Safety and Oil Spill Prevention Audit

California Resources Corporation
Huntington Beach
Onshore Facility

December 2020

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EXECUTIVE SUMMARY

Safety Audit of California Resources Corporation (CRC), Huntington Beach Onshore Facility (HB Onshore)

A Safety and Oil Spill Prevention Audit of the California Resources Corporation (CRC) Huntington Beach onshore processing facility (HB Onshore) and state oil and gas lease upland production areas was started in September 2019. Fieldwork for the audit was completed in September 2020.

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 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

CRC is an oil and natural gas exploration and production company with operating properties exclusively in the state of California. CRC explores for, produces, gathers, processes, and markets crude oil, natural gas, and natural gas liquids in each of California's four major oil and gas basins: San Joaquin, Los Angeles, Ventura, and Sacramento.

Description of the Facilities

The CRC HB Onshore facilities are located about 40 miles southeast of the Los Angeles International Airport in the City of Huntington Beach, on the east side of Pacific Coast Highway. Facilities include three geographical components: the Highlands, Lowlands, and Townlot leases with onshore well areas producing from offshore state leases; (PRC 91, 163, 392, 425, and 426), as well as an onshore production facility that treats oil and gas before sales and shipment. The onshore production facility consists of oil dehydration and water processing facilities; a tank farm with an oil sales site; a gas processing and H_2S removal unit; CO_2 processing unit (Amine Unit) to meet sales gas specifications; a warehouse complex; and related subsea and onshore pipelines. The facility also processes oil and gas that is sent ashore from Platform Emmy located in state waters to the southwest, one mile off Huntington Beach.

The onshore operation currently has 111 producing wells and 50 active water injection wells. These numbers include two production areas in the North and South Bolsa Chica Wetlands which were not audited. Currently, CRC offshore and onshore leases combine to produce 3,805 Barrels of Oil per Day (BOPD), 113,588 Barrels of Water per Day (BWPD), and 1,197 Thousand Cubic Feet of Gas per Day (MCFD) of natural gas.

The oil-producing formations are typically below hydrostatic pressure and require an artificial (mechanical) lift to produce. Therefore, the potential for a well blowout is minimal. The onshore wells are produced using rod-pumping units and electric submersible pumps. The onshore graded drainage pattern, location of equipment, pads, and pits are intended to minimize environmental damage and aesthetic impact.

Safety Audit Results

The Safety and Oil Spill Prevention Audit (safety audit) found the HB Onshore facilities comply with applicable safety and regulatory requirements. An adequate level of safety and environmental protection has been achieved for facility operation activities. The established safety culture also ensures the protection of workers, the public, and the environment.

The facilities were found to be in an acceptable state of repair, clean, and well organized. CRC appears to have well-established safety, health, and environmental programs. A consistent safety and environmental awareness culture has developed from these programs. Employee safety program participation identifies and reduces workplace hazards, increases job performance, and promotes teamwork to reach organizational key performance indicators (KPIs). Personnel have sufficient knowledge and training in their jobs which ensures they can perform their tasks safely, effectively, and efficiently. Their skills and knowledge provided valuable assistance to the safety audit team.

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

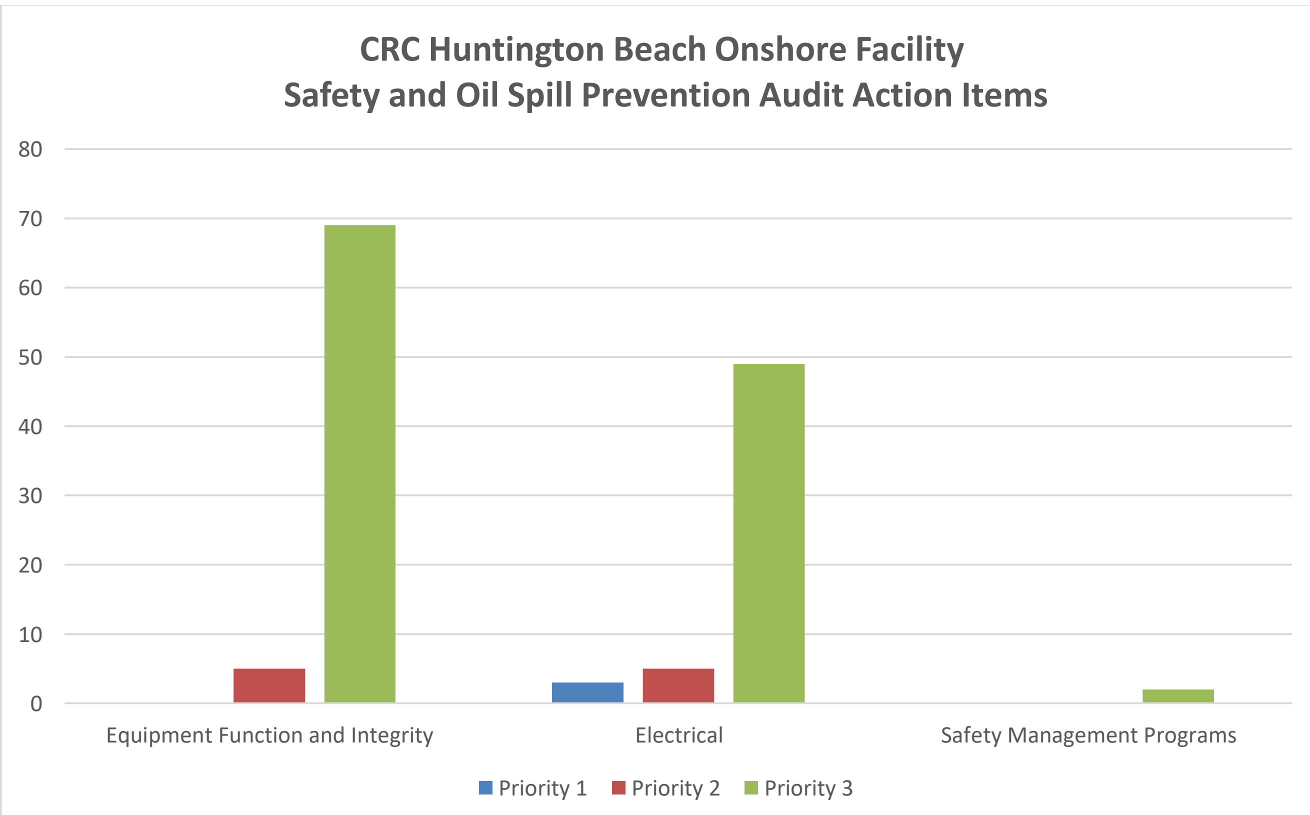
Firefighting, life safety, and spill response equipment meet National Fire Protection Association (NFPA) and regulatory requirements. Firefighting equipment and extinguishers are regularly serviced, maintained, and tested. Fire extinguishers are mounted, located, and identified so that employees can make use of them when needed. In addition, employees are required to take an online fire extinguisher refresher course yearly and must achieve a passing score.

Corporate safety programs are in place and fully implemented. CRC uses a software system to record, manage, and analyze safety-related data. The facility process control and safety shutdown systems are designed, installed, and maintained according to applicable codes and standards. Employees are appropriately trained in operating procedures, safe work practices, and the use, care, and limitations of all required personal protective equipment (PPE).

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 133 action items, a 23% reduction from the previous audit. The previous audit identified 10 priority 2 action items and 163 priority 3 action items. The current audit found three priority one action items; each of these were openings in electrical equipment due to missing cover plates. These items were corrected during the audit. The number of priority two action items held steady at ten. The number of priority three action items decreased to 120.

The following chart 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.



Introduction

California Resources Corporation
Huntington Beach
Onshore Facility

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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. The Commission staff is 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 6103, 6108, 6216, 6301, 6873(d), 8755, and 8757 provide authority for Commission regulations, as well as the Safety 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 safety systems inspection program, helps prevent oil spills and other accidents with on-site inspection and verification activities. The Safety Audit Program also aids prevention through review of facility design, maintenance policy and procedures, human factors, and other aspects of safety management.

During the safety audit, MRMD team members systematically assess an organization's facilities, safety management programs, identify action items to be addressed, and provide feedback for improvement in preparation of a written report. Their areas of emphasis include:

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

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" is used to categorize and track action items. The matrix contains recommended corrective actions and a risk-based 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 proposed corrective actions.

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

California Resources Corporation (CRC) currently operates the Huntington Beach state leases that include Platform Emmy and the Huntington Beach onshore (HB Onshore) facility. Platform Emmy is located 1.3 miles offshore from Huntington Beach. The state leases are part of the Huntington Beach Field originally discovered by Standard Oil Company on May 4, 1920, when oil was struck at 2,199 feet in Huntington Beach. This field has produced more than one billion barrels of oil in its history.

CRC is an oil and natural gas exploration and production company with operating properties exclusively in the state of California. CRC explores for, produces, gathers, processes, and markets crude oil, natural gas, and natural gas liquids in each of California's four major oil and gas basins: San Joaquin, Los Angeles, Ventura, and Sacramento.

The operation currently uses waterflooding to produce a total of 3,805 barrels of oil per day (BOPD), 113,588 barrels of water per day (BWPD), and 1,197 thousand cubic feet per day (MCFD) of natural gas between the onshore and offshore leases. The oil formations in this mature oil field are typically below hydrostatic pressure. The onshore production area covers over 1,300 acres and encompasses six leases (i.e., PRC 91, PRC 163, PRC 392, PRC 425, PRC 426 and PRC 4736). The onshore field operation has 78 active production wells using 60 electrical submersible pumps (ESP) and 18 beam pumping units for artificial lift. The wells that originate onshore produce approximately 3,387 BOPD, 73,386 BWPD and 981 MCFD of natural gas.

1.3 Facility Description

The HB Onshore facility is in the City of Huntington Beach, in Orange County, California. The onshore facility has well areas and facilities to process the oil and gas for sales and shipment. The majority of the facility is bounded by Pacific Coast Highway on the west side, residential housing on the east, and sits on relatively flat terrain. There are three well areas that are included in this safety audit: the Highlands, Lowlands, and Townlot areas. The production operations at the North and South Bolsa Chica Wetlands are not included. Platform Emmy's production is comingled with the onshore production that is processed at this facility.

The produced fluid mixture of oil, water, and gas from the various leases travels from the wellheads to Free Water Knock Outs (FWKOs). The FWKOs provide initial separation of the produced fluid and gas. Produced water from the FWKOs is processed on site and is injected back into the formation. The oil emulsion and gas streams are processed to meet sales specifications before entering the Lease Measuring System (LMS) units.

The LMS meters track total barrels of oil produced from the different leases before the oil is commingled and sent to the stock tanks. Sales oil is measured by the Lease Automatic Custody Transfer (LACT) meter and shipped by pipeline and tanker truck to area refineries.

Water separated from oil at the free water knockouts is sent to skim tanks. There, residual oil is skimmed off and routed to wet oil tanks. Produced water that comes from the skim tanks is sent to the Wemco flotation units. These units use mechanical agitation to remove dispersed oil droplets and suspended solids from the water. Produced water is then sent to injection charge pumps and on to Water Plant #4 injection pumps. The fluid from the water plant is then injected into seven zones as part of the waterflood program.

Gas from the platform and the onshore sites is sent to several units for processing to reach sales quality. These units include the Gas Plant for removal of hydrogen sulfide and the Amine Unit for removal of carbon dioxide (CO_2). The natural gas is distributed to facility systems (e.g., fuel gas and makeup gas) that require it and as “sales gas” to the Southern California Gas Company pipeline system.

Facility Condition Audit

California Resources Corporation
Huntington Beach Onshore Facility

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2.0 FACILITY CONDITION AUDIT

2.1 Goals and Methodology

The primary goal of the Facility Condition Audit Team was to evaluate the current maintenance and integrity of CRC's onshore facilities. The on-site inspection involved a systematic 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 Commission regulations. Tasks to complete this evaluation included field verifications of the key drawings/plans, overall condition inspection, a review of system and equipment maintenance histories, assessments of specific systems and equipment using checklists, and technical review of safety systems design. 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 or 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: Facility work areas were clean and orderly, free of slip and trip hazards, waste materials (e.g., refuse, oilfield wastes), and fire hazards. The warehouse shipping and receiving areas were marked and well organized. There was an adequate supply of clearly marked refuse containers throughout the entire facility and all refuse appeared to be well controlled. Scheduled collection of waste contributes to good housekeeping practices. Employee facilities are adequate, clean, and well maintained. Washrooms are cleaned once a day and have a good supply of soap and hand towels. Portable units were in satisfactory condition with no obvious health or sanitation concerns.

Drip pans and splash guards are used throughout the facility to prevent spills and pollution. If a substance accidentally drips onto the ground, personnel clean it up immediately. Absorbent materials are stored in an emergency trailer located near the electrical personnel office and on all facility work vehicles. They are readily available for wiping up greasy, oily, or other liquid spills. Tools are available and stored in suitable fixtures for easy access. They are promptly 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: Stairs, walkways, gratings, and ladders throughout the HB Onshore facilities appeared to be of safe design and construction. Safeguards were in place wherever there was a need to transition between levels and for routine access to equipment. However, crossover bridge catwalk structures along the Highlands wellhead strip area were not secured to a stable foundation. The 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. Portable ladders and other necessary work equipment appeared to be in good working order and free from oil and grease. Fixed metal ladders and appurtenances were painted to resist corrosion. CRC'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 posted and accessible. Evacuation routes are explained during initial worker orientation, safety meetings, and are reviewed as part of the work permit system. They are identified with signs posted throughout each of the facilities.

2.2.4 Labeling, Color Coding and Signs: The design, application, and use of signs and symbols within the facility define specific workplace hazards. CRC adheres to the Occupational Safety and Health Administration (OSHA) 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, and fire safety equipment is red. The Equipment Site Safety Plans displayed at assembly areas need to be updated to correspond to the current levels and locations of protective equipment. Additionally, an Equipment Site Safety Plan diagram should be added to the evacuation assembly area at the Seapoint Street gate.

Warning signs were posted at the entrance to each facility. They were visible and identified safety hazards. Signs are also posted at each well to identify the owner/operator, number of the lease, and number of the well as required by California Geologic Energy Management (CalGEM) regulations.

NFPA 704 hazard identification diamonds were visible on all tanks, vessels, buildings, and chemical storage totes. The posting of these labels is an indication of good facility emergency planning and conformance with the Uniform Fire Code.

2.2.5 Security: Physical and operational security measures are in place to prevent unauthorized entry into the CRC facilities. Process facilities are manned twenty-four hours a day, seven days a week with at least two operators present at all times. Also, a private security guard is present at the main gate during normal business hours. CRC also uses a system of colored placards placed on vehicles entering the lease. These placards are used to determine who is authorized to be on the property and who is not. Lease surveillance cameras, fencing, facility lighting, locked doors, and electronically controlled gates at access locations are also used as a deterrent to unauthorized entry and vandalism. Facility personnel also provide monitoring with normal surveillance activities of the pipelines and process facilities.

2.2.6 Hazardous Material Handling and Storage: Flammable and combustible liquids were found properly stored in safety cans and drums following Cal/OSHA and NFPA 30 regulations. The bulk chemical totes were correctly labeled, appeared structurally sound, and had adequate containment in the event of a leak. There was a minor concern regarding sun-faded labels on several chemical totes on the facility. The fading has made it difficult to read the label and identify the contents in the tote and related hazards. No loose combustible material or empty drums were left on the premises.

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 stored in places where they would not be knocked over or damaged. Shade structures have been constructed around the facility to prevent exposure to direct sunlight.

Safety Data Sheets (SDS) containing information on all chemicals used in the workplace were up-to-date and accessible to all employees. SDSs are provided at the site of chemical use (chemical injection skids, individual totes) by storing copies in document boxes throughout the facility.

Various issues with emergency eyewash and shower combination units were observed during the audit. Non-functioning, malfunctioning, and missing emergency eyewash and shower units were reported to CRC by the Safety Audit Team.(EFI – 2.2.6.01 to 2.2.6.04) A contractor performs monthly tests of this equipment's function and is expected to report non-compliant conditions to CRC. CRC has increased oversight of this contractor's performance since these issues were not presented on their monthly report.

2.3 Field Verification of Plans

2.3.1 Process Flow Diagrams (PFD): The PFD drawings are considered a part of the necessary design documentation for a facility. The PFD drawings for each of the facilities were up-to-date and showed the flow through the plant processes and equipment.

2.3.2 Piping and Instrumentation Diagrams (P&ID): A comprehensive field verification of P&IDs was performed for all onshore production and process facilities. Several of the drawings provided, which included those for the Water Plant, Highlands Strip, Tank Farm, and Gas Processing facilities required revision. Numerous priority 3 action items were generated regarding the accuracy of P&IDs.

2.3.3 Fire Protection Drawings: The fire protection drawings for all locations were surveyed with some updates or corrections needed. These drawings show important information about the firefighting system including the diesel fire pump or source of firefighting water pressure, the fire main or distribution system, the location of main valves, stationary monitors, portable extinguishers, and hydrants. These drawings are posted at different locations within the Tank Farm facilities to comply with the requirement for providing required emergency information.

2.4 Condition and Integrity of Major Systems

2.4.1 Piping: An external visual inspection of the piping systems at all locations in this facility was performed in conjunction with P&ID verification. This visual inspection and evaluation work observed the outside condition of the piping, painting, coating, and checked for signs of misalignment, vibration, or leakage. The evaluation also included the condition of pipe hangers and supports with some broken or missing brackets observed during the field survey. (EFI – 2.4.1.02) 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 condition and maintenance of piping throughout the facility were found to be generally good. The selection of piping materials and components, e.g., valves, flanges, bolts, welds are compatible with the process, operating parameters, and environment.

CRC 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., API 570, DOT pipeline inspections, etc.). Results from thickness measurements, inspections, repairs, and other tests are readily available and recorded within a computer-based maintenance system (Maximo). This maintenance management system stores and generates maintenance activities. Inspection history, data, and scheduling is managed in CREDO mechanical integrity management software.

2.4.2 Tanks: Facility tanks are subject to CRC's written inspection and maintenance plan. The maintenance plan follows API codes, standards, Recommended Practices (RP), and other applicable industry safety standards. The maintenance strategy also conforms to applicable State regulations and uses appropriate work practices and procedures. Routine external/internal maintenance inspections occur on a five-year cycle and more often if conditions require it. Tank documentation includes inspections, repairs, alterations, and reconstruction records. In addition, tank shell ultrasonic thickness data showing locations and results are measured and recorded 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.

Safety devices for the stock tanks are compliant with MRMD regulations. A high level in the tanks will cause the shut-in of all oil and water processing. The design and capacity for secondary tank battery containment meet EPA Spill Prevention Containment and Countermeasures (SPCC) requirements. The concrete containment system is designed to be impermeable to crude oil, can hold 110 percent of the contents of the largest tank, and provides the required containment. The required high and low-level sensors are displayed on the Tank Farm process computers and provide the required alarms to alert operators to significant tank conditions.

2.4.3 Pressure Vessels: There are a variety of pressure vessels at the facility, ranging from air receivers to three-phase separators, that are used on the lease to process the oil, gas, and produced water. 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, CRC has tailored inspection cycles to match the safety risks posed by particular classes of pressure vessels. CRC also uses a mechanical integrity management program called CREDO to determine vessel inspection frequencies. CREDO uses vessel wall thickness, corrosion allowance, and minimum thicknesses (t-mins) as well as operating temperature and pressures to determine the inspection frequency. Vessel inspections (external and internal) are completed within 5-year intervals using non-destructive examination techniques.

Analysis of pressure vessel inspection records determined that inspection frequency is being achieved following API 510 guidelines. Inspection recommendations, maintenance activities, and design information are documented and recorded within the pressure vessel's permanent record. However, a review of these records found that a few pressure vessels had passed their due dates for inspections. This finding was communicated to CRC personnel and work orders were generated to schedule required inspections.

External inspection of the pressure vessels found no evidence of leakage, distortion, or cracks at welds or structural attachments, or defects of vessel connections but did identify some minor concerns regarding corrosion, grounding, and several damaged swing gates used to access vessels and tanks. These were addressed with action items. Internal inspection records show acceptable corrosion rates with no major concerns or defects of the pressure vessels.

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. The relief system components were evaluated for installation, design, maintenance, and functionality. They included:

- Relief Devices and Piping
- Flare Header System
- Liquid Knockout Drums
- Ground Flare

A visual inspection of the system determined that all laterals and headers are arranged so that the outlet from each relief valve does not form a liquid trap. Similarly, the sizing of the discharge piping and the relief manifold provide adequate relieving capacity and protection to the corresponding vessel(s) from overpressure. Process knockout drums are designed for vapor-liquid separation and prevention of liquid carryover. As with many older installations, the relief valves and associated piping were sized for a much higher production rate than the present.

Isolation block valves are installed on the inlet and outlet lines to pressure safety valves (PSVs) lines for ease of maintenance. During normal operations, these valves on the inlet and outlet are opened and locked or car sealed in that position. Rupture disks are also used to protect against corrosion and reduce fugitive emissions on the upstream side of relief valves in the Gas Plant and Amine facilities. These disks are used in conjunction with computerized sensors to alert operators of an abnormal increase in pressure via Tank Farm monitors.

The maintenance and servicing records for all PSVs comply with applicable regulations and recommended standards (e.g., API Standard (Std) 520, API Std 521, and Cal/OSHA 6551). PSVs are tested and serviced by an outside contractor. The inspection frequency is normally every five years or less, depending on the application of the relief valve. Service records were in order with no action items identified.

The ground flare is sized to take into account the number of relief valves discharging into the flare header. Analysis of the flare found that it was designed to comply with all safety, environmental and regulatory mandates. Additional design considerations included the relationship between the facility and its neighbors (e.g., smoke suppression, flame radiation, noise, and visibility).

2.4.5 ESP, Pump Units, Wellhead Equip.& Well Safety Systems: The onshore wells are considered incapable of natural flow or after flow, once the artificial lift is stopped. Therefore, subsurface safety valves (SSSV's) or other automated shutdown valves are not required on production flow lines. Since gas can flow from the casings, block and bleed systems have been provided at the wellheads. Onshore electrical submersible pump (ESP) wells can be shutdown remotely via the Tank Farm lease emergency shutdown (ESD).

2.4.6 Fire 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. Systems typically include:

- Smoke Detectors
- Flame Detectors
- Combustible Gas Detectors
- Fusible Links

An audit of the smoke detectors in the control rooms and occupied office spaces found them energized, free of excess dust, and overall in physically good condition. Records showed these smoke detectors are visually inspected on a routine basis and smoke entry tested semiannually according to NFPA 72 inspection frequencies by facility technicians.

Temperature safety elements (e.g., fusible link and plug loops) within the Tank Farm and the Gas Plant were visually inspected and found to be in good working order. The fusible plug system was pressurized, constructed of non-corrosive materials, and in good condition. Inspection, maintenance, and testing records showed CRC technicians inspect the temperature safety elements annually according to NFPA 72.

Fire detection in the Tank Farm relies on surveillance from operating personnel rather than a dedicated detection system. The Tank Farm has fusible links at the vapor recovery unit but no types of flame detectors for the oil storage or production areas. A response to a fire at the Tank Farm rests on the operator who after observing a fire, must initiate the notification to the local fire department and try to secure the source of fuel. In a worst-case scenario, there is the possibility that fire within the Tank Farm could grow in intensity or involvement before operating or surveillance personnel could detect it. Currently, all fire protection components and related safety systems have been approved and deemed adequate by the City of Huntington Beach Fire Department (HBFD). In addition, a local fire department station is located less than two miles from the facility.

The fire detection systems on the Amine, Gas Plant, and Micro Turbine units meet Commission regulations 2132(g)(4) and are appropriate in design and scope. The fire detection systems in use at these units consist of UV/IR flame detectors, and combustible gas/vapor detectors. The Gas Plant also employs a deluge system triggered by fusible plugs in its active fire protection system. These systems appear to be well maintained and in good operating order with no deficiencies noted.

2.4.7 Firefighting Equipment: The primary firefighting system required by Commission regulations and the local fire authority consists of a city water pressurized loop system supplying water to hydrants, deluge sprinklers, stationary monitors, and foam stations. The equipment is located within the Tank Farm and Gas Plant. A previous test of the system hydraulics, by a fire protection engineer, showed that the fire pump could supply the Gas Plant deluge system and stationary monitor streams with adequate flow and pressure. Weekly test results are recorded and retained for comparison purposes as required by NFPA 25, 5-4. The firefighting system appears to meet the minimum fire equipment requirements found in NFPA 11, 13, 15, and 20 guidelines.

The original basis of design for the fire protection system used area risk management to determine the total capacity of the firewater system. Based upon the risk rankings more protection is provided to the area of the facility requiring the greatest amount of protection (e.g., Gas Plant). The Huntington Beach Fire Department (HBFD) approved all detailed plans along with equipment types and locations. The fire department also reviewed hazard and operability studies (HAZOPs) and Safety Analysis Function Evaluation (SAFE) charts for the Tank Farm before approval was given for the Tank Farm modernization project and construction of the Gas Plant. Fire response depends on early hazard detection and the ability of the local fire department to contain and extinguish a flammable liquid or gas fire. In addition to the primary fire main system, the facility is equipped with portable fire extinguishers as required by the HBFD.

Visual inspection of the firewater piping and fittings found that they were in good condition and free of mechanical damage. On the other hand, missing fire main labeling, and pipe to soil interface was found in different locations along the fire main loop. Fire loop supports, hangers, and braces were secure and undamaged. Hydrants were protected from vehicle impact with adequate protection barriers. Leaking hydrants and damaged hydrant wrenches were reported to CRC personnel during the audit.

The fixed water monitors used throughout the processing areas were inspected for leaks and nozzle range of motion. As part of CRC's maintenance program, pivot points on the monitor are regularly greased, ensuring proper operation in the event of a fire.

A foam system (3% aqueous film-forming foam (AFFF)) is employed within the Tank Farm for controlling liquid hydrocarbon fires in the oil stock tanks. The foam storage vessel is adjacent to the Tank Farm control room and requires operator activation. The system is designed to provide an air-excluding continuous blanket of foam to the surface of the oil stored in the stock tanks. Vallen Safety Services tests the foam concentrate for contamination and dilution regularly. Records show a history of continuous 5 year and annual California State Fire Marshal certified testing of all facility firefighting equipment.

The HBFD has primary authority regarding firefighting requirements. Their personnel inspect and verify that the firefighting equipment provided meets their requirements.

2.4.8 Emergency Shutdown System (ESD): 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 detection systems are installed within the Gas Plant, Micro Turbine, and Amine unit. These gas detection systems alert personnel to the presence of low-level concentrations (20% of LEL) of flammable gas/vapor by a computer-generated alarm and a local beacon. As the concentration of the gas approaches 60% of LEL, the emergency shutdown (ESD) of these units occurs. H_2S gas detection systems are also installed in units where there is a presence of H_2S gas and the potential for release. These detectors do not initiate shut-in/isolation actions but provide audible and visual alarms when the concentration of H_2S reaches 10 ppm.

All H_2S and combustible gas detection systems were inspected and found to be in good working order and met Commission requirements. Calibration, testing, and maintenance of this system are conducted and recorded monthly by CRC personnel. Sensor histories and test results are kept electronically in Maximo and available upon request.

Hydrogen sulfide dispersion modeling assessed the risk of a gas release to the public and nearby housing tracts. 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. Computer modeling determined that no significant exposure risks were present and an H_2S detection system along the perimeter wall was not needed.

2.4.9 Safety and Personal Protective Equipment (PPE): Manual pull ESDs can be found in the Gas Plant area. When activated, all plant gas feeds are blocked in and diverted to the ground flare. Individual lease ESDs are available through the Wonderware operator interface. The interface allows operators to shut down individual leases as necessary to stop oil production and gas flow in the event of an emergency.

The ESD system was found to effectively alarm, shutdown process activity, and close shutdown valves (SDVs) as designed. The safety system also permits the continued operation of the firefighting systems during an emergency. These stations were identified and made of corrosion-resistant materials to ensure reliable operation. Optical flame detectors, e.g., Lower Explosive Limit (LELs) and Ultraviolet/Infrared (UV/IR) Flame Detectors, have the ability to shutdown individual process units, while a high-high level alarm (LAHH) on the stock tanks will initiate a full facility shutdown. These safety detectors and tank level alarms can be found within each of the onshore facility's process units (Tank Farm, Gas Plant, Micro Turbine, and Amine Units). The sensors and level instrumentation are tested and documented semi-annually.

2.4.10 Instrumentation, Alarm and Paging: The process instrumentation has evolved into digital control through previous facility upgrades. Production controls and instrumentation are part of a Digital Control System (DCS) that is connected to the tank farm by digital networks. Within the DCS, programmable logic controllers (PLCs) are used to control and monitor all the process equipment and instruments in the various plants. Operations management software (Wonderware) provides the operator interface displaying 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 and input devices used by the operators to operate the facility are known as Human Machine Interfaces (HMI). There are simple graphic displays that mimic the process on the operator's console located in the Tank Farm control room. 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 (Auto or Manual)

- Output Change
- Trending
- Alarm Management
- Report(s)
- 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 not only displayed and audible in the control room; they are also sent to a paging system that alerts operators who may be away from the control room.

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, maintained, and calibrated annually. Records are readily available and the device history can be tracked through Maximo. 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: Uninterruptable power supply (UPS) systems and portable generators provide emergency power at the onshore facilities. The UPS systems provide approximately ½ hour of backup power to the individual facility PLCs. If needed, additional power to the PLCs can be supplied by portable generators. These generators are sized to supply power to a few vital circuits and their operation is only limited by the amount of fuel available. 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 power company's 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.

Facility emergency lighting is restricted to handheld flashlights and truck-mounted spotlights. In the event of a power outage, the safe shutdown of the facilities can be accomplished using the backup instrument air compressor.

2.4.12 Spill Containment: The secondary containment provided around tanks and fluid handling equipment meets the EPA's Spill Prevention Control and Countermeasure (SPCC) regulations. This system coupled with routine visual inspections by operating personnel reduces the consequences of a leak or rupture if one were to develop. The containment volumes provided by the spill containment walls for the Tank Farm were also carefully reviewed. The assessment found that containment for the stock tanks as well as for the skim tanks is adequately sized to meet regulatory requirements. The containment volumes provided will contain more than the volume of the largest tank plus the recommended allowance for precipitation while excluding the volumes occupied by other tanks.

2.4.13 Spill Response: Oil spill response for the onshore facilities is outlined in CRC's Oil Spill Contingency Plan (OSCP). The plan satisfies both federal and state regulations and is discussed in more detail in the Safety Management Programs section of this report. Spill response equipment identified in the plan is stored in an emergency trailer located near the electrical personnel office. The trailer is stocked with a variety of pollution control equipment that exceeds minimum requirements. An outside contractor checks and maintains these inventories monthly. The inventory consists of spill booms, absorbent pads, generator, shovels, rakes, hand tools, flashlights, tape, etc. Contract personnel are the primary responders to minor onshore spills with CRC personnel available if needed. For larger onshore spills, the same outside contractors mentioned above can and will respond if called on with the addition of Ecology Control Industries (ECI) environmental services vacuum trucks. In addition, CRC schedules Qualified Individual notification checks, facility spill boom deployment drills, and tabletop drills annually to test the incident command system. The entire response plan is tested on a triennial basis by either conducting a worst-case discharge drill or by ensuring that other portions of the plan's components are exercised at least once during other drills occurring within the same three-year period.

2.5 Mechanical Integrity / Preventive Maintenance Program

The Preventive Maintenance and Mechanical Reliability sections provide a general overview of CRC's corporate philosophy and approach to implementing a successful reliability program. The section also provides findings when appropriate. Preventive maintenance and job scheduling are controlled by a "maintenance planner". The maintenance planner reviews new work orders daily and assigns an in-house craft or outsources the task to a contractor/vendor depending upon the workload and specific job requirements. The planner also stages commonly used parts and supplies while critical spare parts are located in the warehouse. This approach provides CRC with maintenance task optimization and decreases the chance of equipment failure Also, the record-keeping process was updated by migrating the PSV, tank, and pressure vessel records from hard to electronic copies of the historical files.

The computerized maintenance management system (Maximo) is utilized to manage and track activities. Operating personnel can access Maximo to generate a work order. These work orders can range from a simple filter change to major equipment repair. Maximo gives the CRC maintenance planner 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. 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. This proactive approach to piping integrity and risk control has been enhanced in recent years and has produced positive results. Several different methods are being used to improve the life of the various piping systems that include:

- Primer, Paint, and Tape Wrap Coatings (External)
- Epoxy Coatings (Internal)
- Cement Lining
- Cathodic Protection
- Chemical Treatment

A chemical vendor provides the facility with a chemical injection program that satisfies the operational needs of the onshore facilities. 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.

Sacrificial anodes are used in conjunction with other forms of corrosion control such as protective coatings, wherever systems are exposed to a corrosive environment. 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 as to the source of a detected deficiency.

Evaluation of the maintenance condition resulting from CRC's management practices found that the facility is designed, operated, and maintained in a manner that permits safe, reliable operation. Its success is due to operational groups (management, engineering, operations, and maintenance) being fully integrated into an effective team committed to following inspection, testing, and preventive maintenance "best practices". There was one Priority 2 action item generated, asking CRC to evaluate the condition and safety of the pipe corridor roadway crossing located near the east end of the facility. (EFI – 2.5.01) Degradation of the concrete slab is exposing rebar with surface cracks, spalling, and delamination that can lead to corrosion of the rebar and possible failure of the roadway crossing. This crossing is heavily traveled and stress from vehicles and/or truckloads may cause additional damage or failure of the structure.

2.6 Production Safety Systems

Analysis of facility 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 safety audit of the HB Onshore facility. The automated control and safety systems have been designed using applicable codes, standards, and industry practices.

Plant status, controls, and alarms are displayed in real-time via HMI displays located in the tank farm control room. The automated control system monitors and controls facility processes in separate operating areas. The automated displays help minimize the effects of undesirable events and mitigate consequences from upsets. When hazards cannot be eliminated or controlled through design, CRC uses a hierarchy of health and safety controls (e.g., Administrative and Engineering Controls) to eliminate hazards or reduce exposure to hazards.

Facility production safety systems also include pressure safety devices (PAHHs) which are capable of shutting down the processes associated with individual FWKOs. There are LELs and UV/IR detectors in the Amine, and Gas Plant, that can shut in these specific process areas. Finally, a total facility shut down can be activated by the stock and skim tank high level shut down safety devices (LAHH). All systems are functional and appear to be properly designed and maintained.

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Electrical System Audit

California Resources Corporation Huntington Beach Onshore Facility

December 2020

3.0 ELECTRICAL SYSTEM AUDIT

3.1 Goals and Methodology

The primary goal of the Electrical Team (ELC) was to evaluate the electrical systems and operations of the California Resources Corporation (CRC) Huntington Beach onshore (HB Onshore) facilities to determine if it conforms to recognized and appropriate electrical Codes and industry standards. The ELC system audit included the electrical equipment located at onshore sites: Highlands, Gas Processing Unit, Tank Farm, and Fort Apache.

References used in the review of facilities include documents published by the American Petroleum Institute (API), National Fire Protection Association (NFPA), the State of California Electric Code (CEC), and State Lands Commission (Commission) regulations. The ELC Team review comments are based on those publications, which primarily include API Recommended Practice (RP) 500, API RP 540, CEC documents, and other applicable industry standards. The drawings used in support of the audit were electrical single-lines, site plans, and hazardous area classification drawings provided by CRC for the facility.

Specific tasks to accomplish this goal at each location included a systematic process of field verification of electrical single-line diagrams, plan drawings, hazardous area classification drawings, visual observations, and maintenance practices. The use of inspection checklists, code and standard compliance checklists, and review of the electrical system design for conformance to codes and standards were utilized to complete the audit. This report includes a summary of the electrical systems included in the audit.

Section 3.0 of the Action Item matrix provides a detailed listing of the locations and items identified for correction. The matrix is organized into subsections that correspond to this report. Each section is discussed below along with examples of typical items encountered.

3.2 Hazardous Area Electrical Classifications Drawings

The API RPs 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 500, CEC Articles 500, 501, and 504, and NFPA 70E. The hazardous area electrical classification drawings (HAECD) are generally representative of the existing conditions and area class elements.

The purpose of an HAECD is to define the locations of boundaries and areas where specific electrical materials and 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 and the level of the hazard to ensure compliance with CEC requirements. HAECDs are required to include the information necessary for designers, electricians, and other personnel to perform work in and around classified areas.

The nature of oil and gas production has evolved with the use of various chemical additives, which, in some cases, are flammable. The storage and dispensing of these chemicals is accomplished using portable totes. The HAECDs include identification of the planned locations of totes but due to the changing needs of production, the proper placement of totes will require regular verification with the HAECDs.

Areas that contain walls, depressions, and barriers to natural ventilation where flammable liquids or vapors may be present require evaluation and identification of the appropriate Electrical Area Classification. All areas known to contain flammable liquids or vapors are required to be identified on an HAECD. These areas are generally found to be classified correctly.

Portable chemical tanks are used for treatment and injection and are located throughout the facilities. The tanks are portable, but the locations of the tank installations are, by definition, permanent and have pumps which operate continuously. Many of the portable tanks contain flammable liquids. The lines, pumps, and fittings associated with the tanks are also a source of hazard and require classification of the areas affected. These areas were found to be classified correctly.

All equipment enclosures, raceways, conduit sleeves, metal totes, and well casings are required to be electrically bonded in classified areas. Bonding was observed to be in place with no specific problems noted.

General-purpose electrical enclosures (load centers, motor control centers (MCC), control panels, etc.) are only suitable for use in unclassified areas. In general, electrical equipment installed in Classified areas was found to be explosion-proof, National Electrical Manufacturers Association (NEMA) 4, purged, or otherwise suitable for use in Classified areas. Purged enclosures are monitored and equipped with an alarm when purge pressures drop below a minimum level. No specific action items were identified.

Conduit seals are required at classification boundaries. Locations where conduits originate outside of classified areas and travel through classified areas without the use of a junction box, fitting, or coupling, may cross boundaries of Division 2 areas without a seal. No specific action items were identified.

3.3 Electrical Power Distribution System, Normal Power

Electrical System Configuration: Electric utility service is supplied by Southern California Edison (SCE) for the facility. The HB Strip site receives power at 66kV from an SCE oil-filled transformer. The facility utilizes power at 12.47kV, 4160V, or 480V through a radial distribution system to supply plant loads. The Fort Apache service is supplied from the HB Strip at 12.47kV via underground cable and conduit. The Fort Apache site utilizes power at 480V.

3.3.1 Electrical Single-Line: The electrical single-line drawings provided by CRC were used for review of the HB Onshore facility electrical system. During the audit, sizes and rating of the equipment was recorded for comparison to existing drawings. The audit focused on power distribution systems of 12.47kV, 480V, and 240V and excluded lower voltage systems. The Gas Plant and Water Injection Plant 4 use 4160V power for their largest loads. The rest of the onshore facilities have 12.47kV to 480V transformers and 480V MCCs that supply local loads. The drawings were available and located at the site library. The high voltage single line is up to date but could be improved by including more detailed equipment rating information and capturing operational notes that are presently taped to the equipment. Single-lines for 480V MCCs throughout the facility should be updated per the matrix to better represent recent system modifications. (ELC - 3.3.1.02 thru 53)

3.3.2 Electrical Service Capacity: The facility receives power from SCE at 66kV. The main service 66-12.47kV transformer is rated at 22.4MVA and transforms voltage to 12.47kV for facility distribution from the main 2000A, 12.47kV switchgear. A single 12.47kV feeder is dedicated to service for Platform Emmy. The main 12.47kV switchgear is identified to be rated at 2000A but a notice posted on the equipment indicates the maximum load should not exceed 1000A due to construction of the bus. The limitation to 1000A, 21.6MVA at 12.47kV is based on the SCE service capacity limit and should be identified on the single line diagram. The service capacity limitation is based upon the transformer maximum rating of 22.4MVA, which is slightly higher than the posted capacity of the main switchgear.

The power system capacity, in general, appears to be adequate for present usage and loads based on observation of equipment connected for each site. During the site visit the main 12kV switchgear loading was approximately 660A, 14.25MVA. Load flow studies should be performed for the 12.47kV system, including each substation, to verify feeders and equipment are adequately rated for the load. Utility short circuit duty should be verified a minimum of every five years when the facility arc flash hazard assessment is updated as required by NFPA 70E. The updated arc flash hazard assessment is due to be completed in 2020. It is recommended that the facility's electrical single-line diagrams be updated before preparing the updates to the Arc Flash Hazard study.

A physical inspection of motor starters and circuit breakers revealed that, in general, overcurrent protection was appropriate. The feeder protection devices on Bus HS-SWR-1, HS-SWGR-2, and HS-SWGR-3 have been replaced with SEL-751 relays. The application of overcurrent devices concerning equipment rating is generally satisfactory.

3.3.3 Electrical System Design: The 12.47kV power distribution system is essentially a radial design configuration. A radial feeder configuration consists of a single circuit to supply the load, much like the hub and spoke configuration of a wheel. When a fault occurs on one feeder or a feeder needs to be taken offline for maintenance in a radial system, there is no alternate path to feed the normal loads of that feeder. Distribution systems components could be added that would provide better operational flexibility and maintenance opportunities. It may be worth evaluating whether the potential operational, safety and cost impacts of losing individual feeders and their associated loads warrant upgrading the distribution system from a radial to a loop configuration to improve operational reliability and maintenance flexibility.

The reliability of the electric system is determined primarily by the availability of SCE to supply loads and the condition and operational readiness of the facility distribution system. The reliability of the electrical system also depends on the condition and operation of each system component. At one time in the past, the on-shore facilities were supplied from two SCE 66kV feeders. The second SCE 66kV feeder and substation were removed from service. However, provisions exist to restore the second SCE 66kV service, which may be necessary to accommodate future peak loads and improve electric power reliability. A maintenance and inspection program, properly implemented, is key to assuring the highest level of reliability.

Electrical maintenance has been integrated into the MAXIMO computer database and tracked. Electrical system maintenance is due to be performed based on NFPA 70B recommendations.

3.4 Electrical Power Equipment Condition and Functionality

3.4.1 Equipment Condition: The electrical equipment includes both indoor and outdoor installations located in non-hazardous areas. The indoor installations include concrete masonry unit (CMU) type block buildings, steel buildings, steel sheds, and canopy structures with side shields. Some of the buildings are conditioned. The outdoor equipment is rated NEMA 3 or NEMA 4 and is weatherproof.

Enclosures consist of mild steel with corrosion-inhibiting coatings, stainless steel, and fiberglass resin material. Corrosion of ferrous material is caused by salt air and fog. Shed structures with side screens have been installed above the NEMA 3 12.47kV load interrupter switchgear to protect the equipment from the effects of corrosion from the elements. Equipment enclosures require periodic treatment to maintain their integrity. Equipment supports and racks consist of galvanized and painted steel angle iron and electrical "strut". The harsh environmental conditions require treatment of corrosion inhibiter to slow deterioration, but with time, supports will ultimately require replacement.

Cable tray is used for cable installation throughout the facility. The tray and tray support structures are in good condition overall.

3.4.2 Safety Procedures: The electricians follow a mandatory set of procedures designed to enhance personnel safety and reduce the potential for shock and injury. Electricians are responsible to complete a task checklist before beginning any work. The checklist includes identification of hazards that might be associated with the task and the measures to be employed to minimize the hazard, risks. A lock-out tag-out program is well documented and implemented. The use of H_2S three-way and four-way gas detectors is required for entry to confined spaces and hot work in classified areas.

Lock-Out/Tag-Out practices are established by CRC, and by observation, are being implemented. Energy control (procedure) permits are available for completion using computers in the tank farm which indicates the procedure to be taken and sign-offs required to safely perform maintenance tasks.

Electrical systems shall be designed to minimize the risk of hazards to operating personnel. CEC 110.16 requires that arc flash hazard warnings be provided on electrical equipment to warn personnel of the potential electric arc flash hazards. NFPA 70E-2018, Standard for Electrical Safety in the Workplace, provides guidance for labeling and selecting personal protective equipment (PPE). Arc flash hazard warnings and labeling are, in general, provided on all energized equipment. The CRC electrical safety program described the training, qualifications, and personal protective equipment necessary to perform live electrical work. It was confirmed with CRC that the studies for arc flash hazards are being updated every five years. An update of the arc flash hazard study is due in 2020. Many of the existing warning labels are deteriorated and require replacement. The requirements for arc flash hazard notification and information to be included on arc flash hazard labels continues to be changed with each Code cycle. The existing labels require replacement to comply with new Code requirements or due to being illegible due to deterioration or being faded. An Arc Flash Hazard study update is also needed at this time based on recent electrical system changes that have been completed that will impact both short circuit duty and fault clearing times.

CEC article 590.6(B)(2) requires a written assured grounding program that is continuously enforced at the site by one or more designated personnel. CRC has such a program that is being enforced. CRC also requires third parties to implement their own programs. It is recommended that CRC require all third parties to comply with the color code sequence being implemented by CRC to avoid confusion and the unintentional use of a cord set that has not been tested quarterly, as required.

CRC has implemented a comprehensive training program to educate and inform all workers of the hazards associated with electrical systems. Personnel are required to complete regular, periodic training and hazard awareness training regarding the proper and mandatory use of personnel protective equipment.

The working clearance required around electrical equipment is generally maintained. Also, no life safety systems are installed that require permanent emergency electric power sources.

Circuit identification nameplates are rusted, missing, hard to read, or no longer applicable because equipment has been removed. This can cause confusion when operating or de-energizing equipment for maintenance. Several switches supplying equipment did not have load identification and need to have identification nameplates added. (ELC - 3.4.2.05)

Panel schedules have been well maintained and updated. CRC has made a concerted effort to update the panel schedules. This is an ongoing effort. It is also recommended that equipment identification labels be made consistent with process diagrams and electrical single-line diagrams, as well as the established naming convention.

3.4.3 Equipment Maintenance Practices: The HB Onshore facilities use System Application Product (SAP) software to track and generate maintenance work orders up until the acquisition of the lease by CRC. In 2012, the SAP databases were mapped over to the MAXIMO database by CRC. Currently, the server for the MAXIMO database is located in CRC facilities in Long Beach, CA. Work orders for the electrical system are generated by MAXIMO.

The reliability of the electric system is primarily dependent on the availability of the SCE power supply in addition to the condition and operational readiness of the on-shore facility distribution system. A sound maintenance and inspection program, properly implemented, is key to assuring the highest level of reliability. Electrical maintenance has been integrated into the new MAXIMO computer database and tracking system which is fully implemented.

Access to the database is restricted based on user credentials. However, authorized users have full access. Production foreman and operators have limited access to create work orders and update work order status. New equipment records are documented and assembled in an Asset Addition Form, which is reviewed by engineering lead personnel. These records are transferred to the Field Operations Supervisor (FOS) for review and approval before delivery to the Maintenance Planner. The Maintenance Planner assigns an asset number and completes the asset record in MAXIMO including preventive maintenance procedures and their frequencies. All new equipment requires a Pre-Startup Safety Review (PSSR) that identifies action items for documentation including maintenance procedures. Once the asset is created and entered the system, work orders are generated automatically by MAXIMO. The orders are produced 30 days or less before the work is required. Work orders are scheduled and tracked for each asset and will include activity required weekly, quarterly, semi-annually, annually, five-years, etc. Material required to complete the task is also identified in the work order. A warehouse located on-site maintains commonly used consumables and certain renewable parts. The planner scheduler or FOS can issue purchase orders for items not in stock up to a certain dollar limit.

In addition to MAXIMO generated work orders, corrective work orders can be generated by CRC personnel. Corrective work orders document field observations and are submitted to the FOS for review and implementation. Personnel also submit recommendations to the FOS for any changes to a work order. Completed work orders are given to the FOS for review and then input into MAXIMO by one of the Super-users. Final documentation includes notes, test reports, photographs, third party paperwork, procedures, and any other information deemed critical or beneficial regarding the asset.

The main switchgear protective relays were last tested and calibrated in 2015 and 2016. NFPA 70B, Recommended Practice for Electrical Equipment Maintenance, and NETA recommend visual inspection of switchgear every twelve months and electrical testing and calibration at 3-4 year intervals.

Safety Standards in the Operations Manual are provided to cover the electrical equipment Lockout/Tagout/Blockout program. CRC has implemented a hazard identification program that requires personnel to complete paperwork before performing all work on operating equipment and facilities. The paperwork includes hazards identification, PPE, and other measures to mitigate hazards. All paperwork must be closed out at the completion of the tasks.

Given the harsh environmental conditions near the seashore, the overall condition of the electrical equipment can be rated as fair. The existing equipment is a mix of original and new. The original equipment is approaching the end of its design life and is being maintained on a regular basis. The rating condition of fair can be attributed to age, a result of exposure to the elements, collateral damage during site activities, and the ongoing need for maintenance in this type of aged facility. Broken and missing enclosure covers, broken supports, rusted enclosures, deteriorated weatherproof gaskets, and missing bolts all indicate the need for continual attention to basic maintenance housekeeping activities.

CEC 110-13, Mounting Electrical Equipment, requires all electrical equipment to be firmly secured to the surface on which it is supported. CEC Article 300-11, Securing and Supporting, requires all electrical raceways, cable assemblies, boxes, cabinets, and fittings to be secured or fastened in place. Additional mounting, support, and securing requirements are also provided in the CEC for individual types of installations and conditions. Securing and supporting electrical equipment, cables, and materials need to be consistently addressed and managed throughout the facility.

Cover plates were missing in several MCCs, including HS-MCC-3C2, HS-MCC-4A1, and HS-MCC-4A3. These were categorized as priority 1 action items and corrected immediately by CRC. (ELC – 3.4.3.01, 3.4.3.03, and 3.4.3.04) Several junction boxes and conduit fitting covers are missing or not properly seated against box flanges to provide an adequate seal in classified areas. Covers must be flange-face to flange-face or box if bolt-on type or five full threads engaged if screw-cover type. (ELC – 3.4.3.02, 3.4.3.05, 3.4.3.07, and 3.4.3.09 thru 3.4.3.12)

3.5 Grounding

CEC Articles 250 and 501 provide the requirements for power system grounding and bonding in oil production facilities. Significant portions of the requirements for grounding are established to prevent or reduce the possibility of injury to personnel from shock. The grounding system also contributes to a reduction of equipment damage either from induced voltages or during fault conditions. The three types of grounding required at the facility are power system circuit grounding, equipment equipotential grounding, and static control grounding. Power system grounding at the facility is well designed and the conductors and connections appear to be in good condition overall. All equipment enclosures, raceways, conduit sleeves, metal totes, and well casings are required to be electrically bonded in Class 1 areas. In general, grounding system installations observed were found to be adequate at the facility.

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. That is, ground circuit bonding shall be continuous from the load back to the power transformer grounding electrode system. The best way to achieve ground circuit continuity is to include properly sized (CEC 250) equipment grounding conductors with each set of power conductors from the source of power to the load. Equipment bonding conductors to major equipment, such as transformers, switchgear, and the like, were installed and appeared adequate.

CEC Article 501-16(b) requires that all liquid-tight conduit used in hazardous areas be supplemented with either an internal or external ground bonding jumper. A spot check of the facility found external grounds have been added to many of the liquid-tight conduits where needed.

3.6 Emergency Electrical Power

3.6.1 System Configuration: There are several uninterruptible power supply (UPS) systems distributed throughout the HB facility to power the Automation System programmable logic controllers (PLCs) and related equipment. The emergency generator power supply at the onshore facility is limited to the PLC and safety systems. Small gasoline generators are available for temporary installation and connection as an alternate source of power to supply 120V for the battery charger to maintain battery power levels needed for the operation of PLC and safety systems at the Tank Farm and gas processing units and similar systems at MCC-400. There is no backup power source to supply production or process equipment.

3.6.2 Equipment and Component Ratings: UPS unit ratings are 120/240V and 10kVA or less. The amp-hour capacity varies with the connected load and is limited to a few hours in most cases. The units are installed indoors or in cabinets.

3.7 Electric/Diesel Fire Pumps

The firewater pump is diesel engine driven. The engine has an electric jockey pump to maintain fire water line pressure. The firewater pump, battery charger, and battery bank are regularly tested, and periodic maintenance is performed.

3.8 Process Instrumentation

A supervisory control and data acquisition (SCADA) system is installed on-shore for the remote monitoring of producing wells. The SCADA system monitors voltage, amperage, power factor, and pump status with annunciation for over/under and overload conditions. Data acquisition for 30 days is available for tending analysis of individual wells. This system provides enhanced capability for operating surveillance of producing wells. The process control wiring generally complies with the code. Intrinsically safe systems comply with CEC Article 504 requirements.

3.9 Lighting Systems

The recommended illumination levels are provided in API RP 540, Electrical Installations in Petroleum Processing Plants. The light levels should be a minimum of five footcandles for manifolds, pump-rows, and valves. Active stairs, operating platforms, gauge glasses, instruments, and separators should have a minimum of five footcandles per API RP 540. HB staff should conduct a comprehensive lighting audit and take corrective action to eliminate areas with low lighting levels. A mix of light emitting diode (LED), incandescent, fluorescent, high-pressure sodium, and metal halide lighting is used throughout the facility.

Emergency lighting is limited and there are very few area lights that are connected to standby or emergency sources. Battery pack “bug-eye” lighting exists in electrical equipment buildings. However, this type of lighting is intended for emergency egress purposes, and not for task lighting. Battery pack lighting is intended to provide minimal illumination (less than two footcandles) for up to 90 minutes. It is recommended that an evaluation be used to evaluate areas that need improved emergency lighting.

3.10 Special Systems

The ELC Team review comments for special systems are based on API RP 14F, API RP 540, and CEC documents.

3.10.1 Safety Control Systems: Safety control systems are required to be a combination of devices arranged to safely affect facility 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. Process emergency shutdown system logic is programmed in a PLC system. Facility controls and safety features are designed to be fail-safe and have redundant capabilities. ESD at the Recovery Substation is hardwired to breaker controls and has a contact for remote shutdown via the Automation PLC system.

3.10.2 Gas Detection Systems: Combustible gas detection systems (LEL, and H_2S) are employed to detect combustible gas leaks in equipment and piping and to warn personnel of explosive and toxic concentrations to initiate remedial action. The gas detection systems are located at the Dew-Point Control Unit (DCU), Amine, and Microturbine units. These are all powered from a battery back-up power supply located at the PLC Cabinet in the Stretford Control Room or from the digital control system (DCS), MCC, PLC, and UPS. All these detectors are checked periodically to ensure the alarm sounds locally and in the control room.

3.10.3 Fire Detection Systems: Ultraviolet and infrared (UV/IR) detection systems are also located at the DCU, Amine, and Microturbine units. There is also a fusible link system at the DCU compressor and the DCU Glycol Skid. All detectors have clean lenses and are checked with a UV/IR test lamp periodically to ensure alarms are actuated locally and in the control room.

3.10.4 Aids to Navigation: Not applicable to on-shore facilities.

3.10.5 Communication: Communications systems are established to provide for normal and emergency operations. Onshore facilities make use of portable radios, phones, cell phones, and computers via ethernet based networks. The radio system is supported by two Motorola XPR 8400 repeater units located in the server room with UPS support and multiple portable radios. There are two types of phone systems in use onshore. In the Tank Farm control room, there is a POTS (Plain Old Telephone System aka landline). The majority of phones throughout the site are IP based on a dedicated Cisco Voice System located in the server room at the refurbished training building. Ethernet-based communications use a star configuration. The Cisco Voice System and the Network Equipment have an APC 3000 UPS for each rack with ~4-hour capacity. There is a provision to manually hook up a portable generator to power this communications equipment at the training building.

Systems used for emergency communication should have battery-operated power supplies with the amp-hour capacity to supply the load for at least four hours of continuous operation. Landlines, microwave, wireless radio, cellular phones, and computer networks are available for communication between facilities.

3.10.6 General Alarms: The onshore facility has a horn and beacon light at the DCU, beacon alarm at the Drain Tanks (for H_2S), and beacons at the Stretford Unit as well as Electric Buildings 1, 2, 3, & 4. Audible alarms are on the human machine interface (HMI) screens for the Automation System. Each of these devices is powered by UPS systems associated with the Automation PLC System.

3.10.7 Cathodic Protection: A portion of the onshore cathodic protection equipment appears to be out-of-service. It is our understanding that a decision has been made to discontinue onshore Pulse Rectifier production for well casing cathodic protection. Pulse Rectifiers will continue to be operated until their end of life. No upgrades or repairs are planned for the onshore Pulse Rectifier system. As Pulse Rectifier units fail they will be disconnected and abandoned. Systems that are not functional should be removed. It is recommended that CRC provide details of the corrosion control and monitoring program, as well as future plans to modify the program, to the Commission's Mineral Resources Management Division for information and review.

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Safety Management Programs

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4.0 SAFETY MANAGEMENT PROGRAMS

4.1 Goals and Methodology

The goal of the safety management program audit was to verify that CRC 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. CRC's safety management programs are composed of organizational and operational procedures, design management, audit programs, and other methods defined by API, OSHA, and the EPA. The audit began with the review of the Operating Manuals, other required emergency and spill response plans, training programs, and additional specific programs that CRC uses to cover other elements of the Safety and Environmental Management Program for the HB Onshore facilities.

4.2 Operations Manual

CRC has a system in place for determining what procedures or processes need to be documented. 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 concise, systematic, easy-to-read format with sufficient detail so that trainees with limited experience or knowledge of the procedure can successfully carry out the task with minimal supervision. The information presented in the operations manual was found to be clearly written, not overly complicated, and reflected best industry practices.

The SOPs are maintained and accessible via the company intranet system to all CRC personnel and available for print with hard copy versions located on-site at main office and tank farm facility control room. A comprehensive review of the SOPs is performed to determine that pertinent operating information is readily available within the different manuals. The SOPs are reviewed internally annually and updated by authorized CRC personnel to ensure that they remain current. When applicable, a review date is recorded in each SOP that has been reviewed. If an SOP describes a process that is no longer followed, it is removed from the file and/or manual.

4.3 Spill Response Plans

The CRC Oil Spill Contingency Plan (OSCP) 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 the HB Onshore facilities, Platform Emmy, 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 OSCP 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 OSCP was reviewed and noted to have a long approval history. It meets Federal (40 CFR Section 112.5) and State Office of Spill Prevention and Response (OSPR) standard requirements. CRC staff is familiar with the OSCP and holds annual spill drills to increase the effectiveness of their spill response. The OSCP received its last comprehensive update on June 15, 2017. The plan should be reviewed regularly and when other related plans, such as the Spill Prevention, Control, and Countermeasures (SPCC) Plan, are updated. Changes should be managed by authorized CRC 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, Action Item. (SMP- 4.3.01)

4.3.1 EPA Spill Prevention Control and Countermeasure (SPCC) Plan: The SPCC Plan is an EPA requirement. An electronic version of the SPCC Plan was reviewed for compliance and appears to meet the EPA Rule. The CRC SPCC Plan has been prepared following good engineering practices. The plan provides engineering, operation, maintenance, and management strategies to minimize the potential of a spill or release of oil products (e.g. fuel and petroleum/lubricating oil) from certain storage and operational equipment and activities, and in the event of a spill, to prevent the spill from entering a navigable waterway or adjoining shorelines. The SPCC Plan is approved by management and certified by a licensed professional engineer.

4.4 Training and Drills

CRC has a comprehensive initial training program for new workers and ongoing training for experienced employees that includes optional and mandatory training for all personnel. A computer-based training matrix known as Training Mine alerts personnel to upcoming training requirements and maintains a history of all training activities. Topics of some of the basic and annual training that is conducted to satisfy mandatory OSHA and spill response requirements include Hazardous Communications, Personal Protective Equipment (PPE), Incipient Firefighting, Control of Hazardous Energy (Lockout/Tagout), Confined Space Entry, Hot Work, Respiratory Protection, Hydrogen Sulfide (H_2S), First Aid/CPR Medic Inclusive, Work Authorization Permitting, Hazardous Waste Operations and Emergency Response (HAZWOPER), DOT Pipeline Operations, Oil Spill Drills, and Process Safety Management.

Facility operations training consists of on-site instruction. There is a job task qualification program where operators are trained and tested for competence in the safe operating procedures for the process they operate. The on-the-job training process is a strict testing and evaluation method. Both the lead operator and operation’s supervisor must sign off on the training and qualification. Next-level promotion is based on progression through these operating requirement elements. Each level of training requires successful completion and a field competency demonstration before advancement to the next level can occur. Situational awareness training helps employees recognize abnormal operating conditions, as well as what to do in the event of an incident.

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, and equipment deployment drills. Exercises range from a discussion about how things would occur to the deployment of equipment and mobilization of staff. CRC management reviews the lessons learned during oil spills and exercises to revise and improve contingency plans.

The Health, Safety, and Environmental (HSE) Coordinator uses Training Mine to track employee training requirements and job description. Training and drill records are maintained and available to regulatory agencies upon request. CRC's training program appears to meet all requirements for safety management systems and spill response. No action items were identified.

4.5 Safety Management Programs

A CRC corporate program that parallels the OSHA Process Safety Management (PSM) standard, is used to control workplace hazards. While the Huntington Beach facilities are not subject to OSHA PSM regulations, CRC has voluntarily 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.

CRC'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 CRC's senior management has defined, documented, and endorsed its safety policy. Safety management functions within the organization are connected with the safety of their personnel. This connection can be seen in the planning, developing, organizing, and implementing of CRC's safety policy; together with the measuring and auditing of the performance of those functions.

Additional assessment and feedback regarding CRC's safety management programs will be afforded by the Safety Assessment of Management Systems (SAMS) that is conducted after the safety 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 safety audit and the results are kept confidential between the Commission and the operating company.

Human Factors Audit

California Resources Corporation Huntington Beach Onshore Facility

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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 spill prevention audit of the CRC Huntington Beach lease facilities. Interview results are considered confidential between the Commission and CRC and will be contained in a separate report.

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

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

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

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

5.2 Human Factors Audit Methodology

The Commission's Mineral Resources Management Division (MRMD) will schedule the SAMS interviews with CRC staff and sub-contractors after this report is issued. Interview responses will be evaluated according to SAMS guidelines and a separate confidential report summarizing the results will be generated. The MRMD staff will provide a confidential report accompanied by a formal presentation that summarizes the report to CRC management.

Action Item Matrix

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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
ASME	American Society of Mechanical Engineers
BAP	Best Achievable Protection
BEP	Business Emergency Plan
BOPD	Barrels of Oil Per Day
BWPD	Barrels of Water Per Day
CalGEM	California Geologic Energy Management Division
CalOSHA	California Occupational Safety and Health Administration
CEC	California Electrical Code
CFC	California Fire Code
CMU	Concrete Masonry Unit
Commission	California State Lands Commission
CP	Control Panel
CRC	California Resources Corporation
DCS	Digital Control System
DCU	Dew-Point Control Unit
DOT	Department of Transportation
EFI	Equipment Functionality and Integrity
ELC	Electrical
EPA	Environmental Protection Agency
ERP	Emergency Response Plan
ESD	Emergency Shutdown
ESP	Electrical Submersible Pump
FOS	Field Operations Supervisor
FSL	Flow Safety Low
FSV	Flow Safety Valve
FWKO	Free Water Knock Out
HBFD	Huntington Beach Fire Department
HAECD	Hazardous Area Electrical Classification Drawing
HB Onshore	Huntington Beach Onshore Processing Facility
HF	Human Factors
HT	Heater Treater
HMI	Human Machine Interface
H_2S	Hydrogen Sulfide
IR	Infrared
KPI	Key Performance Indicators
kV	KiloVolt
kVA	KiloVolt Amperes
kW	Kilowatts
LACT	Lease Automatic Custody Transfer
LAHH	Level Alarm High High
LED	Light Emitting Diode

LEL	Lower Explosive Limit
MCC	Motor Control Center
MCFD	Thousand Cubic Feet per Day
MOC	Management of Change
MRMD	Mineral Resources Management Division
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NETA	InterNational Electrical Testing Association
NFPA	National Fire Protection Association
OSCP	Oil Spill Contingency Plan
OSHA	Occupational Safety & Health Administration
OSPR	Office of Spill Prevention and Response
P&ID	Piping and Instrumentation Diagrams
PAHH	Pressure Alarm High High
PFD	Process Flow Diagram
PHA	Process Hazard Analysis
PLC	Programmable Logic Controller
PM	Preventive Maintenance
PPE	Personal Protective Equipment
PRC	Public Resources Code
PSH	Pressure Safety High
PSHL	Pressure Safety High-Low
PSI	Pounds per Square Inch
PSL	Pressure Safety Low
PSM	Process Safety Management
PSSR	Pre-Startup Safety Review
PSV	Pressure Safety Valve
ROE	Radius of Exposure
RP	Recommended Practice
SAFE	Safety Analysis Function Evaluation
SAMS	Safety Assessment of Management Systems
SAP	System Application Product
SCADA	Supervisory Control and Data Acquisition
SCBA	Self Contained Breathing Apparatus
SCE	Southern California Edison
SDS	Safety Data Sheet
SDV	Shutdown valve
SMP	Safety Management Programs
SOP	Standard Operating Procedures
SPCC	Spill Prevention Control & Countermeasure
TEC	Technical
UV/IR	Ultraviolet/Infrared
UFC	Uniform Fire Code
UPS	Uninterruptable Power Supply
UT	Ultrasonic Thickness
UV	Ultraviolet
V	Volt

Appendix B
Best Practices

1.0 BEST PRACTICES

1.1	Best Achievable Protection/ Best Achievable Technology	PRC 8750
	Inspection of Marine Facilities	PRC 8757
	Commission Oil & Gas Regulations	Title 2 CCR Art. 3 - 3.6

2.0 FACILITY CONDITION AUDIT

Goals and Methodology

2.1	General Facility Conditions	
	2.1.1 Housekeeping	Commission 2123 & 6539
	2.1.2 Stairs, Walkways, Gratings, & Ladders	CAL OSHA Title 8 CCR
	2.1.3 Escape/ Emergency Egress/ Exits	CAL OSHA 22, 25, 3215 & 6577
	2.1.4 Labels, Placards, & Signs	CAL OSHA & API RP 14J
	2.1.5 Security	Commission 2123
	2.1.6 HAZMAT Handling & Storage	OSHA 29 CFR 1910.1200
2.2	Field Verification of Plans	
	2.2.1 PFDs	Commission 2132(a)(2) & API 51R
	2.2.2 P&ID	Commission 2132(a)(2) & API 51R
	2.2.3 Fire Protection Drawings	Commission 2132(g)(4)(G) & API 51R
2.3	Condition and Integrity of Major Systems	
	2.3.1 Piping	Commission 2129(b) & (c), CAL OSHA 6533, API 570 & CFR 1910.106(c)(4) ANSI 31.3
	2.3.2 Tanks	Commission 2129(b) & (c), API 650 & 653
	2.3.3 Pressure Vessels	Commission 2129(b) & (c), ASME Boiler & PV Code Sect. VIII, API 510 & RP 572, CAL OSHA 8 CCR 6551(c) & 46 CFR 53
	2.3.4 Pressure Relief, PSVs and Flare Sys.	Commission 2132(g)(3), API Std 520, Std 521 & RP 576
	2.3.5 ESP, Pump Units & Wellhead Equip.	Commission 2132(a)(4)
	2.3.6 Fire Fighting Detection Systems	Commission 2132(g)(4)(A) & NFPA 25-*10.2.5.1*
	2.3.7 Fire Fighting Equipment	Commission 2132(g)(4)(A) & NFPA 25-*10.2.5.1*
	2.3.8 Emergency Shutdown System (ESD)	Commission 2132(g)(1)
	2.3.9 Safety & Personal Protective Equipment	CAL OSHA (8 CCR Numerous)
	2.3.10 Instrumentation, Alarm and Paging	Commission 2132(g)(1)&(2) & CAL OSHA 8 CCR 5189
	2.3.11 Auxiliary Generator / Prime Mover	Commission 2132(g)(7)
	2.3.12 Spill Containment	Commission 2139 & 2140, 40 CFR 112.7(c) & OSPR GOV CODE 8670
	2.3.13 Spill Response	Commission 2139 & 2140 GOV CODE 8670

2.4	Mechanical Integrity/Preventive Maintenance	Commission 2129(c) CAL OSHA 8 CCR 5189 (j)
2.5	Production Safety Systems	Commission 2129(a), 2132(g) CALGEM 14 CCR 1747 OSHA 29 CFR 1910 API RP 75
	Onshore Production Safety System	Commission 2129(a), 2132(g) CAL OSHA 8 CCR 5189 OSHA 29 CFR 1910 CALGEM 14 CCR 1712 - 1724 API RP 51R

3.0 ELECTRICAL SYSTEM AUDIT

3.1	Goals and Methodology	
3.2	Electrical Hazardous Area Classification Dwgs. • *Level of classification* • *Extent of classification*	API RP 500, NFPA 70
3.3	Electrical Power Dist. System, Normal Power *3.3.1 Electrical Single Line* *3.3.2 Electrical Service Capacity* *3.3.3 Electrical System Design*	API RP 540, NFPA 70
3.4	Elec. Power Equip Condition and Functionality *3.4.1 Equipment Condition* *3.4.2 Safety Procedures* *3.4.3 Equipment Maintenance Practices*	API RP 540, NFPA 70
3.5	Grounding	API RP 540, NFPA 70
3.6	Emergency Electrical Power *3.6.1 System Configuration* *3.6.2 Equipment and Component Ratings* *3.6.3 Electrical System Design Safety*	NFPA 70, NFPA 110
3.7	Electric/Diesel Fire Pumps	NFPA 20, NEC 696
3.8	Process Instrumentation	Commission 2129 et seq. API RP 540, NFPA 70
3.9	Lighting Systems	Commission 2129 et seq. CALGEM 14 CCR 1743 (a)-(c)
3.10	Special Systems	Commission 2129 et seq. CALGEM 14 CCR 1743&1747 API RP 75 OSPR GOV CODE 8670 ISA RP7.1, RP 12.1, 12.2 ISA S7.4, S12.4
	3.10.1 Safety Control Systems	Commission 2129 et seq.
	3.10.2 Gas Detection Systems	Commission 2129 et seq. CALGEM 14 CCR 1747.6
	3.10.3 Fire Detection Systems	Commission 2129 et seq. CALGEM 14 CCR 1743&1747 API 2001 & RP 75
	3.10.4 Aids to Navigation	USCG 33 CFR Subcp. C, Part 67

3.10.5	*Communication*	USCG 33 CFR Subcp. C, Part 67
3.10.6	*General Alarms*	USCG 33 CFR Subcp. C, Part 67
3.10.8	*Cathodic Protection*	API RP 651, NACE RP 01-76, 0675

4.0 SAFETY MANAGEMENT PROGRAMS

4.0	Goals and Methodology	API RP 75 SEMP OSHA 29 CFR 1910.119 CAL OSHA 8 CCR 5189
4.1	Operations Manual	Commission 2173, OSPR PRC 8758
4.2	Spill Response Plan	Commission 2139 OSPR GOV CODE 8670
	4.2.1 SPCC Plan	40 CFR 112.7
4.3	Training and Drills	Commission 2140 CALGEM 14 CCR 1747.5 OSPR GOVC 8670
4.4	Safety Management Programs	Commission 2175 OSPR GOVC 8670 40 CFR 112.7 OSHA 29 CFR 1910.119 API RP 75 CAL OSHA 8 CCR 5189

5.0 HUMAN FACTORS AUDIT

5.1	Process Safety Management	CAL OSHA 8 CCR 5189 API RP 75 CSLC SAMS

Appendix C
References

GOVERNMENT CODES, RULES, AND REGULATIONS

Cal/OSHA	California Occupational Health and Safety Administration
3215	*Means of Egress*
3222	*Arrangement and Distance to Exits*
3225	*Maintenance and Access to Exits*
3308	*Hot Pipes and Hot Surfaces*
3340	*Accident Prevention Signs*
5189	*Process Safety Management of Acutely Hazardous Materials*
6533	*Pipe Lines, Fittings, and Valves*
6551	*Vessels, Boilers and Pressure Relief Devices*
6556	*Identification of Wells and Equipment*
CCR	California Code of Regulations
1722.1.1	*Well and Operator Identification*
1774	*Oil Field Facilities and Equipment Maintenance*
1900-2954	*California State Lands Commission, Mineral Resources Management Division Regulations*
CFR	Code of Federal Regulations
29 CFR	*Part 1910.119 Process Safety management of Highly Hazardous Chemicals*
30 CFR	*Part 250 Oil and Gas Sulphur Regulations in the Outer Continental Shelf*
33 CFR	*Chapter I, Subchapter N Artificial Islands and Fixed Structures on the Outer Continental Shelf*
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
B31.3	*Petroleum Refinery Piping*
B31.4	*Liquid petroleum Transportation Piping Systems*
B31.8	*Gas Transmission and Distribution Piping Systems*
Y32.11	*Graphical Symbols for Process Flow Diagrams*
API	American Petroleum Institute
RP 11ER	*Guarding of Pumping Units*
RP 51R	*Onshore Oil and Gas Production Practices for Protection of the Environment*
RP 55	*Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*
RP 500	*Classification of Locations for Electrical Installations at Petroleum Facilities*

RP 505	*Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2*
API 510	*Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*
Std 520	*Design and Installation of Pressure Relieving Systems in Refineries, Part I and II*
Std 521	*Guide for Pressure-Relieving and Depressuring Systems*
RP 540	*Electrical Installations in Petroleum Processing Plants*
RP 550	*Manual on Installation of Refinery Instruments and Control Systems*
API 570	*Piping Inspection Code*
RP 574	*Inspection Practices for Piping Systems Components*
API 650	*Welded Steel Tanks for Oil Storage*
RP 651	*Cathodic Protection of Aboveground Petroleum Storage Tanks*
Std 653	*Tank Inspection, Repair, Alteration, and Reconstruction*
Spec 6A	*Wellhead Equipment*
Spec 6D	*Pipeline Valves, End Closures, Connectors, and Swivels*
Spec 12B	*Specification for Bolted Tanks for Storage of Production Liquids*
Spec 12J	*Specification for Oil and Gas Separators*
Spec 12R1	*Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service*
Spec 14A	*Subsurface Safety Valve Equipment*

ASME American Society of Mechanical Engineers

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

ISA Instrument Society of America

55.1	*Instrument Symbols and Identification*
102-198X	*Standard for Gas Detector Tube Units – Short Term Type for Toxic Gases and Vapors in Working Environments*
S12.15	*Part I, Performance Requirements, Hydrogen Sulfide Gas Detectors*
S12.15	*Part II, Installation, Operation, and maintenance of Hydrogen Sulfide Gas Detection Instruments*
S12.13	*Part I, Performance Requirements, Combustible Gas Detectors*
S12.13	*Part II, Installation, Operation, and Maintenance of Combustible Gas Detection Instruments*

NACE National Association of Corrosion Engineers

RPO169	*Control of External Corrosion on Underground or Submerged Metallic Piping Systems*

NFPA National Fire Protection Agency

20	*Stationary Pumps for Fire Detection*
25	*Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*
70	*National Electric Code*
704	*Identification of the Hazards of Materials for Emergency Response*

CEC California Electric Code

Appendix D
Team Members

FACILITY CONDITION TEAM

CSLC – MRMD	David Rodriguez David Calderon Ryan Horton Steve Staker
CRC	Kathryn Sanders

ELECTRICAL TEAM

CSLC – MRMD	David Rodriguez David Calderon Ryan Horton
PES	Doug Effenberger
CRC	Alan McGraw

TECHNICAL TEAM

CSLC – MRMD	David Rodriguez David Calderon Ryan Horton
CRC	Senem Weaver

SAFETY MANAGEMENT TEAM

CSLC – MRMD	David Rodriguez David Calderon Ryan Horton
CRC	Clint Harris Senem Weaver