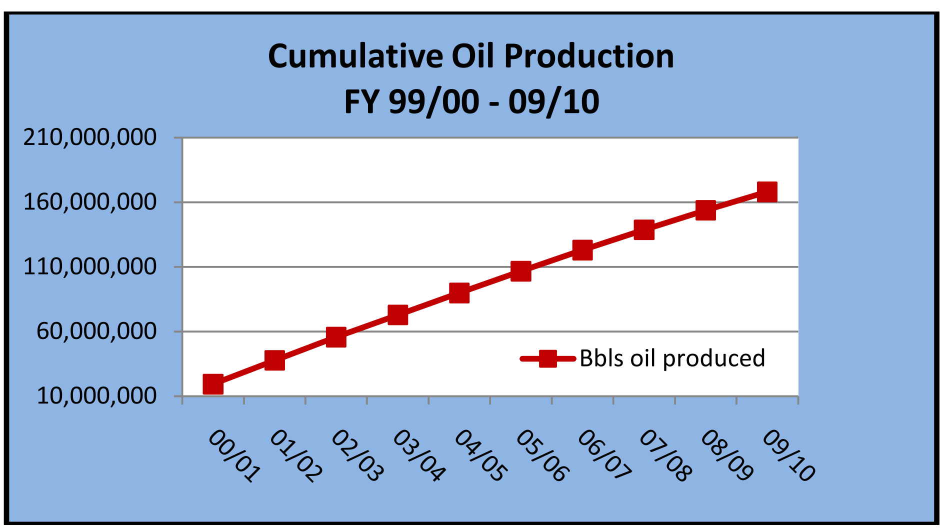


All offshore production facilities deliver their oil and gas to onshore processing and sales facilities via offshore pipelines, located on the oil lease or in State right-of-way leases. In addition to pipelines serving platforms and islands in State waters, the State manages right-of-way leases for pipelines crossing State lands that deliver oil and gas to shore from federal oil platforms beyond the three mile limit. A total of 36 oil and gas pipelines (approximately 100 miles) cross State waters.

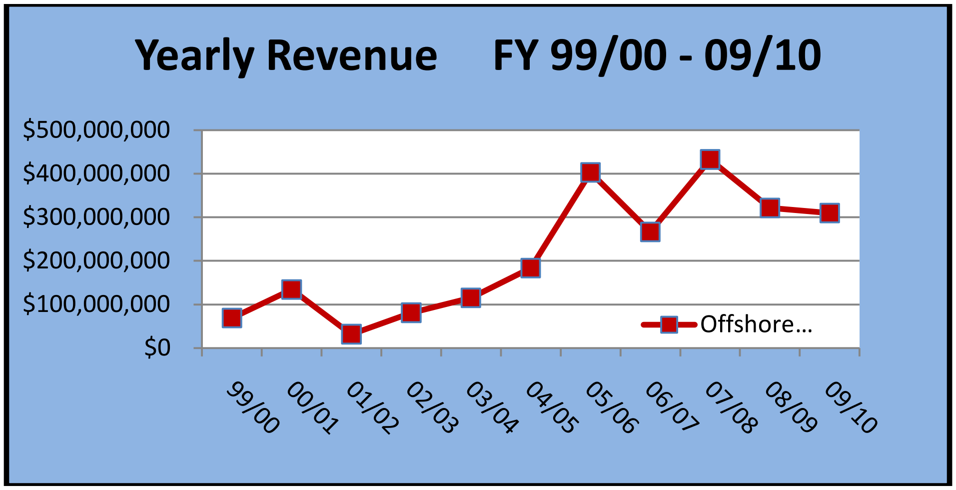
The number of active wells producing offshore oil on State offshore interests has remained between 1,030 and 1,105 throughout the past 10-year period (with minor fluctuations).



Over the past 10 years, approximately 168 million barrels of oil (7 billion gallons) have been produced, treated and transported from State offshore leases. Because of the maturity of the fields currently under lease in the State, production will continue to decline without any new sources of oil. The majority of wells drilled or re-drilled are used to replace current wells and production.



During this same 10-year time span the cumulative revenue collected from offshore oil production has totaled more than $2.4 billion. For the most recent fiscal year of 2009/2010 the revenue was approximately $310 million and has averaged almost $350 million per year for the past five years.



The MRMD staff that implement the programs discussed in this report are highly qualified, trained, and experienced professionals who have given the CSLC the highest level of service to assure the safest operations in State waters. The CSLC staff has played a significant part in generating and maintaining "non-tax revenue" for the State through safe management and leasing of State mineral interests, particularly oil and gas resources. In addition, through rules and regulations, and statutory leasing authority, the staff has developed strong and effective safety standards for offshore drilling, which have been adopted by the industry.

Staff is presently engaged in updating existing oil and gas drilling and production regulations. MRMD efforts in these updates have been under development on an ongoing basis, but, in light of the Deepwater Horizon spill, the need for timely adoption has become apparent. The extent to which the CSLC has imposed new requirements through already existing leases has mainly depended on securing cooperation from the lessees, whom have been compliant, or by lease amendment as part of a lessee project application. Now, however, the CSLC recognizes, pursuant to PRC §8755, it may have the authority to impose new regulations upon all existing leases. Regardless, the staff is confident that, as in the past, the lessees will understand and agree with the need for the updated requirements.

3. Oil & Gas Project Review Process

The CSLC's MRMD is staffed with geologists, engineers (in varied disciplines) and specialists in oil and gas, geothermal and mineral leasing, exploration and development, many of whom are registered professionals, have advanced degrees, or years of field experience. MRMD is headquartered in Long Beach, and it has field offices in Huntington Beach and Santa Barbara. Its priority is the orderly oversight and management of state resources, under the Commission's leadership, in a safe and environmentally protective manner.

MRMD is responsible for regulating all oil and gas activities on State leases, 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, these 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.

A Safety and Oil Spill Prevention Audit Program was implemented in the 1990's. The Safety Audit tasks include the comprehensive evaluation of the design of the safety systems of the offshore platforms and islands, and the associated onshore processing facilities, as well as a review of the corporate "safety culture," on a five year basis.

All existing oil and gas production operations started as resource development proposals submitted by prospective applicants. The review process for these projects involves a rigorous and comprehensive assessment by many CSLC Divisions, examining all aspects of the project. Project management and coordination of the reviews are performed by MRMD which solicits input from engineering and geologic, operations, environmental, legal, finance, and surface leasing divisions. The objective of these project assessments is to ensure that proposed projects fully implement all of the regulations, policies, programs, and environmental mitigations that would be required for Commission consideration

Should the Commission decide to approve an oil production or development project, MRMD staff reviews and approves individual well drilling programs on State oil and gas leases both for resource management and for safety and spill prevention purposes, and reviews, inspects, and monitors the structural performance of the platforms including recurring structural surveys for fitness, structural modifications, and periodic major structural evaluations. All new drilling projects from current platforms require a rigorous structural requalification to ensure that the facility is safe and capable to implement the project, and to require any strengthening or maintenance required to bring the facility up to current codes. In addition MRMD reviews, inspects, and monitors those pipelines under CSLC jurisdiction and cooperates with those other agencies where there is joint responsibility.

B. Marine Terminal Operations (MFD)

1. CSLC Authority

The 1989 *Exxon Valdez* and the 1990 *American Trader* crude oil spills in Alaska and Huntington Beach respectively prompted the Legislature to assess oil spill prevention mandates. The Legislature found that because of the inadequacy of spill cleanup and response measures and technology, the emphasis must be put on prevention, if the risk and consequences of oil spills are to be minimized. The Legislature passed the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act of 1990 ("the Act") which expanded CSLC's oil pollution prevention jurisdiction. Specifically PRC §8755, cited above, requires that CLSC regulations provide the "Best Achievable Technology and Best Achievable Protection" (BAT/BAP) at all marine terminals, whether or not on lands leased from the Commission.

The Act defined marine terminal as any marine facility used for transferring oil to or from a tank ship or tank barge. CSLC created the Marine Facilities Division (MFD) to implement the Act's marine terminal inspection and regulation mandates.

2. Existing Marine Terminal Operations

As CSLC was given new responsibilities and duties to prevent oil spills into state waters, it created the Marine Facilities Division (MFD), consisting of administrative offices in Long Beach and field offices in Hercules and Long Beach. MFD responsibilities included:

- Regularly inspecting and monitoring the operations of all marine terminals;
- Adopting rules and regulations for reviewing the location, performance standards, and other characteristics of all existing and proposed marine terminals;
- Developing rules and regulations for the content of marine terminal Operations Manuals for protection against oil spills; and
- Ensuring the best achievable protection of the public health and safety and the marine environment in the regulation of all marine oil terminals.

III Oil Spill Prevention Programs

A. Oil Production Spill Prevention Programs (MRMD)

1. Regulations

Drilling, production and offshore operating activities are conducted by lessees and in a manner that conform to CSLC drilling and production regulations found in the California Code of Regulations (CCR) at Title 2, Division 3, Chapter 1, and specifically in Articles 3.2, 3.3, 3.4, and 3.6. The regulations cover every phase of an oil and gas project's life cycle from inception to abandonment, and pollution prevention during that time. The following is a condensed and paraphrased compilation of the relevant drilling, production, and pollution prevention regulations.

a. Article 3.2: Oil and Gas Drilling Regulations

The drilling regulations are found in Article 3.2 of the CCR cited above. They cover requirements from the review of a proposed drilling program to the ultimate abandonment of every well on state property. More specifically, they cover what must be included in the drilling program for a complete engineering review, requirements for casing, cementing of the casing, blowout prevention equipment, drilling fluids ("mud"), drill site and rig safety equipment, pipeline installation, integrity, and maintenance, and abandonment requirements. The MRMD staff also receives, and engineering staff reviews, daily drilling reports from any well drilling on a state lease.

Table 1. Article 3.2: Oil and Gas Drilling Regulations

§2128 (d) Drilling Program	The drilling program must comply with all laws and regulations, requires "good oilfield practice" (which, at a minimum, is equivalent to the best American Petroleum Institute [API] recommended practice and other relevant codes). Every well drilling proposal must be approved by staff before drilling can begin. This entails a complete engineering review of all aspects of the well design and associated programs (casing, cementing, mud, etc). Prior to commencing drilling operations from a mobile drilling rig (drillship, semi-submersible rig or "jackup" rig), the lessee must conduct a well site investigation, and receive approval by staff, to demonstrate that the conditions of the ocean bottom are environmentally compatible and suitable for the proposed well site and. Additionally, in drilling operations from a drill ship or semi-submersible rig (a.k.a. "floating operations"), staff must be provided in the detailed drilling procedures additional safeguards while removing the drilling riser and for running and cementing the casing strings.

§2128 (e) Well Casing Requirements.	The regulations require that casing setting depths be based on all relevant geological and engineering factors, including, among other things, water depth and zones of lost circulation or other unusual characteristics.
§2128 (f) Casing Cementing Requirements	The regulations require that the lessee use appropriate cementing technology in order to achieve adequate cement fill up and bonding on all casing cementing operations. Additionally, our regulations require a cement bond log to be run following primary cementing of the casing to aid in determining whether a good bond and adequate cement fill up has been achieved.
§2128(g) Pressure Testing of Casing	Upon completion of the cementing operations a pressure test must be completed on all strings of casing (except the conductor), to the minimum levels outlined within the regulation to determine if a leak may be present. If during the test the pressure declines more than 10 percent in 30 minutes, or if there is any other indication of a leak, corrective measures must be taken so that a satisfactory test is obtained.
§2128 (i) Blowout Prevention Equipment (BOPE) Requirements	This section does not specify the number or types of Blowout Prevention Equipment (BOPE), but requires that all portions of a blowout prevention system be designed for the well conditions and that alternate methods of well control are available in the event of failure of any one portion of the system (i.e., redundant systems). If one component of the system that is vital to well control becomes inoperative, drilling operations shall be suspended as soon as possible without danger to the well until the inoperative equipment is repaired or replaced.
§2128 (j) Pressure Testing, Operational Testing, Inspection, and Maintenance of Blowout Prevention Equipment	BOPE and related control equipment must be tested to specifications outlined in the regulations as follows: 1) when installed on the well; 2) after setting each casing string; 3) before drilling into any known or suspected high pressure zone; 4) at least once a week during drilling; and 5) following repairs or replacement that necessitates breaking any pressure seal in the system.
§2128 (m) Mud Program	The mud program must be designed to prevent the loss of well control. Adequate quantities of mud materials must be maintained at the drill-site and shall be readily accessible for use in well control. Three areas covered in the regulations are

(Drilling Fluids/Mud Control, cont.)	mud control, mud quantities, and mud testing equipment. The mud density is the primary control of formation pressures in the well. The mud control requirement outlines procedures to be followed during pipe "trips" out of the hole (replacing the drill bit) and for mud degassing equipment. The mud quantities section requires that the mud program tabulate, by depth and hole size, the minimum volume of mud and materials to be maintained at the drill site to keep the mud "in shape." Also, there must be sufficient weight material to increase the mud to the maximum density in the program if needed. A daily inventory of mud materials must also be maintained and drilling operations suspended if the required minimum quantities are not on hand. Lastly, monitoring equipment and mud testing requirements during the drilling operations are required. This includes the following devices: recording mud pit level indicator, mud-volume measuring device, mud-return or full-hole indicator, and gas-detection equipment (all relating to early indication of an imbalance of mud weight to formation pressure).
§2128(n) Drilling Practices & (o) Inspection	Drilling Practices provides guidelines and procedures for four critical operations that may be encountered during drilling operations. They include carefully observing the volume of mud used to fill the hole when pulling drill pipe from or returning it into the hole, posting the maximum pressures allowed do build up against the BOPE in the event of a "kill" procedure, the rate of pulling or running drill pipe, and how to handle produced fluid during drill stem testing. The Drilling Inspection regulations give staff the authority to perform inspections of the drilling operations to verify that operations are being conducted in accordance with regulations and the approved well drilling program.
§2128(q) Plugging & Abandonment	Prior to abandoning a well the lessee must file a written notice of intention to abandon the well with CSLC staff. The notice covers the current condition of the well and the proposed method of abandonment. Written approval is required from CSLC staff prior to commencement of any abandonment operations. The regulations outline the formation zones that need to be isolated, isolation of open hole and casing, the length of plug that must be used, the testing methods to determine the placement and hardness of each plug, and recordkeeping.

b. Article 3.3: Oil and Gas Production Regulations

The production facility (platforms and associated onshore facilities) regulations are found in Article 3.3 (Production Regulations). They cover requirements from well completions (and completion programs), well, wellhead, production and platform safety systems (testing and inspections), well maintenance work, Hydrogen Sulfide (“H_2S”) detection precautions and planning, electrical systems, fire and fire fighting systems, welding practices, pipeline operations and maintenance.

Table 2. Article 3.3: Oil and Gas Production Regulations

§2132 (a-g) Production Facility Safety Equipment and Procedures	These regulations require compliance with all laws and regulations and, as with the drilling regulations, require “good oilfield practice” (always assumed to be the best API recommended practice and other relevant codes). All well completion programs, including wellhead equipment, must be approved by staff, and any change to the program or equipment must also be approved. This is also a requirement for any remedial and/or well maintenance work. Subsurface safety valves are required in the well if it can flow without artificial means (i.e., pumping, gas lift, or other lifting mechanism). Monthly testing of all subsurface safety valves, and surface safety valves, is required, and the tests are witnessed and approved by MRMD inspectors. Safety devices on wells on artificial lift and all flowlines must also be tested monthly, and are witnessed and approved by MRMD inspectors. Supervision and training requirements for production well workers are also found within this Article. Subsurface injection projects require prior approval of staff in state lands. At a minimum the production facility safety equipment and procedures must meet all API recommended practices (API RP 14C). An integrated safety control system **(automatic shut down)** is required on offshore facilities and is witnessed and approved by staff. Fire and gas detection systems are also tested monthly. This is but a quick overview but these regulations are comprehensive and discuss each piece of equipment and system on the facilities and, pursuant to this regulation, require monthly testing witnessed by MRMD staff.
§2132 (h) Pipeline Operations and Maintenance.	Pipeline inspection requires **annual** smart pigging or hydrostatic pressure testing (to 1.5 times maximum operating pressure – the highest requirement of any regulations in state or federal California waters), and the results are reviewed by a MRMD staff engineer.

c. Article 3.4: Pollution Control and Article 3.6: Operation Manual & Emergency Planning Regulations

Article 3.4 (Pollution Control) and Article 3.6 (Operation Manuals and Emergency Planning) of the CCR's cited above, describe emergency planning requirements to avoid oil spills, and the content of operations manuals required for every facility.

Article 3.4: Oil Spill Contingency Planning/Critical Operations and Curtailment Plans: §2139 & §2141- CSLC regulations require a staff approved oil spill contingency plan (or an OSPR approved plan per the Act) and require a "Critical Operations and Curtailment Plan," that is, what the operator will do if operations need to be suspended during critical operations such as running casing, cementing, or environmental upset (Staff knows of no other regulatory agency that requires such a plan).

Article 3.6: Operations Manual & Emergency Planning: §2170 - §2175- CSLC regulations require all marine facilities under CSLC jurisdiction to prepare, and receive staff approval of, an operations manual describing equipment and procedures employed to protect the public health and safety and the environment and to prevent oil spills. The manual must demonstrate compliance with all applicable operating rules and regulations of the CSLC and lease terms. The manual must include all emergency response plans for oil spills, detection and operations in hydrogen sulfide environments, fire fighting, well control, natural disaster response, facility evacuation, critical operation curtailment plans, security, communications, and a description of all systems safety and personnel safety information.

2. Pollution & Safety Programs

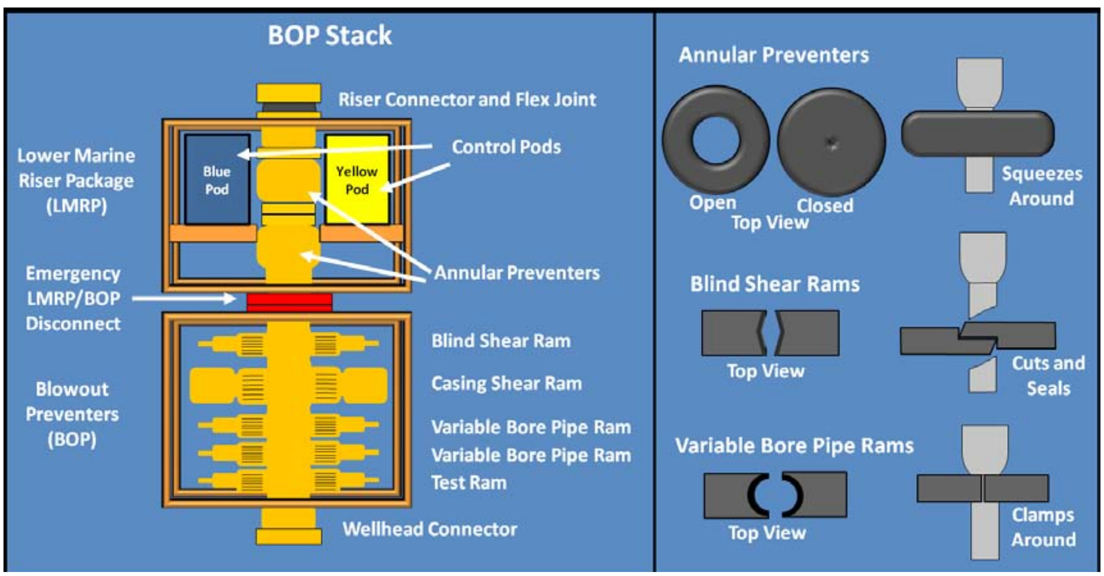
MRMD assures operator compliance with the drilling and production regulations through a series of technical oversight programs developed and conducted by the MRMD engineering staff. These programs, described below, involve technical review and site surveillance programs performed by engineers and technicians, most being established and developed over many decades and provide comprehensive analysis, oversight, and surveillance of offshore oil operations.

a. Drilling and Well Programs

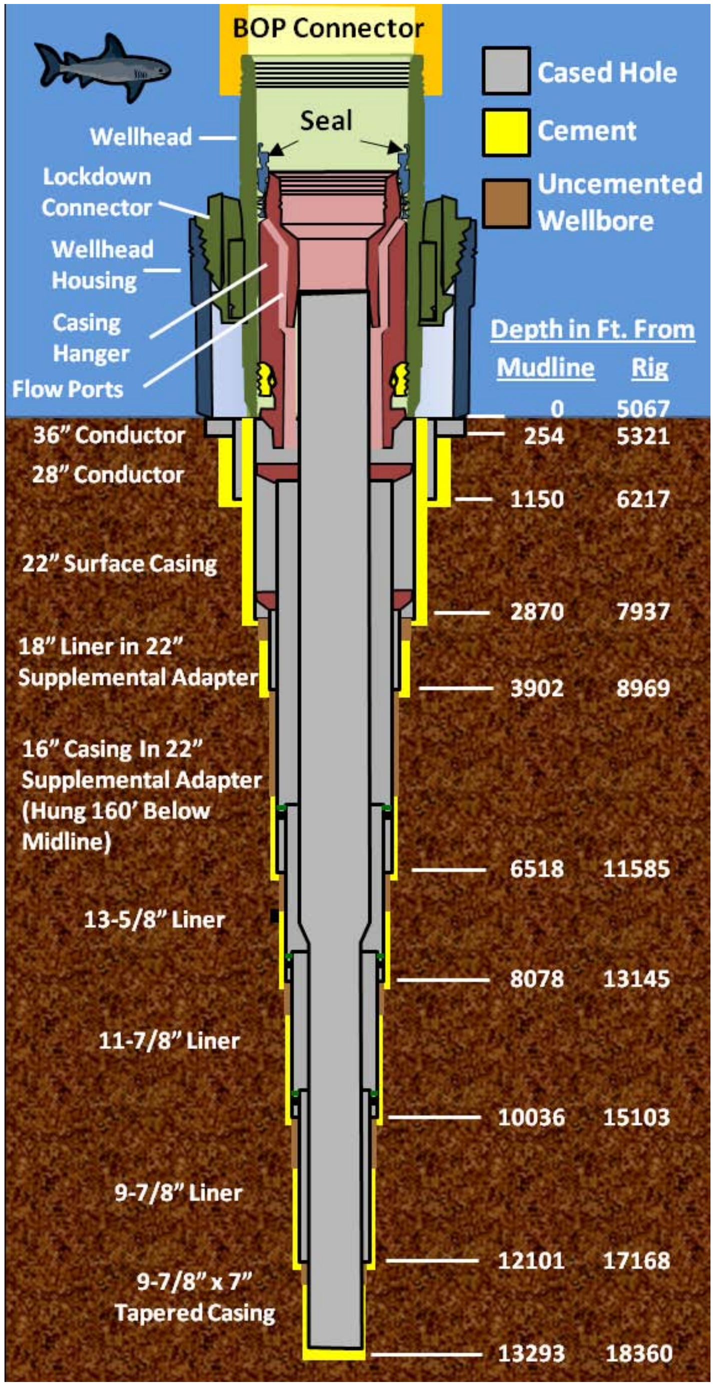
Drilling, redrilling, workover and abandonment programs are reviewed on a per well basis to ensure they are complete and meet or exceed all CSLC regulations.

A typical drilling program review encompasses the following components and engineering review.

- **BOPE** - The BOPE stack is configured to allow closing in of the wellbore safely and efficiently when and if needed. The BOPE stack has a pressure rating that exceeds any pressures to be encountered from the wellbore while drilling. Staff calculates the potential maximum surface pressure from the total depth of the well which is used to determine size and pressure rating of the BOPE stack. The Division of Oil, Gas, and Geothermal Resources (DOGGR) staff witnesses the pressure testing of the BOPE stack after installation (or prior to installation on a "floating operation"). Weekly testing of the BOPE stack is verified by staff through daily morning reports of the rig activity. As provided by the CSLC regulations, drilling personnel are required to have current BOPE safety training and certifications are provided to CSLC staff. The following is an illustration (from Energy Training Resources, LLC) of a blowout prevention "stack" and types of preventers (annular, pipe, blind/shear) used on the Macondo well (the British Petroleum well that suffered the blowout in the Gulf of Mexico).



- **Casing** – The casing program for the well contains the specifications and length of each casing string to be run into the well. The casing design and setting depths are reviewed by staff. Staff uses pressure gradient and reservoir pressure data to calculate maximum allowable casing setting depths with applicable engineering safety factors. The collapse strength, burst rating and tensile stress factors are all considered when approving the type, weight, grade and coupling thread type of the casing to be run. A pressure test against the open formation is required when drilling out of a casing string. This test establishes an equivalent mud weight circulating density which is used in determining subsequent casing setting depths. This is a crucial actual field measurement because it could pre-empt the original casing design criteria and cause a casing string to be set and cemented at a shallower point than designed before drilling ahead. Redrill wells must pass a pressure test of existing (original) casing and a casing inspection log is required to ensure the integrity of the casing before the redrill commences. The following illustration (from Energy Training Resources, LLC) shows casing and cementing from the Macondo well.



Macondo Well Diagram
Showing Casing/Cementing

- **Cementing** - Staff reviews the cementing procedure for each casing string included in the drilling program. Cementing is a process in well drilling that usually occurs after steel casing is lowered into the freshly drilled hole. Liquid cement is pumped down the well in such a manner that it fills the space between the casing and the drilled hole so that, when it hardens, it creates an impermeable seal between the casing and the drilled hole. It is important to have this cement seal for many reasons:
    1. The cement supports the casing in the hole;
    2. The cement seals off, and creates a barrier to, the formation pressure and fluids from the surface both inside and outside (in the space between the casing and drilled hole) the casing (a potential cause for a blowout);
    3. The cement prevents any contamination from occurring by, or within, the zones that have been drilled through; and,
    4. The cement seal prevents any zone liquid or gas from entering the well except from the interval desired.

  These procedures are reviewed to ensure adequate fill volumes are being used behind the casing strings to cover oil and gas zones and fresh water zones. Compositions of the cement mixtures (and additives) are also reviewed for adequate compressive strengths. Surface casings require cement returns to the surface, while intermediate casing strings require cement coverage 200 feet into the preceding larger casing. Production casings require cement coverage 500 feet above the highest oil and gas zones. A cement bond log is run on intermediate and production casings to ensure cement fill and adequate cement bonding and has been achieved. The log is submitted to staff for review.

- **Drilling Fluids ("Mud")** – Staff reviews the mud program within the drilling program. The mud's weight counters formation pressures downhole and helps prevent gas or fluids from invading the wellbore, which would cause a "kick". An uncontrolled "kick" at the surface is a "blowout." Mud weight material of sufficient quantity for the maximum density in the drilling program must be available on site at all times. There is a zero discharge policy which is strictly enforced. Staff visits the site two to three times per week. Pit Volume level indicators and gas level detection equipment with alarms are required on the mud system to monitor mud volumes and mud returns. A mud report describing the volumes, physical and chemical characteristics and quantities in the active and reserve drilling fluids system is filled out daily at the drilling site by a drilling fluids engineer. The drilling mud type and characteristics may change as each section of the well is drilled and each phase of the mud program is reviewed by staff.

Workover and abandonment programs are reviewed thoroughly for completeness as well. Workover and abandonment programs currently represent a far larger percentage of the program review workload than drilling and redrilling programs.

Abandonment programs are reviewed to ensure that the placement and size of cement plugs seal the wells properly. Workover programs are reviewed by staff for compliance with our oil and gas regulations.

Each program review is performed by engineering staff and routed through engineering management for final review and sign off before programs are approved.

b. Platform Inspections

The MRMD Inspection/Audit Program uses a two-pronged approach to assure Best Achievable Protection on marine facilities in its jurisdiction. First, the safety system must be designed correctly to prevent spills, and maintenance and training programs must be sufficient to preserve system integrity and provide qualified operation. This is discussed below in the "Facility Safety Audits" section. Second, the facility must be inspected regularly to verify that it is reliable and kept in a fully operable condition. Protection would be compromised by either design flaws or operational deficiencies.

The Platform Inspection Program provides the reliability part of the protection equation. Inspections are conducted at every offshore facility monthly, per MRMD regulations, and are conducted by MRMD inspectors from the Huntington Beach or Goleta field offices.

The core of each inspection is physical testing of the facilities production and processing alarms and shutdowns. This includes each well's surface and subsurface safety valves, the emergency shutdown system, high and low pressure and level alarms installed in vessels and tanks, 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 life saving equipment are reviewed. Additionally, 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 complete, and includes testing of an average of 317 devices. Deficiencies are corrected immediately, or the affected equipment is shut down and isolated, which may require shut in of the entire facility.

The platform inspections provide assurance that the safety systems are kept in good operating condition, and that the equipment to respond to emergencies and spills is available and in good operating condition. The Inspectors also conduct daily surveillance of operations, pollution checks at facilities, beaches, and along pipelines, as well as royalty production verification duties.

c. Pipeline Inspections

CSLC regulations require that all oil and gas pipelines in State waters be internally and externally inspected annually. The test equipment and procedures must have prior approval, and the results of the tests must be reviewed and approved by MRMD engineers, in order to continue operation of the pipeline.

For the internal inspection, an electronic "smart pig" inspection is required. This inspection is performed by pumping an electronic magnetic flux tool through the pipeline. The tool measures and records wall thickness along the entire length of the pipeline, which identifies any internal or external variations in thickness. Thin spots due to corrosion are identified, as well as any damage to the pipeline. Smart pig runs are analyzed by MRMD engineers using American Society of Mechanical Engineers (ASME) criteria and compared with previous runs to evaluate corrosion trends and remaining service life. If a smart pig run is not mechanically feasible, a hydrostatic test to 1.5 times the maximum operating pressure of the pipeline is required. The test pressure is required to be held for eight hours in order to pass. This standard is more stringent than any other known state or federal regulations for oil pipelines. Hydrostatic tests are witnessed by an MRMD engineer, and evaluated using a material balance spreadsheet developed by MRMD and used by many operators to verify absence of leaks.

The external inspection of a submerged pipeline may be conducted by a diver or remote operating vehicle (ROV). The external inspection is used to detect damage, movement, free spans (unsupported section of pipeline), or foreign objects lying across the pipeline, that may cause failure due to physical movement or accelerated corrosion. Video tapes and diver reports of external pipeline inspections are reviewed by an MRMD engineer, and corrective actions coordinated with the pipeline operator if necessary.

d. Facility Safety Audits

As noted above, the Safety Audit Program provides an analysis of the technical design of a facility's safety system and verification that the alarms and controls have been installed and operate as designed, and comply with MRMD regulations and industry standards from API, ASME, American Society for Testing and Materials (ASTM), National Association of Corrosion Engineers (NACE), and other professional organizations. This analysis requires that the facility's "Piping and Instrumentation Drawings," a schematic representation of the layout and specifications of all wellheads, flowlines, process piping, vessels, alarms, and controls at the facility, be field verified for accuracy before the technical evaluation is conducted. The audit also reviews equipment maintenance and corrosion prevention and inspection programs and results to evaluate fitness for purpose of pressure vessels, tanks, and piping. The design, maintenance, and condition of the electrical power distribution circuits and fire detection and control systems are analyzed and inspected by a third-party contractor. Training and qualification programs are reviewed to assure competent training in, and oversight of, operation of the facility, and the Facility Operating Manual and Spill Prevention Plan are reviewed to evaluate adequacy of procedures for normal operation, upset conditions, and response to spill incidents. Organizational safety culture, and the level of maturity of safety programs, is evaluated by a Safety Assessment of Management Systems (SAMS) procedure, which assesses these factors through a series of confidential interviews with a cross-section of company operators, engineers, management, and contractors. The SAMS evaluation is a tool that addresses human error factors, and which can be used by the operator to improve programs to reduce human error.

The safety audit provides a comprehensive evaluation of facility design, condition, procedures, and personnel qualifications, producing a matrix of action items that are prioritized by risk, and corrected during a follow-up phase. Safety audits are repeated every five years, as recommended by industry and government codes.

e. Structural Assessments

Another MRMD oversight program is the Platform Structural Reassessment Program. Since the 1990s, all offshore platforms in State waters have been analyzed to API RP2A standards by the operators using finite element numerical modeling programs and a non-linear time-history analysis to determine whether they would withstand a 100-year return period storm event and a 1000 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 many of the platforms. Since the analyses, the underwater jacket structure of each platform is inspected on a periodic basis as outlined in API RP 2A guidelines, and corrective measures implemented as required. Facility modification proposals 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 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 to require any strengthening or maintenance needed to bring the structure up to current codes. Verification of these analyses is performed by an MRMD staff civil engineer with expertise in structural analysis.

3. Spill & Safety Record

There are inherent risks involved with these operations. The MRMD's highest priority is public health and safety, and environmental protection. The Division'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 to be minimized.

As noted earlier, over the past 10 years approximately 168 million barrels of oil (7 billion gallons) have been produced, treated and transported from State offshore leases from an average of between 1,000 and 1,100 wells.

On average, offshore oil spill incidences in state waters from oil and gas drilling and production operations occur at a frequency of less than 12 per year, and account for less than half a barrel (+/- 21 gallons) in total volume. Except for one 5-barrel spill that occurred in the Long Beach Harbor three years ago, spills that do occur are generally measured in drops or ounces.

The low volume and infrequent incidence of spills is a testament to the commitment and dedication to safety by our lessees, and the effectiveness of the CSLC's safety and pollution prevention regulations and programs. However, this does not mean, nor do we mean to imply, that a serious spill could never happen from our facilities, but that both our lessees and staff have remained vigilant and helped ensure that state operations have had no serious problems.

4. Update of Current Regulations

Most of the current CSLC regulations were adopted in 1980 and developed as a response to the blowout of Platform A in Federal waters off Santa Barbara in 1969. They are still considered highly effective. However, over time staff has, for clarity and/or in response to legislation or new information (usually from incidents on state or federal platforms), added other requirements not spelled out in the current regulations by including new lease terms (for specific drilling requirements) or as a condition of approval of drilling or facility programs. Staff is currently completing an update of these regulations, including a new Article specifically addressing facility safety audits. Once completed, these new and updated regulations will be brought for Commission approval and then go through the codification process with the Office of Administrative Law (OAL). Staff will also include amendments as applicable based on the ultimate findings from the investigation of the Deepwater incident in the Gulf of Mexico (as reviewed below). Staff is also reviewing the current updates suggested for the federal regulations, as well as the state's Division of Oil, Gas, and Geothermal Resource

regulations in the Office of Administrative Law review process (in response to AB 1960 legislation).
Some highlights of the update include the following:

- The “Definitions” section would be expanded to clarify many of the terms used.

- The numbering system and headings would be revamped for ease of use in finding specific regulations (i.e., more “user friendly”).

- Good oil field practice definition would be changed to Best oil field practice (relates to our BAT/BAP responsibility).

- Changed Blowout prevention and control plan would state that it must be approved by staff *prior* to initializing drilling operations.

- Cement Bond Surveys would be upgraded to state that survey is to be run ***before*** further drilling is commenced (intermediate casing and below) or whenever the BOPE is removed from the well and that pressure is to be relieved from the well while survey is being run.

- Casing Pressure tests would be changed to include positive <u>and</u> static tests on intermediate and subsequent casing strings.

- A subsea blowout preventer stack would be required to include an acoustic or other “tertiary” remote communication device (in addition to “dead man” and ROV “hot tap”), and ram redundancy and/or use of “variable bore rams” added for drilling out intermediate and subsequent casing strings.

- On subsea installations, alternating control pods on successive operational tests would be changed from *may be used* to *shall be used*.

- A new Article 3.7 would be added detailing the Commission’s safety audit program requirements.

- The pipeline operation, maintenance and inspection section would be expanded and requires that reports on inspection submitted by operator must include written evaluations of test results, with supporting calculations that confirm the pressure integrity of the pipeline and its suitability for continued service.

- Article 3.6 Operations Manual and Emergency Planning section would be upgraded.

- A new Article 3.8 would be added regarding underground injection and disposal projects.

- All regulations, whether updated, added or otherwise unchanged, would be adopted or readopted pursuant to PRC §8755.

5. Preliminary Assessment of CSLC Regulations In Light of British Petroleum's (BP) Gulf of Mexico Blowout

The CSLC staff has closely monitored the BP blowout that occurred in the Gulf of Mexico, particularly as it may relate to the regulations, programs and practices which the CSLC applies to offshore oil production activities in State waters. Although a thorough federal investigation is currently underway but not yet complete, there has been some published information suggesting some of the contributing causes of the blowout. MRMD staff has assessed this information as to how the State's offshore environment, safety programs and regulations compare to those implemented on the BP Deepwater Horizon well.

Offshore Environment:
The Gulf of Mexico incident occurred approximately 50 miles from the Gulf Coast and at 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 at a pressure of approximately 10,000 pounds per square inch. These are very extreme conditions compared to California state waters.

In the State of California 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 (having produced over many years), and most wells require external assistance 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 BP drilling environment. Unfortunately however, our drilling occurs closer to shore so any spill would almost certainly impact the shoreline quickly.

Blowout Prevention Equipment:
BP's blowout prevention equipment (BOPE) did not close off the wellbore as it is designed to do, though the cause is presently unknown. The BOPE appeared to be configured with the necessary redundancies that conform to industry standards; however, there is some indication that part of the redundant closing system was leaking. This might also explain why the rig was unable to disconnect the riser from the BOPE and move off the site to prevent the explosion and destruction of the vessel. It has also been reported that the two backup systems did not function properly.

The State's BOPE requirements also provide for redundancies in the BOPE design. Our regulations require testing of this equipment at specific intervals and that testing is observed by State inspectors, and recorded in well reports. Additionally, the BOPE is on the surface (at the platform level), not on the sea floor (below the “floating” drilling rig as was the case on the BP well). This access makes testing and maintenance easier and safer.

Well Casing:

The details of the BP Deepwater Horizon casing design and the decisions made by BP for the design are still under investigation. It is not known what level of technical review was made by the regulating agency.

Wells in State waters are designed to conform to the expected well conditions, and the design is reviewed by State engineers before the well programs are approved for drilling.

Cementing of Casing:

Reports that BP’s Deepwater Horizon casing was cemented improperly need to be verified during the ongoing investigation. We do understand, however, that the cement quality, quantity, and placement within the well were not verified through the use of cement bond survey tools. This equipment is designed to verify where the cement has been placed around the casing, how high the cement has risen, and how adequately it has adhered to the well casing and the geologic formation.

State regulations require a cement bond log survey to be performed in all well casings that are placed through the oil bearing interval of the well to ensure that a sufficient cement bond (and shield) has been attained. If not, staff requires the operator to do a “remedial” cementing to correct the deficiencies.

Daily Reports:

With regard to daily drilling reports, it is staff’s understanding that the Gulf Coast Minerals Management Service staff (recently renamed the Bureau of Ocean Energy Management, Regulation, and Enforcement) received these reports on a weekly basis.

State regulation requires daily drilling reports to be called or faxed into MRMD for review by an engineer on a daily basis during all drilling activity.

Staff also requires that any changes to a casing, cementing, drilling, or production plan be approved by staff prior to the operation. The operator must contact the staff drilling engineer, who in turn may contact the Chief Engineer and/or the Division Chief, to review, discuss, and agree that the modification affords equivalent or higher engineering and safety, and conforms to our regulations and industry and local practices.

Staff has examined all reported problems and disasters (like the BP blowout) to learn how and why these problems occur. We constantly review industry and academic articles and reports, and final reports from inquiries as to the cause of every major problem and review the findings against our current regulations, lease terms, and policies, in order to build the safest and best programs in the industry.

B. Marine Terminal Spill Prevention Programs (MFD)

1. Regulations

Pursuant to PRC §8755, CSLC has completed the following regulations to provide the best achievable protection of the public health and safety and of the environment by using the best achievable technology:

- Marine Facilities Oil Spill Prevention (permanent regulations effective 12/5/91);
- Article 5, Marine Terminal Inspection and Management Regulations (effective 12/20/92);
- Article 5.3, Marine Terminal Personnel Training and Certification (effective 4/9/94);
- Article 5, Enforcement Amendment (effective 4/9/94);
- Article 5, Miscellaneous Amendments (effective 11/7/94);
- Article 5.5, Marine Terminal Oil Pipelines (effective 9/1/98, amendment effective 3/4/07);
- Article 5.1, Marine Terminal Physical Security (effective 2/24/03);
- Oil Transfer and Transportation Emission and Risk Reduction Act (effective 9/12/02); and
- CCR Title 24, Part 2 (CBC) Chapter 31F, "Marine Oil Terminals;" informally referred to as "MOTEMS" (effective 2/6/06).

MFD has an ongoing process to review and accordingly modify its rules and regulations, to ensure that all operators of marine terminals within the state's jurisdiction provide the best achievable protection of public health, safety, and the environment.

The MFD process for developing regulations is based upon review and analysis of:

(1) International and national industry standards and practices (e.g., International Safety Guide for Oil Tankers and Terminals (ISGOTT), International Maritime Organization, Oil Companies International Marine Forum**,** American Society for Testing of Materials, American Petroleum Institute);

(2) Federal regulations (e.g., U.S. Coast Guard, Title 33 of the Code of Federal Regulations (CFR) Parts 154 –156); and,

(3) Other states' regulations (e.g., Washington) and other California agency regulations (e.g., California State Fire Marshal and the Office of Spill Prevention and

Response).

Findings based on this analysis of worldwide practices, regulations, and technologies are then reviewed for feasibility and practicality for California application, with the recommendations by Technical Advisory Groups (TAGs), composed of representatives of industry, government, academia and environmental organizations. Staff then develops proposed regulations that are reviewed during an extensive public comment phase, that are frequently modified in response to comments received, that are then submitted to the Commission, and then, if approved, submitted to the California Office of Administrative Law (OAL) for evaluation of compliance with the Administrative Procedures Act. A brief history of the development and revision of the MFD's regulations is provided below:

■ Article 5 - Marine Terminals Inspection and Management

These regulations built upon and improved the initial Marine Facilities Oil Spill Prevention regulations by adding: (1) International Safety Guide for Oil Tankers and Terminals (ISGOTT) recommendations; (2) more comprehensive requirements for the exchange of information between terminals and vessels/barges; (3) pre-transfer conference requirements; (4) requirements for a Declaration of Inspection (DOI); (5) new operations manual requirements; (6) preventive booming requirement at time of transfer; (7) requirement for tugs and Assistant Mooring Masters at offshore terminals; and (8) enforcement procedures.

To review CSLC's recommended revisions for feasibility and practicality of application, staff convened a TAG. CSLC prepared draft regulations that went through three rounds of public comments (392 comments) and public hearings. Regulations were reviewed and passed by OAL on November 20, 1992, and became effective on December 20, 1992.

■ Amendments to Article 5 - Marine Terminals Inspection and Management

Amendments which improved Article 5 in the last review cycle included requirements for: (1) notification of structural or equipment damage at terminals; (2) prevention of electrical arcing at onshore terminals through use of insulating flanges or non-conducting hoses; (3) transfer of packaged cargo and vessel's stores only after authorization by both persons in charge; (4) limitations on continuous hours of work for terminal personnel; (5) equipment testing and conditions per federal requirements; (6) National Fire Protection Association's electrical hazardous area diagram to be provided at the terminal; (7) annual bathymetric surveys at offshore terminals; and (8) booming during ballasting and deballasting.

These amendments were based on staff analysis and recommendations developed during three meetings with a TAG, which ended in May 1993. The TAG recommendations were then developed into draft regulations that went through a public hearing and comment process. These amendments were approved by the OAL on October 1994, and became effective November 7, 1994.

■ Article 5.3 - Marine Terminal Personnel Training and Certification (T & C)

The provisions of this article were based on information that included: (1) CSLC-funded studies on human and organizational errors, conducted at the University of California, Berkeley; and (2) human factor studies completed by the State of Washington in 1993. These studies revealed that more than 80% of oil spills at marine terminals can be traced to human and organizational errors.

Recommendations, based in part on the above studies, were reviewed with a TAG, during three meetings from March-May 1993. Draft regulations were developed by CSLC and went through two rounds of public hearings and public comment periods. The regulations became effective April 9, 1994.

■ Article 5.5 - Marine Terminal Oil Pipelines

These provisions were created in response to the need for greater precision in testing and maintenance of marine oil terminal pipelines. Unlike the federal regulations found in Title 49, of the Code of Federal Regulations, Article 5.5 addresses the peculiarities relative to the generally shorter lengths of pipelines found at marine terminals.

In what has become standard practice, a TAG was convened to develop these regulations and the regulatory package was subjected to the established public review and comment period required by administrative statute and monitored by the OAL.

MFD has worked closely with the California State Fire Marshal to identify the overlaps in jurisdiction at marine terminals. Through an MOU, joint inspections have been conducted at all subject marine terminals, and the jurisdictional "lines of demarcation" have been established in writing. This cooperation has resulted in increased regulatory oversight.

■ Article 5.1 - Marine Terminal Physical Security

Following the terrorist attacks of September 11, 2001, CSLC staff polled marine terminal operators regarding security measures in place to protect terminal personnel and assets against terrorism. Except for fencing and lighting, staff found few measures implemented to deal with potential terrorist events. Beyond the apparent public safety concerns, a terrorist act against a marine terminal could also give rise to a substantial oil spill.

As in previous cases, the CSLC convened a TAG and developed new regulations in concert with U.S. Coast Guard, state fire and police agencies, and marine terminal representatives. The new regulations included the establishment of security plans for each terminal, as well as requiring marine terminal security officers to implement the plan and update it as necessary. These regulations, like others previously created, were subjected to public comment and review.

- Oil Transfer and Transportation Emission and Reduction (OTTER) Act

The California Legislature found that a significant amount of oil is shipped by tank vessel between the Los Angeles and San Francisco areas. The Legislature found that one of the results of vessel traffic along the central coast and into the ports of the Los Angeles and San Francisco areas is that tons of oxides of nitrogen are emitted into the air each day, which could negate efforts made on land to meet federal ozone standards and other public health air quality goals. The Legislature declared that current, accessible and accurate data regarding oil transportation is critical to determining the potential environmental quality, public health, and environmental justice consequences that must be analyzed by state and local agencies for environmental impact reports and statements, emergency response planning, permit issuance, and air quality mitigation efforts. A further finding of the Legislature was that tracking trends of these oil shipments is necessary to promote public safety, health and welfare, and to protect public and private property, wildlife, marine fisheries, other ocean resources, and the natural environment in order to protect and to preserve the ecological balance of California's coastal zone, coastal waters, and coastal economy.

The OTTER Act required CSLC staff to collect air emissions data from ocean shipping companies transporting oil between the Los Angeles and San Francisco areas. The OTTER Act further required emission reports to the Legislature on or before April 1, 2004 through April 1, 2009. The OTTER Act expired on January 1, 2010. Inasmuch as the OTTER Act set forth the specific duties of the State Lands Commission, no regulations were developed nor required pursuant to the Act.

- California Building Code, Chapter 31F - Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS)

The MOTEMS have been in effect since 2006. There will be progressive implementation, and by 2015, 30 fixed onshore marine oil terminals in California will comply. These mostly geriatric marine structures, currently being used to transfer multi-millions of gallons of oil per day, will be technologically and physically upgraded to modern standards. Prior to the MOTEMS these facilities, most over 50 years of age (considered to be the life span of marine structures), had no required, uniform inspection program, no rules for seismically upgrading the terminals, and no determination of fitness for mooring and berthing larger vessels. Vessel sizes have progressively grown since the 1920's, and most of these terminals were designed for substantially smaller vessels, with smaller wind sail areas and impact velocities. Mooring dolphins and berthing substructures are not sufficient for mooring/berthing today's much larger size fleet, coupled with new requirements for tank vessels to be double hulled. The seismic design criteria from the 1920's, even up to the most recent terminal built in the 1980's, needs to be re-evaluated, and soil failures, including liquefaction, lateral spreading, slope stability were not even considered in the original designs. All of these factors contribute to serious deficiencies to continuing operations of California's marine oil terminals.

As a result of the 1994 Northridge earthquake, the Federal Emergency Management Agency (FEMA) made available Hazard Mitigation Grant Program (HMGP) funds to develop standards to reduce the damage to critical infrastructure facilities from the next earthquake. The funding was available to state/local agencies that could show that the efforts would result in enforceable codes. MOTEMS was started with a FEMA grant of $600K that was then increased to $900K, with the additional funding from the Oil Spill Prevention Administration Fund.

As the project matured, additional research and funding went to provide tsunami run-up values for the San Francisco Bay (only Southern California was included in the original MOTEMS version), passing vessel studies to determine additional loads on moored vessels, and more recently simplified methods to determine the seismic demand/capacity of pile supported structures. This final effort will be completed by the end of 2010.

This new MOTEMS code, now part of the California Building Code (CCR Title 24, Part 2, Volume 2, Chapter 31F "Marine Oil Terminals"), requires compliance in the following areas:

- Mandated periodic above and underwater inspections, with records maintained.

- Geotechnical upgrades, to avoid massive liquefaction, lateral spreading and structural collapse.

- Seismic rehabilitation, so that the structures can survive a 475-year return period earthquake, with repairable damage within months, and without a major oil spill. These same criteria have been applied to California's oil refineries; the intent is to have marine terminals be "hardened" to the same level as refineries.

- Mooring and berthing of vessels, using engineering tools to determine actual terminal operating limits.

- Upgrades in piping systems, to withstand seismic displacements that were never considered in the original design.

- A comprehensive fire plan, implemented to greatly reduce the possibility of a major fire/explosion at the terminal. Firefighting tools, manpower and resources must now conform to current standards for oil terminals.

- Mechanical and electrical systems must be verified, upgraded and replaced as necessary.

- Tsunami run-up values for the Ports of Los Angeles, Long Beach, Port Hueneme and the San Francisco Bay – to be used for emergency planning.

The MOTEMS is the first code of this type in the United States and has become a international seismic standard for piers/wharves. It is referenced in a PIANC (Maritime Navigation Commission of the International Navigation Association) text, "Seismic Design Guidelines for Port Structures", 2001, by the Working Group No. 34 and in 2004 NEHRP (FEMA 450, National Earthquake Hazard Reduction Program). MOTEMS is recognized as the seismic analysis/design resource for the U.S. military "Unified Facilities Criteria, Design: Piers and Wharves, 28 July 2005." It has become part of California's SHMP (State Hazard Mitigation Plan) and has been integrated into the California Emergency Management Agency's (CalEMA) 2010 revision to the state's emergency planning. Through this program, one major marine oil terminal has been seismically instrumented in the S.F. Bay. During an earthquake, these instruments can determine if the in-structure response was greater than the design capacity. It can be decided whether this facility and/or others should shut down for inspection above and below the water line, and its continuing fitness-for-purpose determined.

2. Contingency Planning

Although the Act gives the authority for approval of marine facility contingency plans to the Office of Spill Prevention and Response (OSPR), CSLC participates in contingency planning. Marine terminal contingency plans are reviewed by CSLC-MFD for consistency with approved operations manuals. The Act established the Review Subcommittee of the State Interagency Oil Spill Committee (SIOSC). The Subcommittee is made up of the chief executives of the Department of Fish and Game, the State Lands Commission, the California Coastal Commission, the State Fire Marshal, the State Oil and Gas Supervisor, and the State Water Resources Control Board, and for matters in their jurisdiction, the San Francisco Bay Conservation and Development Commission.

All regulations and guidelines adopted pursuant to the Act are submitted to the review subcommittee for review and comment, including amendments to the California oil spill contingency plan.

CSLC staff attends the regularly scheduled meetings of the politically appointed Oil Spill Technical Advisory Committee. This committee is established to provide public input and independent judgment of the actions of the OSPR and SIOSC. Staff also regularly participates in the U.S. Coast Guard Area Contingency Plan meetings.

3. Spill Prevention Programs

As CSLC was given new responsibilities and duties to prevent oil spills into state waters, it created the MFD, consisting of administrative offices in Long Beach and field offices in Hercules and Long Beach. MFD responsibilities include:

- Regularly inspecting and monitoring the operations of all marine terminals;
- Adopting rules and regulations for reviewing the location, performance standards, and other characteristics of all existing and proposed marine terminals;
- Developing rules and regulations for the content of marine terminal Operations Manuals for protection against oil spills; and
- Ensuring the best achievable protection of the public health and safety and the marine environment in the regulation of all marine oil terminals.
- The MFD program works as a system to provide for the best achievable protection of public safety, health, and the environment. Regulations have been adopted for the operations at marine terminals. CSLC requires and approves operations manuals at all marine terminals. A highly experienced Marine Safety staff monitors compliance in the field, observing oil transfers seven days a week. Current Marine Safety staff has an average 31 years of maritime experience. Monitoring is prioritized using an algorithm relating to degree of risk so the highest risk events are attended. Staff monitors all first time tank vessel visits to California. Marine facilities are routinely inspected, and terminals regulated by CSLC must follow up on deficiencies noted during inspections. If violations of other agencies' requirements are observed, those agencies are also notified.
- The entire MFD compliance program relies heavily on information, including an up-to-date, extensive database of activities and compliance issues. MFD has an outreach program with the industry and community, with a purpose of sharing knowledge of better performance, equipment, procedures and personnel qualifications. All the information and knowledge gained by the compliance and outreach programs are fed back into the regulatory cycle. As a result of this cycle, a number of new regulatory programs have been instituted by the CSLC. Marine terminals have been required to increase the range of personnel with certified training, both company (from management down) and contractor personnel. Pipeline testing and maintenance standards have been greatly improved. Engineering inspections of terminal fitness-for-purpose led to the creation of the MOTEMS by the CSLC

and its adoption by the California Building Standards Commission.

There are 10 high seismic risk, 16 moderate risk and 4 low risk fixed onshore California marine terminals. The seismic risk category is based on the volume of oil at risk. To date, both "high" and "moderate" risk terminals have submitted their initial audits, with scheduled completion dates for rehabilitation ranging from now to four to five years into the future. The operator/owner and CSLC must mutually agree upon these dates. Staff will monitor the progress of rehabilitation, to verify that the schedules and repairs are on track. Of the 10 high risk terminals, most will require substantial structural and geotechnical rehabilitation to meet the seismic demand (475-year return period earthquake) of the MOTEMS. The 16 "moderate" risk terminals have similar issues, even though the seismic demand is less than that required for "high risk" terminals. Geotechnical issues involve liquefaction, lateral spreading and slope stability. One other common problem is that the piping systems and seismic displacement of the wharf/trestle are not compatible. This was never considered in the original design, and to avoid a massive oil spill, pipeline stress analyses are now required to verify pipeline integrity during and after an earthquake.

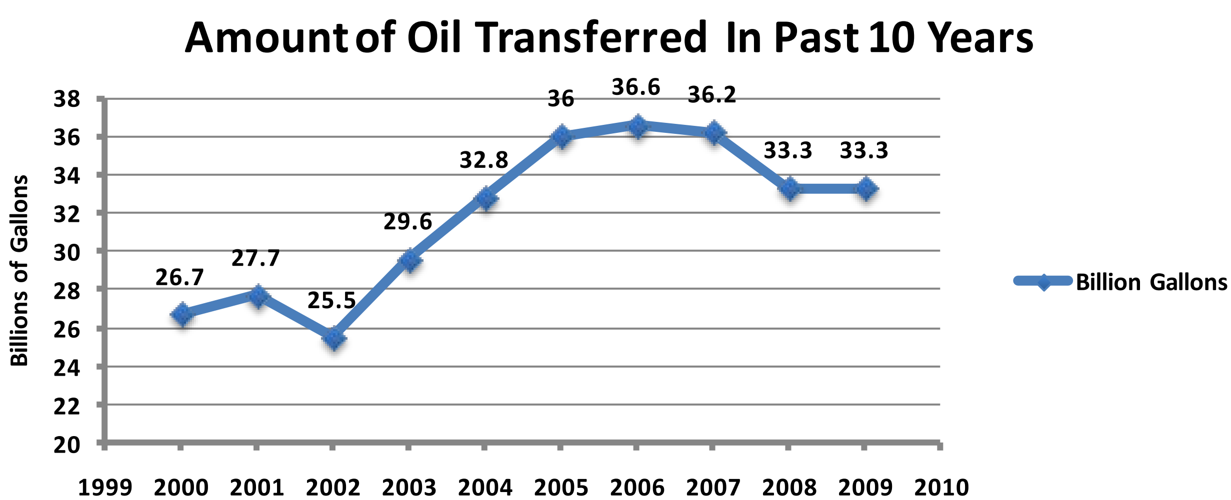
Understanding that, in a marine environment, structures continue to deteriorate over time, the MOTEMS process will continue to monitor the structural and operational health of these terminals, with audits required every three to six years for the remaining life of the structures. With a predicted 50-year expected life span of a marine structure, and the MOTEMS program in-place, geriatric structures will be able to extend their fitness-for-purpose well beyond their original design life.

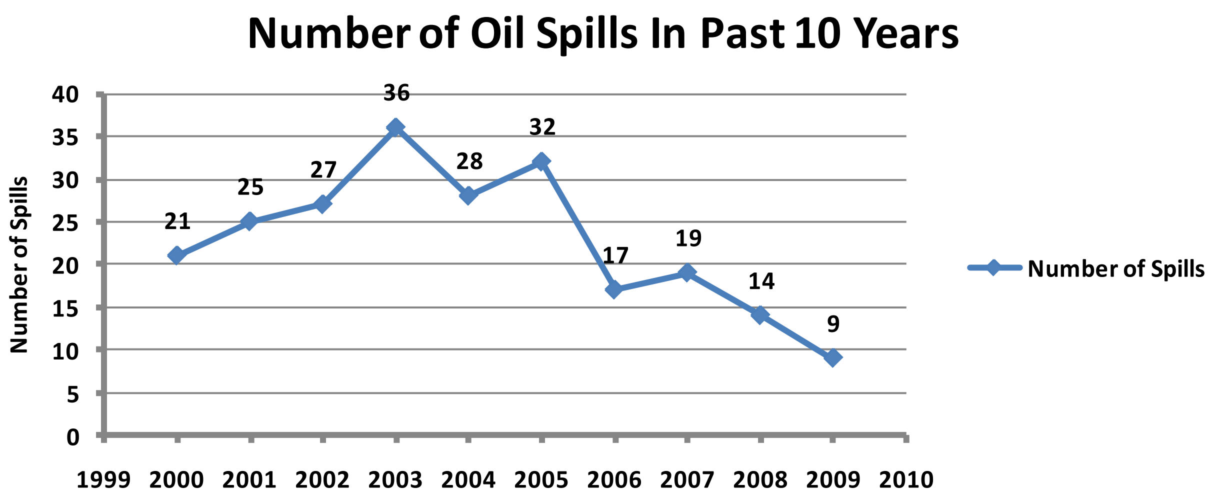
Additionally, any new construction at a terminal will be subject to the MOTEMS code, and in most cases the construction will be subject to the "new" criteria, instead of being treated as "existing".

4. Effectiveness of MFD'S Oil Spill Prevention Program

Every day more than 91 million gallons of oil are transferred at the fifty California marine oil terminals. The marine terminals are either structures fixed to the shore on wharves or piers, moorings located offshore, or mobile (truck/tank vessel) facilities. Transfers are the discharge of cargo by tank vessels-to-shore, or loading of cargo from shore-to-tank vessels. CSLC monitoring and inspection of compliance with regulations has limited both the number and severity of oil spills at marine facilities. The annual number of transfers at California terminals has ranged from 6000 to more than 7000 over the past ten years, and our staff has monitored 45 percent of those transfers. Oil spills have been limited to less than twenty in most years and the quantity of each spill is usually very small, often measured in drops. Since 1995 there have only been two marine terminal spills of more than 1000 gallons. In 2009, in 6596 transfers totaling 33.3 billion gallons of oil through California marine oil terminals, only nine spills resulting in a total of 124 gallons spilled. Many of the spills were caused by the visiting tank vessel or during maintenance. Of the nine spills, seven were related to terminal activities and two were attributable to shipboard activities.

The positive impact of our oil spill prevention program is reflected in the following graphs:




Number of Oil Spills In Past 10 Years
Number of Spills
40
35
30
25
20
15
10
5
0
21
25
27
36
28
32
17
19
14
9
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Number of Spills

C. Pipeline and Terminal Leasing Programs (LMD)

The Land Management Division (LMD) has primary responsibility for the surface management of all sovereign and school lands in California. This responsibility includes the identification, location, and evaluation of the State's interest in these lands and its leasing and management. LMD is therefore responsible for the leasing of marine oil terminals and many of the rights-of-way that accommodate petroleum pipelines or other pipelines and conduits linking offshore oil platforms to onshore facilities. LMD is also responsible for the leasing of rights-of-way for pipelines crossing many bays and rivers throughout the State.

The Land Management Division coordinates with staff of the Mineral Resources Management Division (MRMD), the Marine Facilities Division (MFD), and the Division of Environmental Planning and Management (DEPM) to develop lease provisions applicable to these types of leases. At present, the leases for these uses contain the following provisions addressing the use and maintenance of the lease premises and the steps to be taken in case of an oil spill or discharge:

- For new construction, a Lessee must provide plans for review and approval by CSLC staff prior to construction, construction monitoring reports, and a set of as-built plans showing the final location of the improvements;

- Every Lessee must maintain records of all inspection, repair, testing, and maintenance activities and provide copies of those records to the CSLC staff;

- A Lessee must provide copies of all pipeline test procedures, prior to testing, for CSLC staff’s review and approval;

- Review and approval by CSLC staff is required prior to any repairs or modifications by the Lessee to the pipeline and improvements;

- Every Lessee must provide a copy of the current pipeline operations and maintenance manual and provide updates as they are available;

- A Lessee’s operator must conduct training classes and periodic drills simulating a pipeline leak and the procedures to be followed when a potential leak is detected;

- Every Lessee must provide a copy of the Hazardous Spill Contingency Plan or other such contingency plan that includes: response to various major and minor spill scenarios; list of spill clean-up materials and equipment available onsite; and a spill notification protocol and procedures;

- Notification requirements are specified in case of a spill, including 24-hour emergency phone number;

- Information to be provided to CSLC staff in case of a spill, regardless of the cause or responsible party, must include the following:
    - The name and company of the person reporting;
    - The name and telephone number of a representative of the Lessee that CSLC staff may contact for further information;
    - The estimated time and date of the spill;
    - The source of the spill, if known;
    - The person or persons responsible for the spill, if known;
    - The substance spilled, if known;
    - The estimated quantity spilled;
    - The cause of the spill, if known;
    - The action taken in response to the spill; and
    - Any additional information as may be requested by the CSLC staff following notification of a spill.

- All plans for abandonment and/or removal and restoration of the lease premises are to be to the satisfaction of the CSLC staff and are to be completed within a certain time frame (90 days is often used, but this is negotiable) after expiration of the lease or after the Lessee has obtained all permits or other governmental approvals as required by law.

In addition to leases involving transportation of oil, LMD also leases sovereign land for use as commercial marinas. Many of these commercial marinas have fuel docks for the dispensing of gasoline for boats. The leases for the marinas with fuel docks incorporate many of the same provisions as the leases involving oil, particularly with respect to a spill contingency plan. In addition to these provisions, the commercial marina leases have a provision that the Lessee must implement Best Management Practices (BMPs) for Marina Owners/Operators. These BMPs address a range of subjects including: emergency planning, sewage discharge, underwater boat hull cleaning, solid waste, and storm water runoff. Three of the BMPs apply directly to oil and fuel spills; Marina Owners/Operators are required to do the following:

- **Petroleum Management**

    - Instruct staff not to use detergents or emulsifiers on a fuel or oil spill.
    - Post emergency telephone numbers posted in prominent locations at the marina to report oil or chemical spills.
    - Install and use of fuel/air separators on air vents or tank stems of inboard fuel tanks to reduce the amount of fuel spilled into surface waters during fueling (although this is a recommendation, rather than a requirement).
    - Provide a collection site for used oily pads and used oil or provide information on how and where to dispose of them.

- **Hazardous Wastes**

    - Have a marina policy to manage hazardous wastes and hazardous materials.
    - Post a prohibition on the disposal of used oil, antifreeze, paint, solvents, varnishes and batteries into the dumpster or general collection waste receptacles.
    - If providing for hazardous waste collection, manage the wastes in a proper fashion through the use of structurally sound, non-leaking containers, in accordance with all local, state and federal laws.
    - In the event of a spill or leak, clean up and dispose of materials promptly and properly and report the spill to all appropriate entities.
    - If operating a collection facility is not feasible, provide information to tenants on how and where to dispose their wastes.
    - Encourage the use of alternative products to hazardous household chemicals. There are many non-toxic or less-toxic products that can be used as alternatives.

- **Liquid Waste**

    - Train marina employees in oil spill response procedures.
    - Keep adequate spill response equipment and materials in strategic locations.

In light of the environmental damage and economic impact caused by the BP oil spill in the Gulf of Mexico, LMD has initiated a review of its lease practices and provisions. For example, in the past, the bond (surety) and insurance amounts on a long-term lease may have remained unchanged through the full lease period. Surety requirements in surface leases for petroleum-related facilities in the 1970s and 1980s often ranged from \$10,000 to \$100,000, while insurance was often between \$1,000,000 and \$3,000,000. In recent years, LMD staff has begun reviewing the bond and insurance amounts during the lease term for adequacy whenever the opportunity arises (i.e., applications for lease amendments and assignments). The result has been that many of these leases have been updated to more current amounts, including surety levels of \$1 to \$3 million and insurance of \$5 to \$10 million, or even more depending on the facilities and the potential for liability.

Recommendations:

In addition to reviewing its current insurance and bond requirements for adequacy, the Division is considering the following actions:

- Add a provision to new leases allowing CSLC staff to review and adjust insurance and bond amounts at five-year lease anniversaries;

- Add a provision to new leases allowing CSLC staff to review and approve oil spill contingency plans;

- Incorporate a provision that, whenever possible, old pipelines must be able to be retrofitted, modified, or reconstructed to allow smart pigging; and,

- Review and update all provisions of the lease (particularly those relating to oil spill prevention and response and bond and insurance requirements) when any discretionary approval of the Commission is required, such as with an amendment or assignment of the lease.

Together with the other Divisions of the CSLC, LMD strives to stay abreast of changes in the oil and gas industry. By continuously updating and adapting our lease practices and provisions, both the Division and the Commission are better prepared to respond to an oil or fuel spill and protect valuable public lands.

D. Environmental Planning and Management Program (DEPM)

1. Overview

The Division of Environmental Planning and Management (DEPM) was organized in 1975 to ensure Commission compliance with the provisions of the California Environmental Quality Act (CEQA), and to provide analytical staff services (policy and technical) to the members of the Commission, to its Executive Officer, and to the line programs, including the Mineral Resources Management Division (MRMD), Marine Facilities Division (MFD), and Land Management Division (LMD). With respect to oil spill prevention and system safety, DEPM functions include the following:

- Ensure that potential environmental impacts associated with projects proposed by applicants for leases from the Commission (e.g., oil and gas development projects, marine oil terminals, rights-of-way that accommodate petroleum pipelines on State lands under the Commission's jurisdiction, and marine oil terminal and oil pipeline abandonment projects) are reviewed and analyzed. Specifically DEPM staff manages the preparation of Environmental Impact Reports (EIRs) designed to provide current, accessible and accurate data related to proposed projects that are critical to analyses of the potential environmental quality, public health and safety, environmental justice, and other impacts.
- When significant impacts are identified, evaluate feasible project alternatives, work with applicants to modify their project proposals and formulate mitigation strategies to eliminate or reduce to the maximum extent feasible the intensity of the impacts and focus on the protection of sensitive resources.
- Provide the public with the opportunity to participate effectively in all steps of the environmental review process from notice about a pending project to the identification of potential environmental impacts, project alternatives, and mitigation measures.
- Coordinate with other state, federal, local, and regional agencies and the public in the review of oil development and transportation projects that may affect State lands. These entities include:
    - California Coastal Commission;
    - California Department of Fish and Game including its Office of Spill Prevention and Response;
    - California Natural Resources Agency;
    - San Francisco Bay Conservation and Development Commission;
    - State Water Resources Control Board and Regional Water Quality Control Boards;
    - Bureau of Ocean Energy Management, Regulation, and Enforcement (formerly the Minerals Management Service);
    - National Marine Fisheries Service;

    - U.S. Coast Guard;
    - U.S. Environmental Protection Agency;
    - U.S. Fish and Wildlife Service;
    - City of Goleta;
    - Santa Barbara County Energy Division;
    - Ventura County Planning Division; and
    - Local and regional Air Pollution Control Districts and Air Quality Management Districts
- For projects approved by the Commission, conduct or oversee mitigation monitoring activities to ensure that the mitigation measures and lease conditions adopted by the Commission to mitigate the potential environmental impacts of an approved project are implemented and effective.

2. Evaluation of Projects Involving Oil Development and/or Transportation

DEPM's environmental scientists evaluate complex projects, such as offshore oil and gas development proposals and marine oil terminals, to ensure compliance with CEQA, the National Environmental Policy Act (NEPA) if applicable, and other federal and state laws and regulations. For projects where the Commission is the designated CEQA Lead Agency, DEPM staff manages consultants contracted to prepare EIR's/Environmental Impact Statements (EISs) and other environmental documents for lease applications reviewed by the Commission, review the detailed and complex materials provided for the EIRs/EISs, and oversee compliance with the terms of EIR Mitigation Monitoring and Reporting Programs. While lease negotiations conducted by CSLC staff entail only the lands for which Commission has jurisdiction, DEPM's environmental review is required by law to evaluate the whole of each project (e.g., the full extent of a several-mile-long oil pipeline from shore to an offshore platform located in federal waters).

Typically, DEPM staff determines that any project that may result in an oil spill requires the preparation of an EIR, since the impacts of a spill would potentially be significant and unmitigable. On behalf of the CSLC, specific tasks undertaken by DEPM staff often include the following.

- Review project application materials, determine final acceptance of project descriptions and data requirements, and determine the level/type of environmental documentation needed.
- Represent the CSLC on Joint Review Panels or similar interagency groups created to fulfill the above functions in the preparation of EIR/EISs by the CSLC, as a CEQA Lead Agency. (DEPM staff also participates in review panels associated with CEQA documents prepared by other Lead Agencies, for which the CSLC serves as a Responsible and/or Trustee Agency under CEQA.)
- Prepare a Statement of Interest and select a consultant from the submittals.

- Prepare a Notice of Preparation (NOP) and hold a public scoping meeting.
- Meet with the Applicant and public interest groups.
- Prepare a public Draft EIR, and Final EIR. Develop significance criteria, analyze potential environmental impacts, identify and analyze project alternatives, hold additional public hearings, and prepare responses to comments.
- Determine final acceptance of consultants' materials, as modified by DEPM staff's environmental scientists, for compliance with applicable statutes and regulations. Determine final acceptance of products for public hearings and the Commission.
- Prepare a staff report and agenda item for Commission hearings, with recommended actions such as overriding considerations, findings, etc.

The CSLC is held accountable by the time frames mandated under CEQA and the State Permit Streamlining Act. The outcome is the timely processing of a lease application culminating in the consideration for approval by the Commissioners at a public meeting whereby action will be taken on the applications.

The CSLC is currently the CEQA Lead Agency on six marine oil terminal lease renewals and three proposed oil development projects, and DEPM staff are also participating in the review of three other related projects where the local jurisdictions are the CEQA Lead Agency (see list of projects below).

	Where CSLC is the CEQA Lead Agency	Where CSLC is a Responsible or Trustee Agency
Oil and Gas Development and/or Pipeline Projects	• Carone Petroleum Corporation - Oil and Gas Lease • Venoco Full Field Development • Venoco PRC-421 Recommissioning Project	• Venoco Line 96 Modification Project *[Santa Barbara County]* • Venoco Paredon Project *[city of Carpinteria]* • Venoco Montalvo Wells *[Ventura County]*
Marine Terminal Projects	• Chevron El Segundo Marine Terminal • Chevron Long Wharf Marine Terminal Mitigation Monitoring • Nustar Selby Energy LP (Shore) Marine Oil Terminal Lease • Shell Martinez Marine Terminal • Tesoro Avon & Amorco Wharfs • Venoco Ellwood Marine Terminal Mitigation Monitoring	

After the CSLC considers the application, and if the issuance of a lease or project is approved, DEPM staff and its contractors continue to monitor the construction and implementation of each approved project to ensure that all mitigation measures are being met by the Applicant.

3. Examples of Oil Spill-Related Analyses and Mitigation Measures

EIRs prepared by DEPM include an analysis of Operational Safety/Risk of Accidents for the project if applicable. For example, in the August 2010 public Draft EIR for the proposed renewal of Chevron's El Segundo Marine Oil Terminal lease, the Project EIR "describes and assesses the system safety, reliability, and hazardous materials associated with both current and proposed operations at the [Marine Terminal]. System safety and reliability includes issues such as fires, explosions, and oil and product spills from the Marine Terminal (both the onshore portion and the offshore pipelines and berths) and from vessels that visit the Marine Terminal."

DEPM EIRs prepared for marine terminal lease renewals also:

- Describe those aspects of the existing environment that may impact operational safety (e.g., geology, seismicity, soil, wind, wave, and potential sea-level rise conditions that directly or could potentially affect the structural integrity of the terminal or the vessels that would use the terminal over the lease period), or that may be affected by an accident associated with the operation of the project, including transportation of crude oil and petroleum products to and from the terminal.
- Summarize the existing vessel traffic levels and patterns and other marine terminals within the project area.
- Summarize the historical casualties involving tank vessels and marine terminals within the area.
- Describe measures in place to allow the safe movement of marine vessels within the project area and to respond to emergency situations.
- Apply modeling and present modeling results to estimate the potential effects and extents (areas that could be impacted) of hypothetical oil spill scenarios.
- Summarize the laws and regulations that may affect the safety and potential risk from the facility and its operation.
- Analyze the potential for impacts associated with the project and the project alternatives, evaluate cumulative impacts from the proposed project and other projects in the regions, and present appropriate mitigation.

Approved mitigation can include both structural improvements and measures to improve response planning and reduce event frequency and size. For example, in the Chevron Long Wharf Marine Terminal lease renewal, which was approved by the Commission in March 2007, the project EIR analyzed (among other potential impacts) the potential for spills, and the response capability for containment of oil spills, from the terminal during transfer operations. Mitigation measures approved by the Commission for this potentially significant impact included the following:

> **OS-3b***. Install tension-monitoring devices at Berth 1 to monitor mooring lines and avoid excessive tension or slack conditions that could result in spills. An alarm system (visual and sound) that incorporates communication to the control-building operator shall also be a part of the system. In addition, if any vessel drifts (surge or sway) more than 7 feet from its normal manifold or loading arm position at any other terminal berth, Chevron shall install, within 6 months after the incident, tension-monitoring devices at such berth.*
>
> **OS-3c***. Install Allision Avoidance System (AAS) at the terminal to prevent damage to the pier and/or vessel during docking operations. Prior to implementing this measure, Chevron shall consult with the San Francisco Bar Pilots, the U.S Coast Guard, and the staff of the CSLC and provide information that would allow the CSLC to determine, on the basis of such consultations and information regarding the nature, extent and adequacy of the existing berthing system, the most appropriate application and timing of an AAS at the Chevron Long Wharf.*
>
> **OS-4.** Chevron shall confer with the California State Lands Commission (CSLC) regarding Group V oil spill response technology including potential new response equipment and techniques that may be applicable for use at the Long Wharf. Chevron shall work with the CSLC in applying these new technologies, as agreed upon, if recommended for this facility**.**
>
> **OS-6b.** Chevron shall develop a set of procedures and conduct training and drills for dealing with tank vessel fires and explosions for tankers berthed at the Long Wharf. The procedures should include the steps to follow in the event of a tank vessel fire and describe how Chevron and the vessel will coordinate activities. The procedures shall also identify other capabilities that can be procured if necessary in the event of a major incident. The procedures shall be submitted to the U.S. Coast Guard and California State Lands Commission within 90 days of lease renewal.
>
> **OS-7b.** Chevron shall respond to any spill from a vessel traveling to or from the wharf, moored at its wharf, related in any way to the wharf, or carrying cargo owned by Chevron, as if it were its own, without assuming liability, until such time as the vessel's response organization can take over management of the response actions in a coordinated manner.

In many cases, the MOTEMS implemented by the MFD have established requirements for preventative maintenance that include periodic inspection of all components related to transfer operations. Chevron is required to comply with those requirements. For potential impacts not addressed by the MOTEMS, the above measures help to reduce the potential for spills and their associated impacts. However, even after implementation of all mitigation measures, the EIR concluded that the impacts associated with the consequences of larger spills, greater than 50 barrels would remain significant.

Other EIRs with oil spill prevention and response components that were recently approved by the Commission or that are currently being prepared or reviewed by DEPM staff include the following.

- On June 1, 2009, the Commission approved the renewal of an existing lease for Venoco's Ellwood Marine Terminal, which is located in Santa Barbara County. At the time of the lease renewal, the barging operation transported produced oil in a single-hulled barge. As an example of reducing the risk of an oil spill, a mitigation measure was incorporated in the EIR and approved by the Commission that requires Venoco to replace the single-hulled barge with a double-hulled barge within 18 months of lease renewal to lessen the risk of an oil spill from potential hull penetration. A double-hulled barge (*Olympic Spirit*) is currently being approved for use at the marine terminal.

- The Venoco Line 96 Modification Project, which is a new, proposed onshore oil pipeline in Santa Barbara County, if approved and operational, would eliminate the barging operations at the Venoco Ellwood Marine Terminal. Replacing the Venoco Ellwood Marine Terminal with an onshore oil pipeline would greatly reduce any oil spill impacts to the marine environment since barging the oil will be eliminated. CSLC staff is working with Santa Barbara County to help this project get approved and constructed and work with the County during the decommissioning phase of the marine terminal.

Together with the other CSLC Divisions and in coordination with other agency partners, DEPM strives to (1) include in its CEQA documents all applicable, feasible measures to prevent oil spills from occurring or to mitigate potential oil spill impacts to the maximum extent feasible and (2) ensure that all applicant-proposed measures and CEQA-required Mitigation Measures are implemented for any and all approved projects. EIRs prepared by DEPM staff in the future will also continue to provide modeled results of worst-case oil spills and will briefly address the use of dispersants, dispersant use protocols, and potential impacts in the marine environment.

IV Challenges

As can be seen from the varied and great array of work done by staff, the complexity of facilities and advances in technology, and the unique expertise required for the agency, the ability to hire, train, and keep knowledgeable and experienced staff is paramount to the staff's effectiveness. Loss of staff through attrition (to higher paying industry positions) and rapidly increasing retirements has left a stratified workforce and increasing vacancy and loss of institutional knowledge. Recent budget crises and news accounts regarding the state work force (furloughs, lay-offs, and pay reductions) has not helped the situation either. The ability to successfully address the challenges described below, regarding staffing, hiring, retention, and training, will determine whether the Commission's oil spill prevention programs can maintain the high standards reflected in this report.

A. Staffing

1. MRMD Inspection Program Structure and Staffing

The structure and staffing needs of the MRMD's Inspection Program require upgrading to address the changes in complexity and technological make up of the operating systems on offshore platforms in State waters.

The upgrades required are largely in the organizational structure of the program. A new hierarchy of skills and responsibilities will need to be created that can provide a full range of platform oversight functions and capabilities that will allow the MRMD to more effectively analyze inspection data, evaluate system performance and reliability, perform equipment and system function trends, and better assess and help predict failure occurrences.

Specifically, the Inspection organizational structure needs to add skilled staff to perform these analyses. Specialist skilled in equipment design, function, and data analysis are needed to fill the gap that presently exists in the organization between inspector and supervisor.

Adding a Specialist position to the program will require reclassifying the Inspector series. Efforts in this area have been attempted in the past, with no success because of recurring State budget crises.

The MRMD has long recognized the importance and need to upgrade the Inspector program since its early formation as a surveillance and recording function. Data and information taken from the inspection process, however, could not be fully evaluated into the most meaningful form, so the benefits of the inspection were only partially realized.

With a restructuring and reclassification of the Inspection position series, upgrades in salary will also be required. Recruiting individuals with the skills capable of assessing and evaluating the myriad of complex data requires competing with private industry. The private sector is the only source of qualified individuals for this type of work. They are highly paid, and in great demand. At our present Inspector series salary levels, we are unable to attract these people. Even hiring qualified Inspectors to fill vacancies in those ranks is very difficult because of the great discrepancy in salaries for those skills. A salary survey conducted a few years ago demonstrated that salaries lagged those in equivalent positions in other government agencies and private industry by as much as 30%. As our Inspector ranks become depleted through attrition or movement to the private sector, the ability to replace them will become extremely difficult, to the point that the program capabilities and objectives will be threatened.

This situation is a very high priority need for the MRMD, and one that will be effectively resolved with the full support of agency and Commission management.

2. MFD Staffing

Additional staffing is needed to accommodate an increased scope of oversight for marine terminal operations and engineering. These include:

a. Two Engineering Inspector positions to monitor and enforce compliance of all State marine terminals with the Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS). In addition to monitoring MOTEMS-driven construction projects, staff must continue to track and assess MOTEMS audits, to be conducted every three to six years. Post-event inspections must be conducted after significant, potentially damage-causing events such as earthquakes, storms, vessel impact, etc.

b. Three Specialists to establish and carry out Safety Systems Audits at marine terminals. The operations at these marine terminals are physically complex, and include a significant number of human interactions. Staff should review closely how marine terminal owners and managers are performing in identifying systemic risks based on properly conducted risk assessments. This will provide a basis for determining the adequacy of the risk control measures employed at State marine terminals

B. Hiring & Retention

Salary compaction and pay parity deficiencies have led to severe difficulties in hiring and retaining qualified individuals to fill vacancies in all the varied and multi-disciplinary sections of the Commission. Fewer and fewer of the applicants are found to meet the minimum qualifications for the positions. Even when found, successful applicants have declined job offers due to insufficient salary and we have lost employees accepting industry jobs offering higher salaries.

The challenges experienced in the Inspector series discussed above have also been experienced in the engineering ranks. Salary compaction disparities have resulted in engineering supervisors receiving less salary than the engineers they supervise. The examination process produces few qualified applicants from outside the agency, and few successful applicants accept job offers, due to better pay opportunities elsewhere. As in the inspector ranks, several employees have left the Division to accept jobs offering better pay in private industry.

Hiring and retention challenges have been aggravated in the last few years by a wave of retirements. Replacement of these positions has come largely from within. Besides the loss of talent, expertise, and institutional knowledge of division history and involvement in operator projects, replacement of these positions by promotion from within has reduced the depth of our resources. Additionally, stratification of Commission personnel and experience, and more near term retirements of management, will inevitably reduce the institutional knowledge and training. While the Division actively pursues qualified candidates to fill technical position vacancies to maintain the skill levels and expertise required by those positions, and to allow for senior staff to pass on institutional knowledge, this situation seriously jeopardizes the ability of the Commission to maintain an active and critical role in all of the programs discussed in this overview.

C. Training

Successful conduct of the above programs requires expertise in a variety of specialty disciplines, as well as experience and training in oilfield drilling, production, offshore construction, and facility inspection procedures. Maintaining currency with new developments in these specialty disciplines requires continuing education, which is provided through industry training courses and professional society conferences and workshops, many of which are outside the State. Training budget limitations and limitations on the number of out-of-state trips present severe obstacles to providing staff adequate opportunity to receive the information necessary to stay abreast of current technology and developments. In addition, retirements and consequent replacements increase the amount of training required for new staff to perform their duties.

D. Funding (OSPR)

The Oil Spill Prevention and Response Act (Act) provided for the collection of a fee sufficient to carry out the purposes of the Act. The fee is imposed on owners of petroleum received at marine terminals from outside the state. Additionally, an operator of a pipeline pays the fee for each barrel of crude oil originating from a production facility in marine waters and transported via pipeline operating across, under, or through the state marine waters. These fees constitute the Oil Spill Prevention and Administration Fund (OSPAF). Currently the Board of Equalization is collecting $0.05 per barrel. The fund is administered by the Administrator of the Office of Spill Prevention and Response (OSPR).

In FY 2010/2011, CSLC is budgeted for more than $11 million of the more than $39 million available for appropriation. The OSPAF makes up 39% of the CSLC budget. Each year the legislature appropriates funds for agencies to carry out the mandates of the Act. Although the OSPAF has carried over a positive balance in past years, recent OSPR projections show a deficit of over $3 million at the end of FY 2011/2012 if additional funding is not identified. Action, such as raising the per barrel fee, will be necessary to avoid a deficit. Failure to act will likely result in reductions to both CSLC and DFG's programs.

V Recommendations

1. Bonding. Add a provision to new leases allowing CSLC staff to review and adjust insurance and bond amounts every five to ten years. Consider legislation to mandate adequate bonding provisions for oil and gas marine facilities in order to cover all the terms of the lease, including final abandonment. This is required because an inadequate abandonment, or non-abandonment, by insolvent companies would not ensure that a lease be left in a safe and pollution free condition.

2. Enforcement (Cease & Desist Authority). Renew the effort from 2000 for legislation to give the Commission cease and desist authority over operations in state waters (add to Oil Spill Act?)

3. Training in Well Control. Redefine the requirement that our lessees provide, or ensure that, every drilling crew, operator personnel, and contractors have adequate training in well control and be "certified" by participation in a minimum 3-day course on well control every 4 years, and require a one-day refresher course every year (that includes review of well control equipment, its use in well control situations, and a kick control simulation (using a computer or test well).

4. Mitigating Loss of Technical Expertise and Institutional Knowledge. Meet the challenges required to maintain the knowledge and experience by hiring technical persons having drilling and geological expertise, and expedite cross-training efforts of existing staff in all disciplines with direction and mentoring by senior staff within 3-5 years of leaving state service.

5. Update MRMD Drilling & Production Regulations. Update current regulations, and re-adopt all other Commission regulations pursuant to PRC §8755, for oil and gas drilling and production on state lands. As detailed within this report, staff is currently completing an update of the Commission's oil and gas drilling and production regulations, including a new Article specifically addressing our facility safety audit program, and plans to move those through the Office of Administrative Law (OAL) process in the near future.

6. Resubmit Reclassification of the Mineral Resources Inspector Series to include the Inspector Specialist position and adjust the pay scale by January 1, 2011, to create a modern fully functional inspection program structure.

7. Increase Marine Facilities Division staff to accommodate an increased scope of oversight for marine terminal operations and engineering by requesting additional staff through the budget process.

8. Support legislation to increase the Oil Spill Prevention and Administration Fund per barrel fee to provide additional funding for the State's oil spill prevention programs.

EXHIBIT B

LIEUTENANT GOVERNOR ABEL MALDONADO

MEMO: APPLYING LESSONS LEARNED FROM THE DEEPWATER HORIZON OIL SPILL

RECOMMENDATIONS ON BETTER PROTECTING CALIFORNIA'S COASTLINES AND OCEAN WATERS

STATE CAPITOL, ROOM 1114, SACRAMENTO, CALIFORNIA 95814 • PHONE(916) 445-8994

To: Chair John Chiang, California State Lands Commission
Commissioner Ana Matosantos, California State Lands Commission

From: Commissioner Abel Maldonado, California State Lands Commission

CC: Executive Director Paul Thayer, California State Lands Commission
Governor Arnold Schwarzenegger

As Commissioners on the California State Lands Commission, we have been charged with the stewardship and oversight of offshore oil production leases in California state waters. This is a weighty responsibility. California's coastline and environmental assets not only are homes to a wide array of unique ecosystems that play a large role in our state's way of life, they are also the anchors to some of our biggest economies – tourism, fishing, seafood. In its tourism industry alone, California is on the receiving end of $90 billion per year. California cannot become lax in its oil spill prevention regulations, and we must remain diligent on promoting responsible oil production. While governmental regulation should not be cumbersome, it does need to be stringent, effective, and make protecting the environment and the economy the top priority.

As our nation weathers a difficult recession, the Gulf of Mexico's Deepwater Horizon oil spill has compounded and exacerbated an already battered Gulf economy. Their coastal lands are threatened by millions of gallons of oil swirling in their waters, and currently endangering their fishing and seafood industries. Their tourism industry may be facing up to an 18 percent decline that could be directly attributed to the spill. This will have a devastating impact on the state's economy, where tourists and seafood wholesalers spend $1.5 billion per year. Mississippi and Alabama similarly, also see tourism and seafood industry expenditures of $5 billion annually. What's critical to note is that the Deepwater Horizon oil spill's environmental and economic impact will expand beyond the Gulf states and leave a lasting ripple-effect on the entire nation. Every state has a stake in their long and short-term environmental and economic recovery.

On July 26, 2010, I led the official California Delegation to the Gulf and brought economic and environmental resources to Louisiana to assist in its recovery from the catastrophic Deepwater Horizon oil spill. While there, I had a productive meeting with Louisiana state officials from the Office of State Lands and their Natural Resources Department to discuss best practices, lessons learned, and to strategize on better protecting California's coastline. It has now been widely reported that poor regulatory oversight contributed to the blowout explosion on the Deepwater Horizon oil rig. California already has a strong and unique oil spill prevention and response system, but with the risks of offshore oil drilling still frighteningly apparent, learning from another coastal state recovering from an unprecedented disaster is an important step to ensuring California does not face its own epic oil spill catastrophe.

RECOMMENDATIONS

California's wells are different than the wells located in the Gulf of Mexico, with shallower waters and less pressurized drilling. However, blowout prevention practices and stringent oil spill contingency plans are paramount to preventing and responding effectively to catastrophic oil spills. Therefore I propose the following actions:

- **Revise Worst Case Discharge Scenario With Planning Standard of 30 Days**
  In June, 2010, the Federal Minerals Management Services issued a National Notice to Lessees and Operators of Federal Oil and Gas Leases of the Outer Continental Shelf that made a series of spill prevention and response recommendations and mandates. Specifically, the Notice mandated that lessees recalibrate and update Lessees' blowout scenarios and worst case discharge scenario descriptions in their document they must file with the federal government. I recommend that the State of California aligns with the Federal governments standards by mandating that Lessees' update their oil spill contingency plans with a revised planning standard. Currently the planning standard in California is for a worst case discharge scenario in a 7 day uncontrolled release. To ensure the response plan is as effective and stringent as needed to protect California's coastlines, I propose the Commission recommend to the Administrator of the Office of Spill Prevention and Response to revise the planning standard to accommodate a thirty day uncontrolled release.

- **Examine Instituting Third-Party Inspections For Blowout Prevention Equipment**
  In light of reports of infrequent and lack of comprehensive inspection of blowout apparatus in the Gulf of Mexico, I also recommend the Commission examine the efficacy of instituting third-party inspections, verification of designs and certification of operation for blowout prevention equipment on lessee platforms. Who would conduct the certification and inspections and how often they would need to occur can be recommended by Commission staff and presented at the next State Lands Commission meeting for Commissioner review.

Conclusion

California does indeed possess a strong and unique oil spill response and recovery system that is fully developed and functional. In times of catastrophe, however, it is our responsibility to ensure that every lesson that emerges be examined and applied as necessary. There is much to be learned from the Deepwater Horizon oil spill and Californians deserve our every effort to safeguard our natural resources. Given the stewardship entrusted to us, I encourage my fellow Commissioners to consider my recommendations and work with the Commission staff to implement these oil spill prevention policies that better protect our coastline and ocean waters.

Thank you for your consideration.

Commissioner Abel Maldonado

EXHIBIT C
(Updated 10/21/2010)

A REVIEW OF FEDERAL LEGISLATION REQUIRING THIRD-PARTY CERTIFICATION

Introduction

The State Lands Commission Staff (staff or SLC staff) is responding to the Lt. Governor's request to review the recommendations which are incorporated into two bills presently being considered in Congress (HR3534 and HR5626), regarding "third-party" certification for blowout prevention equipment (BOP or BOPE) and well design (with respect to casing and cementing). Staff has reviewed the latest version of those bills, and the Notice to Lessees (NTL's) sent by the Minerals Management Service (now the Bureau of Ocean Energy Management, Regulation and Enforcement or BOEMRE), and specifically NTL No. 2010-N05 (June 8, 2010, entitled "Increased Safety Measures for Energy Development on the OCS"), and evaluated to what extent the provisions in these bills would enhance the offshore drilling safety requirements already provided in state regulations, policies and procedures. Staff has also made inquires of other coastal states regarding whether they are considering adoption of the third-party certification or other changes to their regulations as a result of the Deepwater blowout.

The bills and the NTL's reviewed are very similar, and require that the Lessee and/or Operator of an offshore drilling operation "obtain written and signed certification from a BOEMRE approved independent third party" for the BOPE and well design ("for safe cementing and casing"). However, the detail of the third-party review is left somewhat vague, and one must assume that is to give BOEMRE the necessary latitude to develop standards appropriate for the varied drilling conditions encountered in the various drilling regions affected, and the differences between surface and subsea blowout prevention systems.

HR 3534 requires the Secretary of the Interior to establish appropriate standards for the approval of independent third-party certifiers for BOPE, well design, and cementing. HR 5626 also requires the "appropriate Federal official" to issue regulations that require the operator to obtain a written and signed certification from an approved independent third party that has conducted a detailed physical inspection, design review, system integration test, and function and pressure testing of the BOP. HR5626 also requires a third-party certification of the well and cementing design. It appears that the requirements discussed in both bills are intended to apply to state waters as well, and HR3534 adds that a State may submit a plan demonstrating requirements comparable to, or alternate requirements providing an equal or greater level of safety. Additionally, although not part of the requested review, staff also discusses the third-party certification review required for "requalification" of offshore structures (platforms in particular) currently required by current OCS federal regulations, and required by MRMD staff as part of all recent applications for projects from existing platforms, both state and federal (Platforms Holly, and jointly with the BOEMRE, Platform Hogan).

General Considerations for the Use of Independent Third-Party Certification

1. Risk/Benefits. Drilling in California waters poses less probability and consequence of well blowouts than in other states. Formation pressures are fairly normal, reservoir productivity is generally lower, and water depth is shallower. Drilling operations are less problematic because they are primarily development wells in fields where conditions are known factors, rather than exploratory wells. Drilling operations are almost exclusively conducted from fixed platforms rather than floating facilities, and therefore BOPE stacks are located on the surface (production deck of the platforms), rather than on the seafloor. This accessibility facilitates inspection, maintenance, and repair of the BOPE and control systems.

2. Staffing. The greatest benefit from third-party certification would be expected where inspection and enforcement staffing levels are low compared to drilling activity levels. The scale of California operations, especially drilling operations, is virtually incomparable to the Texas-Louisiana Gulf Coast with its hundreds of platforms and drilling vessels and thousands of wells. Additionally, because of the joint jurisdiction of the SLC and the Division of Oil Gas and Geothermal Resources (DOGGR) on offshore drilling, the percentage of operations/installations inspected is much higher than in the Gulf. That being said, however, the uncertainties of agency resources created by State budget difficulties, and future hiring and retention of employees with the required experience, may increase the usefulness of third-party certification in the future.

3. Complexity of design/installation. The basic benefit of third-party certification derives from the independent analysis of engineering design and observation of the implementation of that design. In simple terms, the more eyes looking at something, from different angles, the more likely a design or installation deficiency is to be detected while there is still time to do something about it. The most common use of the third-party verification process is in the design and construction of large civil engineering projects. Such projects are characterized by massive scale, high degree of complexity, use of cutting-edge technology, frequent use of new or unique designs, materials, and installation procedures, and **high consequence of failure**. For such projects, third-party verification has long been recognized as central to quality control. The Certified Verification Agent (CVA) program that MMS developed for the design and installation of offshore platforms (discussed later) is an excellent example of an application where third-party certification produces substantial benefit.

Drilling offshore California involves only one of the above characteristics. The consequence of a blowout is unacceptable (high consequence of failure). This one inescapable factor, however, is of sufficient magnitude to require a detailed and sober review of the proposed uses of independent third-party certifications, even in our lower risk drilling environment.

4. Other Coastal States. SLC staff contacted other states to discuss their actions subsequent to the BP incident and Notice to Lessees issued by the Minerals Management Service. An Alabama Oil and Gas Board staff member informed our staff that the region they manage contains deep, sour gas reservoirs but not oil zones. The Texas Railroad Commission staff engineer stated that they were in the process of updating their reporting forms to operators in order to gather more information on the oil and gas operations in bays and inland waterways. Neither agency indicated or knew of any plan to adopt the third-party review process at this time.

Third-Party BOPE Certification
Discussion and Recommendations

1. The Proposed Federal Legislation. The independent third-party certification for BOPE in the legislation requires a detailed physical inspection, design review, system integration test, and function and pressure testing of the BOPE to determine that:

- [the] BOPE is designed for (the) specific drilling conditions, equipment, and location where it will be deployed, and for the specific well design;
- (the) BOPE will operate effectively and as designed when deployed;
- each blind shear ram or casing shear ram will function effectively and is capable of shearing the casing or drill pipe;
- emergency control systems will function under the conditions in which they will be deployed; and,
- (the) BOPE has not been compromised or damaged from any previous service."

The equipment must be recertified every 180 days after "commencement of drilling," and the emergency control systems of BOP's must be tested at least every 14 days.

2. Current State Review & Inspection. Both the SLC and DOGGR have specific and comprehensive BOP equipment regulations. All well programs are reviewed by both agencies to ensure compliance with those regulations. The DOGGR has the primary responsibility to inspect the BOPE on drilling projects anywhere in the State, including offshore drilling on state leases. Their inspections ensure that the BOP equipment required is present and in working order, and require both function and pressure testing upon the initial installation (generally after the surface casing is set and anytime the equipment is changed on subsequent casing settings). Staff may, and usually does, send an engineer out to witness the inspection on state offshore operations. We recommend that the DOGGR be included in any further discussions of their inspections and/or comments on third-party certification discussions.

As discussed in part above, where you have limited resources in a very active area, such as in the Gulf of Mexico, third-party certification appears to be a valuable benefit for the regulators. In California waters, where activity is more limited and state oversight is available, such certification is less beneficial, but, as described below, still presents some benefits to state operations.

3. Current BOEMRE Implementation. In discussions by staff with the Pacific BOEMRE, they have already commenced requiring their federal lessees to use an independent third-party professional engineer, of the lessee's choosing, to certify all current BOP equipment in use in the Pacific Outer Continental Shelf (OCS), per their NTL 210-N05 (and in anticipation of the legislation). They are also requiring all casing design and cementing programs submitted to have been reviewed and approved by an independent third-party professional engineer (also of the lessee's choosing). If and when any legislation is passed to require the third-party certification, the regulations will be amended to clarify the process, and, we assume, to develop guidelines for the required qualifications of those certifying agents. We would recommend that SLC staff engineers be involved in those discussions, or if that is not practicable, to review the approved candidates for approval on state offshore operations.

4. Benefit. Although it has been noted that state oversight on the function and pressure testing of the BOP equipment on drilling wells is a primary function of DOGGR, and a secondary function of Commission staff, there are additional benefits that a more detailed inspection and certification can provide beyond those already in place. Staff has considered the legislation as stated and discussed above, but has also considered the depth of the certification that should be required, since the specifics of the "details" of the review are silent. If only determining that the equipment is sufficient and in place, functioning and able to hold pressure, little benefit is achieved over current inspection. However, if the certification goes further, to inspect the internal mechanism and materials and to determine the condition and serviceability of the equipment, as well as the optimum layout of the auxiliary equipment and design of the system as a whole, then there is a significant benefit, not only to the public and personnel safety for blowout prevention, but to the operator's drilling contractor who may not have considered the design for the specific platform space and operation. Further, a third party may also provide experience that state and federal regulators don't acquire locally because of the limited exposure to drilling operations.

While requiring recertification every 180 days may seem excessive, it would, at least initially, serve as an impetus for a higher level of maintenance on the BOP equipment (in order to assure passing the inspection and reducing the down-time and cost to the operator).

5. Recommendations.

- Staff's research concludes that some benefits may be derived from third-party certification of the BOPE, and so recommends support to apply that measure to State requirements for drilling offshore wells. Staff would like to be in a position to participate in the discussions regarding the detail of the certification, and the requirements and approval process for the third-party consultants. Regardless, staff recommends that third-party certification of the BOP equipment be added to the current process for updating our state offshore drilling regulations, and provide the detail staff, in consultation with the DOGGR, believes required to be a benefit.

- Require re-certification every 180 days.

- State regulations (both Commission and DOGGR) require that BOP equipment be function tested daily and pressure tested on a weekly basis (as opposed to every 14 days in the legislation), and, in addition, that the “emergency shut-in system” (a remote shut-in in the event of communication failure between the rig and BOPs) for subsea BOP equipment (extremely rare – last seen in the mid-1980’s) be tested at least every 14 days. Subsea preventers must also be “stump-tested” on the drilling vessel prior to installation on the well head (on the sea floor). Therefore, the pending legislative requirement is already in place on California state operations.

- Although not discussed, we also recommend that all offshore wells employ a blind-shear pipe ram in place of the blind ram used now. This would provide one more tool in a well control situation and not add any additional height to the BOP “stack” (since physical safety and space limitations may require significant diversion from the specific stack requirements of the pending federal legislation). Staff believes that the space restrictions on current drilling platforms will necessitate some tailoring of the final regulations for the local drilling conditions (and as alluded to in the first bullet of the proposed legislation discussed above).

Third-Party Well Design Certification
Discussion and Recommendations

1. The Proposed Federal Legislation (both HR3534 and HR5626). The operator must obtain a written and signed certification from an independent third party approved and assigned by the appropriate Federal official that any proposed drilling well design meets the requirements for safe cementing and casing.

2. Current State Review & Inspection. The SLC has specific and comprehensive regulations regarding casing design (for exploratory wells) and cementing operations. All well programs are reviewed by both SLC and DOGGR to ensure compliance with those regulations. Both agencies require the operator to submit a fully detailed drilling program for staff review. SLC staff engineers provide a comprehensive review of all drilling and work-over programs, DOGGR permits, and other collateral materials relevant to the drilling, completion, and production of every project, and prior to the drilling of each well, on state leases. The staff review includes the casing design, cementing program, drilling fluids program, blowout prevention equipment and spill prevention plan, and all other relevant material and information before approving the well.

The casing design and setting depths are reviewed by staff. Staff uses pressure gradient and reservoir pressure data to calculate maximum allowable casing setting depths with applicable engineering safety factors. The collapse strength, burst rating and tensile stress factors are all considered when approving the type, weight, grade and coupling thread type of the casing to be run. Upon completion of cementing the casing, a casing bond log, or similar electronic log, is required by SLC regulation to ensure adequate and complete cementing of the casing and hole have occurred. Wells to be "redrilled" must also pass a pressure test of existing (original) casing, and a casing inspection log is required to ensure the integrity of the casing before the redrill commences.

Finally, staff reviews the cementing procedure for each casing string included in the drilling program. All procedures are reviewed to ensure adequate fill volumes are being used behind the casing strings to cover oil and gas zones and fresh water zones. Compositions of the cement mixtures (and additives) are also reviewed for adequate compressive strengths.

3. Current BOEMRE Implementation. As stated above, it is our understanding, after discussions with the Pacific BOEMRE, that they have already commenced requiring all casing design and cementing programs submitted to have been reviewed and approved by an independent third-party professional engineer of the lessee's choosing. Re-stating again, if and when any legislation is passed to require the third-party certification, the regulations will be amended to clarify the process, and, we assume, to develop guidelines for the required qualifications of those certifying agents.

4. Benefit. While staff provides the same comprehensive review, a third party will provide another "set of eyes," particularly for exploratory wells, where more unknowns come into play. The engineering firms should have the latest well drilling software and, we assume, would have the latest resources and information regarding drilling and specific problems to which we may not always have access.

5. Recommendations.

- Staff recommends support for this requirement in the pending legislation.

- Staff believes that, although a comprehensive, thorough and independent review is provided by the State, and safety benefits may be marginal in the developed fields of California state waters, the added review could nonetheless be meaningful, especially on exploratory wells.

- The added review would be done prior to submission of the drilling program to staff (and the DOGGR), and would not slow down or add to the review process already conducted.

Third-Party Structural Certification
Discussion and Recommendations

1. Current BOEMRE Regulation. Under the Federal CFR30, 250.900, operators wishing to construct new platforms, or which contemplate major modifications of, or repairs to, existing platforms, must follow and apply the Federal Platform Verification Program (PVP), which requires a third-party verification of the analysis and design by a "Certified Verification Agent" (CVA). Although this is already a current federal regulation, and not part of the pending federal legislation, staff felt it was important to add this discussion to demonstrate that we have a need to adopt some of the latest federal requirements,

2. Current State Requirements. For any modification that increases loading on a platform by 10 percent or more, SLC requires the platform requalify per API guidelines. In addition, for platform requalification, staff applies the Federal Platform Verification Program (PVP) which requires a third-party verification of the analysis and design by a Certified Verification Agent (CVA).

There is currently no other state regulation requiring platform requalification. However, SLC staff has required all platforms that propose new projects involving drilling into state leases to requalify under the federal guidelines to the latest storm and seismic standards. We have coordinated efforts with the MMS (now BOEMRE) to requalify federal platforms that have applied to drill into state leases. Additionally, SLC staff requires all the operators to follow current API RP 2A Standards, Building Code Standards, American Institute of Steel Construction (AISC) standards, American Concrete Institute (ACI) standards, American Welding Society (AWS) Standards, etc. for all the platform structural modifications and repairs. Also, we require that all engineering design documents to be certified by a California Registered Civil/Structural Engineer.

3. Recommendation. Staff recommends that the federal standards for requalification of offshore structures, specifically the Platform Verification Program and use of a Certified Verification Agent, be added to the current process updating our state offshore drilling regulations.