

# Safety and Oil Spill Prevention Audit

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DCOR, LLC  
Platform Eva



California State Lands Commission

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December 2016

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# Safety and Oil Spill Prevention Audit

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DCOR, LLC  
Platform Eva  
Huntington Beach

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# Executive Summary

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DCOR, LLC  
Platform Eva  
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# Executive Summary

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## *Safety Audit of Platform Eva*

The Safety and Oil Spill Prevention Audit of DCOR, LLC's Platform Eva, Huntington Beach (HB) started in July 2014. All fieldwork was finished in November 2014 with the completion of the Electrical portion of the audit in 2015. Similar audits of Platform Esther and Fort Apache (Ft. Apache) were completed concurrently and are subjects of separate reports.

The objective of the Safety Audit is to ensure that safety and offshore operational integrity is maintained at oil and gas production facilities on State leases and that they comply with state and federal regulations. Production facilities must also meet the Best Achievable Protection requirement of Public Resources Code (PRC) 8755. The assessment follows proven CSLC audit practices in combination with applicable regulations and standards used in Appendix C.

## *Company Background*

DCOR, LLC is the current owner of Platform Eva and holds interest in the state oil and gas leases at the Seal Beach location. The company was formerly known as Dos Cuadras Offshore, LLC and changed its name to DCOR, LLC in July 2005. DCOR was founded in 2001 and is based in Ventura, California with additional offices in Bakersfield, Huntington Beach, Los Angeles, Santa Barbara, California, and Dallas, Texas. DCOR operates eleven offshore platforms. The company is owned and controlled by Mr. William M. Templeton.

## *Facility Description*

Platform Eva is located 2.1 miles offshore of Huntington Beach, California on State Oil and Gas Leases PRC 3033.1 and PRC 3413.1, in 58 feet of water. The Huntington Beach field was discovered on May 24, 1920 when Standard Oil Company struck oil onshore at 2,199 feet. Development of the field revealed that it extended offshore, and Platform Eva was erected in 1962 by Unocal, and began production in 1963.

The facility is a permanent, fixed-base drilling and production platform with a 12-legged jacket structure anchored to the ocean bottom with pilings through each of the legs. Platform Eva currently has 16 active producing wells and 12 active H<sub>2</sub>O injection wells. Current production rates are approaching 1,430 barrels of oil per day (BOPD), 32,500 barrels of water per day (BWPD), and 160 thousand cubic feet (Mcf) of natural gas per day.

Platform Eva began operation in 1963, as an asset of Union Oil Company of California (Unocal). Nuevo Energy Company purchased the Platform in 1996. Plains Exploration and Production Company (PXP) assumed ownership of the platform in 2004 after a merger with

Nuevo Energy. PXP subsequently sold the property to DCOR in 2004. DCOR began operating the platform in 2005.

The oil producing formations in the Belmont Field are typically below hydrostatic pressure, and require artificial lift (electric submersible pumps), making the potential for a well blowout minimal.

### *Safety Audit Results*

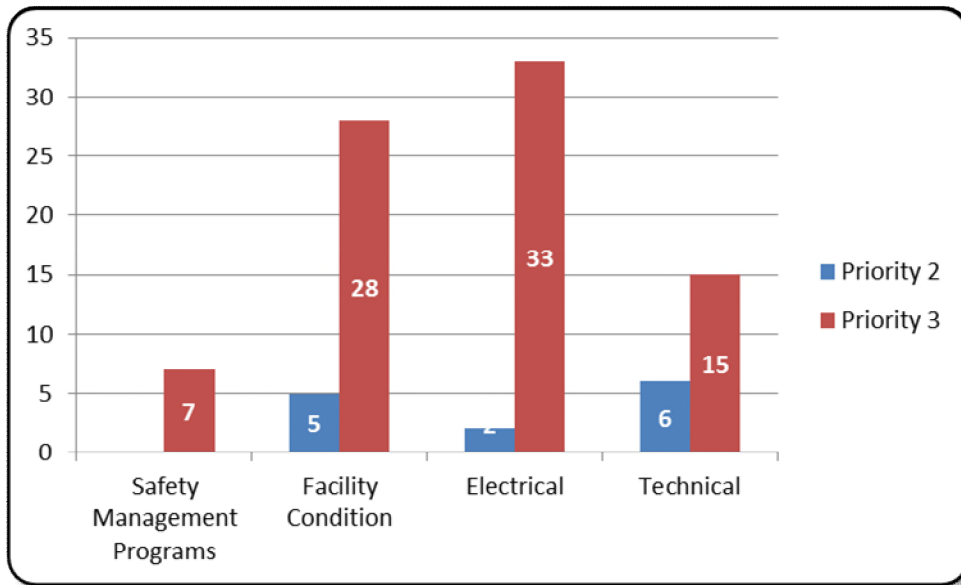
The Safety and Oil Spill Prevention Audit found that Platform Eva complies with applicable safety and regulatory requirements with the exception of the items listed in the action item matrix in Section 6D. The platform appears to be in good condition and safety systems and equipment remain fit for service; however, moderate corrosion was evident in some areas, primarily steel plate flooring and walkways. Appropriate measures are necessary to curb or minimize the occurrence of corrosion on platform decking and walkways. While DCOR has a corrosion-monitoring program in place, a more robust corrosion control program is necessary for inspection and prevention of corrosion to ensure a safe and productive operation. Although corrosion is an ongoing problem for the platform, repairs of steel plate flooring and walkways were taking place at the time of the audit. DCOR does use performance indicators but they are focused primarily on safety critical aspects of inspection and maintenance and do not specifically measure the effects of external corrosion.

DCOR has well established behavior based safety policies, health, and environmental programs. A consistent and positive safety and environmental culture is evident in DCOR employees that augments mechanical reliability, functional performance, and teamwork. The established safety culture also helps to ensure the protection of workers, the public, and the environment. Personnel are knowledgeable, and provided valuable assistance to the State Lands Audit Team.

Safety systems and equipment remain fit for service. However, a number of tanks and pressure vessels are in need of internal inspections. Without design verification protocols, the equipment or system may not meet the intended requirements under operating conditions. Risk reduction and environmental protection can only be ensured through scheduled inspections, testing, and preventive maintenance practices.

The safety audit identified 96 action items. No priority one-items were identified. The number of priority two-action items was also quite low at 14 with the majority (82) being low risk priority three-action items. This is a favorable result since the number is on par with other comparable facilities and since the items are mostly priority three, which is the lowest in terms of significance or risk. Resolution of the priority two-action items is required within 120 days, and resolution of the priority three-actions items is required within 180 days from issuance of this report.

The following chart displays the action items identified by the subject teams that total 96. This distribution is similar to the other facilities in California where the items identified are typically related to piping, equipment, electrical, and system condition and maintenance.





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# Introduction

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DCOR, LLC  
Platform Eva  
Huntington Beach

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## 1.0 INTRODUCTION

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### 1.1 Safety Audit Background

The California State Lands Commission (CSLC) Mineral Resources Management Division (MRMD) conducts safety audits of lessees and operators for lands in which the State has an interest. CSLC sponsored safety audits ensure oil and gas production facilities on State leases or granted lands are operated in a safe and environmentally sound manner, comply with Federal, State, and local codes/permits, and follow industry standards and practices. CSLC staff is tasked with oil spill prevention in California's ocean and tidelands, prevention of waste, conservation of natural resources, and ensuring public safety. Public Resources Code (PRC) 6103, 6108, 6216, 6301, and 6873(d) provide authority for these endeavors.

In 1990, the California legislature enacted the Lempert, Keene, Seastrand Oil Spill Prevention Act and directed SLC to inspect these facilities to ensure that Best Achievable Technology (BAT) standards for prevention of oil spills are met. CSLC conducts frequent inspections of onshore and offshore oil and gas drilling and production facilities to ensure that these standards are enforced to safeguard the public and environment. The Safety Audit Program, together with the monthly inspection program, aids in preventing oil spills and other accidents. Added prevention efforts occur through a review of drilling, pipeline inspection, facility design, maintenance, human factors, and other aspects of safety management.

Audit team members systematically assess the organizations' current performance levels and provide feedback for improvement. Their areas of emphasis include:

- Equipment Functionality and Integrity (EFI)
- Electrical (ELC)
- Technical (TEC)
- Safety Management Programs (SMP)
- Human Factors (HF)

Appropriate company contacts and resources are identified at the start of the audit. Progress and deficiency reports are communicated periodically throughout the audit process. An "action item matrix" is used to classify and track action items. The matrix identifies items needing corrective action and priority ranking. Action items are prioritized in three levels according to risk and severity. A report highlighting the strengths and weakness of the facility is created from the matrix items.

Draft copies of this report and the action item matrix are provided to the company during the audit. The final audit report is prepared for company management, affording them the opportunity to address the findings and recommendations. Throughout the clearance phase of the audit, the MRMD team continues to coordinate with the operator in evaluating the adequacy of corrective actions and tracking progress of the proposed corrective actions.

This program could not be successful without the cooperation and support of the operating company. The safety audit benefits both the company and the State by reducing workplace hazards, environmental incidents, property damage, and in particular, oil spills. Previous experience shows safety assessments help increase operating effectiveness,

efficiency and lower operating cost. History has also shown that improving safety and reducing incidents makes good business sense.

## **1.2 Platform History**

Platform Eva is an offshore oil and gas production facility operating within the boundaries of the State of California in the Belmont Oil Field. The facility is located 2.1 miles offshore of Huntington Beach, California on State Oil and Gas Leases PRC 3033.1 and PRC 3413.1, in 58 feet of water. Discovery of the field occurred on May 24, 1920 when Standard Oil Company struck oil onshore at 2,199 feet.

Platform Eva began operation in 1963, as an asset of Union Oil Company of California (Unocal). Nuevo Energy Company of Houston, Texas purchased Platform Eva along with the majority of Unocal's California assets in April of 1996. The company initially retained Torch Operating Company to operate their California assets for several years before assuming operations. Nuevo Energy operated the facility until May of 2004 when Plains Exploration and Production Company (PXP) took over after a merger with Nuevo Energy. PXP subsequently entered into a purchase and sales agreement with DCOR, a Texas based LLC, in September of 2004, which involved the sale of PXP assets including Platform Eva and Ft. Apache to DCOR. The sale closed in December of 2004 with the approval of the lease assignment by the State Lands Commission on October 20, 2005. PXP continued operating the facility for DCOR until the State Lands Commission approved the lease assignment.

Platform Eva is currently owned and operated by DCOR, LLC. DCOR, LLC is a limited liability corporation with offices in Ventura, California and Dallas, Texas. DCOR is owned and controlled by Mr. William M. Templeton. DCOR owns and operates eleven offshore platforms. These include Platform Esther in state waters off Huntington Beach and Platform Edith located approximately ten miles offshore in federal waters, as well as eight other offshore platforms located in the Santa Barbara Channel.

## **1.3 Platform Description**

Platform Eva is a permanent, fixed-base drilling and production platform. The platform, installed in 1964, is a vertical, 12-legged jacket structure anchored to the ocean bottom with pilings through each of the legs. The platform has two primary decks and one small subdeck. The upper and lower primary decks are the drilling and production decks. Modifications and improvements to the platform include a newly renovated galley and deck extension to accommodate the new auxiliary generator and tool room. In addition, the newly revamped control room not only included architectural improvements but also ergonomic design upgrades.

The primary purpose of Platform Eva is to recover, process, and ship crude emulsion to Fort Apache for further processing. The field is currently producing approximately 1,430 barrels of oil per day (BOPD), 32,500 barrels of water per day (BWPD), and 160 thousand cubic feet per day (MCFD) of natural gas. There are 16 active producer wells, 12 active water injection wells and one gas injection well (A-12). At least two operating personnel per shift continually operate the platform and monitor operations. Visitors and contract personnel vary depending on platform operations and maintenance.

The platform consists of a drill deck, production deck and subdeck. The Main Deck houses the well bay, production and injection wellheads, process tanks, pressure vessels, and pumps. The deck also contains the control room, equipment shop, storage rooms, electrical switchgear, and other equipment required to support platform production operations. The lower subdeck, located below the production deck, contains waste collection tanks and pumps which are used to capture liquids and rainwater recovered from process and gravity drains. The Dive Deck is located just above the water line and consists of grated walkways around the platform perimeter. The subdeck also includes the boat landing where personnel are transferred on and off the platform.

Variable speed electrical submersible pumps (ESPs) are used to produce the wells and bring fluid to the surface. The oil, water and gas flow into a three-phase gross separator V-301. After separation and metering, oil flows to the shipping tank and is pumped to shore via an 8" wet oil line. The shipping tank is equipped with high-low shut-in controls and alarms according to MRMD 2132(g)(2) regulations. Operator control or involvement is not necessary unless there is a malfunction of the level control sensors. The wet oil flows to a DCOR onshore treating and separation facility (Fort Apache). Dehydrated oil is then shipped via the Crimson Pipeline to the refinery. A vault located on the beach allows access to isolation valves.

Produced water from the gross separator (V-301) flows through the hydrocyclone skid where suspended solids and liquids (such as oil) are removed from the water before flowing to the downstream enhancement vessel (DEV) and to the Injection Pumps. High pressure water from the injection pumps is injected into wells as part of an enhanced oil recovery system. The pumps are controlled by a variable frequency drive (VFD) which will allow for speed control of the pumps, thus altering the actual rate of flow in response to the level in the water injection enhancement vessel (V-302).

Gas from the casing gas header, gross oil separator (V-301), and test separators flow to the low-pressure rotary gas compressor CBA-C240. The low pressure gas compressor is used to increase the gas pressure before discharging the gas to the suction of the main gas compressor C-100. The sour gas then enters the Amine Unit, which removes H<sub>2</sub>S and CO<sub>2</sub> from the gas stream through absorption and chemical reaction making the gas marketable and suitable for transportation. Stripped waste gas from the Amine reboiler is sent to the Tail Gas Compressor where the gas (≈10 Mcfd) is disposed of via an injection well.

Sweet wet gas from the Amine Unit and Platform Edith enters the second stage of the main gas compressor C-100. The wet gas then flows to the water vapor removal system (Glycol Dehydration Unit). The glycol process strips the natural gas of most of its water content to meet typical pipeline and process specifications before flowing into the sales gas pipeline. Condensate (i.e., liquid hydrocarbons) obtained from the natural gas is transferred to the shipping tank and commingled with the produced oil.

The sales gas is odorized upstream of the 6-inch subsea gas pipeline before departing the platform. The odorant (mercaptans) is added for public safety and complies with the Code of Federal Regulations Title 49 Part 192.625. Once the gas reaches shore and enters the SoCal Gas transmission line it is metered and routed to the AES power plants. During periods of low demand or power plant shutdown, the gas can be routed back to Platform Edith for flaring rather than shutting down Platform Eva. In addition, the Platform Eva Gas Gathering

Pipeline System also transports gas received from Platform Edith to a tie-in near the intersection of Warner Avenue and Los Patos Avenue.

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# Facility Condition Audit

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DCOR, LLC  
Platform Eva  
Huntington Beach

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## 2.0 FACILITY CONDITION AUDIT

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### 2.1 Goals and Methodology

The primary goal of the Safety and Oil Spill Prevention Audit Team was to evaluate the topside equipment and mechanical integrity of DCOR's Platform Eva offshore facilities. The audit team inspected the platform thoroughly including the safety, production, and electrical systems, and identified the regulatory requirements applicable to each. Field tasks included confirmation of accuracy of facility drawings/plans, review of testing, inspection, and equipment maintenance histories, and completing a variety of facility condition checklists. All of these tasks enable technical design review of the platform's safety systems. The audit report reflects this "system by system" process and includes a description and assessment of each system, and any significant action items or observations. Specific sections of the report may address personnel safety concerns, while others are more applicable to facility process safety. The facility condition audit is also an essential preliminary element that is later used while assessing the organization's safety management program development and implementation.

### 2.2 General Facility Conditions

2.2.1 Workplace Housekeeping: Platform Eva was clean and orderly. The production office is well organized and contains up to date reference materials. There are adequate clearly marked refuse containers, and there was no noticeable debris scattered about the platform. Containment devices such as drip pans are also used to help eliminate ocean contamination if a leak were to occur. Restrooms are located on the Production and Drilling Decks, and were found to be in good condition with no obvious health or sanitation concerns.

2.2.2 Stairs, Walkways, Gratings and Ladders: The stairs, landings, walkways, gratings, and ladders on the platform were in good to poor condition due to the effects of external corrosion in some areas. (EFI – 2.2.2.01) Access to the equipment for operation and maintenance appeared to be satisfactory. Safeguards were in place wherever there was a need to transition between levels, and for routine access to equipment. However, corrosion seems to be an ongoing problem for the platform. Repairs of steel plate flooring and walkways were taking place at the time of the audit. The portable ladders observed were in good condition and free from oil and grease. DCOR's safe work practices define the use and care of platform ladder equipment.

2.2.3 Escape / Emergency Egress / Exits: Escape routes, emergency egress, and exits are free and unobstructed. Safe briefing areas are shown on the Station Bill and are discussed during the platform orientation. In the event of an emergency, personnel will be directed by intercom to report to the appropriate safe briefing area based upon the location of the emergency and/or wind direction. Windsocks are located for maximum visibility and appeared to be in good condition. Emergency lighting is generally adequate throughout the platform and the illumination was satisfactory. Emergency evacuation of the platform is accomplished by crew boat although evacuation by helicopter is an option. No access or egress issues were identified.

2.2.4 Labeling, Color Coding and Signs: The design, application, and use of signs and symbols on the platform are adequate. The signs follow Occupational Safety and Health

Administration (OSHA) and American National Standards Institute (ANSI) recommendations. Fire diamonds were visible on all tanks, vessels, and chemical storage totes. The posting of fire diamonds comply with the Uniform Fire Code.

2.2.5 Security: Physical and operational security measures are in place on Platform Eva to prevent unauthorized entry. The platform is manned twenty-four hours a day, seven days a week with at least two operators present at all times. There is a limited route of access from the boat landing and there are a sufficient number of restricted access signs posted which are visible from all sides. Authorized personnel travelling to the platform must be pre-listed on an approved boat log before boarding. Ship Services deck hands check that each person's name appears on the boat log. In addition, personnel are checked for proper identification and swing rope certification. After regular business hours, platform security gates prevent unauthorized access from the boat landing to the upper decks of the platform. In addition, information security protects the confidentiality, integrity and availability of data from accidental or intentional misuse by people inside or outside the facility.

2.2.6 Hazardous Material Handling and Storage: The storage of flammable and combustible liquids on Platform Eva appears to conform to Cal-OSHA and NFPA 30 standards. Material Safety Data Sheets (MSDS) containing information on all chemicals used in the workplace were kept in the Control Room and accessible to all personnel.

Chemical and diesel storage on the platform appears to be properly located, and protected against external damage and leaks. Bulk chemical totes have proper labeling and adequate containment in the event of a spill.

Compressed gas cylinders were secured and legibly marked to identify the gas content. Empty and unused cylinders were observed to have closed valves with protection caps in place. Cylinders are stored in places where they could not be knocked over or damaged.

## **2.3 Field Verification of Plans**

2.3.1 Process Flow Diagrams (PFD): Process Flow Diagrams (PFD's) provided by DCOR were found to be reasonably accurate. Two priority 3 discrepancies were noted because drawings did not match actual produced gas piping. (EFI - 2.3.1.01 & 02)

2.3.2 Piping and Instrumentation Diagrams (P&ID): Field verifications of the P&ID's were reasonably accurate; however, minor updating is required. The discrepancies in the P&ID included valve sizing and piping errors, missing equipment and out of service or removed equipment.

2.3.3 Fire Protection Drawings: Firewater / Foam Utility Flow Diagram and the Platform Station Bill were available and reviewed for Platform Eva. The Firewater / Foam drawing is current and up to date.



## 2.4 Condition and Integrity of Major Systems

2.4.1 Piping: An external visual inspection of the piping systems was performed using a checklist, piping drawings and inspection records. The visual inspection noted coating failures, signs of misalignment, vibration and leakage. The evaluation also included the condition of pipe hangers and supports as well as any field changes or temporary repairs not recorded on the piping drawings. Other key information such as material selection, piping design and maintenance practices was also considered during the inspection. The piping throughout the platform was in good condition, and piping materials and components were compatible with the operating parameters and environment. However, a majority of piping on the platform was showing signs of coating failure (peeling and blistering). It appears that the coatings are experiencing natural deterioration and degradation due to age. CSLC recommends DCOR conduct a failure analysis of platform paints and coatings and determine which systems are most in need of painting. Repair of the piping coatings should be based on survey findings.

DCOR uses continuing routine and risk based piping inspections to achieve a desired level of facility safety, environmental protection, and unscheduled downtime. Inspection frequencies are set up according to regulatory requirements and established guidelines, for example, American Petroleum Institute (API) Recommended Practice (RP) 570 and Department of Transportation (DOT) pipeline inspections. Oil and gas piping visual inspections occur annually while subsea oil and gas pipelines are inspected annually using an electronic survey tool. Results of thickness measurements for the piping systems along with repair recommendations are stored electronically. No issues were noted. Results from thickness measurements, inspections, repairs and other tests are readily available and recorded within a database system called Microsoft Access. A maintenance management system called Mainsaver is used to generate maintenance and inspection activities.

2.4.2 Tanks: Tanks located on an offshore platform are maintained following a program of external and internal examinations based upon API RP 653. DCOR's maintenance practice follows API 653 recommendations, industry standards, and regulatory requirements. Tank documentation includes inspections, repairs, and alterations.

There are three active tanks on Platform Eva: shipping tank V-103, storage tank T-101, and well cleanup tank T-102. Externally, the three tanks appear to be in good condition. Although the external inspections were within API 653 recommended frequencies, no records of internal inspections within the last twenty years were found for Storage Tank T-101 and Vent Scrubber T-105 resulting in two Priority 3 items. (EFI – 2.4.2.02 & 03)

In an effort to extend the service life of equipment, DCOR has reclassified a few of their pressure vessels to tanks. This change allows DCOR to alter their inspection frequencies and shell thickness requirements thus extending the life of the equipment. However, PSV records show that a reclassified vessel (T-101) still had the old PSV (#50) installed. With the change from a pressure vessel to a tank the required safety device should reflect the change in safety device requirements. This issue is addressed under *2.2.4 Relief Systems*.

2.4.3 Pressure Vessels: Good maintenance management ensures the mechanical integrity of pressure vessels. This can be achieved through a program of external and internal examinations and integrity assessment methodologies. The external and internal inspection intervals for all pressure vessels were reviewed for compliance with applicable regulations,

recommended practices, (e.g. API RP 510 and CSLC 2132(g)(3)), and record keeping. DCOR's Mechanical Integrity Engineer tracks wall thickness, corrosion rates, inspection due dates, and predicts retirement dates for individual pressure vessels based on total metal loss and risk. Contractors perform vessel inspections (external and internal) within 5-year intervals using nondestructive examination techniques. External inspections found no evidence of leakage, distortion or cracks at welds, foundation damage, corrosion, or defects of piping connections. Internal inspection records show corrosion to be low and at a predictable rate with no major concerns.

However, records identified three vessels as having no internal inspections within the last ten years resulting in four Priority 2 deficiencies. The vessels included Gas Scrubber V-111, Inlet Scrubber V-220 and Vacuum Lift Trap V-230. (EFI – 2.2.3.01 – 04) Eleven vessels, HZZ-7 Gas Exchanger, HZZ-13 Stabilizer Feed/Bottoms Exchanger, DAJ-303 Charcoal Filter, DAJ-304 Sock Filter, and PV-401 16" Oil Separator, MBD-1 Cold Separator, NBC-4 Stabilizer Reboiler, NBC-5 EG Reboiler (glycol reboiler), NBC-5A Surge Tank, NBD-8 Refrigerant Deoiler, were also found to be lacking external inspections within the last five years resulting in Priority 3 deficiencies. (EFI 2.4.3.06 – 16) In addition, documentation (U1A) for Gross Separator V-301 could not be located. (EFI 2.4.3.05)

2.4.4 Relief System: The piping for the relief vent system on Platform Eva was evaluated for condition, functionality and maintenance. The primary purpose of the pressure relief system is to ensure protection for facility personnel and equipment from overpressure conditions that may happen during process upsets, equipment failure, and external fires. The relief vent system is designed with a vent stack, flame arrestor and a scrubbing vessel to remove liquid hydrocarbons. If any of those events should occur, the vent gas system will collect and discharge any gas from the pressurized process components to the atmosphere. Vent gas exiting the system is dispersed to the atmosphere through a flame arrestor. The flame arrestor allows gas to pass through it but stops a flame in order to prevent a larger fire or explosion. The flame arrestor is inspected annually for clogging. No discrepancies were noted.

Testing of the pressure relief valves (PSVs) are done every six months according to MRMD 2132(g)(3)(D). DCOR utilizes Instrument Control Services (ICS) of Ventura for the PSV testing program on Platform Eva. Several action items were written in regards to PSV's. These items include correction of typographical errors on the ICS inspection report. PSV descriptions did not match the PSV designation on the P&ID's. (EFI – 2.4.4.06) Two ICS tags appear to use the same description for the same PSV. (EFI – 2.4.4.07) A priority 2 action item was issued because it appears that when the old Power Water Surge Tank was converted from a pressure vessel to a storage tank the PSV was not changed to reflect the reclassification. (EFI – 2.4.4.08) Another priority 2 was issued because there is no record of PSV 511 on the Odorant Expansion Tank being tested. (EFI – 2.4.4.09) Three priority 3 items were issued because isolation valves on three PSV's were not car sealed open. (EFI – 2.4.4.01 – 03)

2.4.5 ESP, Pump Units, Wellhead Equip. & Well Safety Systems: Surface safety valves (SSV), flow safety valves (FSV) and shutdown valves are installed on wells, flow lines, process lines and pipelines to shut down and isolate a line if a leak was to occur. SSVs and FSVs are tested monthly as required by CSLC regulations to ensure they function and are capable of holding pressure without leaking. No problems were noted.

2.4.6 Fire Detection Systems: The fire detection systems utilized on platforms are designed to detect fires in their earliest stages and alert personnel to the existence of a fire on the platform. The fire detectors are integrated into a system to automatically activate emergency alarms, initiate Emergency Shutdown (ESD), isolate fuel sources (i.e., wells, pipelines, etc.), start the firewater pump, and activate the deluge system. The fire detection system on Platform Eva utilizes:

- Gas Detectors (11)
- UV/IR Detectors (17)
- Heat Detector (1)
- Smoke Detectors (7)
- H<sub>2</sub>S Detectors(7)

Smoke detectors are placed in electrical rooms, offices and galley. Any detection of smoke or products of combustion will sound the fire alarm over the platform PA when activated. The platform also utilizes ultra-violet and infrared (UV/IR) flame detectors (fire eyes), which detect fires by monitoring in both the UV and IR spectral ranges. Fixed flammable gas Lower Explosive Limit (LEL) detectors continuously monitor for the presence of combustible gas and are set to detect lower explosive level concentrations at 25%, triggering an audible alarm; in addition, they will automatically activate the shut-in sequence when concentrations reach 45%. These settings more than meet the required standards of 60% and 80% respectively per MRMD 2132(g)(5)(C)(D). The UV/IR detectors found in the well bay and production area of the platform will activate the fire alarm, ESD and deluge systems.

The fire detection system is designed with bypasses to allow for testing. A MRMD inspector witnesses the flame, flammable gas, smoke and H<sub>2</sub>S detectors operation during monthly testing and records the results. No discrepancies were noted.

2.4.7 Fire Fighting Equipment: Fire-fighting equipment is strategically located on the platform to provide for fire-fighting capabilities. The fire-fighting equipment consists of firewater pumps, foam, hose reels, monitors, deluge system, dry chemical and CO<sub>2</sub> extinguishers. This equipment is installed on the platform to cool, control and/or extinguish fires.

Platform Eva's fire pumps are vertical shaft turbine-type pumps. The primary fire pump is electric-driven and the secondary fire pump is diesel-driven. CSLC regulations require firefighting systems be maintained under NFPA 20 and 25 standards. Champion Fire Systems, Inc. of Rancho Cucamonga conducted annual flow tests of the primary firewater pump in April 2014 and the secondary firewater pump in August 2014. Both firewater pumps passed their annual testing and no problems were noted.

The firewater pumps feed into the fire water main, which is designed as a loop system allowing connected fire-fighting systems to be supplied from two directions. The fire main is a seawater pressurized wet system (water filled) to avoid delay in the water supply. Fire main piping appears properly supported and adequately maintained. The firewater hose stations are strategically located throughout the platform and provide proper coverage of the target area typically from two directions.

Dry chemical fire extinguishers comply with CSLC 2132(g)(4)(F), NFPA and OSHA regulations. Fire extinguishers were in their named places, fully charged and in operable

condition. A third-party contractor does maintenance and testing of all portable fire extinguishers in the workplace. Inspections occur monthly with servicing yearly. The company provides required annual online training to familiarize employees with the safe work practices of fire extinguisher use and the hazards involved. No deficiencies were noted.

2.4.8 Combustible Gas and H<sub>2</sub>S Detection: The flammable gas detection (LEL) system is made up of 11 fixed gas sensors that immediately identify the presence of flammable gas when predetermined action levels have been exceeded. These detectors continuously monitor for the presence of combustible gas and are set to detect lower explosive level concentrations at 25% by triggering a distinct audible alarm tone; in addition, they automatically activate the shut-in sequences when concentrations reach 45%. These limits more than meet the required standards of 60% and 80% respectively per CSLC 2132(g) (5) (C&D). The tone produced by LEL alarms is different from the normal alarm tones. No issues were noted with the LEL detectors.

The installation of a hydrogen sulfide (H<sub>2</sub>S) wireless detection system became necessary in November 2014 with the rise of H<sub>2</sub>S levels in the production stream. The rise of H<sub>2</sub>S levels in Platform Eva's process gas was attributed to secondary recovery efforts. An Amine Unit was installed on the platform to remove H<sub>2</sub>S and CO<sub>2</sub> from the process gas in order to meet sales gas specifications. In addition, the reclassification of the platform to an H<sub>2</sub>S facility required additional MRMD regulation compliance. Through a Hazard and Operability Study DCOR addressed the additional compliance requirements by developing, updating or installing the following:

- Seven new wireless H<sub>2</sub>S sensors
- Audible alarms with indicator lights
- Appropriate piping upgraded meet sour gas service
- Car seals placed on valves going to atmosphere
- Update operations manuals with H<sub>2</sub>S information
- The addition of four Self Contained Breathing Apparatuses
- H<sub>2</sub>S Contingency Plan
- Well maintenance and rig operations would receive H<sub>2</sub>S precautions, and other protective items were identified

These compliance actions by DCOR act to address the items listed by MRMD letter dated November 4, 2014. Installation and testing of the wireless H<sub>2</sub>S sensors took place in March 2016.

2.4.9 Emergency Shutdown System (ESD): The platform is equipped with eight manual ESD stations that comply with CSLC 2132(g)(1)(A). Activation of an ESD will cause shut-in of all wells and pipelines as well as the complete shutdown of the production facility in the event of fire, pipeline failure or other catastrophe. This is in addition to other safety devices that have the ability to shutdown the platform. The ESD stations on Platform Eva are tested monthly in bypass mode to ensure automatic shutdown systems are functioning properly. MRMD inspectors witness and record the results of the tests. During semi-annual testing, one of the manual ESD stations or process shutdowns is fully tested with an actual live test to ensure the platform will shutdown in sequence as designed. The ESD system appears fully compliant with API RP 14C. No problems were noted.

2.4.10 Safety and Personal Protective Equipment (PPE): DCOR has a written policy to provide a safe and healthy workplace, and to comply with all applicable federal and state regulations about occupational safety and health. All personnel entering a DCOR facility must at a minimum wear hard hats, safety glasses, hard toe boots, fire resistant clothing (FRC), and personal H<sub>2</sub>S monitors where required. Personal Protective Equipment (PPE), such as hearing protection, face shields, rubber gloves, aprons, and fall protection that may be needed are found in the DCOR Safety Manual, Safe Work Permit or Job Safety Analysis (JSA). In addition, PPE requirements are listed in work permits and safe work practices. DCOR also uses their morning safety meeting to stress the need for safety awareness, potential job hazards, and the use of proper PPE. No issues about the use of PPE were noted while on the platform.

All first time visitors to Platform Esther must complete orientation and training at Ship Services in San Pedro. The DCOR orientation includes viewing an instructional video, answering a written quiz, and satisfactorily demonstrating their swing rope capability before travel to the platform is authorized. DCOR's PPE requirements are outlined in the training video. First-time platform visitors to Platform Esther receive a site-specific briefing upon arrival.

2.4.11 Lighting: Platform Eva appears to have sufficient lighting to conduct safe operations throughout the platform. Mounted fixtures with high-pressure sodium vapor provide primary area lighting or similar type lighting is used. Control room and emergency lighting is tied into the emergency generator and is designed to operate if the platform loses its primary electrical supply. Additional information regarding lighting levels can be found in the electrical portion of the safety audit.

2.4.12 Instrumentation, Alarm & Paging: The process instrumentation and control has been upgraded from pneumatic to digital through past facility upgrades. Production controls and instrumentation are now part of a Digital Control System (DCS) that is connected to the platform by digital networks. Within the DCS, PLCs are used to control and oversee all the production or process equipment and instruments on the platform. Operations management software (Wonderware) provides the operator interface displaying plant wide activities. The software also has the ability to detect instrument errors and equipment failure. This ability, in combination with optimizing features, makes both start up activity and operational routines much easier and more efficient for operators. Wonderware also supports information management that shows historical information which can be used to improve process efficiency and plant performance.

The platform's DCS system is effective in helping the operator in handling an emergency. All process alarms appear in three different colors and frequencies to display various priorities. Platform Eva's safety shutdown system originating functions are annunciated so operators can find out the cause of the event. A distinctive audible alarm is used to distinguish the shutdown system alarm from an ordinary process alarm. First-out alarm displays on the Human Machine Interface (HMI) use time tags to identify pre-shutdown process alarms and shutdown events allowing the operator to take corrective action before the protective system activation occurs. The alarm management and control using this arrangement avoids alarm floods and continuous alarm rates that could cause a critical alarm to go undetected. Facility alarms are tested yearly and safety shutdowns are tested monthly. Facility test results and maintenance records are easily tracked, and recovered within Mainsaver. However, audible general alarms in the switchgear and MCC rooms were difficult to hear. API RP 14F (i.e., 11.16.1.2) requires that alarms must be able to be heard throughout

the facility. An action item was issued to improve the ability to hear alarms in these locations. (ELC – 3.10.6.01)

2.4.13 Auxiliary Generator / Prime Mover: DCOR purchased a new Caterpillar Model C-9 Generator Set rated at 313 KVA 250 KW 60 Hertz in 2011 to replace its aging generator. A deck extension was required to accommodate the installation of the generator required a deck extension to accommodate the new dimensions. The generator has a higher capacity and can provide up to 48 hours of runtime without refueling. The new auxiliary generator set has an automatic transfer switch and has the capacity to power all platform lighting, control room, galley, weld shop including 480 Volt service for welding, sump pump T-104, shipping pump # 1, waste water pump WP-101, UPS main power supply, Alaska crane, HVAC blower # 2, air compressor B and fog horn. The generator is tested monthly and appears to be regularly maintained. No concerns were noted.

2.4.14 Spill Containment: Spill containment equipment for Platform Eva appeared to be adequate and in good condition. A 6-inch lip at the bottom of the handrails traversing the entire production deck and drill deck serve as passive containment. Deck drains handle rainwater, spills and process leaks. The fluid is then routed to the Waste Water Tank located on the Sub Deck. Fluids from the Waste Water Tanks are then pumped to the shipping tank.

Platform Eva maintains 1500 feet of Series 4300 Expandi-boom (two 750-foot sections), 240 feet of sorbent boom, and four bags of assorted sorbent pads to contain any spill that might get into the ocean. Spill supplies are maintained and inventoried on a monthly basis by DCOR operating personnel and is part of the CSLC monthly safety inspection. Platform Eva meets all federal and state requirements for spill containment.

2.4.15 Spill Response: In addition to Platform Eva's two Expandi-booms and sorbent pads mentioned previously, DCOR maintains additional resources that include tracking flags, electronic tracking buoys and a marine radio. The Ship Services contracted crew boat is utilized for initial boom deployment.

DCOR is a member of a cooperative of oil producers, refiners, transporters and shippers that provide funding to Marine Spill Response Corporation (MSRC). MSRC is a national non-profit USCG classified Oil Spill Removal Organization (OSRO) with a large inventory of vessels, equipment, and trained personnel. Locally MSRC operates three oil spill response vessels (OSRV), two boom boats, two deployment boats, and a shallow water barge from Berth 57 at the Port of Long Beach. Boom deployment drills occur semi-annually with MSRC. The last Office of Spill Prevention and Response (OSPR) spill drill and boom deployment occurred on October 16, 2014 and was witnessed by a CSLC representative.

An Oil Spill Contingency Plan is required by California Department of Fish and Game, Office of Spill Prevention and Response (OSPR) regulations and a Facility Response Plan is required by federal Environmental Protection Agency (EPA) regulations. These two plans will be discussed in more detail in the Safety Management Programs Audit.

2.4.16 Cranes: The cranes on Platform Eva consist of an electric powered Seatrax Crane nominally rated at 44 tons and a smaller electric-driven Alaskan crane. The industry standard for cranes is API RP 2D, Operation and Maintenance of Offshore Cranes. Additionally, cranes in state waters are subject to Cal OSHA regulations pertaining to cranes.

DCOR employs crane mechanics, who inspect and repair the cranes on DCOR platforms. The audit staff observed training and re-certification of crane operators during the course of the audit. After reviewing crane records, it appeared that monthly, quarterly and yearly inspections were being performed as required. The records also contained documentation to show that needed repairs were being corrected in a timely manner. No deficiencies were identified.

## **2.5 Mechanical Integrity**

This section gives a general evaluation of the maintenance program and comments on management's approach to mechanical integrity. DCOR has an acceptable strategy for equipment that is of minimal importance to operations or has low cost. Equipment designated as run-to-failure are fixed in the event of a breakdown (by repair, restoration or parts replacement) until it is more feasible to simply replace the equipment.

Preventative maintenance (PM) is another maintenance strategy employed by DCOR. The company uses a computer-based preventive maintenance program called Mainsaver to manage equipment, and to minimize the threat of oil spills and their impact on the environment. The maintenance program has the ability to schedule preventative and corrective maintenance, track work order status and record asset costs. In the past, DCOR lacked the expertise to oversee the inspection and management of vessels, tanks and piping. DCOR has since remedied the situation with the addition of a Mechanical Integrity Engineer. The engineer is tasked with implementing the correct maintenance strategies, done at the right frequency, to decrease the rate of failure and increase equipment reliability. However, during the audit, the inspection program for vessels, tanks and piping did not appear to be completely linked with Mainsaver. Since a good PM program is performance based, the shortcoming makes preventive maintenance scheduling and record keeping unreliable. (EFI – 2.5.02)

The physical condition of the platform varied significantly from good to fair. The platform shows several common modes of coating failure that has led to corrosion. Common areas of coating failures observed on the platform include:

- Beam Edges
- Fasteners
- Pipe Supports
- Mechanical Damage

Due to the condition of platform paint coatings, and corrosion, CSLC recommends DCOR use this opportunity to evaluate the effectiveness of their Corrosion Control Program. The program should have management's commitment, and place emphasis on monitoring and evaluation of control measures. In addition, all operating personnel should be provided with appropriate training to enable effective identification of corrosion that may be of concern. (EFI – 2.5.01)

## **2.6 Production Safety Systems**

DCOR's platform production facilities, including process equipment, and pipelines are designed, installed, and maintained in a manner which provides for safety of operation, and protection of the environment. Platform Eva's production facility is protected with basic and

secondary surface safety systems designed, tested, and maintained in accordance with API RP 14C.

Safety Analysis Function Evaluation Charts included in API RP 14C are utilized as an analysis technique to documentation and determine the effects and requirements of components in the safety system. All safety devices and their functions were analyzed by comparing the SAFE Chart and facility piping and instrumentation diagram/drawings (P&IDs). The comparisons matched all safety and shutdown devices, as well as, emergency support systems (ESS), to their functions. The review of SAFE chart logic found all devices were related to their functions and a proper level of protection is being maintained. However, not all of the platform safety devices and their functions were listed on the SAFE Chart making the evaluation of the chart incomplete. (TEC – 2.6.02 & 03)

All platform wellheads SSV's are inspected, installed, and tested in accordance with CSLC 2132(a)(9)(A) & (D) and API RP 14C. Surface safety valves found on wells will automatically close to isolate the well and prevent oil and gas from escaping into the environment. Any SSV that does not operate properly, or if fluid flow is observed during the leakage test, is either repaired or replaced.

Extensive fire and safety systems are installed throughout the platform. Included in these systems are safety devices that automatically shut down oil and gas production if an emergency occurs. In addition, every operator/contractor on the platform is authorized to shut down the platform should they detect an unsafe condition. As part of the surface production safety system, valves are used to isolate the various process systems and lessen the environmental impact should any system problem be identified. Should evacuation be necessary, platform personnel have several choices ranging from helicopter, crew boat, and life rafts.

Process Hazards Analyses (PHAs) are performed as part of the Management of Change (MOC) process and before any construction can begin on a new project. This systematic approach for identifying, evaluating, and controlling the hazards of the process helps build-in additional safe guards and can help evaluate the contribution of each safety device or system protection. When hazards cannot be removed or controlled through design, DCOR uses a hierarchy of health and safety controls (e.g., Administrative and Engineering Controls) to eliminate hazards or reduce exposure to hazards.

The Human Machine Interface computer helps the operator manage and understand the status of the process control, and the safety systems. The HMI provides a graphics-based visualization of the platform control and monitoring system. The user interface resides in a Microsoft Office-based Windows computer that communicates with a PLC for specific functions, along with the Digital Control System on the platform. This equipment allows operators to control the process within authorized parameters. Uniformity in process settings among the different operating crews is carried out through a strict safety systems procedure that restricts operator access to the program control code. Separation of safety-related functions from process control reduces the risk of common cause failures and assures the safety system will function properly. Bypass switches for functional testing provide "no interruption" to the normal process operation. System safety integrity is maintained when a device is placed in bypass by procedures, and the use of an alarm to signal an active bypass. Additionally, facility controls and safety features are designed to be fail-safe, and have redundant capacities.



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# Electrical Systems Audit

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DCOR, LLC  
Platform Eva  
Huntington Beach

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## **3.0 ELECTRICAL SYSTEMS AUDIT**

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### **3.1 Goals and Methodology**

The primary goal of the Electrical (ELC) Team was to evaluate the electrical systems and operations at DCOR offshore Platform Eva to determine conformance to the California Electric Code (CEC) and industry standards. Power Engineering Services (PES), a professional electrical engineering consultant performed these services.

References used in review of the facility include documents published by the American Petroleum Institute (API) Recommended Practice (RP), National Fire Prevention Association (NFPA), the State of California Electric Code (CEC) and State Lands Commission Regulations. The ELC Team review comments are primarily based on those publications, which primarily include API RP 14F, API RP 500, API RP 540, CEC documents, and industry standards. The drawings used in support of the audit were Electrical Single-lines and Area Classification Drawings provided by DCOR for Platform Eva.

Specific tasks to accomplish this goal included a systematic process of field verification of Electrical Single-line Diagrams, Plan Drawings, Area Classification Drawings, and operation and maintenance practices. A comprehensive use of inspection checklists, code and standard compliance checklists, and review of electrical system design for conformance to codes and standards was used to complete the audit. This report includes a summary of the electrical systems included in the audit.

The ELC Matrix, Section 3.0, provides a detailed listing of the locations and items identified for correction. The matrix is organized in sections and each section is discussed below along with examples of typical items encountered.

### **3.2 Hazardous Area Electrical Classification Drawings**

The API recommended practices and CEC requirements provide specific guidelines for the electrical classification of hazardous areas and installation practices for electrical equipment and materials within classified areas. Areas that contain, or may contain, flammable gases and vapors in normal operations can form an explosive environment that is ignitable by hot surfaces, electrical arcs, and sparks. To prevent this from happening, facilities are classified according to the hazard present in the different areas. This is done so all electrical equipment and systems are properly selected and installed. The basis for observations and review comments for all hazardous areas are API RP 500, CEC 500, 501, and 504 as well as API RP 14F. The hazardous area electrical classification diagrams are generally representative of the existing conditions and area class elements. The drawings need to be updated on a regular basis as process and equipment additions and deletions are made. However, the drawings do need to be updated to include process and equipment additions and deletions made since the last revision in 2009. (ELC - 3.2.04, 05 & 07)

The purpose of an Electrical Area Classification Drawing is to define the locations of boundaries and areas where specific electrical installation practices are required to manage the explosive properties of flammable liquids, vapors and other volatile materials. Installation and maintenance of electrical systems requires attention to the type of hazard and the level of the hazard in order to insure compliance with the CEC. Electrical Area Classification Drawings are

required to contain the information necessary for a qualified electrician to perform work in and around classified areas. DCOR drawings DCOR-EV-EL-D-0001, 0002, and 0003 were last revised in May 2013 and require a revision.

The addition, relocation or change in process equipment, lines and valves requires that classified areas be reassessed and that classified boundaries be redrawn. The Area Classification Drawings, in some cases, do not show the present conditions, all new electrical equipment purchased for installation should meet the most stringent requirements and be rated explosion-proof in accordance with code. The Area Classification Drawings, as presented, do not show permanent equipment to scale or in plan. (ELC - 3.2.01, 05 & 08) The drawings should be updated to show equipment similar to the Equipment Location Plan.

Portable chemical tanks are used for fluid treatment and are located throughout the platform. The tanks are portable, but the locations of the tank installations are, by definition, permanent and include meter pumps, which operate continuously. Many of the portable tanks contain flammable liquids but none of the areas where such tanks are in use appear on the Area Classification Drawings. The lines, pumps, and fittings associated with the tanks containing flammable liquids are also a source of hazard, and require classification of the areas affected. Show all totes on the area classification plans. (ELC - 3.2.02)

General-purpose electrical equipment (switches, light fixtures, control panels, etc.) is, in general, not suitable for installation in hazardous locations in classified areas. Electrical equipment that is not suitable for installation in a classified area will need to be relocated, replaced with equipment that is suitable, purged, or non-permeable barriers will need to be installed. After updating and revising the area classification boundaries as required by the matrix, and as described below, additional equipment may be identified as unsuitable. Enclosed and gasketed fittings are suitable for Division 2, but not Division 1. National Electrical Manufacturers Association (NEMA) 3R enclosures are suitable for unclassified areas but not Division 1 or Division 2. Where NEMA 3R enclosures are located in Class I areas they are required to be purged and pressurized per NFPA 496. All pressurized enclosures and buildings were found to have adequate positive pressures during the site visit.

The A22 Transformer on the drill deck, south side near the access hatch should be shown on the Area Classification Drawing, and the P-301A Transformers should be identified. (ELC - 3.2.01) A temporary lab set up has been installed inside electrical room for PDB2. The lab should be removed and relocated. (ELC - 3.2.03)

The plan view does not adequately show production deck Division 1 extent around the well bay. Provide section cut per API RP 500-10.4.1. (ELC - 3.2.04)

### **3.3 Electrical Power Distribution System, Normal Power**

3.3.1 Electrical Single-Line: The Electrical Single-line Drawings used for review of facilities were recently updated to match installed facilities and for use to complete the arc flash hazard study. The drawings are representative of the electrical power system. The audit focused on power distribution systems 480 volt (V) and above and excluded the lower voltage systems. Copies of the latest single-line drawings were received from DCOR, but were not found in the platform electrical files. Discrepancies observed between the installed equipment and the single-line diagrams have been provided to DCOR and are listed in the matrix. (ELC -

3.3.1.01 & 02) As part of the single-line diagram revisions, and arc flash study, it is recommended that the overcurrent protective device ratings be verified to comply with the code.

3.3.2 Electrical Service Capacity: The normal power system capacity appears to be adequate based on present usage observed on switchboard meters. As part of the activity necessary to update the single-line diagrams for the arc flash hazard study it will also be necessary to confirm the overcurrent device rating is appropriate for the connected equipment. The 480V system operating voltage was noted at 468V in some cases. System voltage will fluctuate for a variety of reasons. It is recommended that switchboard voltage levels be reviewed and raised if deemed warranted. (ELC - 3.3.2.02 & 03)

3.3.3 Electrical System Design: The power system installation, in general, appears to be adequate for the present operations.

### **3.4 Electrical Power Equipment Condition and Functionally**

3.4.1 Equipment Condition: In view of the harsh marine environment, the overall condition of electrical equipment is good. There are several items regarding lack of support for the downhole armored cable. In addition to support, the armored cable should be installed to reduce the risk of damage during well drilling and maintenance operations. (ELC - 3.4.1.07)

3.4.2 Equipment Maintenance Practices: Section 4.04 of the DCOR Safety Standards Document covers the Lockout/Tagout/Blockout program. The scope, responsibility and procedures outlined in the document appear to be adequate and complete. The electrical switchgear was inspected and tested in January 2013, and is due for cleaning, inspection, testing, and adjustment in January 2016.

Platform personnel and contractors were not implementing an extension cord and portable equipment testing program. CEC 590 identifies a maximum time constraint of 90 days for temporary installations. No methodology was found in the DCOR literature to test, track or verify that temporary and portable extension cords meet CEC 590. It is recommended that DCOR set up a testing schedule (quarterly, every 90 days) and marking system for temporary power extension cords and a method to identify when cords were last inspected for safety. (ELC - 3.4.2.02)

### **3.5 Grounding**

CEC Article 250 provides the rules for power system grounding and bonding. The requirements for grounding are established to prevent or reduce the possibility of personnel injury due to shock hazards resulting from elevated touch potential as a result of improper grounding. The rules of grounding also contribute to reduction of equipment damage. Three specific types of grounding are required at the facilities:

- Power system grounding.
- Safety or equipment grounding.
- Static grounding.

Transformers of separately derived systems for 480Y/277V, 240Y/120V, and 208Y/120V are solidly grounded and satisfy Code requirements for power system grounding.

Article 501-16, Bonding in Class I areas, states that all non-current carrying metal parts and enclosures associated with electrical components shall be connected together, bonded, and be continuous between the Class I area equipment and the supply system ground. Bonding shall provide reliable grounding continuity from the load back to the power transformer grounding. The best way to achieve this is to include properly sized equipment grounding conductors with each set of power conductors from the source of power to each of the equipment grounding points and include bonding jumpers at points of discontinuity along the route. Equipment bonding conductors to major equipment; transformers, switchgear and the like, were installed and appeared adequate. However, equipment grounding conductors are not installed on all circuits. Bonding is achieved through continuity of raceways and fittings.

Static grounding conductors to the portable storage containers (some containing hazardous liquids) were found to be missing altogether and are required. (ELC - 3.5.01)

### **3.6 Emergency Electrical Power**

A 250 Kilowatts (kW) / 313KiloVolt Amperes (kVA) Caterpillar Model LC5 emergency generator is installed to supply 480V emergency power in the event of a utility power loss. The emergency power is supplied to the 480V emergency motor control center (MCC). It was noted that the new single-line drawing 247EV-E-15, dated 06/08/15, identifies the MCC as "480V Standby MCC". (ELC - 3.6.01) It is recommended that the generator classification of "emergency" or "standby" be established, and then the equipment labels can be finalized. The fuel tank on the generator has a 400-gallon diesel fuel capacity with a full load consumption rate of approximately 20 gallons per hour. The fuel tank must be filled manually from the platform diesel storage tank since there is no day tank or electric driven fuel pump. A written procedure for refueling the 250kW generator should be written and included in safety training procedures.

3.6.1 System Configuration: Electric utility service is supplied by Southern California Edison at 34.5kV via submarine cable from SOCO Substation located at the Huntington Beach Strip. The cable also includes a fiber optic cable for communications, monitoring, and control (see section 3.10.5).

The service location is at the Edison 66kV switchyard and 34.5kV outdoor overhead disconnect located near the California Resources Corp., Huntington Beach facility. The substation supplies a Cutler-Hammer outdoor power-house (Electro-Center) containing 34.5kV, 1200-amp, 1500 Million Volt-amperes (MVA) Bus and medium voltage metal enclosed vacuum breaker. The breaker supplies power for both Platform Eva and Platform Edith via #1/0 AWG 35kV cable routed in tray and below grade conduit to a nearby vault (manhole F). Within the vault, the cable is tee spliced (using separable splices) to separate submarine cables for Platform Eva and Platform Edith.

The submarine cable to Platform Eva supplies 34.5kV electrical power to an SF<sub>6</sub> gas insulated three position switch consisting of a one disconnect switch for the 34.5kV supply and two 200A vacuum interrupter switches. The first vacuum interrupter position feeds a 3000kVA 34.5kV-480Y/277V transformer TX-1 to supply power to the operating platform main

switchgear. The second vacuum interrupter position is connected to a 3000kVA transformer TX-2, 34.5kV-480Y/277V located on the drill deck to supply power to switchgear PDB2 and a second 3000kVA transformer TX-3, 34.5kV-600Y/347V to supply power for drilling operations. At the time of inspection, there were limited well drilling operations in progress.

### **3.7 Electric Fire Pump System**

A 75hp electric fire pump is located on the production deck and controlled through the firewater controller panel located in the MCC room. The electric fire pump has a normal source of power connected ahead of the 4500A, 480V PDB1 main service switchboard breaker in accordance with CEC 695-3(a)(1). A diesel driven fire pump is also available as a backup in the event of a system power failure. One of the control circuit inputs for the diesel fire pump is from a normal source of power.

### **3.8 Process Instrumentation**

The process control system uses a combination of pneumatic, hydraulic and electrical instruments and controls. It includes the use of computers, Programmable Logic Controllers (PLCs) and relay logic to control and interface with valves, solenoids and pump controllers. Alarms are produced by level, temperature, pressure and flow sensors advising operators of process conditions. A number of instruments are outdated but are in the process of being replaced by modern equivalents.

The main servers for Wonderware and process controls are located in the electrician's office on the production deck mezzanine. A four-post cabinet houses the 16kVA Uninterruptable Power Supply (UPS), two servers, and routers. The monitors located in the control room include three Personal Computers (PCs) and two large monitors to provide operator interface to the process control system. The two main PCs are linked to the local Ethernet system and run the Wonderware software package. The third PC is also loaded with the software and may be substituted upon failure of either of the two primary PCs. One other PC is located in the galley to allow remote monitoring (mimic), but no control, of the system.

An Allen-Bradley SLC 5/30 processor PLC is located in control board CP-1 in the control room. Up to five remote PLCs are installed in various locations on the platform and are dedicated to specific tasks and systems control. The PLC-1 in control board CP-1 monitors main control board alarms and functions. The remote PLCs monitor the well point pressures and flow rates, compressor operation, water injection, Variable Frequency Drive (VFD) operation and well data, smoke alarm, and temperature in switchgear rooms and provides outputs for well shutdown. PLCs are interconnected over the RS-485 Data Highway.

During the site investigation, the PLC and server configuration was discussed, but no formal plans, logic diagrams, or instructions for backup or restoration of the system were available. (ELC - 3.8.01)

### **3.9 Standby Lighting**

Fixtures are installed in conformance with the NEC and appear to be located to provide adequate lighting levels for the tasks performed. Fixtures are appropriate types and designs for the environmental and hazardous area conditions.

The emergency lighting is powered from Emergency Panels “EDP2”, “EMLP-1”, and “EMLP-2” which all receive power from the 250kW emergency generator in the event of main power failure. Review of the layout and location of emergency light fixtures indicates adequate provisions for the purpose of safe egress. Emergency lighting is also provided in the control room, electrical rooms, and galley.

Since the platform operates around the clock, seven days a week, operators and maintenance personnel that need to perform work during nighttime hours carry flashlights and use temporary lighting equipment for planned maintenance and larger tasks.

### **3.10 Special Systems (Offshore)**

Special system requirements for offshore production facilities are described in API RP 14F. The ELC Team review comments for special systems are based on API RP 14F, API RP 540 and CEC documents.

3.10.1 Safety Control Systems: Safety control systems are required to be a combination of devices arranged to safely affect platform shutdown. Electrical safety control systems are normally operated energized and fail-safe. Failure of external power to a safety control circuit requires an audible or visual alarm to be initiated or operation of equipment in a fail-safe condition.

Six Emergency Shutdown (ESD) Stations are located on the platform. The stations appeared to be in good working order. The stations include; ESD-1- bottom of galley stairs, ESD-2 - south well bay at stairway to sub-deck, ESD-3 - control room CP-1, ESD-4 - production deck near V-114, ESD-5 - boat landing south side, and ESD-6 - east side stairs near weld shop. Stations are hard wired to the control panel CP-1 in the control room. Fail safe relays in panel CP-1 initiate shutdown of the platform and signal to the general alarms cabinet located in the locker room near the weld shop.

Nine Fire, Abandon Platform, and Man Overboard Alarm Stations (EA-1 through EA-16) are located about the platform. All stations appeared to be in good working order. All stations have been painted red; however, the red paint is faded and is no longer prominent. ESD and EA stations are tested monthly and records are maintained. The DCOR Equipment Location Plans for the production deck are missing four fire alarm push button stations. (ELC - 3.10.1.01, & 3.10.6.01)

3.10.2 Gas Detection Systems: Combustible gas detection systems, lower explosive limit (LEL) and Hydrogen Sulfide (H<sub>2</sub>S) are usually employed to detect combustible gas leaks in equipment and piping, to warn personnel of explosive and toxic concentrations and to initiate remedial action. Eleven gas detector elements (GDEs) are located as follows: GDE-1-1 at the weld shop, GDE-1-2 in MCC room, GDE-1-3 near V105, GDE-1-4 near V302, GDE-1-5 near GC-300, GDE-1-6 above GC-240 enclosure, GDE-1-7 near V-5, GDE-1-8 near V-301, GDE-2-1 at north east side of GC-240 enclosure, GDE-2-2 near T-103 and GDE-2-3 inside GC-240 enclosure. Signals from the gas detectors are hard wired to the General Monitor Gas Detection Modules (model DC-119-311-120) in the control room panel CP-1. Gas monitors are tested monthly and records are maintained.

3.10.3 Fire Detection Systems: Fire and smoke detection is usually employed to detect and warn personnel of fire and smoke conditions and to initiate remedial action. Four Fire-eye type ultraviolet (UV) detectors are provided in an Edison loop around the well bay of the production deck. General Monitor Model FL3101 (UV) and twelve flame detectors protect the remainder of the production deck and sub-deck. Signals are returned to the General Monitor Fire Detection Module (FL802) in the control room panel CP-1. Fire detectors are tested monthly and records are maintained. The DCOR production deck Equipment Location Plan does not include a symbol for the Foam System push button station. (ELC - 3.10.3.01)

3.10.4 Aids to Navigation: The US Coast Guard no longer requires aids to navigation for Platform Eva. The beacons have been removed.

3.10.5 Communication: Communications systems are established to provide for normal and emergency operations. Systems used for emergency communication should have battery-operated supplies good for at least four hours continuous operation as required by API RP 14F. Hand held radios are located in the control room. A UPS capable of providing power for four hours supplies the communications equipment and hand held radio chargers.

Incoming Service: A fiber optic (FO) line is included with the incoming 34.5kV submarine cable from onshore (Fort Apache) to Platform Eva. The FO cable is connected to a modem located above the 34.5kV SF6 switch located at the main interrupter switchgear. The modem and switch are supplied with uninterruptible power from a UPS that is also located on top of the 34.5kV SF6 switch enclosure through a FO/Ethernet converter to the platform Ethernet. Three phone lines and one fax line extend from the converter panel in the switchgear room to the communications shelter on the drill deck where each phone line is converted from digital-to-analog signal for tie-in to the existing phone system.

Also in the switchgear room is located the bridge radios for communication to Platforms Edith and Esther. Communications equipment in the switchgear room is powered through a local UPS unit. The Tripp-Lite UPS unit with two external battery units has capacity to serve the communications equipment for 4 hours.

A radio base station in the communications shelter with a remote terminal in the control room provides radio communication with the crew boat. The antenna for the system is located on the drill deck communications shelter. Emergency power is supplied to a panel in the communications shelter from an emergency source of power.

Commercial TV reception to TVs in the control room and galley is provided by coax cable from an antenna on the heliport access stair.

3.10.6 General Alarms: General alarms shall be audible in all parts of the facility to notify personnel to abandon the facility or respond to an emergency. Red lights can be used in conjunction with the audible alarms. All general alarm sounding devices shall be identified by a sign at each device in red letters at least one inch high describing required personnel response.

The only signs observed were located in the control room. A label above each pushbutton identifies the pushbutton stations for each alarm. Some of these labels at the local stations are difficult to see and read. New readable labels and response signage are required to be installed. (ELC - 3.10.6.01) It is recommended the central paging system be used to



supplement instructions of a general alarm. Alarms are tested monthly and found to demonstrate adequate performance in the outdoor areas.

3.10.7 Cathodic Protection: The impressed current cathodic protection system consists of two cathodic protection rectifiers located in the MCC room and ten anode locations. Rectifier #1 is connected to the six anodes on the West side of the platform (below the drilling area). Rectifier #2 connects to four anodes on the East side. Both units appear to be operating.

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# Safety Management Programs Audit

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## **4.0 SAFETY MANAGEMENT PROGRAMS AUDIT**

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### **4.1 Goals and Methodology**

The goal of the Safety Management Programs Audit was to verify that DCOR uses an organized and systematic effort to identify and analyze the significance of potential hazards in the workplace to manage them and reduce the frequency and severity of undesirable events. DCOR's safety management programs are composed of organizational and operational procedures, design management, audit programs, and other methods defined by Occupational Safety and Health Administration (OSHA) and the Environmental Protection Agency (EPA). The Platform Eva audit commenced with a review of the Operations Manual, Standard Operating Procedures (SOPs), required emergency and spill response plans, training programs, and other key elements. These areas were reviewed before evaluating the other programs that are addressed in their Safety and Environmental Management Program.

### **4.2 Operations Manual**

The content and arrangement of Platform Eva's Operations Manual and SOPs comply with MRMD Regulation 2175 and are approved by DCOR's management. They are readily available in hardcopy, located in the operations office. DCOR is currently in the process of making electronic copies of their manuals and putting them on the company intranet. The manuals are written in a short, step-by-step, easy to read format by staff that are well versed in the subject matter or have worked the process. They also have sufficient detail so that personnel with limited experience or knowledge of the procedure can repeat it unsupervised. Operations validate the procedures contained within the manual before finalization. Whenever procedures are changed or added, the manuals are updated and reapproved. However, a thorough review noted that some of the operating information does not appear to be current and/or up-to-date, including content regarding facility security, contact phone list, flow diagram, and text information. (SMP – 4.2.01 thru 07)

DCOR SOPs and Operations Manual provide specific directives on what steps are to be taken or followed in carrying out procedures. They also include instructions on how to handle upset conditions as well as what operating personnel are to do in emergencies. For example, the operating procedures addressing operating parameters will contain operating instructions about pressure limits, temperature ranges, flow rates, what to do when an upset condition occurs, what alarms and instruments are pertinent if an upset condition occurs, and other topics. Another example of using operating instructions to properly implement operating procedures is in starting up or shutting down the platform.

### **4.3 Spill Response Plan**

An electronic version of DCOR's Oil Spill Response Plan (OSRP) Volume 1-Core, and Volume 2-Supplemental, Santa Barbara Channel and San Pedro Channel, Platforms, Onshore Facilities, and Associated Pipelines dated June 2012 (Revision 8-14) was reviewed as part of the Platform Eva audit. DCOR developed the OSRP to satisfy Federal and State Facility Response Plan requirements. The document defines specific procedures and plans for responding to discharges of oil into navigable waters and seeks to minimize damage to the environment. It identifies the resources needed to implement the plan and communicate

relevant information needed to respond to a spill in a clear, concise and easy-to-use format to manage containment, cleanup, and mitigate the effects of an oil spill.

The document also includes a current copy of the California Certificate of Financial Responsibility (COFR) and provides for an Incident Command system. Communication plans and protection strategies are likewise described in the plan. The contingency plan also identifies and ensures by contract the availability of personnel and equipment necessary to respond to all contingency plan requirements, as required by the California Department of Fish and Game, Office of Spill Prevention and Response (OSPR) regulations, CCR Title 14, Regulation 817.02. The following elements are addressed within the plan:

- Incident Command Organization
- Facility description
- Hazards Evaluation Study and potential worst case spill scenario evaluation
- On-water containment and recovery procedures
- Shoreline protection and clean-up
- Wildlife Care and Rehabilitation procedures
- Response procedures

The plan was found to adequately address the policies and procedures to prevent, evaluate, contain, mitigate, and review the effects of unauthorized discharges. DCOR operating personnel are familiar with name, contact person, and telephone numbers of the spill response organization.

4.3.1 Environmental Protection Agency (EPA) – Spill Prevention Control and Countermeasure (SPCC): The SPCC Plan is an EPA requirement. An electronic version of the SPCC Plan was reviewed for EPA Rule compliance. The plan is prepared following good engineering practices and provides operation, maintenance, and management strategies to lessen the potential of a spill or release of oil products. A licensed professional engineer and company management has approved the SPCC Plan. No action items were identified.

#### **4.4 Training and Drills**

DCOR has a comprehensive primary training program for new employees and continuing training that includes optional and compulsory training for all personnel. DCOR uses a combination of classroom and online computer based training known as Petro-Skills and Compliance Services to alert personnel to upcoming training requirements and maintain a history of all training activities.

Facility operations' training consists of on-site facility instruction. Operators are trained on the operation of the facility and safe work practices for the process. The on-the-job training process is hands on procedural performance and evaluation method. Both the lead operator and operations supervisor must sign off on the training and qualification. Next level promotion is based on progression through these operating requirement elements. Successful completion of the elements and a field competency demonstration is required before advancement to the next level can occur. Situational awareness training helps employees recognize abnormal operating conditions as well as what to do if an abnormal event occurs. A computer based training matrix tracks all training activities and is used to alert management and individual personnel of training requirements. All DCOR operating personnel receive Production Safety

Systems (T-2) Training online through Petro Skills. The course is designed to certify personnel working on offshore production platforms to operate, repair and maintain facilities and safety devices in accordance with the requirements described in Code of Federal Regulations (30 CFR 250), the Bureau of Safety and Environmental Enforcement (BSEE).

Compulsory OSHA and spill response training is also provided. DCOR conducts annual online training to satisfy Cal OSHA training requirements. This training consists of classroom instruction, field briefings, tabletop, equipment deployment drills and computer exercises/tests. Drills, exercises, and safety meetings are conducted on a regular schedule. Exercises, safety meetings, evacuation, and environmental training are held throughout the year. Spill response team members are trained in facility spill plan procedures. Exercises range from tabletop discussions to actual deployment of equipment and mobilization of staff. Most spill drills are unannounced, and personnel are given a scenario, which they must respond to accomplish. After the drill is complete, personnel review their actions to determine what worked well and if any improvements are necessary. If DCOR finds any significant deficiencies in the spill plan after a drill or exercise, the company will record the deficiencies and require changes to the plan. Plan revisions may require additional inspections, drills, and training.

Platform Eva personnel conduct morning safety meetings that include all persons performing work on the platform for both general and topic specific safety subjects. Training and pre-job safety meetings are recorded and documents retained. The audit team has observed that Platform Eva personnel recognize the importance of proper PPE and that the requirements are enforced. There were no action items identified regarding these safety elements.

#### **4.5 Safety Management Programs**

DCOR's Safety Management Program (SMP) is clearly understood and followed by all personnel. The policies and processes are part of an established business strategy and commitment towards continuous improvement. This commitment also requires compliance with safety, health and environmental rules and regulations. Management sets objectives for the organization to follow and the program's success can be related to a reduction of employee injuries. Hazards are identified, evaluated, controlled and managed so that employees, contractors, the public and the environment are protected.

DCOR uses a Behavior Based Safety (BBS) program, which uses a bottom-up approach (focusing on field employees), with top-down support from health and safety management. The safety program promotes interventions that are people-focused and incorporate one-to-one observations (JSA Cards) of employees performing routine work tasks. Timely feedback on safety-related behavior, in the form of coaching and mentoring is also part of the safety program. The BBS process is a proactive approach that encourages employees and contractors to identify hazards and the potential for accidents, in addition to assessing their own behavior as safe or unsafe. DCOR also relies on health and safety training, safety signs, job safety analysis, hazard control, and employee participation (safety meetings) to motivate safe behavior. Employee observations are measured and the frequency count of safe and at risk behaviors are tracked by management.

Assessment and feedback about DCOR's safety management programs can be found in CSLC's Safety Assessment of Management Systems (SAMS), which will be conducted

following this safety audit. The SAMS also provides significant benefits about human factors observations and assessments, which are described in the next section of this report. The SAMS is a separate effort from this safety audit and results are kept confidential between CSLC and the operating company.

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# Human Factors Audit

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## **HUMAN FACTORS AUDIT**

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### **5.1 Goals of the Human Factors Audit**

The primary goal of the Human Factors Audit is to evaluate the operating company's human and organizational factors by using the Safety Assessment of Management Systems (SAMS) interview process. The SAMS is planned to follow the safety and spill prevention audit of DCOR's Platform Eva and other facilities. Interview results are considered confidential between CSLC and DCOR and will be contained in a separate report.

SAMS was developed under the sponsorship of government agencies and oil companies from the United States, Canada, and the United Kingdom to assess organizational factors, enabling companies to reduce organizational errors, reduce the risk of environmental accidents, and increase safety. The assessment was divided into nine major categories to examine the following areas (The number of sub-categories or areas of assessment for each category are included in parentheses.):

- Management and Organizational Issues (9)
- Hazards Analysis (9)
- Management of Change (8)
- Operating Procedures (7)
- Safe Work Practices (5)
- Training and Selection (14)
- Mechanical Integrity (12)
- Emergency Response (8)
- Investigation and Audit (9)

Assessment of each of the sub-categories is derived from one main question with a number of associated and detailed questions to help better define the issues.

The SAMS process is not intended to generate a list of action items. Its purpose is to provide the company with a confidential assessment of where it stands in developing and implementing its safety culture and a benchmark for future assessments.

### **5.2 Human Factors Audit Methodology**

The CSLC Mineral Resources Management Division completed SAMS interviews with DCOR staff and sub-contractors in April of 2016. Interviews were evaluated according to SAMS guidelines. A separate confidential report summarizing the results was generated for the exclusive use and benefit of DCOR.



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# Appendices

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## Appendix A Acronyms

ADM	Administration
ANSI	American National Standards Institute
API	American Petroleum Institute
BAT	Best Achievable Technology
BBS	Behavior Based Safety
CEC	California Electrical Code
CFC	California Fire Code
CSLC	California State Lands Commission
EFI	Equipment Functionality and Integrity
ELC	Electrical
ESD	Emergency Shutdown
ESP	Electric Submersible Pump
FSL	Flow Safety Low
FSV	Flow Safety Valve
HF	Human Factor
H <sub>2</sub> S	Hydrogen Sulfide
kVA	KiloVolt Amperes
kW	Kilowatts
LACT	Lease Automatic Custody Transfer
MOC	Management of Change
MRMD	Mineral Resources Management Division
NEC	National Electrical Code
NFPA	National Fire Protection Association
OSHA	California Occupational Safety & Health Administration
OSPR	Office of Spill Prevention and Response
P&ID	Piping and Instrumentation Diagrams
PHA	Process Hazard Analysis
PM	Preventative Maintenance
PPE	Personal Protective Equipment
PRC	Public Resources Code
PSH	Pressure Safety High
PSHL	Pressure Safety High-Low
PSI	Pounds per Square Inch
PSL	Pressure Safety Low
PSM	Process Safety Management
PSV	Pressure Safety Valve
RP	Recommended Practice
SAFE	Safety Analysis Function Evaluation
SAC	Safety Analysis Checklist
SAMS	Safety Assessment of Management Systems
SCADA	Supervisory Control and Data Acquisition
SCBA	Self Contained Breathing Apparatus
SCE	Southern California Edison
SSV	Surface Safety Valve
TEC	Technical
UBC	Uniform Building Code

UFC  
VSD

Uniform Fire Code  
Variable Speed Drive

## Appendix B Best Practices

### 1.0 BEST PRACTICES

- |     |  |   |
|-----|--|---|
| 1.1 | Best Achievable Protection/ Best Achievable Technology<br>Inspection of Marine Facilities<br>CSLC Oil & Gas Operations | PRC 8750<br>PRC 8757<br>CSLC 2 CCR Art. 3 - 3.6 |
|-----|--|---|

### 2.0 FACILITY CONDITION AUDIT

- |     |   |   |
|-----|---|---|
| 2.1 | Methodology for Audit                                       |   |
| 2.2 | General Facility Conditions                                 |   |
|     | 2.2.1 <i>Housekeeping</i>                                   | CSLC 2123 & 6539  |
|     | 2.2.2 <i>Stairs, Walkways, Gratings, &amp; Ladders</i>      | CAL OSHA Title 8 CCR  |
|     | 2.2.3 <i>Escape/ Emergency Egress/ Exits</i>                | CAL OSHA 3215, 22, 25 & 6577  |
|     | 2.2.4 <i>Labels, Placards, &amp; Signs</i>                  | CAL OSHA & API RP 14J   |
|     | 2.2.5 <i>Security</i>                                       | CSLC 2123   |
|     | 2.2.6 <i>HAZMAT Storage</i>                                 | OSHA 29 CFR 1910.1200   |
| 2.3 | Field Verification of Plans                                 |   |
|     | 2.3.1 <i>PFDs</i>   | API RP 14J  |
|     | 2.3.2 <i>P&amp;ID</i>                                       | API RP 14J  |
|     | 2.3.3 <i>Fire Protection Drawings</i>                       | API RP 14J (6.4.3)  |
| 2.4 | Condition and Integrity of Major Systems                    |   |
|     | 2.4.1 <i>Piping</i>   | ANSI 31.3   |
|     | 2.4.2 <i>Tanks</i>  | CSLC 2132(g)(2), API Spec 12 R1 & API RP 653                                |
|     | 2.4.3 <i>Pressure Vessels</i>                               | CSLC 2132(g)(2), ASME Boiler & PV Code Sect. VIII & API RP 510 PV Insp Code |
|     | 2.4.4 <i>Pressure Relief, PSVs and Flare Sys</i>            | CSLC 2132(g)(3), API RP 14J, 520, 521 & 576                                 |
|     | 2.4.5 <i>ESP, Pump Units &amp; Wellhead Equip</i>           | CSLC 2132(a)(4)   |
|     | 2.4.6 <i>Fire Detection</i>                                 | CSLC 2132(g)(1)(C) & NFPA   |
|     | 2.4.7 <i>Fire Fighting Equipment and Systems</i>            | CSLC 2132(g)(4) & NFPA  |
|     | 2.4.8 <i>Combustible Gas &amp; H<sub>2</sub>S Detection</i> | CSLC 2132(g)(5) & (6)   |
|     | 2.4.9 <i>Emergency Shutdown Device</i>                      | CSLC 2132(g)(1) & API RP14J   |
|     | 2.4.10 <i>Safety &amp; Personnel Protective Equip</i>       | CAL OSHA  |
|     | 2.4.11 <i>Lighting</i>                                      | CAL OSHA  |
|     | 2.4.12 <i>Instrumentation, Alarm, &amp; Paging</i>          | CSLC 2132(g)(1)&(2), API RP 14J & 8 CCR 5189                                |
|     | 2.4.13 <i>Auxiliary Generator/Prime Mover</i>               | CSLC 2132(g)(7)   |
|     | 2.4.14 <i>Spill Containment</i>                             | CSLC 2139 & 2140, 40 CFR 112.7(c) & GOV CODE 8670                           |
|     | 2.4.15 <i>Spill Response</i>                                | CSLC 2139 & 2140 & GOV CODE 8670  |
|     | 2.4.16 <i>Cranes</i>  | CAL OSHA & API RP 2D  |
| 2.5 | Mechanical Integrity  | CSLC 2129(c) & CAL OSHA 8 CCR 5189 (j)                                      |
| 2.6 | Offshore Production Safety Systems                          | CSLC 2132 (g)(1), API RP 14C, 14J, 75 & 29 CFR 1910                         |

Onshore Production Safety System

CSLC 2132 (g)(1), CAL OSHA 8 CCR 5189, 29 CFR 1910 & API RP 51R

**3.0 ELECTRICAL AUDIT**

- 3.1 Goals and Methodology
- 3.2 Hazardous Area Electrical Classification Dwgs RP 500, NFPA 70, 496 & CEC 500 & 501
- 3.3 Electrical Power Dist. System, Normal Power
  - 3.3.1 *Electrical Single Line* API RP 540, NFPA 70 & CEC 110 & 500.5
  - 3.3.2 *Electrical Service Capacity* API RP 540, NFPA 70 & CEC 408.4
  - 3.3.3 *Electrical System Design* API RP 540, NFPA 70 & CEC 110, 240 & 408.4
- 3.4 Elec. Power Equip Condition and Functionality
  - 3.4.1 *Materials & Installation* API RP 540, NFPA 70 & CEC 110, 314, 490 & 501
  - 3.4.2 *Safety Procedures* API RP 540, NFPA 70 & CEC 110, 314, 490 & 501
  - 3.4.3 *Equipment Maintenance Practices* API RP 540, NFPA 70 & CEC 110, 314, 490 & 501
- 3.5 Grounding API RP 540, NFPA 70 & CEC 250, 408.40 & 501.30
- 3.6 Emergency Electrical Power API NFA 70 & 110 & CEC 110 & 700
  - 3.6.1 *System Configuration* API NFA 70 & 110 & CEC 110 & 700
  - 3.6.2 *Equipment & Component Ratings* API NFA 70 & 110 & CEC 110 & 700
- 3.7 Electric Fire Pumps API RP 14F, NFPA 20, NEC 696 & CEC 110 & 700
- 3.8 Process Instrumentation API RP 14F & 540 & NFPA 70
- 3.9 Standby Lighting API RP 14F
- 3.10 Special Systems
  - 3.10.1 *Safety Control Systems* API RP 14C & CEC 110
  - 3.10.2 *Gas Detection System* API RP 14C
  - 3.10.3 *Fire Detection System* API RP 14F & 14G & API 2001
  - 3.10.4 *Aids to Navigation* Coast Guard & CEC 110
  - 3.10.5 *Communication* API RP 14F & CEC 110
  - 3.10.6 *General Alarm* API RP 14F & CEC 760
  - 3.10.7 *Cathodic Protection* API RP 651, NACE RP 01-76 & 0675 & CEC 110 & 250

**4.0 SAFETY MANAGEMENT PROGRAMS AUDIT**

- 4.1 Goals and Methodology API RP 75 SEMP, OSHA 29 CFR 1910.119 & CAL OSHA 8 CCR 5189
- 4.2 Operations Manual OSPR PRC 8758
- 4.3 Facility Oil Spill Response Plan OSPR GOV CODE 8670
  - 4.3.1 EPA – SPCC 40 CFR 112
- 4.4 Training and Drills CSLC 2175 (b)(6)(C, D) & (b)(7)(A,B,C,D) & OSPR GOV CODE 8670

4.5 Safety Management Programs

API RP 75 SEMP,  
OSHA 29 CFR 1910.119 &  
CAL OSHA 8 CCR 5189

**5.0 HUMAN FACTORS AUDIT**

5.1 Goals of the Human Factor Audit  
5.2 Human Factors Audit Methodology

CAL OSHA 8 CCR 5189,  
API RP 75 & CSLC Safety Audit of  
Mgmt Systems (SAMS)

## Appendix C References

### GOVERNMENT CODES, RULES, AND REGULATIONS

CSLC	California State Lands Commission
2123	Lease Operations on Uplands
2129	Article 3.3 -Oil and Gas Production Regulations
2132	Production Regulations
2139	Oil Spill Contingency Plan
2140	Pollution Control and Removal Equipment
2173	General Requirements – Operations Manual
2174	Manual Review
2175	Manual Content
Cal OSHA	California Occupational Health and Safety
3215	<i>Means of Egress</i>
3222	<i>Arrangement and Distance to Exits</i>
3225	<i>Maintenance and Access to Exits</i>
3308	<i>Hot Pipes and Hot Surfaces</i>
3340	<i>Accident Prevention Signs</i>
5189	<i>Process Safety Management of Acutely Hazardous Materials</i>
6533	<i>Pipe Lines, Fittings, and Valves</i>
6551	<i>Vessels, Boilers and Pressure Relief Devices</i>
6556	<i>Identification of Wells and Equipment</i>
CCR	California Code of Regulations
1722.1.1	<i>Well and Operator Identification</i>
1774	<i>Oil Field Facilities and Equipment Maintenance</i>
1900-2954	<i>California State Lands Commission, Mineral Resources Management Division Regulations</i>
CFR	Code of Federal Regulations
29 CFR	<i>Part 1910.119 Process Safety management of Highly Hazardous Chemicals</i>
30 CFR	<i>Part 250 Oil and Gas Sulphur Regulations in the Outer Continental Shelf</i>
33 CFR	<i>Chapter I, Subchapter N Artificial Islands and Fixed Structures on the Outer Continental Shelf</i>
40 CFR	<i>Part 112, Chapter I, Subchapter D Oil Pollution Prevention</i>
49 CFR	<i>Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standard</i>
49 CFR	<i>Part 195, Transportation of Liquids by Pipeline</i>

## INDUSTRY CODES, STANDARDS, AND RECOMMENDED PRACTICES

ANSI	American National Standards Institute
B31.3	<i>Petroleum Refinery Piping</i>
B31.4	<i>Liquid petroleum Transportation Piping Systems</i>
B31.8	<i>Gas Transmission and Distribution Piping Systems</i>
Y32.11	<i>Graphical Symbols for Process Flow Diagrams</i>
API	American Petroleum Institute
RP 2D	<i>Operation and Maintenance of Offshore Cranes</i>
RP 14B	<i>Design, Installation and Operation of Sub-Surface Safety Valve Systems</i>
RP 14C	<i>Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms</i>
RP 14E	<i>Design and Installation of Offshore Production Platform Piping Systems</i>
RP 14F	<i>Design and Installation of Electrical Systems for Offshore Production Platforms</i>
RP 14G	<i>Fire Prevention and Control on Open Type Offshore Production Platforms</i>
RP 14H	<i>Use of Surface Safety Valves and Underwater Safety Valves Offshore</i>
RP 14J	<i>Design and Hazards Analysis for Offshore Production Facilities</i>
RP 51	<i>Onshore Oil and Gas Production Practices for Protection of the Environment</i>
RP 55	<i>Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide</i>
RP 500	<i>Classifications of Locations for Electrical Installations at Petroleum Facilities</i>
RP 505	<i>Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2</i>
API 510	<i>Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration</i>
RP 520	<i>Design and Installation of Pressure Relieving Systems in Refineries, Part I and II</i>
RP 521	<i>Guide for Pressure-Relieving and Depressuring Systems</i>
RP 540	<i>Electrical Installations in Petroleum Processing Plants</i>
RP 550	<i>Manual on Installation of Refinery Instruments and Control Systems</i>
RP 570	<i>Piping Inspection Code</i>
RP 651	<i>Cathodic Protection of Aboveground Petroleum Storage Tanks</i>
Spec 6A	<i>Wellhead Equipment</i>
Spec 6D	<i>Pipeline Valves, End Closures, Connectors, and Swivels</i>
Spec 12B	<i>Specification for Bolted Tanks for Storage of Production Liquids</i>
Spec 12J	<i>Specification for Oil and Gas Separators</i>
Spec 12R1	<i>Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service</i>
Spec 14A	<i>Subsurface Safety Valve Equipment</i>
ASME	American Society of Mechanical Engineers



*Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels," Div. 1 and 2*

ISA	Instrument Society of America
55.1	<i>Instrument Symbols and Identification</i>
102-198X	<i>Standard for Gas Detector Tube Units – Short Term Type for Toxic Gases and Vapors in Working Environments</i>
S12.15	<i>Part I, Performance Requirements, Hydrogen Sulfide Gas Detectors</i>
S12.15	<i>Part II, Installation, Operation, and maintenance of Hydrogen Sulfide Gas Detection Instruments</i>
S12.13	<i>Part I, Performance Requirements, Combustible Gas Detectors</i>
S12.13	<i>Part II, Installation, Operation, and Maintenance of Combustible Gas Detection Instruments</i>
NACE	National Association of Corrosion Engineers
RPO169	<i>Control of External Corrosion on Underground or Submerged Metallic Piping Systems</i>
NFPA	National Fire Protection Agency
20	<i>Stationary Pumps for Fire Detection</i>
25	<i>Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems</i>
70	<i>National Electric Code</i>
704	<i>Identification of the Hazards of Materials for Emergency Response</i>
CEC	California Electric Code

## **Appendix D Team Members**

### **FACILITY CONDITION TEAM**

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry David Calderon
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DCOR	Shane Grinnell Chris Yorba Matt Civitelli
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### **ELECTRICAL TEAM**

CSLC – MRMD	Mark Steinhilber David Rodriguez
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PES	Doug Effenberger
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DCOR	Dennis Conley
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### **TECHNICAL TEAM**

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry Steve Staker David Calderon
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DCOR	Dennis Conley Matt Civitelli
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### **SAFETY MANAGEMENT TEAM**

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry Steve Staker David Calderon
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DCOR	Scott Knight
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