Safety and Oil Spill Prevention Audit

DCOR, LLC

Platform Esther

March 2024

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Executive Summary

DCOR, LLC

Platform Esther

March 2024

EXECUTIVE SUMMARY

Safety and Oil Spill Prevention Audit of DCOR, LLC (DCOR), Platform Esther

A Safety and Oil Spill Prevention Audit of DCOR, LLC's Platform Esther began in June 2022. Safety and Oil Spill Prevention Audit Team fieldwork was completed in December 2023. The electrical portion of the audit was performed by a third-party – P2S, Inc. – whose fieldwork was completed in June 2023.

The objective of this Safety and Oil Spill Prevention Audit is to ensure that oil and gas production facilities on State granted lands are operated in a safe and environmentally sound manner, comply with state and federal regulations, and meet the Best Achievable Protection (BAP) requirement of Public Resources Code 8755. This audit followed the established procedures that have been used by the California State Lands Commission (Commission) for many years. Applicable regulations and standards used during this audit are provided in Appendix C. Audit findings are based on and reference these regulations and standards.

Company Background

DCOR, LLC (DCOR) is the current owner and operator of Platform Esther. The company was formerly known as Dos Cuadras Offshore Resources, LLC and changed its name to DCOR, LLC in 2005. DCOR was founded in 2001 and is based in Oxnard, California with additional offices in Dallas, Texas. DCOR operates two offshore oil production platforms within State waters. The company is owned and controlled by Mr. William M. Templeton.

Facility Description

Platform Esther is an offshore oil and gas production facility operating within the boundaries of California State Waters in the Belmont Oil Field. The facility is located roughly 1.5 miles offshore of Seal Beach, California on State Lease PRC 3095.1 in thirty-eight feet of water.

Platform Esther is a permanent, fixed base, drilling and production platform. The field produces approximately 350 barrels of oil per day, 7500 barrels of water per day, and 200 thousand cubic feet per day (MCFD) of natural gas. There are 23 production wells and seven water injection wells. At least two operating personnel per shift continually operate the platform. Visitors and contract personnel vary depending on platform operations and maintenance activities.

The oil producing formations are below hydrostatic pressure and require artificial (mechanical) lift to produce. Thus, the potential for a well blowout is small. The offshore wells are produced using electric submersible pumps.

Safety Audit Results

The Safety and Oil Spill Prevention Audit found that Platform Esther complies with applicable safety and regulatory requirements apart from the items listed in the action item matrix. 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 the steel plate flooring on the Drill Deck.

DCOR has established behavior-based safety policies, health, and environmental programs. Operations personnel are knowledgeable and provided valuable assistance to the State Lands Audit Team. The established safety culture also helps to ensure the protection of workers, the public, and the environment.

Safety systems and equipment remain fit for service. However, a few pressure vessels were past due for external inspections. Without consistent inspection and condition assessments the equipment may not meet the intended requirements under operating and upset conditions. Risk reduction and environmental protection can only be ensured through scheduled inspections, testing, and preventive maintenance practices.

Action items from the audit are categorized into three subject areas: equipment function and integrity (EFI), electrical (ELC), and safety management programs (SMP). Each of these action items are assigned a priority ranking from one to three: priority one action items pose a high or immediate risk to personnel, the facility, or the environment and must be resolved within 30 days of this report; priority two action items pose a moderate risk potential and must be resolved within 120 days; and priority three action items pose a low-risk potential and must be resolved within 180 days.

The Mineral Resources Management Division (MRMD) Safety Audit Team identified a total of 100 action items, a 61% increase from the previous audit. The current audit found no priority one action items. The number of priority two action items increased to nine from six in the previous audit. The number of priority three action items increased from 56 to 91. This is a favorable result as the number of action items is on par with comparable facilities.

Figure 1 displays the distribution of the action items by subject areas. This distribution is similar to other facilities in California where the items identified are typically related to process equipment, maintenance practices, and electrical systems.

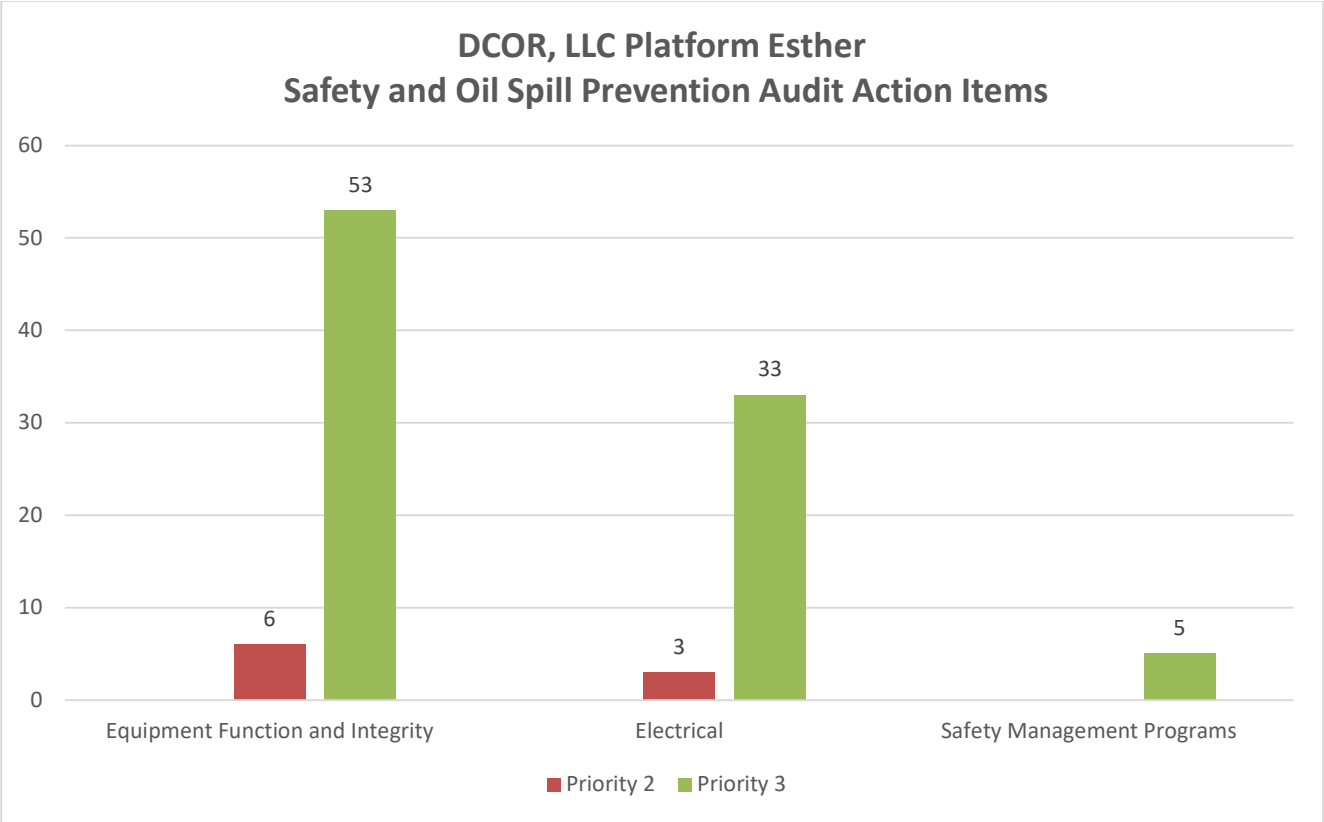

FIGURE 1. DCOR, LLC PLATFORM ESTHER ACTION ITEMS

Introduction

DCOR, LLC

Platform Esther

March 2024

1.0 INTRODUCTION

1.1 Safety Audit Background

The California State Lands Commission (Commission) Mineral Resources Management Division (MRMD) conducts safety and oil spill prevention audits of operators and/or contractors for lands in which the State has an interest. Commission sponsored safety audits ensure oil and gas production facilities on State leases or granted lands are operated in a safe and environmentally sound manner and comply with Federal, State, and Local codes or permits, as well as industry standards and practices. Commission staff are tasked with oil spill prevention in California's ocean and tidelands, prevention of waste, conservation of natural resources, and ensuring that safety and health standards are being met. Public Resources Code (PRC) 6103, 6108, 6216, 6301, 6873(d), 8755, and 8757 provide authority for Commission regulations, as well as the Safety and Oil Spill Prevention Audit Program.

In 1990, the California Legislature enacted the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (California Government Code 8670.1). The Act covers all aspects of marine oil spill prevention and response in California. Under the legislation, marine facilities must provide the Best Achievable Protection (BAP) of the coast and marine waters.

Frequent monitoring and inspections by MRMD staff of onshore and offshore oil and gas drilling and production facilities ensure that BAP is in place to safeguard the public and environment. The MRMD Safety Audit Program, in conjunction with the monthly inspection program, helps prevent oil spills and other accidents with on-site inspection and verification activities. The Safety Audit Program also aids prevention through design review of facility producing, processing, and safety systems, maintenance condition, operating procedures, emergency plans, training and certification programs, human factors, and other aspects of safety management.

During a safety and oil spill prevention audit, MRMD team members systematically assess an organization's facilities, review operating procedures and other safety management programs, identify action items to be addressed, and provide feedback for improvement through preparation of a written report. The areas of emphasis include:

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

Appropriate company contacts and resources are identified prior to the start of the safety audit. Progress reports are communicated to MRMD management personnel and the company throughout the safety audit process and an "action item matrix" has been developed to categorize and track action items. The matrix contains recommended corrective actions and a priority ranking for the specified corrective actions. A graph and table are generated showing the breakdown of the facility's identified action items by area of emphasis.

Draft copies of the report and the action item matrix are provided to the company during the safety audit. The final report is presented to company management formally, which affords

the opportunity to discuss the findings and the corrective actions proposed. Throughout the clearance phase of the safety audit, the MRMD team continues to communicate with the company in resolving the action items and tracks the progress of the corrective actions taken.

This program could not be successfully undertaken without the cooperation and support of the operating company. The safety audit benefits both the company and the State by reducing workplace hazards, environmental accidents, property damage, and oil spills. Previous experience shows safety assessments help increase operating effectiveness, efficiency, and lower operating costs.

1.2 Facility Background

Platform Esther is an offshore oil and gas production facility operating within State waters in the Belmont Oil Field. The facility is located approximately 1.5 miles offshore of Seal Beach, California, on State Oil and Gas Lease PRC 3095.1 in thirty-eight feet of water. Esther was originally installed as a manmade island by Chevron in 1964.

Ninety wells were drilled on the island and initial production began in September 1965. In January 1983, a storm struck and washed away the island and facilities, leaving only well casings above the ocean surface. Chevron temporarily abandoned all the wells by cementing the exposed casings using a workboat. Construction of the platform began in October 1984, and was completed one year later. At that time, all but 21 wells were plugged and abandoned. In December 1988, the Commission approved the Chevron Lease assignment of Lease 3095 to Unocal. Production testing began in May of 1991 and offshore processing facilities were placed online in late 1995. The facility has since had various owners and operators including Unocal, Nuevo Energy Company, and Plains Exploration and Production Company.

Platform Esther is currently owned and operated by DCOR, LLC (DCOR). DCOR is an oil and natural gas exploration and production company with offices in Ventura, California and Dallas, Texas. DCOR explores for, produces, gathers, processes and markets crude oil, natural gas, and natural gas liquids. They own and operate eleven platforms offshore California, two of which are in state waters (Platforms Eva and Esther).

1.3 Facility Description

Platform Esther is a permanent, fixed base, sixty-four-slot drilling and production platform which is anchored to the ocean bottom with pilings at the bottom of the legs. At least two operating personnel per shift continually operate the platform and monitor operations. Transit to the platform is provided by SoCal Ship Services crew boat from Seal Beach. Visitors and contract personnel vary depending on platform operations and maintenance needs.

The platform consists of a drill deck, production deck, a mezzanine area between drill and production decks, two sub decks, and a lower level. The Drill Deck houses the diesel crane, electric crane, chemicals, maintenance equipment area, sorbent booms, and other equipment to support drilling and workover operations. The Production Deck is separated into two sections by a firewall. The South side houses the well bay, which includes the production and injection wellheads and their flow lines. The North side contains the control room, weld shop, electrical switchgear, motor control center, and other equipment required to support platform operations.

The Production Deck also contains the process tanks, pressure vessels, and pumps. The two small sub decks, located just below the Production Deck, contain wastewater collection tanks and pumps, which are used to capture and separate hydrocarbon fluids recovered from process and gravity drains, including rainwater. The lowest level or boat access deck is referred to as the 10ft. level, and it is comprised of grated walkways enabling access to much of the platform's lower structure. The 10ft. level is the deck that provides direct access to the crew boat landing area where personnel are transferred on and off the platform. The 10ft. level can also serve as an area for diving operations to allow inspection of the platform legs and under structure.

Platform Esther has 23 production wells and seven water injection wells. The produced fluids are separated onboard and all produced water is re-injected. The field is currently producing approximately 350 barrels of oil per day (BOPD), 7500 barrels of water per day (BWPD), and 200 thousand cubic feet per day (MCFD) of natural gas. Esther's metered oil pumped to shore via a 3-inch oil line, which ties into Crimson Pipeline at an onshore ground vault and the produced gas is shipped by a 10-inch subsea pipeline to shore.

Facility Condition Audit

DCOR, LLC

Platform Esther

March 2024

2.0 FACILITY CONDITION AUDIT

2.1 Goals and Methodology

The goal of the facility condition portion of the audit was to evaluate the current equipment maintenance and integrity of Platform Esther. The on-site field work involved systematic inspection and evaluation of the different systems, equipment, and facilities using various checklists and methods that the team has developed over the years of auditing. A variety of codes and standards apply in addition to California State Lands Commission (Commission) regulations. Initial tasks to accomplish this goal included field verification of the key drawings/plans, overall condition inspection and evaluation, review of system and equipment maintenance histories, further evaluation of specific systems and equipment using checklists, technical review of safety systems design, and verification of compliance with applicable state regulations and industry codes. The layout of the audit report generally follows a "system by system" method that includes a description and assessment of the facilities with any significant observations. The report addresses the safety of personnel as well as facility and process safety. The assessments of both areas of safety are important when identifying an organization's current level of safety program development.

2.2 General Facility Conditions

2.2.1 Workplace Housekeeping: Platform work areas were clean and orderly, free of slip and trip hazards, waste materials (e.g., refuse, oilfield wastes), and fire hazards. Acceptable refuse containers were provided, and no noticeable waste was on the platform. Regularly scheduled collection of waste contributes to good housekeeping practices. Employee facilities are adequate, clean, and well maintained. DCOR contracts American Integrated Services to service Platform Esther's RedFox Environmental marine sewage treatment unit. Restrooms are supplied with plenty of handwash, paper towels, and there are no other obvious health or sanitation concerns. The marine treatment unit used is certified and meets International Maritime Organization (IMO) & United States Coast Guard (USCG) standards (ex. IMO Marine Environmental Protection Committee (MEPC) 227(64)).

Drip pans and a constructed containment drain system are used throughout the platform to prevent runoff and pollution from deck wastes. If a substance accidentally drips onto the deck, personnel clean it up immediately. Absorbent materials are stored in quickly accessible drum-tote containers or bins and are available for wiping up greasy, oily residue or other liquid spills. Tools are available and stored in suitable fixtures for easy access. They are returned after each use and regularly inspected, cleaned, and taken out of service if visibly worn or damaged. Management policies require workers to pay attention to good housekeeping practices as a basic part of accident and fire prevention.

2.2.2 Stairs, Walkways, Gratings and Ladders: In general, aisles, passageways, stairs, and gratings had sufficient safe clearances, were in good repair, and were clear with no obstructions across or in the aisles to create a hazard. Although corrosion is an ongoing problem for offshore platforms, repairs of steel plate flooring and walkways were taking place at the time of the audit. Sections of the grating on the boat landing level have been severely damaged and need to be replaced. (*Action Item EFI 2.2.2.01*). Some steel plate flooring and walkways on Platform Esther were in poor to severe condition due to the effects of pitting, oxidation, and corrosion primarily in various areas on the south side of the Drill Deck and Production Deck

mezzanine level. (*Action Item EFI 2.2.2.02*). Safeguards were in place in almost all places where there was a need to transition between levels and for routine access to equipment. The elevated work platforms to access the separator vessels (V-5, V-6, and V-7) did not have appropriate safeguards at the fixed ladder openings. (*Action Item EFI 2.2.2.03*). Portable ladders were observed to be in good usable condition and free from oil and grease. Fixed metal ladders and appurtenances were painted to resist corrosion against environmentally harsh conditions. DCOR's safe work practices cover the use and care of ladder equipment in the facility.

2.2.3 Escape / Emergency Egress / Exits: Emergency egress/exit points are clearly marked, accessible, and are covered as part of the initial orientation training to access Platform Esther. Evacuation routes are also reviewed during safety meetings and as part of the work permit system. They are identified with signs posted throughout the platform. During an upset condition, the audible difference in the alarm tones as well as announcements over the public-address (PA) system directs personnel to the appropriate safe briefing area.

Windsocks are located for maximum visibility and appeared to be in good condition. Crew boats are typically used for transport for both operating and contract personnel working on the platform and during emergency evacuation. Evacuation by life raft or helicopter are also options. The design of Platform Esther's primary and secondary or emergency boat landings are considered adequate for their use. 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 define specific workplace hazards. DCOR adheres to the Occupational Safety and Health Administration (OSHA) regulations and American National Standards Institute (ANSI) recommendations. All employees receive instruction on what the signs signify and what, if any, special precautions are necessary to perform their tasks safely. Workplace hazards (e.g., slip, trip, overhead clearance) are marked in yellow. An identifiable red protective coating on fire service piping is required by the National Fire Protection Association (NFPA) and is provided on most piping.

Warning signs were posted properly to identify known safety hazards. They were visible and identified safety hazards, though some signs could be refreshed for legibility. Signs are also posted at each wellhead to identify the lease and well number.

NFPA 704 hazard identification labeling, hazard diamonds, were visible on all tanks, vessels, and chemical storage totes. The posting of hazard diamonds is an indication of good facility emergency planning and conformance with good oilfield practice.

2.2.5 Security: Physical and operational security measures are in place on Platform Esther to prevent unauthorized entry. The platform is staffed twenty-four hours a day, seven days a week with at least two operators during normal operations. There is a limited route of access from the boat landing and restricted access signs are posted which are visible from all sides. Personnel traveling to the platform must be prelisted on an approved crew boat log before boarding. Ship Services deckhands check that each person's name appears on the boat log, as well as checking for proper identification and swing rope certification.

2.2.6 Hazardous Material Handling and Storage: Flammable and combustible liquids were found properly stored and documentation readily available, corresponding to Cal/OSHA

and NFPA 30 regulations. The bulk chemical totes and diesel storage were correctly labeled, appeared structurally sound, and had adequate containment in the event of a leak. Some chemical totes lacked bonding or grounding and some bolts were corroded or missing that would improve structural stability. No loose combustible material or opened empty totes/drums were seen on the premises.

Stored compressed gas cylinders were secured and legibly marked to identify the gas content. Empty and unused cylinders had closed valves with protection caps in place. Cylinders were placed where they would not be knocked over or damaged.

Safety Data Sheets (SDS) containing information on all chemicals used in the workplace were up-to-date and accessible to all employees through the company intranet and within the operations control room.

2.3 Field Verification of Plans

2.3.1 Process Flow Diagrams (PFD) and Equipment Location Plans (ELP): The PFDs are part of the process safety design information for the facility and indicate the general flow of plant processes and equipment. The ELPs illustrate the location of pieces of equipment, including safety equipment, and where they are relative to other pieces of equipment. Some minor changes were needed on the ELPs to reflect current equipment and placement. (*Action Items EFI 2.3.1.01 – 2.3.1.03*)

2.3.2 Piping and Instrumentation Diagrams (P&ID): Field verifications of the P&IDs were reasonably accurate; however, minor updating is required. The discrepancies in the P&IDs included valve sizing and piping identification errors, missing equipment and out of service or removed equipment. (*Action Items EFI 2.3.2.01 – 2.3.2.21*)

2.3.3 Fire Protection Drawings: Firewater / Foam Utility Flow Diagrams were available and reviewed for accuracy. These drawings show important information about the fire-fighting system including the electrical and diesel fire pumps, the fire main, and distribution system. The location of main pipeline valves, deluge system, foam system, hose reels, and emergency connections are all clearly identified; however, some updating is required.

2.4 Condition and Integrity of Major Systems

2.4.1 Pumps and Piping: An external visual inspection of the piping systems at all locations on the platform was performed in conjunction with P&ID verification. This visual inspection and evaluation work observed the condition of the piping, painting, and coating, as well as checked for signs of misalignment, vibration, or leakage. The evaluation of the condition of pipe hangers and supports appeared to be in good condition, though some supports were missing from piping throughout the platform. The evaluation considered other key information such as material selection, piping design, maintenance practices, as well as any field modifications or temporary repairs not recorded on the piping drawings. The selection process of piping materials and components (e.g., valves, flanges, bolts, welds, transitions, and connections) are compatible with the operating parameters and environment. The condition and maintenance of piping throughout the facility were found to be generally good, though some areas showed oxidation and possible surface corrosion. Commission staff recommends that DCOR conduct piping evaluation/analysis of all piping and that exposed piping be protected with

a coating system which has been proven acceptable in a marine environment. (*Action Items EFI 2.4.1.02 – 2.4.1.03*)

DCOR uses a combination of ongoing routine and risk-based piping inspections to achieve the desired level of facility safety, environmental protection, and reduce unscheduled downtime. Inspection frequencies and condition changes are set up according to regulatory requirements and established guidelines (i.e., American Petroleum Institute (API) 570, American Society of Mechanical Engineers B31.3, National Association of Corrosion Engineers (NACE) guidelines, NFPA, etc.). Results from thickness measurements, inspections, repairs, and other tests are readily available and recorded within a computer-based Microsoft Access database. A software-based maintenance management system called Mainsaver is used to generate work orders for maintenance and inspection activities.

2.4.2 Tanks: The tanks on Platform Esther appear to be in good condition and have been inspected within API 653 guidelines. Facility tanks are subject to DCOR's written inspection and maintenance plan, which follows API Recommended Practices (RPs) and standards. The maintenance strategy also conforms to applicable State regulations and uses appropriate work practices and procedures. Routine internal inspections occur on a ten year cycle for tanks handling slop oil. External inspections occur on a five year cycle for tanks handling slop oil and fifteen year cycle for tanks handling water and sewage treatment. Tank documentation includes inspections, repairs, alterations, and reconstruction records. In addition, tank shell ultrasonic thickness data showing locations and results are completed as part of the inspection process. This inspection method searches for flaws and service induced damage as part of determining the suitability of the tank for the intended service. Tank exterior coatings, piping, valves, walls, anchor bolts, and labeling appeared to be in good condition with no evidence of recent damage or active leaks.

2.4.3 Pressure Vessels: Platform Esther pressure vessels are also maintained following a program of external and internal examination for compliance with applicable regulations, recommended practices (e.g., API 510 and Cal. Code Regs, tit. 2, § 2132, subd. (g)(3)), and recordkeeping. These pressure vessels are built according to the American Society of Mechanical Engineers (ASME) Codes and have appropriate controls and safety devices. To improve maintenance efficiency, DCOR has tailored inspection cycles to match the safety risks posed by particular classes of pressure vessels. DCOR's Mechanical Integrity Engineer uses vessel wall thickness, corrosion allowance, and minimum thicknesses (t-mins) as well as operating temperature and pressures to determine the inspection frequency. External vessel inspections are completed within 5-year intervals, while internal inspections and thickness measurements are completed within 10-year intervals using non-destructive examination techniques.

Analysis of inspection records determined that inspection frequency is being achieved following API 510 guidelines for the majority of pressure vessels. Inspection recommendations, maintenance activities, and design information are documented and recorded within the pressure vessel's permanent record. External inspection of the pressure vessels found no evidence of leakage, distortion, or cracks at welds or structural attachments, or defects of connections. Internal inspection records show acceptable corrosion rates with no major concerns or defects of the pressure vessels. However, records identified four pressure vessels

with no reported external inspection within the required timeframes. (*Action Items EFI 2.4.3.03 – 2.4.3.06*).

2.4.4 Relief Systems: The main 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 system serves the major process vessels and components while other relief devices may be located on smaller ancillary components. It is designed with a vent stack, flame arrestor, and a scrubbing vessel to remove liquid hydrocarbons. If any relief 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 while preventing flames traveling back through the system, should the mixture be ignited, in order to prevent a larger fire or explosion. The flame arrestor is inspected annually for clogging. No deficiencies were noted.

The maintenance and servicing records for all pressure safety valves (PSVs) comply with applicable regulations and recommended standards (e.g., Cal. Code Regs, tit. 2, § 2132, subd. (g)(3), API Standard (Std) 520, API Std 521, and Cal/OSHA 6551). PSVs were last tested and serviced in September 2023 by Instrument Control Services (ICS) (Contractors License# 732921). Service records were in order with no action items identified.

2.4.5 ESP, Pump Units, Wellhead Equip.& Well Safety Systems: Safety devices (Pressure Safety Highs/Pressure Safety Lows which deactivate power to the Electrical Submersible Pumps (ESPs)) were verified to be installed on producing wells and flow lines. Monthly safety inspections as required by Commission regulations on Platform Esther are performed jointly by Commission staff inspectors and Esther operators to verify the safe function and operation of all safety devices and automatic shutdown systems and to verify production system integrity. No problems were noted.

2.4.6 Firefighting Detection Systems: MRMD regulations and other facility fire protection requirements include fire detection and alarm systems. These systems are intended to provide early warning and notification of a fire situation. The fire alarm to warn personnel may be activated manually or automatically by the detection sensors. Systems typically include:

- Smoke Detectors
- Heat Detectors
- Ultraviolet and Infrared (UV/IR) Detectors
- Gas Detectors
- Hydrogen Sulfide (H_2S) Detectors

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 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 platform shut-in sequence when concentrations reach 45%. These settings more than meet the required standards of 60% and 80% respectively per California Code of

Regulations, title 2, section 2132, subdivisions (g)(5(C) & (D). The UV/IR detectors found in the well bay and production area of the platform will activate the fire alarm, emergency shutdown (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_2S detectors operation during monthly testing and records the results. No discrepancies were noted.

The fire detection systems on Platform Esther meet MRMD regulations (e.g., Cal Code Regs. tit. 2, § 2132, subd. (g)(1), (g)(4), (g)(5) & (g)(6)(A)) and are appropriate in design and scope. These systems appear to be well maintained and in good operating order with no action items identified.

2.4.7 Firefighting Equipment: The main firefighting system consists of a pressurized fire main system with two fire pumps, foam system, hose reel stations, and a deluge system that covers both the well-bay and Production Deck. The firewater jockey pumps (P-10/P-11) maintain the header pressure at approximately 150 psig. The 400 horsepower electrical-driven firewater pump (P-8) operating on a pressure switch, automatically starts if the firewater header pressure drops to 120 psig. A further drop to 110 psig will automatically start the 400 horsepower diesel driven firewater pump (P-9). While P-8 is considered the primary firewater pump, P-9 can be used in the event of a power failure. Both pumps are rated at 2500 gallons per minute at approximately 150 psig. Fire hose stations are strategically located throughout the platform and arranged to provide coverage of target areas from two different directions. The firefighting systems are installed and maintained under NFPA 20 and 25 standards per CSLC regulation 2132(g)(4).

The annual and five-year State Fire Marshal testing are mandated under California Code of Regulations (CCR) Title 19. Inspection, testing, and maintenance of Platform Esther's firefighting system was last performed by Joy Equipment Protection, Inc. in March 2023. Testing of the foam system (3% aqueous film-forming foam, AFFF) is performed regularly to determine concentrate for contamination and dilution. No deficiencies were noted. MRMD inspectors review records of weekly testing of the firewater pumps and monthly testing of the deluge system as required by MRMD regulations.

Portable fire extinguishers – dry chemical and CO_2 – are located strategically throughout the platform and comply with California Code of Regulations, title 2, section 2132, subdivision (g)(4)(F), NFPA, and OSHA regulations. Portable fire extinguishers are visually inspected monthly, maintained in a fully charged and operable condition, and subject to an annual maintenance check. Cal/OSHA regulations require that employees receive annual training in the use of fire extinguishers for incipient firefighting. The company provides required annual online training to familiarize employees with the general principles of fire extinguisher use and the hazards involved. The hands-on training is provided as part of DCOR's annual block training.

The firewater piping and fittings appear to be adequately maintained. However, some piping throughout the production deck and well bay were found to have excessive surface corrosion damage or missing identifiable protective paint coating. The Commission staff recommends DCOR conduct an evaluation of the firefighting piping for reapplication of red, protective coating.

Fire doors on the Production Deck separating the north and south sides of the platform did not operate as intended as the auto close mechanisms are damaged or disconnected and the

hinges are frozen. (*Action Item EFI 2.4.7.03*) An H-Beam placed on a horizontal run of the fire protection system piping above the Production Deck created an unnecessary external load which may lead to sagging or corrosion. (*Action Item EFI – 2.4.7.05*) The Commission staff recommends DCOR remove this external load from the fire protection system piping and examine for any possible damage and/or corrosion.

2.4.8 Emergency Shutdown System (ESD): The platform is equipped with eight manual ESD stations that comply with California Code of Regulations, title 2, section 2132, subdivision (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. The manual ESD stations on Platform Esther are tested monthly in bypass mode to ensure automatic shutdown systems are functioning properly. Commission 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 shut down as designed.

Combustible and H_2S gas detection systems are intended to provide warning of a hazardous condition that could lead to a fire or toxic gas release. Combustible gas and Ultraviolet/Infrared (UV/IR) flame detection systems are located at key locations on the platform. Additional gas detection is located within the Motor Control Center/Programmable Logic Controller (MCC/PLC) building, operations control room, and safe welding area. These lower explosive limit (LEL) monitors and gas detection systems produce a distinct audible alarm. They alert personnel to the presence of low-level concentrations (25% of LEL) of flammable gas/vapor by a computer-generated alarm and a local beacon. As the concentration of the gas approaches 45% of LEL, the emergency shutdown of these units occurs. The ESD system appears fully compliant with API RP 14C. No problems were noted.

California Code of Regulations, title 2, section 2132, subdivision (g)(6) requires a detection system for offshore production facilities where production is known to contain H_2S. These detectors do not initiate shut-in/isolation actions but provide distinct audible and visual alarms when the concentration of H_2S reaches 10 ppm. When H_2S concentrations reach 20 ppm, the audible alarm becomes a solid tone, and personnel follow procedures to move to safe briefing areas. All H_2S and combustible gas detection systems were inspected, found to be in good working order, and met Commission requirements. Calibration, testing, and maintenance of this system are conducted and recorded monthly by DCOR personnel. Testing of the sensors and system is included in the Commission staff monthly safety inspections.

DCOR has performed hydrogen sulfide dispersion modeling to assess the risk of a gas release on Platform Esther. The model predicted a radius of exposure (ROE) for varying hydrogen sulfide concentrations for both continuous and instantaneous releases to determine whether additional safeguards are needed. No action items were identified.

2.4.9 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_2S monitors. Additional 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, operating procedures, or Job Safety Analysis (JSA). No issues about the use of PPE were noted while Commission staff were on the platform.

An emergency eyewash or shower combination unit has not been provided near the test lab, where operators are exposed to potential chemicals corrosive to the eyes and skin. (*Action Item EFI 2.4.9.02*)

2.4.10 Instrumentation, Alarm and Paging: The process alarm and control instrumentation has evolved into digital control through previous 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, programmable logic controllers (PLCs) are used to control and monitor all the process equipment and instruments on the platform. Operations management software (Wonderware) provides the operator interface that displays plant-wide status and events. The software can also detect instrument malfunction and equipment failure. This capability, in combination with optimizing features of process control, makes both startup activity and operational routines much easier and more efficient for operators. Wonderware also supports information management that shows historical information that can be used to improve process efficiency and plant performance.

The computer screens used by the operators to operate the facility are known as Human Machine Interfaces (HMI). There are simple graphic displays that mimic the process layout schematically on the operator's console, located in the main control room on the platform. The HMI displays at this facility allow the operator to access information and control the process in an uncomplicated manner. Common operator actions possible from the displays include:

- Setpoint change
- Mode selection (Auto or Manual)
- Output change
- Trending
- Alarm management
- Report(s) generation
- Shutdown of selected processes

The integrated alarm systems give an audible indication to alert the operator that an alarm has been activated. The visual indication is then used for alarm identification and evaluation. These audible tones are different for each process location. This difference in sound is used to help operators identify the origin of the alarm. Computer-generated process alarms are capable of being displayed and are audible through loudspeakers located throughout the platform.

The display methods and components are consistent throughout the HMI screens. Adequate information is contained in each of the video displays and all functions are labeled for quick assessment of key information. The graphic displays are concise and clear-cut, reducing the possibility of confusion and operator error.

The facility alarms are tested and calibrated each month. Records are readily available, and the device history can be tracked. All local instrumentation (e.g., pressure gauges, temperature gauges, and recorders) appeared to be properly maintained and in good operating

condition. The design and logic of these systems are further addressed in subsection *2.6 – Production Safety Systems*.

2.4.11 Auxiliary Generator / Prime Mover: An Olympian Model D30P1 30 kW diesel generator provides essential backup electrical energy in the event of a power failure. Manual transfer switches isolate circuits from incoming electrical service. If the generator is running and power is restored, these switches keep the primary power electricity from traveling to isolated circuits until the generator is turned off and the switch is reset to the non-backup position. This method of operation allows for the safe transfer and operation of emergency power.

The generator provides 38 hours of power without refueling. The loads supplied from Panel EM-DP-1 are the central UPS and the Remote MCC Purge system. It is recommended that the loads supplied from the generator be reviewed to confirm that all loads required for operation during a utility power outage are connected to the generator source. This includes all life safety loads, egress lighting, control room loads, alarm and detection circuits, and communication loads, and optional loads. Monthly and annual emergency generator and Auto Transfer Switch (ATS) test records were not available for review. The generator is tested monthly as part of the Commission safety inspection to verify the operational reliability of the system. Historical data showing that routine maintenance is being performed on generating system components and that load tests were not available.

2.4.12 Spill Containment: Spill containment equipment for Platform Esther appeared to be in good condition. A 6-inch lip at the bottom of the handrails traversing the entire Production Deck and Drill Deck serves as passive containment. Deck drains handle rainwater, spills, and process leaks. The drain system should be cleared of debris and inspected regularly to prevent abnormal condition leaks. The drain fluid is routed to the wastewater tank located on the Sub Deck. Fluids from the wastewater tank are then pumped to the shipping tank.

Spill response supplies are maintained and inventoried on a monthly basis by DCOR operating personnel and are part of the Commission monthly safety inspection. Platform Esther meets state requirements for spill containment.

2.4.13 Spill Response: The DCOR Oil Spill Response Plan (OSRP) was developed following Federal and State Facility Response Plan requirements and is discussed in more detail in the Safety Management section of this report.

DCOR maintains equipment on the platform specifically for spill response including sorbent boom and pads, marine radios, company radios and phones, tracking flags, and electronic tracking buoys. In general, the equipment appears to be well kept and is inventoried as part of the Commission staff monthly safety inspection.

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, nonprofit USCG classified Oil Spill Response 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 at Platform Esther occurred on July 13, 2023.

2.4.14 Cranes: Platform Esther is equipped with two cranes, one diesel powered 100-foot boom Nautilus crane nominally rated at 31 tons and a smaller electric-driven 30-foot boom Tech Crane International 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 and load tests are performed by RA Batchelor Co. crane services After reviewing crane records, it appears that monthly, quarterly, and yearly inspections are being performed as required. The records also contained documentation to show that needed repairs were being corrected in a timely manner. Various slings were observed during the audit that showed wear, damage, and did not have required identification labeling. Slings were stored exposed to the elements on the Drill Deck, possibly contributing to the observed degradation. (*Action Item EFI 2.4.14.01*)

2.5 Mechanical Integrity / Preventive Maintenance Program

Preventive maintenance and job scheduling are controlled by Operations foremen and craft supervisors. New work orders are reviewed daily and assigned to an in-house craft or outsourced to a contractor/vendor depending upon the workload and specific job requirements. Critical spare parts and commonly used parts are stored on Esther or in the onshore warehouse. This approach provides DCOR with maintenance task optimization and decreases the chance of equipment failure. Recordkeeping for PSVs, tanks, and pressure vessels has been migrated to electronic files.

The computerized maintenance management system (Mainsaver) is utilized to manage and track activities. Operating personnel can access the system to generate a work order. These work orders can range from a simple filter change to major equipment repair. Mainsaver gives DCOR flexibility to schedule and record these activities based upon the manufacturer's recommendations, operating history, and recognized and generally accepted good engineering practices. Tank and pressure vessel reliability are maintained through regularly scheduled internal, external, and ultrasonic inspections and repairs. Reliability inspections are also standard for all rotating equipment.

Facility Engineers have developed a risk management system to decrease the incident rate of piping leaks for the various piping systems onboard the platform. These piping systems or sections of piping connect the wells via headers to the processing equipment. A risk level is established for the various sections of piping based on service and consequence of failure. When the risk level for a particular section of piping reaches an unacceptable level, engineers implement a corrective or mitigating action on that section of piping to lower the risk level to an acceptable level. Offshore and onshore facilities use several different methods to improve the life of the various piping systems that include:

- Primer, paint, and tape wrap coatings (External)
- Epoxy coatings and liners (Internal)
- Cement lining

- Cathodic protection
- Chemical treatment

A chemical vendor provides the facility with a chemical treatment program that meets the operational needs of the platform. A main component of the program is a corrosion inhibitor. The chemical protects the pipe's internal surface and metal components by forming a protective film. Additionally, the program incorporates corrosion coupons at critical points in the piping for monitoring the effectiveness of the chemical treatment program. This means of corrosion control is provided for select pressure vessels and tanks. Appropriate record keeping from regularly scheduled internal, external, and ultrasonic inspections and repairs provide historical data and often give signs that indicate the source of a detected deficiency.

2.6 Production Safety Systems

Analysis of Platform Esther drawings and PLC logic found that the design of process controls and safety systems is adequately documented, has the appropriate level of safety controls, and is consistent with the previous Commission staff audit. The automated control and safety systems have been designed using applicable codes, standards, and industry practices in accordance with MRMD regulations and API RP 14C.

Platform Esther status, controls, and alarms are displayed in real-time via HMI displays located in the main control room. The automated control system monitors and controls platform processes in separate operating areas. The automated displays help minimize the effects of undesirable events and mitigate consequences from upsets. The safety systems are independent of the Distributed Control System (DCS) alarm system on the platform in case of loss to the communications link.

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.

Safety Analysis Function Evaluation (SAFE) Charts described in API RP 14C are utilized as an analysis technique to document the effects of and determine the requirements for components in the safety system. All safety devices and their functions were analyzed by comparing the SAFE Chart, facility P&IDs, and other documents. The comparison matched all safety and shutdown devices and emergency support systems (ESSs), with their functions and verified that the required level of protection is being maintained.

All platform production wellheads utilize artificial lift and have safety devices installed to shut off power in the event of abnormally high or low pressures as required by California Code of Regulations, title 2, section 2132, subdivision (a)(10)(A) and API RP 14C. The pressure safety devices are tested monthly by the MRMD Inspections group.

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. 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, automatic shutdown valves are installed per MRMD regulations and API RP 14C to isolate the various process systems and lessen the environmental impact should a system problem be identified. Should evacuation be necessary, platform personnel can leave the platform by helicopter, boat, or by using the available life rafts.

DCOR has performed a Hazard and Operability (HazOp) Process Hazard Analysis (PHA) study for the whole platform. Their Management of Change (MOC) process includes the use of a PHA tool, in a style similar to HazOp, for changes to facilities, equipment, and processes, when the Facility Engineer decides it is appropriate. This systematic approach for identifying, evaluating, and controlling the hazards of the process helps build-in additional safety 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., elimination-substitution-engineering controls-administrative controls-PPE) to mitigate, eliminate, or reduce exposure to hazards.

Electrical System Audit

DCOR, LLC

Platform Esther

March 2024

3.0 ELECTRICAL SYSTEM AUDIT

3.1 Goals and Methodology

The primary goal of the Electrical (ELC) Team was to evaluate the electrical systems and operations at Platform Esther to determine conformance to the California Electric Code (CEC) and industry standards.

References used in the review of the facility include documents published by the American Petroleum Institute (API), the National Fire Prevention Association (NFPA), the State of California Electric Code (CEC), and State Lands Commission (Commission) Regulations. The ELC Team review comments are primarily based on those publications, which include API RP 14F, API RP 500, API RP 540, CEC documents, and industry standards.

Specific tasks to accomplish this goal included a systematic process of field verification of electrical single-line diagrams, plan drawings, hazardous area electrical classification drawings, and operation and maintenance practices. A comprehensive use of inspection checklists, code and standard compliance checklists, and a review of electrical system design for conformance to codes and standards was utilized 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 into sections. 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. The basis for observations and review comments for all hazardous areas are API RP 14F and RP 500, as well as CEC Articles 500, 501, and 504. The hazardous area electrical classification drawings (HAECDs) are generally representative of the existing conditions and area class elements. However, the drawings do need to be updated to include process and equipment additions and deletions made since the last revision in 2020. (*Action Items ELC 3.2.01 – 3.2.02*)

The purpose of an HAECD 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 require attention to the type of hazard and the level of the hazard to ensure compliance with the CEC. HAECDs are required to contain the information necessary for a qualified electrician to perform work in and around classified areas. DCOR drawings DCOR-ES-EL-D-0341, -0342, and -0343 were last revised in February 2020 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. If the HAECDs 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 the Code. The HAECDs, as presented, do not show permanent equipment in the plan (*Action Items ELC 3.2.01 – 3.2.02*). 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 HAECDs. 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 portable chemical tanks on the HAECDs (*Action Item ELC 3.2.01*).

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, and 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. During our first visit, the Motor Control Center (MCC) building had its doors open and a large fan blowing air through the building. On our second visit, the MCC building doors were closed and the HVAC seemed to be back in service.

Drill Deck: The area classification plan drawing, DCOR-ES-EL-D-0341, was received for the drill deck. The drawing appeared to adequately show the extent of area classification for the permanent installation, but the equipment layout needs to be updated. Several pieces of equipment such as T-219A and T-220A have been removed and must be updated on the plan. There also have been permanent additions such as the electric crane and XQL-1 quarters transformer that must be updated on the plan drawing. The drawing was last issued in March 2016 (*Action Item ELC 3.2.02*).

Production Deck: The production deck area classification plan drawing, DCOR-ES-EL-D-0342 was last issued in February 2020 and does not reflect the latest equipment locations. The location of the new portable chemical tank between Well-219 and Well-214 as well as the Oxygen and Acetylene tank storage located next to the Weld shop should be added to the floorplan. (*Action Item ELC 3.2.01*).

Sub Deck: Area classification plan drawing DCOR-ES-EL-D-0343 was received for the sub deck and is complete and up to date.

3.3 Electrical Power Distribution System, Normal Power

3.3.1 System Configuration: The single-line drawings received for use and reference during the assessment are dated February 04, 2020, and are generally representative of the electrical power system. It is recommended that the single lines be revised to include missing information, device and circuit identification that matches field installed labeling, and additional

system information needed for engineering purposes (*Action Items ELC 3.3.1.01 – ELC 3.3.1.12*).

3.3.2 Electrical Service Capacity: The Platform's normal power system capacity appears adequate based on present usage. Overcurrent protection and wire sizes were found to be appropriate. The application of overcurrent devices related to equipment ratings is generally satisfactory. It is recommended that DCOR confer with Southern California Edison (SCE) to establish the SCE service capacity limit and any other limitations such as motor inrush and number of motor starts per day (*Action Item ELC 3.3.2.01*).

3.3.3 Electrical System Design: Electric utility service is supplied by SCE at 12kV via submarine cable from shore (SCE Building). The service location is at the SCE 1st Street facility. The SCE disconnect supplies power to Platform Esther via 1-3/C #500kcmil 15kV rated cable routed in below-grade conduit to an on-shore vault and then by submarine cable to the platform. The submarine cable to Platform Esther supplies 12kV electrical power to the main Switchboard (MSW-1). This switchboard lineup consists of one main non-fused disconnect switch for the 12kV supply and three fused disconnect switch positions supplying transformers on the platform as follows:

- The first fused disconnect position feeds a 3750/4200kVA, 12kV-2400V transformer (TX-1) located above the switchgear room and used to supply power to the operating platform main 2.4kV switchgear (MSW-2 and MSW-3).
- The second fused disconnect position supplies the first position of a three-position SF6 sectionalizing switch (MSW-4) located above the switchgear room. The SF6 switch position 2 is a 600-amp rated RFI (resettable fault interrupter) that feeds the 1100/1120kVA, 12kV-480V transformer (TX-2) located above the switchgear room and is used to supply power to the 480V motor control center lineup (MCC-1) in the main switchgear room. SF6 switch position 3 in a 600-amp RFI that supplies power to the 3000/3750kVA Rig transformer (TX-D).
- The third fused disconnect position is connected to a 2500/2800kVA, 12kV-480/277V transformer (TX-3) located at the southeast corner of the production deck.

The two (2) 250kW Micro-Turbines installed on the Drilling Deck have been removed from service. The Rule 21 protection should be removed and the SCE service interconnection agreement should be replaced with a standard power purchase contract (ELC 3.3.3.01).

3.4 Electrical Power Equipment Condition and Functionally

3.4.1 Equipment Condition: Given the harsh environmental conditions of the open sea, the overall condition of electrical equipment can be rated as good. Several locations where conduit supports were rusted or otherwise inadequate are noted in the Matrix. A few missing covers, broken and missing supports, rusted enclosures, deteriorated weatherproof gaskets and missing bolts occur to a small extent throughout the facilities (*Action Items ELC 3.4.1.01 – 3.4.1.02*). It's also recommended to test the oil quality of transformers TX-1, TX-2, and TX-3 (*Action Item ELC 3.4.1.03*).

3.4.2 Equipment Maintenance Practices: Section 4.04 of the DCOR Safety Manual – Safety Standards covers the lockout/tagout/blockout program. The scope, responsibility, and procedures outlined in the document appear to be adequate and complete.

Arc flash hazard labeling and Personal Protective Equipment (PPE) requirements are currently being updated by DCOR (*Action Item ELC 3.4.2.01*). Arc flash labels will need to be installed on electrical equipment once the Arc Flash Hazard Assessment is finalized if it is determined that the arc flash incident energy has changed or the label information requirements included in the latest edition of NFPA 70B have changed (*Action Item ELC 3.4.2.01*).

Relay test labels on the 12kV and 2.4kV Switchgear breakers indicate that this equipment was last tested in July 2014. NFPA 70B maintenance and testing of equipment is recommended to be performed at regular intervals based on the voltage rating, type of equipment, and service conditions. It is recommended that DCOR utilize a database software program, such as MAXIMO, to schedule and track maintenance activity (*Action Item ELC 3.4.2.02*).

Electrical equipment instruction manuals should be available on the platform. Several manuals were available, but many are missing and not readily available to personnel (*Action Item ELC 3.4.2.02*). In addition to maintenance manuals, the equipment wiring schematics and diagrams are needed for troubleshooting and reference for use in design. Electrical schematics and wiring diagrams for all equipment utilizing wired controls should be available on the platform (*Action Item ELC 3.4.2.02*).

Several devices were identified as requiring replacement, repair, shielding, protection, or additional support, or were missing installation hardware. It is recommended to take the appropriate action as noted in the matrix to protect and reduce the risk associated with neglected maintenance items (*Action Items ELC 3.4.2.03 – 3.4.2.05, 3.4.2.07 – 3.4.2.13*).

Proper clearance of all equipment is required by CEC 110.26. The working space in front of the auxiliary (AUX) switchboard (SWBD) is not adequate. It is recommended to remove or relocate Schlumberger Unicomm control panels to allow for proper working clearance (*Action Item ELC 3.4.2.06*).

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 because of improper grounding. Three specific types of grounding are required at the facilities: power system grounding, safety or equipment grounding, and static grounding.

System grounding is as follows:

- Transformer TX-1, 12kV-2.4kV, 3-phase, 4-wire is resistance grounded through a 400A, 10-Sec resistor.
- Transformer TX-2, 12kV-480V is high resistance grounded 5-Amp, with ground indication and alarm on the MCC-1 main switchgear room.
- Transformer TX-3, 12kV-480V is solidly grounded at the Auxiliary MCC building.

- Transformers TX-4, and TX-5 located above the main switchgear room and the 15kV transformer in the Auxiliary MCC building provide separately derived systems, for 208Y/120 Volt equipment. These transformers are solidly grounded and satisfy Code requirements for power system grounding.
- TX-D Drill Deck, 12kV-600V is solidly grounded and supplies the drill deck.

CEC 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, 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 grounding conductors are not installed on all circuits and bonding is achieved through continuity of raceways and fittings. Equipment bonding conductors to major equipment; transformers, switchgear, and the like, were installed and appeared adequate.

CEC Article 501-16(b) requires that all liquid-tight conduits used in a hazardous area be supplemented with either an internal or external ground bonding jumper. In the past flex conduits that have bonding included were identified with a distinctive green mark painted on the conduit. A spot check of the marked conduits confirmed bonding.

3.6 Emergency Electrical Power

3.6.1 System Configuration: An existing 30kW, three-phase, 208Y/120V standby package generator is installed for operation in the event of a utility power outage. The generator supplies the emergency panel “EM-DP1” through a 150-amp auto-transfer-switch (ATS). Emergency Panel “EM-DP1” supplies the following:

- 10-hp emergency air compressor (C-3)
- Motor control center (MCC) room purge fan
- 20kVA uninterruptible power supply (UPS) unit

To ensure the generator has adequate capacity, the existing load and peak load data should be assessed. Perform load calculations for any additional load to be added to the generator that is identified as required or necessary. (*Action Item ELC 3.6.1.01*)

The UPS provides ride-through to maintain critical control and communications systems during the period while the backup generator is started and transfer initiated. The MGE UPS unit feeds a dedicated UPS panel to Panel UPS-DP-1 and maintains power for the emergency systems listed below:

- Control Room computers and equipment
- General Alarm and Shutdown systems
- Modicon programmable logic controllers (PLC) and I/Os for process control and monitoring
- Communications and public address system, phone

- Fire eyes and gas detection systems
- Navigation lights and foghorn
- Emergency egress lighting; control room, well bay, MCC-1
- Remote terminal units (RTU)s, both Chevron RTU #1 and Lease automatic custody transfer (LACT) RTU #2
- Fire pump charger
- GC 300 PLC FLARE

3.6.2 Equipment and Component Ratings: California Code of Regulations, title 2, section 2132, subdivision (g)(7) requires "an auxiliary electrical power supply shall be installed to provide sufficient emergency power for all the equipment required to maintain the safety of operation in the event the primary electric power fails". The 30kW packaged generator supplies 38 hours of power, without refueling power to Panel EM-DP-1 which includes the central UPS and the Remote MCC purge system. It is recommended that the loads supplied from the generator be reviewed to confirm that all loads required for operation during a utility power outage are connected to the generator source. This includes all life safety loads, egress lighting, control room loads, alarm and detection circuits, communication loads, and optional loads. (*Action Item ELC 3.6.2.01*).

The packaged generator complete with a base fuel tank and weather enclosure is in an unclassified area on the Drill Deck and is easily accessible for maintenance and testing. The emergency generator and ATS test records were not available for review. UPS power is provided from a 20kW unit in the main switchgear room. The Schneider Electric Symmetra PX is a packaged unit complete with a bypass and batteries in a common cabinet.

3.6.3 Electrical System Design Safety: Critical systems are supplied from the backup generator and emergency UPS system. The UPS system is fed from panel board EM-DP-1 but does not appear on the single-line diagram. The UPS connection to panel EM-DP-1 as well as panel UPS-DP-1 should be shown on the single-line drawing to make clear the supply feed to the critical systems (*Action Item ELC 3.6.3.01*).

3.7 Electric Fire Pumps

A 400hp electric firewater pump (P-8) is located on the Production Deck and fed by the normal power system from switchboard MSW-3 at 2,400V. The electric firewater pump provides the primary system for fire suppression.

A diesel-driven fire pump is also available in the event of a system power failure. The diesel is equipped with a pneumatic (air-driven) starter. A 10hp emergency air compressor, C-3, supplied from the backup power system (generator), is used to maintain starting air for the diesel fire pump should utility power not be available.

The fire protection/deluge system is a wet system with water pressure maintained by the firewater jockey pump during normal operations. The fire alarm pushbuttons do not activate the firewater pump. Instead, the loss of pressure in the deluge system starts the electric fire pump. Further loss of pressure will start the diesel-driven fire pump.

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, PLC 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. Several instruments are outdated but are in the process of being replaced by modern equivalents.

Two redundant computers (PC) are located in the communications room and the monitors located in the control room provide an operator interface to the process control system. There is also a backup PC located in the Auxiliary MCC room. The PCs are linked via Modbus+ and run on the Wonderware software package.

Programming for the PLC is resident on the PLC. In the event of a PLC processor failure, backups of the latest programming are also stored on the company server located in the Communications Room. The main electrical switchgear room houses two PLCs that monitor the LACT units. No formal procedure to track changes, backups, or backup frequency of the logic was available during the inspection.

Two other monitors, one located in the Aux MCC room and the other in the crew galley allow remote monitoring (mimic) of the system.

The Allen Bradley PLC located in the control board CP-1 in the control room is connected via Modicon S908 data highway to five I/O drops, two located within CP-1 and three in panels in the Aux MCC building. These effectively monitor and control operations on the platform. Control and monitoring from shore are provided through the spread spectrum radio system from the RTU on platform Esther to an RTU located at the 1st Street, Seal Beach facility.

3.9 Standby Lighting

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

The emergency lighting is powered from the UPS Panel which receives power from the UPS with backup from the emergency generator in the event of extended main power failure. Lighting plans for each Deck of the Platform are needed for review. The lighting plan should include the fixture locations and types, illumination levels required, egress pathways, and the fixtures connected to an emergency source. The lighting plans should show all lighting controls. (*Action Item ELC 3.9.01*).

Since the platform operates around the clock, seven days a week, operators and maintenance personnel may need to perform work during nighttime hours. DCOR indicated that personnel working at night carry flashlights and temporary lighting equipment is available for planned maintenance and larger tasks.

3.10 Special Systems

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 effect 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 the operation of equipment in a fail-safe condition.

Emergency Shutdown Stations (ESD) are located throughout the platform. The stations appeared to be in good working order. Locations include:

- Drill Deck – South stair near the heliport
- Production Deck – At North and South Stair
- Production Deck – Control panel CP-1 and Control Room entrance
- South Stair between Production and Drill Deck

Stations are hard-wired to the control panel CP-1 in the control room. In addition, the flame detection system will activate an ESD automatically if flames are detected in the well bay or production areas. Relays in panel CP-1 are fail-safe types.

Fire and Abandon Platform Alarm Stations (FA) are located on the platform decks. All stations appeared to be in good working order. Emergency stations have plastic identification labels (Fire – white letters with red background, Abandon Platform – red letters on white background). Stations are generally mounted on red-painted supports. ESD and FA stations are tested monthly and records are maintained.

3.10.2 Gas Detection Systems: Combustible gas detection systems, Lower Explosive Limit (LEL) and Hydrogen Sulfide (H_2S) types 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.

Gas detector elements (GDEs) are located on the Production Deck as follows:

1. Between columns C5 and D5 (above and west of V-301)
2. Between columns C3 and D3 (above and southwest of V-7)
3. Between columns C4 and B5 (above V-6)
4. Between columns C6 and B7 (above vapor recovery unit)
5. Between columns C1 and B2 (above V-205)
6. Above vessels V-1 and V-2
7. Above vessel V-9
8. Above GC-300 compressor skid

Detectors are battery-powered and portable, communicating wirelessly to the control room. Detectors are located about 15 feet high in the structure over the equipment. Gas detectors and monitors are tested monthly and records are maintained.

3.10.3 Fire Detection: Fire detection and smoke detection are usually employed to detect and warn personnel of fire and smoke conditions and to initiate remedial action. Fire-eye-type UV detectors are provided on Platform Esther around the well bay, production area, and mezzanine of the Production Deck along with selected tankage areas of the sub deck. Fire-eye detectors in the well bay have been relocated from column line C facing out to column line D facing in. This was done to reduce nuisance alarms caused by foreign sources (i.e. distant welding, flash photography, etc.) external to the platform. Fire-eye signals are returned to the DET-TRONICS Fire Detection Modules in the control room panel CP-1. Fire detectors are tested monthly and records are maintained. Stand-alone smoke detectors are provided on the ceilings of the control room, locker rooms, galley, telecom, and electrical rooms throughout the platform. Units appear to be active but were not tested during the inspection.

3.10.4 Aids to Navigation: The US Coast Guard no longer requires aids to navigation in offshore facilities close to the shore.

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 of continuous operation as required by API RP 14F. A UPS capable of providing power for four hours supplies the communications equipment. Communications equipment is located in the telecom room adjacent to the control room. A radio base station in the telecom room with a remote terminal in the control room provides radio communication with the crew boat.

Incoming Service: Verizon phone service is connected through a fiber optic (FO) line that is included within the incoming 34.5kV power submarine cable from shore (Fort Apache) to Platform Eva. At Eva, the fiber optic cable is separated from the power cables at the main interrupter switchgear in the switchgear room and routed through a FO/Ethernet converter to the platform Ethernet. A spread spectrum radio system links the telecom system at Platform Eva to Platform Esther. Communications equipment on Esther is powered through the UPS unit.

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 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 the required personnel response. Audible alarms and communication announcements could be heard throughout the platform at all locations tested.

3.10.7 Cathodic Protection: No cathodic protection rectifier system is installed on the platform. Platform corrosion control is provided through sacrificial anodes and painting and continued monitoring by personnel and maintenance of equipment and structures.
The production pipeline receives its protection against corrosion from facilities based on shore. The production pipeline consists of a double-wall construction with high-pressure interior tubing and low-pressure outer casing for leak detection. An increase in pressure in the outer pipe would indicate a product line leak, while a decrease in pressure indicates outer casing leak.

Safety Management Programs

DCOR, LLC

Platform Esther

March 2024

4.0 SAFETY MANAGEMENT PROGRAMS

4.1 Goals and Methodology

The goal of the safety management program section of the audit is to verify that DCOR, LLC (DCOR) has required programs, plans, and manuals in place and that the company uses a safety management approach to manage hazards and thereby 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 California State Lands Commission (Commission) Mineral Resources Management Division (MRMD) Article 3.4, 3.6 and American Petroleum Institute (API) Recommended Practice (RP) 75. The audit began with a review of the operating procedures, other required emergency and spill response plans, training programs, and additional specific programs that DCOR uses to cover other elements of the Safety and Environmental Management System (SEMS) for Platform Esther.

4.2 Operations Manual – Operating Procedures

DCOR's Operating Procedures provide the necessary information for operations employees to understand what procedures and system processes are needed to safely operate Platform Esther. Individuals knowledgeable with the process and its hazards write the Standard Operating Procedures (SOPs). These individuals are also familiar with the subject matter and typically have performed the work and operated the process. The SOPs are written in a simplified, easy-to-read format with sufficient detail so that trainees with limited experience or knowledge of the procedure can successfully carry out a given task with minimal supervision. Operations employees validate the procedures before finalization. A thorough review of individual procedures noted that some of the information does not appear to be current or is missing, including equipment location plans, pressure safety valve settings, number and identification of active wells, and references are made to figures and charts that are not present. (*Action Items SMP 4.2.01 – 4.2.02*). The contents of an Operations Manual, including Operating Procedures, are required to be kept current at all times. (Cal. Code Regs., tit. 2, § 2174 subd. (b)(1) and § 2175 subd. (b)(5)(B))

The SOPs are maintained and accessible via the company intranet system to all DCOR personnel and available to print. Hard copy versions are located on the platform in the main office control room. A periodic review of the SOPs by Operations personnel is performed to ensure that pertinent operating information is readily available and correct. The SOPs are also reviewed when operations or equipment are substantially changed. They are updated by authorized DCOR personnel to ensure the contents remain current and the date of review/revision is recorded in each SOP. If an SOP describes a process that is no longer followed, it is removed from the file and/or manual. Some of the operating procedures information does not appear to be up-to-date or consistent between different sections (*Action Items SMP 4.2.01 – 4.2.02*). For example, equipment location diagrams were not reflective of current platform configuration and conflicting values for pressure safety valves were given.

4.3 Spill Response Plans

The DCOR Oil Spill Response Plan (OSRP) was developed following Federal and State Facility Response Plan requirements. The document defines procedures and plans for responding to discharges of oil into navigable waters and seeks to minimize damage to the environment, natural resources, and facility installations. The plan covers Platform Eva, Platform Esther, onshore facilities, and associated pipelines. 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

Also contained within the OSRP are operating procedures the facility implements to prevent oil spills, control measures installed to prevent oil from entering navigable waters or adjoining shorelines, and countermeasures to contain, clean up, and mitigate the effects of an oil spill. The OSRP was reviewed and noted to have a long approval history. It meets Federal (Code of Federal Regulations (CFR) Title 40 Section 112.5) and State Office of Spill Prevention and Response (OSPR), CCR Title 14, Regulation 817.02 standard requirements. DCOR staff is familiar with the OSRP and holds annual spill drills to increase the effectiveness of their spill response. The OSRP presented for audit review was revised in January 2021, and includes a copy of the California Certificate of Financial Responsibility (COFR). This version of the plan was submitted to California's Department of Fish and Wildlife (DFW) in April 2023 and is currently under review by the Contingency Planning Unit. Spill plans are required to be resubmitted for review once every five years (CCR Title 14, 816.05(a)(1)(A)). A comprehensive review of the OSRP will be undertaken during the Fort Apache onshore facility audit.

4.4 Training and Drills

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 includes hands-on procedural performance and evaluation. Both the lead operator and operations supervisor must sign off on the training and qualification. Promotion to the next Operator level is based on progression through these operating requirement elements. Successful completion of all 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.

Compulsory OSHA and spill response training is also provided. DCOR conducts annual online training to satisfy Cal/OSHA training requirements. DCOR's administrative training coordinator employs a computer-based training (CBT) matrix that tracks all training activities and is used to alert management and individual personnel of training requirements. All DCOR operating personnel receive Production Safety Systems (API RP T-2) Training, as well as other

annual required CBT courses that are developed by DCOR in-house through PetroSkills on-line training programs. The training program 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 API RP 75 that "initial" and "periodic" training be provided to employees and contractors on operating procedures, safe work practices, and emergency response and control. This standard requires that offshore operations and maintenance personnel receive training on safety and anti-pollution devices, maintenance and crane operation, well control, and hydrogen sulfide, as appropriate. Other applicable regulations can be found in CFR Title 30 Chapter II Subchapter B – the Bureau of Safety and Environmental Enforcement's (BSEE) regulations for Offshore.

Spill response team members are trained in the procedures developed for the facility spill plan. This training consists of classroom instruction, exercise evaluation briefings, tabletop exercises, and equipment deployment drills. Exercises range from a discussion about how things would occur to the deployment of equipment and mobilization of staff. Most spill drills are unannounced, and personnel are given a scenario that they must respond to. If DCOR finds any significant deficiencies in the spill plan after a drill or exercise is complete, the company will record the deficiencies and require changes to the plan. DCOR management reviews the lessons learned during oil spills and exercises to revise and improve contingency plans. Revisions of the plan may require additional inspections, drills, and training.

Platform Esther personnel conduct mandatory safety meetings for task specific condition changes or scheduled operator rotation that include all persons performing work on the platform for both general and topic specific safety subjects. Training and pre-job safety meetings are documented; records are retained and available upon request. During fieldwork, the Safety Audit Team observed Platform Esther personnel's acknowledgment of the importance of proper Personal Protective Equipment (PPE) and its use at all appropriate times. There were no action items identified regarding these safety elements.

4.5 Safety Management Programs

DCOR's Safety and Environmental Management Systems (SEMS) plan parallels API RP 75 for a Safety and Environmental Management System for Offshore Operations and Assets and is used to control workplace hazards. DCOR has integrated its corporate safety management program into the facility. This practice has improved its operating reliability, system operating efficiency, and reduced incidents involving the release of hazardous materials beyond the facility boundaries.

DCOR has other written safety plans for facilities that operate under specific hazardous conditions. DCOR's hydrogen sulfide (H_2S) contingency plan is a systematic analysis of the hazards associated with H_2S and the methods required to reduce the hazards to an acceptable level. H_2S Contingency Plan requirements include emergency evacuation procedures, a plot plan of the facility, required personal protective equipment, and other precautions that are necessary to work safely with H_2S. A review of the plan identified deficiencies in the required contents. (*Action Item SMP 4.5.01*).

An Emergency Response Plan (ERP) that complies with California CCR Title 8 Section 3220 and 5192(q)(1)&(2) was also provided. Changes to this plan should be managed by

authorized DCOR personnel to ensure new or different operating conditions are contemplated, qualified staff is available to perform necessary functions, operator and personnel certifications are current, and information relating to regulatory agencies is up to date. A review of DCOR's Emergency Response Plan (ERP) identified needed updates to equipment location plans. (*Action Item SMP 4.5.02*)

DCOR's safety policy sets a clear direction for the organization to follow and is a part of their established business performance goals. The objective of their safety policy is to set down in clear-cut terms management's approach and commitment to health and safety at their facilities. Audit team observations and interviews with employees and contractors confirmed that DCOR's senior management has defined, documented, and endorsed its safety policy. Safety management functions within the organization correlate with the safety of their personnel. This connection can be seen in the planning, developing, organizing, and implementing of DCOR's safety policy.

Additional assessment and feedback regarding DCOR's safety management programs will be afforded by the Commission's Safety Assessment of Management Systems (SAMS) that is conducted after the safety and oil spill prevention audit. The SAMS also provides significant benefits regarding human factors observations and assessments described in the next section of this report. The SAMS is a separate effort from this audit and the results are kept confidential between the Commission and the operating company.

Human Factors Audit

DCOR, LLC

Platform Esther

March 2024

5.0 HUMAN FACTORS AUDIT

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 oil spill prevention audit of the DCOR Huntington Beach lease facilities (Platform Esther, Platform Eva, and Fort Apache Onshore). Interview results are considered confidential between the Commission and DCOR and will be contained in a separate report.

SAMS was developed under the sponsorship of government agencies, including the California State Lands Commission (Commission), 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 – 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 several associated and detailed questions to help better define the issues and degree of integration of safety management programs.

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, areas of relative strength and weakness, and a benchmark for future assessments.

5.2 Human Factors Audit Methodology

The Commission's Mineral Resources Management Division (MRMD) will schedule individual SAMS interviews with a cross section of DCOR field operators and sub-contractors and engineering, supervisorial, and management staff after the safety audit reports for Platform Eva, Platform Esther, and the Fort Apache onshore facility are completed. Interview responses will be evaluated according to SAMS guidelines and a separate confidential report summarizing the results will be generated. Responses of specific individuals to questions are kept anonymous in the report. MRMD staff will provide a confidential report and offer a formal presentation that summarizes the report to DCOR management.

Action Item Matrix

DCOR, LLC

Platform Esther

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Appendices

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Appendix A
Acronyms

- A — Amperes
- AFFF — Aqueous Film-Forming Foam
- ANSI — American National Standards Institute
- API — American Petroleum Institute
- AUX — Auxiliary
- ATS — Auto-Transfer-Switch
- ASME — American Society of Mechanical Engineers
- BAP — Best Achievable Protection
- BEP — Business Emergency Plan
- BOPD — Barrels of Oil Per Day
- BSEE — Bureau of Safety and Environmental Enforcement
- BWPD — Barrels of Water Per Day
- Cal/OSHA — California Occupational Safety and Health Administration
- CBT — Computer Based Training
- CCR — California Code of Regulations
- CEC — California Electrical Code
- CFC — California Fire Code
- CFR — Code of Federal Regulations
- CO_2 — Carbon Dioxide
- COFR — Certificate of Financial Responsibility
- Commission — California State Lands Commission
- DCOR — DCOR, LLC
- DCS — Distributed Control System
- DFR — California's Department of Fish and Wildlife
- DOT — Department of Transportation
- EFI — Equipment Functionality and Integrity
- ELC — Electrical
- EPA — Environmental Protection Agency
- ERP — Emergency Response Plan
- ESD — Emergency Shutdown Device
- ESP — Electrical Submersible Pump
- ESS — Emergency Support Systems
- FA — Fire and Abandon
- FO — Fiber Optic
- FRC — Fire Resistant Clothing
- GDE — Gas Detector Element
- HAECD — Hazardous Area Electrical Classification Drawing
- HazOp — Hazard and Operability
- HF — Human Factors
- HMI — Human Machine Interface
- H_2S — Hydrogen Sulfide
- HVAC — Heating, Ventilation, and Air Conditioning

- ICS Instrument Control Services
- IES Illuminating Engineering Society
- IMO International Maritime Organization
- IR Infrared
- ISA International Society of Automation
- JSA Job Safety Analysis
- kV KiloVolt
- kVA KiloVolt Amperes
- kW Kilowatts
- LACT Lease Automatic Custody Transfer
- LED Light Emitting Diode
- LEL Lower Explosive Limit
- LLC Limited Liability Corporation
- MCC Motor Control Center
- MCFD Thousand Cubic Feet per Day
- MEPC Marine Environmental Protection Committee
- MOC Management of Change
- MRMD Mineral Resources Management Division
- MSRC Marine Spill Response Corporation
- NACE National Association of Corrosion Engineers
- NEC National Electrical Code
- NEMA National Electrical Manufacturers Association
- NETA International Electrical Testing Association
- NFPA National Fire Protection Association
- OSHA Occupational Safety & Health Administration
- OSPR Office of Spill Prevention and Response
- OSRO Oil Spill Response Organization
- OSRP Oil Spill Response Plan
- OSRV Oil Spill Response Vessel
- P&ID Piping and Instrumentation Diagrams
- PA Public Address
- PFD Process Flow Diagram
- PHA Process Hazard Analysis
- PLC Programmable Logic Controller
- PM Preventive Maintenance
- PPE Personal Protective Equipment
- PPM Parts per Million
- 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
- PSSR Pre-Startup Safety Review
- PSV Pressure Safety Valve

- ROE Radius of Exposure
- RP Recommended Practice
- RTU Remote Terminal Units
- SAC Safety Analysis Checklist
- SAFE Safety Analysis Function Evaluation
- SAMS Safety Assessment of Management Systems
- SCBA Self Contained Breathing Apparatus
- SCE Southern California Edison
- SDS Safety Data Sheet
- SEMS Safety and Environmental Management Systems
- SMP Safety Management Programs
- SOP Standard Operating Procedures
- SPCC Spill Prevention Control & Countermeasure
- SWBD Switchboard
- TEC Technical
- T2 Production Safety Systems Training
- T-Min Minimum Thickness
- UV/IR Ultraviolet/Infrared
- UPS Uninterruptable Power Supply
- Unocal Union Oil Company of California
- USCG United States Coast Guard
- UT Ultrasonic Thickness
- UV Ultraviolet
- V Volt
- VFD Variable Frequency Drive

Appendix B
Best Practices

Regulatory References

MRMD – California Code of Regulations (CCR), Title 2
CalGEM – CCR Title 14
Cal/OSHA – CCR Title 8
EPA – Code of Federal Regulations (CFR) Title 40
OSHA – CFR Title 29
USCG – CFR Title 33
BSEE – CFR Title 30 Part 250

1.0 INTRODUCTION

1.1	Best Achievable Protection/Best Achievable Technology	PRC 8750
	Inspection of Marine Facilities	PRC 8757
	Commission Oil & Gas Regulations	MRMD Articles 3 - 3.6

2.0 FACILITY CONDITION AUDIT

2.1	Goals and Methodology	
2.2	General Facility Conditions	
2.2.1	*Workplace Housekeeping*	MRMD 2129; Cal/OSHA 6539
2.2.2	*Stairs, Walkways, Gratings, & Ladders*	MRMD 2129; Cal/OSHA 3273,3212; OSHA 5(a)(1),1910.22(d)(1); NACE RP 0176; API RP 2A
2.2.3	*Escape/ Emergency Egress/ Exits*	Cal/OSHA 3215, 6577
2.2.4	*Labels, Color Coding and Signs*	MRMD 2129; Cal/OSHA 6151(c)(1); API RP 14J; OSHA 5(a)(1); NFPA 704; USCG 146.135
2.2.5	*Security*	MRMD 2122
2.2.6	*HAZMAT Handling & Storage*	MRMD 2129; Cal/OSHA 5164(c); OSHA 1910.106, 1910.1200; NFPA 30, 400
2.3	Field Verification of Plans	
2.3.1	*Process Flow Diagrams (PFDs)*	MRMD 2129, 2132; OSHA 1910.151, 1910.266; ANSI Z358.1; NFPA 10, 30, 72; API RP 14J, 75
2.3.2	*Piping & Instrumentation Diagrams*	MRMD 2129 2132; API RP 14J, 75; OSHA 5(a)(1)
2.3.3	*Fire Protection Drawings*	MRMD 2129, 2132; Cal/OSHA 6183; OSHA 1910.144; NFPA 14, 72

2.4	Condition and Integrity of Major Systems	
2.4.1	*Pumps & Piping*	MRMD 2129; Cal/OSHA 6533; OSHA1910.106, 5(a)(1); API 570, API RP 14E, 75; NACE Guidelines; ANSI B31.3
2.4.2	*Tanks*	MRMD 2129; API 650, 653
2.4.3	*Pressure Vessels*	MRMD 2129; ASME Boiler & PV Code Sect. VIII; API 510, API RP 572; Cal/OSHA 6551
2.4.4	*Relief Systems*	MRMD 2132; API RP 14J, 520, 521, 576
2.4.5	*ESP, Pump Units & Wellhead Equip.*	MRMD 2132
2.4.6	*Firefighting Detection Systems*	MRMD 2132; NFPA 25 & 72
2.4.7	*Firefighting Equipment*	MRMD 2129, 2132; Cal/OSHA 6151, 6533; OSHA 1910.144, 1910.160; NFPA 20, 25, 80; API 570, API RP 14E; NACE Guidelines; DCOR Safety Manual Section 3.01
2.4.8	*Emergency Shutdown System (ESD)*	MRMD 2132; API RP 14J
2.4.9	*Safety & PPE*	MRMD 2129; 2132; Cal/OSHA 1602, 3389, 5162; OSHA 1910.151, 1910.134; ANSI Z358.1; DCOR Safety Manual
2.4.10	*Instrumentation, Alarm and Paging*	MRMD 2129, 2175, 2132; OSHA 5(a)(1); API RP 14J
2.4.11	*Auxiliary Generator / Prime Mover*	MRMD 2132, 2129; Cal/OSHA 2940.13; OSHA 5(a)(1); DCOR Safety Manual Section 4.0 LOTO Blockout Procedures.
2.4.12	*Spill Containment*	MRMD 2139, 2140; EPA 112.7(c); California Government Code 8670
2.4.13	*Spill Response*	MRMD 2139 & 2140; California Government Code 8670
2.4.14	*Cranes/Slings*	MRMD 2129; CA Government Code 8670; Cal/OSHA 5042; OSHA 1910.184; API RP 2D
2.5	Mechanical Integrity/Preventive Maint.	MRMD 2129; API RP 75
2.6	Production Safety Systems	MRMD 2129; API RP 14C, 14J, 75; CalGEM 1747

3.0 ELECTRICAL SYSTEM AUDIT

3.1	Goals and Methodology	
3.2	Hazardous Area Electrical Classification Dwgs. • *Level of classification* • *Extent of classification*	API RP 500; NFPA 70
3.3	Electrical Power Dist. System, Normal Power	CEC 110.16, 110.22, 110.24; API RP 540; NFPA 70E; General
	3.3.1 System Configuration	
	3.3.2 Electrical Service Capacity:	
	3.3.3 Electrical System Design:	
3.4	Elec. Power Equip Condition and Functionality	CEC 110.11, 110.12, 110.13, 110.16, 110.26, 320.30, 300, 500.8, 501.10; API RP 540; NFPA 70B
	3.4.1 Equipment Condition	
	3.4.2 Safety Procedures	
	3.4.3 Equipment Maintenance Practices	
3.5	Grounding	API RP 540; NFPA 70
3.6	Emergency Electrical Power	MRMD 2132; API RP 14F; CEC 700.3, 700, 701; NFPA 70, 110
	3.6.1 System Configuration	
	3.6.2 Equipment and Component Ratings	
	3.6.3 Electrical System Design Safety	
3.7	Electric/Diesel Fire Pumps	NFPA 20; NEC 696
3.8	Process Instrumentation	API RP 540; NFPA 70
3.9	Standby Lighting Systems	CalGEM 1743; IES RP 7; API RP 540; CEC 700
3.10	Special Systems	CalGEM 1743,1747; API RP 14J, 75 Cal. Government Code 8670; ISA RP 7.1, RP 12.1, 12.2 ISA S7.4, S12.4
	3.10.1 Safety Control Systems	*Special systems codes above*
	3.10.2 Gas Detection Systems	MRMD 2132; CalGEM 1747.6; API RP 14J
	3.10.3 Fire Detection Systems	MRMD 2132; CalGEM 1743 & 1747; API RP 14J, 75, & 2001;
	3.10.4 Aids to Navigation	USCG Subchapter C, Part 67
	3.10.5 Communication	USCG Subchapter C, Part 67
	3.10.6 General Alarms	USCG Subchapter C, Part 67
	3.10.8 Cathodic Protection	API RP 651; NACE RP 01-76 NACE RP 06-75

4.0 SAFETY MANAGEMENT PROGRAMS

4.1	Goals and Methodology	API RP 75
4.2	Operations Manual	PRC 8758; MRMD 2129, 2175; API RP 75 & API RP 574
4.3	Spill Response Plan	Cal. Government Code 8670
4.4	Training and Drills	MRMD 2132; Cal/OSHA 650; API RP 75
4.5	Safety Management Programs	MRMD 2132 & MRMD 2129; Cal/OSHA 3220; Cal. Government Code 8670; EPA 112.7; API RP 75

5.0 HUMAN FACTORS AUDIT

5.1	Goals of the Human Factors Audit	
5.2	Human Factors Audit Methodology	MRMD 2129(b) & (c); Commission Safety Audit of Management Systems (SAMS); API RP 75; BSEE Subpart S

Appendix C
References

GOVERNMENT CODES, RULES, AND REGULATIONS

CCR CALIFORNIA CODE OF REGULATIONS

Title 2, Division 3, Chapter 1. State Lands Commission

2102-2175	*Sections of particular interest in Safety and Oil Spill Prevention Audit*
2129	*General Provisions, including references to "all applicable laws, rules, and regulations of the United States and the State of California" and "good oilfield practice".*
2132	*Production Regulations*
2132(a)	*Well Completion*
2132(g)	*Production Facility Safety Equipment and Procedures*
2175	*Operation Manual Content*

Title 8, Division 1, Chapter 4. Division of Industrial Safety [Cal/OSHA]

1602	*Work Over or Near Water*
2940.13	*Hazardous Energy Control Procedures*
3212	*Floor Openings, Floor Holes, Skylights and Roofs*
3220	*Emergency Action Plan*
3273	*Working Area*
3340	*Accident Prevention Signs*
3389	*Life Rings and Personal Flotation Devices*
3400	*Medical Services and First Aid*
3944	*Guard Clearances*
5042	*Safe Operating Practices*
5162	*Emergency Eyewash and Shower Equipment*
5164	*Storage of Hazardous Substances*
6151	*Portable Fire Extinguishers*
6183	*Fire Detection Systems*
6533	*Pipe Lines, Fittings, and Valves*
6551	*Vessels, Boilers and Pressure Relief Devices*

CFR CODE OF FEDERAL REGULATIONS

29 CFR	*1910.22 Walking-Working Surfaces*
29 CFR	*1910.106 Flammable Liquids*
29 CFR	*1910.134 Respiratory Protection*
29 CFR	*1910.144 Safety Color Code for Marking Physical Hazards*
29 CFR	*1910.146 Permit-Required Confined Spaces*
29 CFR	*1910.151 Medical Services and First Aid*
29 CFR	*1910.160 Fixed Extinguishing Systems, General*
29 CFR	*1910.184 Slings*
30 CFR	*Part 250 Oil and Gas Sulphur Regulations in the Outer Continental Shelf*
33 CFR	*Chapter I, Subchapter N, Outer Continental Shelf Activities*
40 CFR	*Part 112, Chapter I, Subchapter D, Oil Pollution Prevention*

49 CFR	*Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standard*
49 CFR	*Part 195, Transportation of Liquids by Pipeline*

INDUSTRY CODES, STANDARDS, AND RECOMMENDED PRACTICES

ANSI — AMERICAN NATIONAL STANDARDS INSTITUTE

Z308.1	*Workplace First Aid Kits*
Z358.1	*Emergency Eyewash & Shower Standard*

API — AMERICAN PETROLEUM INSTITUTE

RP 2A	*Planning, Designing, and Constructing Fixed Offshore Platforms*
RP 14E	*Design and Installation of Offshore Production Platform Piping Systems*
RP 14F	*Design and Installation of Electrical Systems for Offshore Production Platforms*
RP 14G	*Fire Prevention and Control on Open Type Offshore Production Platforms*
RP 14H	*Use of Surface Safety Valves and Underwater Safety Valves Offshore*
RP 14J	*Design and Hazards Analysis for Offshore Production Facilities*
RP 54	*Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations*
RP 75	*Safety and Environmental Management System for Offshore Operations and Assets*
510	*Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*
RP 540	*Electrical Installations in Petroleum Processing Plants*
570	*Piping Inspection Code*
RP 574	*Inspection Practices for Piping System Components*

ASME — AMERICAN SOCIETY OF MECHANICAL ENGINEERS

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

NACE — NATIONAL ASSOCIATION OF CORROSION ENGINEERS

RP 01-76	*Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production*

NFPA — NATIONAL FIRE PROTECTION AGENCY

10	*Standard for Portable Fire Extinguishers*
14	*Standard for the Installation of Standpipe and Hose Systems*
20	*Stationary Pumps for Fire Detection*
25	*Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*
30	*Flammable and Combustible Liquids Code*

	70	*National Electric Code*
	72	*National Fire Alarm and Signaling Code*
	80	*Standard for Fire Doors and Other Opening Protectives*
	400	*Hazardous Materials Code*
	496	*Standard for Purged and Pressurized Enclosures for Electrical Equipment*
	704	*Identification of the Hazards of Materials for Emergency Response*
CEC		CALIFORNIA ELECTRIC CODE
	110.11	*Deteriorating Agents*
	110.12	*Mechanical Execution of Work*
	110.13	*Mounting and Cooling of Equipment*
	110.16	*Arc-Flash Hazard Warning*
	110.22	*Identification of Disconnecting Means*
	110.24	*Available Fault Current*
	110.26	*Spaces About Electrical Equipment*
	300	*General Requirements for Wiring Methods and Materials*
	320.30	*Securing and Supporting Armored Cable, Type AC*
	500	*Hazardous (Classified) Locations, Classes I, II, and III, Divisions 1 and 2*
	501	*Class I Locations*
	501.10	*Wiring Methods*
	700	*Emergency Systems*
	700.3	*Emergency Systems, Tests and Maintenance*
	701	*Legally Required Standby Systems*

Appendix D
Team Members

FACILITY CONDITION TEAM

Commission – MRMD	David Calderon Gabriel Chapa Ryan Horton Crystal Pelka
DCOR	Nicholas Holmes Francisco Nauta James Parcher

ELECTRICAL TEAM

Commission – MRMD	David Calderon Gabriel Chapa Ryan Horton Crystal Pelka
P2S	Doug Effenberger
DCOR	Christopher Kenz

TECHNICAL TEAM

Commission – MRMD	David Calderon Gabriel Chapa Ryan Horton Crystal Pelka
DCOR	Martin Elu

SAFETY MANAGEMENT TEAM

Commission – MRMD	David Calderon Gabriel Chapa Ryan Horton Crystal Pelka
DCOR	Riston Francis