Safety and Oil Spill Prevention Audit

California Resources Corporation
Long Beach Unit

California State Lands Commission

June 2019

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EXECUTIVE SUMMARY

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A Safety and Oil Spill Prevention Audit of the California Resources Corporation (CRC) Long Beach Unit (LBU) was started in June 2017. Fieldwork for the audit was completed in April 2019.

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 for many years and the applicable regulations and standards commonly used 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. CRC carries out the day-to-day operations of the LBU for the State of California and the City of Long Beach.

Description of the Facilities

CRC LBU is engaged in drilling and production operations of oil and gas from four man-made islands in Long Beach Harbor, as well as onshore well areas, production facilities, and support facilities. Island Freeman encompasses about twelve acres, while islands Grissom, White, and Chaffee cover approximately ten acres each. Crew boats transport employees, contractors, and visitors to and from the islands while materials and supplies are shipped by barge and tugboat with operations conducted from a landing near the warehouse and field office complex. The islands and onshore facilities are interconnected by a system of subsea and buried onshore pipelines. The onshore facilities that are part of the LBU are located within the Pier J area of the Port of Long Beach and include well areas at sites J-1, J-3, J-4, and J-5, as well as the J-6 tank farm, J-2 processing facility, and Broadway and Mitchell processing and shipping facilities. The islands and onshore facilities remain much as originally designed, with the addition of wells to Island Chaffee producing from the Belmont Offshore field (PRC 186.1). The LBU has over 1300 active wells – 846 production wells and 493 injector wells. Daily production from the LBU as of May 2019 is approximately 20,000 barrels of oil and 7,400 MCF of gas.

Safety Audit Results

The Safety and Oil Spill Prevention Audit found the LBU complies 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 effectively and efficiently. Their skills and knowledge provided valuable assistance to the MRMD safety audit team.

Safety systems and equipment remain fit for service. However, several 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.

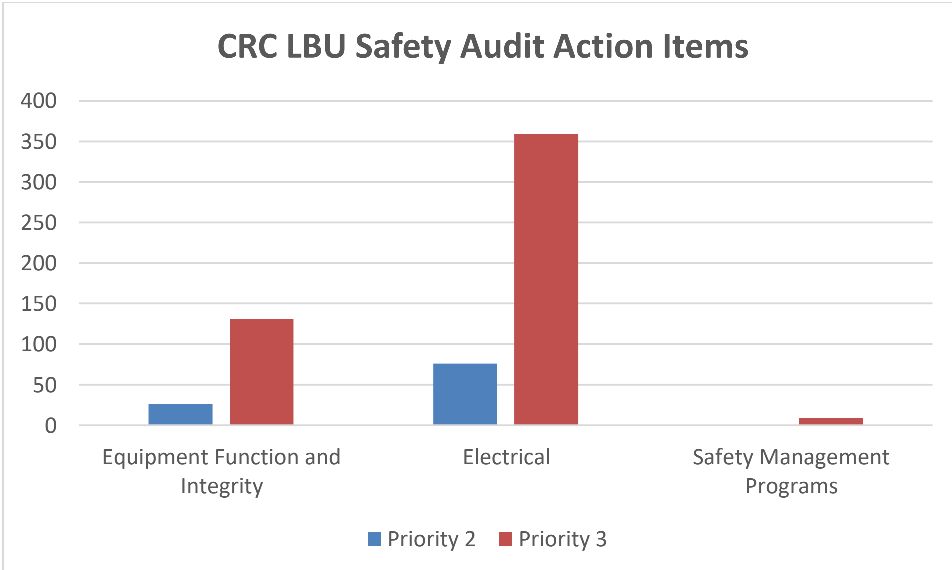
Firefighting, life safety, and spill response equipment meet NFPA and regulatory requirements. Firefighting equipment and extinguishers are regularly serviced, maintained and tested. Fire extinguishers are mounted, located, and identified so that employees can make use of them when needed. In addition, 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 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 MRMD safety audit team identified a total of 601 action items, a 60% reduction from the previous audit. The 2012 audit found two priority one action items, while the current audit found none. The number of priority two action items decreased from 507 to 102. The number of priority three action items decreased from 997 to 499. The reduction in the number of action items is partly due to combining multiple instances of a specific item at a common location into a single action item.

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
Long Beach Unit

June 2019

1.0 INTRODUCTION

1.1 Safety Audit Background

The Mineral Resources Management Division (MRMD) conducts safety 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 inspection program, helps prevent oil spills and other accidents with an 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 a 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)
- Safety Management Programs (SMP)
- Human Factors (HF)

Appropriate company contacts and resources are identified prior to the start of the Safety Audit. Progress reports are communicated 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 priority ranking for the specified corrective actions. A graph/table highlighting the strengths and weakness of the facility is generated from the matrix items.

Draft copies of the report and the action item matrix are provided to the company throughout the Safety Audit. The final safety audit 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 and efficiency, and lower operating costs.

1.2 Facility History

The California Resources Corporation (CRC) Long Beach Unit (LBU) is located within the Wilmington Oil Field in California. The Wilmington Oil Field is part of a larger, 22-miles northwest by southeast, Torrance-Wilmington structural trend that reaches from the Pacific coast near Hermosa Beach through the Palos Verdes Peninsula to the Pacific coast off Seal Beach. The Wilmington Field portion is an eight-mile long, highly faulted, asymmetrical anticline lying mostly within the City of Long Beach. It is the third largest field in the contiguous United States with ultimate recovery estimated at three billion barrels of oil. It encompasses both tidelands (lands granted to the City of Long Beach by the State), uplands, and offshore areas leased by the State. It has produced over two and one-half billion barrels of oil through primary production and secondary water flooding from more than 6,150 wells drilled to date.

The LBU encompasses the eastern portion of the Wilmington Field: the combined area of the City's granted tidelands (Tract I – 86.4%), the upland areas (Townlot Tracts – 9.8%), and the State's tidelands (Tract II – 3.8%). Operations began in the mid-1960s from onshore areas within the Harbor District while the four landscaped oil islands were being constructed. The oil-producing formations in the Wilmington Field are at or below hydrostatic pressure, and the wells require artificial (mechanical) lift to produce. The field has been produced under waterflood since the 1960s to enhance recovery and to control subsidence; this has resulted in high water cuts for the current production. Oil is mostly produced from intervals ranging in depths from 2,000 feet to 8,500 feet, with a handful of wells that measure over 11,000 feet in depth. The LBU has over 1300 active wells – 846 production wells and 493 injector wells.

Legislation enacted in 1964 allowed the City of Long Beach to contract out the operation of the eastern offshore portion of the field. Four man-made islands were built and named after the astronauts that lost their lives during the early years of the U.S. space exploration (Grissom, White, Chaffee, and Freeman). The original consortium of operators: Texaco, Humble, Union, Mobil and Shell formed the THUMS Long Beach Company to serve as contractor for the City of Long Beach. THUMS constructed the islands and expanded Pier J adjacent to the Long Beach Harbor, forming the LBU. Occidental Oil and Gas Holding Corporation acquired THUMS from ARCO in 2000 creating Oxy Long Beach, Inc. California Resources Corporation was separated in June 2014 from parent company Occidental Petroleum and continues to be the agent for the field contractor operating the LBU on behalf of the State of California and the City of Long Beach.

Wells on Island Chaffee also produce oil from the western portion of the Belmont Offshore Field (PRC 186.1), a State offshore lease located approximately one mile south of the City of Seal Beach in Orange County. Production of the field began after a drilling island (Belmont Island) was constructed in 1954. The field was shut-in in 1994, the wells were abandoned, and Belmont Island's removal was completed in 2002. Redevelopment of the field from Island Chaffee began in 2005. Currently, there are 27 wells producing from PRC 186.1 on Island Chaffee.

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.

1.3 Facility Description

CRC LBU is engaged in drilling and production operations of oil and gas from four man-made islands in Long Beach Harbor, as well as onshore well areas, production facilities, and support facilities. Island Freeman encompasses about twelve acres, while islands Grissom, White, and Chaffee cover approximately ten acres each. Crew boats transport employees, contractors, and visitors to and from the islands while materials and supplies are shipped by barge and tugboat with operations conducted from a landing near the warehouse and field office complex. The islands and onshore facilities are interconnected by a system of subsea and buried onshore pipelines. The onshore facilities that are part of the LBU are located within the Pier J area of the Port of Long Beach and include well areas at sites J-1, J-3, J-4, and J-5, as well as the J-6 tank farm and J-2, and Broadway and Mitchell processing and shipping facilities. The islands and onshore facilities remain much as originally designed, with the addition of wells to Island Chaffee producing from the Belmont Offshore field (PRC 186.1).

Wells at the LBU employ downhole electric submersible pumps to produce crude oil. The wells are grouped in large cellars at each island and other well sites. At the island facilities, produced oil, water, and associated natural gas are processed through Free Water Knockouts (FWKOs) that provide initial separation of the produced fluid and gas. Produced water from the FWKOs is treated on site and is normally injected back into the formation. The oil emulsion and the gas streams are then sent through subsea pipelines and onshore gathering lines to the J-2 processing facility.

The J-2 processing facility further separates the produced emulsion into gas, water, and oil components, while removing any solids that are entrained. The J-2 facility works in concert with the nearby J-6 tank farm which can hold some production volume during processing and stores the crude oil that is ready for sale and shipping.

The gas from the islands and onshore gas production is routed to the hydrogen sulfide (H_2S) absorption unit at the J-2 facility. The sweetened gas then travels to the Broadway and Mitchell gas processing facility where it is further dehydrated and processed to meet sales specification. A refrigeration process is used to dehydrate the gas, removing water vapor and hydrocarbon condensates from the gas stream. Recovered hydrocarbon condensates are injected into the oil shipping line. The Broadway and Mitchell facility also meters the oil sold and certifies the custody transfers of the crude oil to the individual shipping companies via pipelines to a customer, typically a refinery. Much of the gas is normally sent to the nearby power plant to generate power directly for the local electric utility grid. Daily production from the LBU as of May 2019 is approximately 20,000 barrels of oil and 7,400 MCF of gas.

Facility Condition Audit

California Resources Corporation
Long Beach Unit

June 2019

2.0 FACILITY CONDITION AUDIT

2.1 Goals and Methodology

The primary goal of the Safety Audit Team was to evaluate the current maintenance and integrity of California Resources Corporation (CRC) Long Beach Unit (LBU) Islands and associated Onshore facilities. The facilities audit used a planned method of collecting accurate information about each of the four Islands (Grissom, White, Chaffee, and Freeman). Onshore facilities – Pier J-1 thru 6 sites, Pier G Warehouse, and the Broadway and Mitchell (B&M) facility – were examined in similar fashion. The on-site inspection involved a systematic evaluation of the systems, equipment, and facilities using checklists and methods that the team has developed over years of auditing. A variety of industry codes and standards apply to the facilities, in addition to State and Federal regulations. Initial tasks to accomplish this goal included field verification of key drawings/plans, condition inspection and evaluation of the facility, a review of system and equipment maintenance histories, further evaluation of key systems and equipment using checklists, and technical review of the safety system design. The layout of this report is generally "system by system" and includes a description and assessment of the facility with any significant observations. The report addresses 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 development. The Power Plant was not included in the scope of this audit.

2.2 General Facility Conditions

2.2.1 Workplace Housekeeping: Housekeeping is crucial to safe workplaces. It can help prevent injuries and improve productivity and morale, as well as make a good first impression on visitors. CRC's housekeeping strategy is more than a one-time initiative; it encourages constant monitoring and auditing. Regular walkthrough inspections are done, hazards are reported, and employees are trained to help sustain housekeeping. Goals and expectations are set and audited. It is also the foundation for fire prevention.

In addition, workplace safety and health laws establish regulations designed to eliminate personal injuries and illnesses from occurring in the workplace. The laws consist primarily of federal and state statutes. Federal laws and regulations preempt state ones where they overlap or contradict one another.

To help prevent slip, trip and fall incidents, CRC uses the following employee guidance and work practices:

- Report and clean up spills and leaks.
- Keep walkways and exits clear of items.
- Warning signs to identify hazards.
- Drip pans and guards.

Facility work areas were clean and orderly, free of slip and trip hazards, waste materials (e.g., refuse, oilfield wastes), and fire hazards. There was an adequate supply of clearly marked refuse containers throughout each facility and all refuse appeared to be well controlled. Regular collection of waste contributes to good housekeeping practices. Employee facilities consist of a men's and women's restroom located within the Production Office. They appear to be used predominantly by CRC personnel. There appears to be a satisfactory number of Porta-Potties with hand wash stations located throughout the remote locations. The Porta-Potties on location are clean and well maintained.

2.2.2 Stairs, Walkways, Gratings, and Ladders: The majority of stairs, walkways, gratings, and ladders throughout the facility appeared to be of a safe design and construction. Safeguards were in place wherever there was a need to transition between levels and for routine access to equipment. The aisles, passageways, stairs, and gratings had sufficient safe clearances and were clear with no obstructions across or in the aisles to create a hazard. However, multiple CRC Island cellar access stairways and fixed emergency escape ladders weren't properly secured to their foundation. As a result, a number of Priority 3 action items were generated to review their condition throughout all locations. One Priority 2 action item was generated for Island White due to this condition occurring more frequently. (EFI – 2.2.2.01)

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 are painted to resist corrosion. CRC's safe work practices cover the use and care of ladder equipment on the facility.

2.2.3 Escape / Emergency Egress / Exits: Emergency exits, escape routes, and gathering points are clearly posted and easily accessible. Evacuation routes are explained during initial worker orientation and safety meetings, as well as being reviewed as part of the work permit system. They are clearly identified with signs posted throughout the facility. Due to the design, size, and open arrangement of the remaining equipment inside the facility, there were no areas of concern regarding access and egress.

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 Occupational Safety and Health Administration (OSHA) and American National Standards Institute (ANSI) recommendations. All employees receive instruction on what the signs mean and what, if any, special precautions are necessary to perform their task safely. Workplace hazards (e.g., slip & trip) are marked in yellow, and fire safety equipment is marked in red.

Required signs, including owner/operator contact information, were posted at the entrance and where needed within each facility. They were clearly visible and identified safety hazards. Tanks and vessels within the facilities were clearly identified as confined spaces with warning placards posted at manways to warn personnel of potential hazards. Field verification of multiple CRC Island well cellars indicated the lack of identifiable labelling of pipelines. It is imperative to properly identify pressurized lines for personnel safety.

Fire diamonds were visible on all tanks, vessels, buildings, and chemical storage totes with the exception of one; Freeman's Mix Tank 504 was missing its National Fire Protection Association (NFPA) label. The posting of fire diamonds is an indication of good facility emergency planning and conformance with the Uniform Fire Code (UFC).

2.2.5 Security: Physical and operational security measures are in place to prevent unauthorized entry into CRC facilities. The process facilities are manned twenty-four hours a day, seven days a week with at least two operators present at all times. Fencing, facility lighting, locked doors, and electronically controlled gates at access locations deter unauthorized entry and vandalism. Facility personnel provide monitoring with normal observation activities of the pipelines and process facilities.

Private security guards provide protection at the Pier J boat landing and parking lot. Since Island locations have restricted access, all contractor and company personnel must present a CRC issued identification card for crew boat and barge access.

2.2.6 Hazardous Material Handling and Storage: The storage of flammable and combustible liquids conform to California Occupational Safety and Health Administration (Cal OSHA) and NFPA 30 regulations. Safety Data Sheets (SDS) are readily available for each hazardous substance and can be found inside the Production Office. Chemical storage appears to be properly protected against external damage and leaks. Bulk chemical totes were observed to have proper labeling and adequate containment in the event of a spill.

Compressed gas cylinders were secured and legibly marked identifying the gas content. Empty and unused cylinders had closed valves with protective caps in place. Cylinders were generally stored in places where they would not be knocked over or damaged because of contact.

2.3 Field Verification of Plans

2.3.1 Process Flow Diagrams (PFD): The PFDs are considered a part of the necessary design documentation for a facility. The PFDs for the Islands and Onshore production facilities were generally up to date and showed accurate flow through the plant processes and equipment.

2.3.2 Piping & Instrumentation Diagrams (P&ID): The P&IDs for the Islands and Onshore facilities were accurate to a large degree with only minor corrections needed. There was a significant improvement in this documentation since the previous safety audit completed in 2012. P&IDs are now in electronic format and kept up to date with as-built arrangements shown. The minor corrections that were identified included some recent modifications that were missing, incorrectly shown, or did not have redline corrections available to show the current as-built configuration. While unlikely to pose a serious problem, the Management of Change process (MOC) should have identified the drawing changes and eliminated these errors. Despite the overall good condition, one Priority 2 action item was generated due to incorrect safety equipment. Island White (EFI – 2.3.2.07) shows a Safety Shower and Eyewash station located near the Waste Water Sludge Pump. In the field, an Eyewash station was not in the vicinity.

2.3.3 Fire Protection Drawings: The fire protection drawings for all locations were found to be accurate and up-to-date. These drawings show important information about the fire-fighting system, the primary and backup pumps or source of firefighting water pressure, the fire main or distribution system, the location of main valves, stationary monitors, hose reels, portable extinguishers, and hydrants. These drawings are the basis for the emergency information posted at key locations on each facility.

2.4 Condition and Integrity of Major Systems

2.4.1 Piping: An external visual inspection of the piping systems at each facility was performed to evaluate the condition of the piping in conjunction with P&ID verification. This visual inspection evaluated the external condition of the piping for signs of coating or paint deterioration, misalignment, temporary repairs, excess vibration, and leakage. The assessment also included checks for piping support, corrosion, and broken brackets, as well as any modifications not recorded on the piping drawings. The evaluation considered other key information such as material selection, piping design, and maintenance practices.

CRC uses a combination of ongoing routine and risk-based piping inspections to achieve a desired level of facility safety, environmental protection, and unscheduled downtime. Inspection frequencies are set up according to regulatory requirements and established guidelines (e.g., American Petroleum Institute (API) 570 and Department of Transportation (DOT) pipeline inspections). 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 as well as saving inspection data. The maximum allowable operating pressure of each pipeline is established based on these results and CRC LBU's policy is to not operate a pipeline that has greater than 50% wall loss. Facility pipelines are used according to condition with the best lines carrying produced fluid, second best are reserve, and third best are to be used for emergency only. The primary corrosion prevention program used at the facilities is coatings, then chemical inhibitors and cathodic protection. Piping fitness throughout the leases was found to be in generally good condition with the exception of the following Priority 2 action items that were generated as a result. It was noted that a fair portion of the 1500lb. and 2200lb. high pressure water injection lines on Island Grissom (EFI – 2.4.1.02), Island White (EFI – 2.4.1.03), and Island Chaffee (EFI – 2.4.1.03) exhibited signs of bare piping, corrosion, and coating failure.

CRC LBU management has allocated resources annually to ensure the integrity of the subsea pipeline systems. Eight steel lines ranging from 6-inches to 14-inches in diameter transport oil and gas to Pier J, while four internally cement coated subsea lines ranging from 12-inches to 18-inches transport produced water from Pier J to the four Islands for re-injection. Corrosion prevention and maintenance of the sub-sea pipelines is a continual process and the internal condition of the steel lines are evaluated via periodic electronic smart-pig inspection. Utility and inspection pigs are used as a maintenance tool for the in-service oil and gas-shipping lines from the Islands to J-2 Onshore location. The pipeline pigs are introduced into the line via a pig trap, which includes a launcher and receiver. Utility pigs sweep the line by scraping the sides of the pipeline and pushing debris and/or corrosion inhibitor ahead every other week. Inspection pigs, or smart pigs, gather internal information about the pipeline every three years. This information includes pipeline diameter, curvature, bends, temperature and pressure, as well as remaining wall thickness. Visual inspections are conducted quarterly on all exposed pipeline surface sections that transfer oil and gas products.

In addition to the smart pig runs, the steel lines utilize cathodic protection to prevent external corrosion. Chemical treatment with corrosion inhibitors coupled with maintenance pigging twice per month helps mitigate internal corrosion. Coupons are utilized to determine the effectiveness of the corrosion inhibitors. The coupons are pulled at regular intervals and weighed to determine metal loss, from which corrosion rate and remaining service life are calculated. Because the subsea lines are buried, an external inspection is not possible; however, weekly visual line surveys by crew boats check the ocean surface for indication of leakage. DOT regulations require that shutdown valves on these lines are tested quarterly. The integrity of the cement lined pipelines used for produced water is maintained by use of cathodic protection, corrosion inhibitors, pressure testing, and internal video inspection surveys. Main Onshore underground pipelines connecting the Onshore sites and processing facilities have been recently replaced. CRC has demonstrated that it has a very well managed pipeline maintenance program that takes appropriate actions to ensure a high degree of reliability from these lines.

2.4.2 Tanks: Facility tanks are subject to CRC's written inspection and maintenance plan. The maintenance plan follows API Standard 653: Tank Inspection, Repair, Alteration, and Reconstruction practices and other accepted industry 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. Tank documentation includes inspections, repairs, alterations, and reconstruction records. In addition, tank shell ultrasonic thickness (UT) data showing locations and results are completed as part of the inspection process. This inspection method searches for flaws and service induced damage as part of determining the suitability of the tank for continued service.

Tank exterior coatings, piping, valves, walls, roofs, anchor bolts, and labeling appeared to be in good condition, for the most part, with no evidence of recent damage or active leaks. A comprehensive review of the internal tank inspection records was performed to assess the current maintenance condition. As a result, it was determined that several tanks are overdue for external UT inspections at various locations.

An external assessment discovered there were a number of other concerns pertaining mostly to foundation issues, corroded stairwells, and missing nameplates. Island Chaffee's Water Receiving Tank was noticed to have a distorted upper tank ring. Facility engineers were notified and will assess the condition to determine if the tank is fit-for-service.

CRC maintains tank reliability through regularly scheduled internal, external, and ultrasonic inspections and repairs. Reliability inspections are also standard for all rotating equipment. The maintenance planner reviews new work orders daily and assigns an in-house craft or outsources the task to a contractor/vendor depending upon workload and specific job requirement. CRC advised that commonly used parts and supplies are stocked on each Island facility while critical spare parts are stored in the warehouse.

Safety devices for the stock tanks are compliant with Commission regulations. A high level in the tanks will cause a shut-in of all oil and water processing. The design and capacity for secondary tank battery containment meets Environmental Protection Agency (EPA) Spill Prevention, Control, and Countermeasure (SPCC) requirements. The concrete containment system is designed to be impermeable to crude oil and can hold 110% of the contents of the largest tank. The required high and low-level sensors are displayed on facility 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 to process the oil, gas, and produced water. These pressure vessels are built according to American Society of Mechanical Engineers (ASME) Codes and have appropriate controls and safety devices. In order to improve maintenance efficiency, CRC has tailored inspection cycles to match the safety risks posed by particular classes of pressure vessels. CRC uses a maintenance 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 internal inspections are not to exceed every ten years using non-destructive examination techniques per API 510 Pressure Vessel Inspection Code. External vessel inspections are required at least every five years.

Analysis of pressure vessel inspection records determined that external inspection frequency is being achieved at least every five years in accordance with API 510 guidelines. Inspection recommendations, maintenance activities, and design information is documented and recorded within the pressure vessels permanent record. A review of the records determined that several pressure vessels had shells that appear to have fallen below T-min on Island White (EFI – 2.4.3.01 thru 2.4.3.03) and Island Freeman. (EFI – 2.4.3.01) An external UT inspection is recommended to determine the current shell thickness. These findings were communicated to CRC personnel and they are currently reviewing each of the vessels to determine what action is required.

A thorough visual external inspection of the pressure vessels was performed and found some evidence of missing or painted nameplates and identified some concerns regarding anchoring and other foundation damage.

2.4.4 Relief Systems: The primary purpose of the facilities pressure relief system is to ensure protection of facility personnel, equipment, and the environment from overpressure conditions that may happen during process upsets and external fires. The main relief system serves the major process vessels and components while other local relief devices may be located on smaller ancillary components. The relief system components were evaluated for installation, design, maintenance, and functionality. They included:

- Protected Equipment
- Pressure Safety Valves (PSV)
- PSV Inlet and Discharge Piping
- Relief Header
- Vent Sumps
- Vent Scrubber
- Vent Stack

Relief discharge piping is constructed such that it does not present a safety concern. The piping is sloped, properly supported, and accounts for all vapor and liquid flow. The discharge system includes vent sumps with high-level alarms installed to alert operations of an abnormal release of fluid. A high-level float coupled with an island shut-in within the vent scrubber prevents fluid from reaching the vent stack by shutting down production wells and opening a dump valve to the pipe trench.

Increases in Island Grissom's production required resizing of the Free Water Knockout (FWKO) pressure safety valves and vent line. PSVs and discharge piping were resized based on API Recommended Practice (RP) 521: Guide for Pressure-Relieving and Depressuring Systems. The calculation procedures were well documented and the MOC reflected accepted practices with no concerns noted.

Additional analysis of the system revealed that PSVs appeared appropriate for each piece of equipment and used the correct size inlet and outlet piping with a set point at or below the maximum allowable working pressure (MAWP).

The maintenance and servicing records for PSVs comply with applicable regulations and recommended standards, as well as, recordkeeping within a preventive maintenance system, API STD 520, 521 and Cal OSHA 6551. A thorough review of the PSV records did, however, generate a number of Priority 2 concerns. They are as follows: Island White's Mechanic Shop Air Receiver requires a PSV replacement due to inspection frequency (EFI – 2.4.4.02) and AWT T-46 inspection records indicate the PSV should be tested. (EFI – 2.4.4.01) Island Chaffee had some PSVs with missing records, PSV record settings that do not match the drawings, and PSVs that need to be tested. (EFI – 2.4.4.01 thru 2.4.4.21) Island Freeman had PSVs whose set pressure on the drawings do not match their records and/or the pressure is not shown at all. (EFI – 2.4.4.01 thru 2.4.4.09) Onshore locations have PSVs that need to be tested, and one drawing with a pressure setting that does not match the records. (EFI – 2.4.4.01 thru 2.4.4.05) B&M has either PSVs settings not shown on the drawing or that do not match, PSV settings higher than data sheet, PSVs that need to be tested, and block valves before PSVs that are not car sealed open. (EFI – 2.4.4.01 thru 2.4.4.09)

PSVs are tested using OSHA guidelines and serviced by an outside contractor. There were several administrative discrepancies between listed PSVs and process drawings. When brought to the attention of CRC personnel, these differences were corrected immediately.

2.4.5 ESP, Pump Units, Wellhead Equipment & Well Safety Systems: The production wells are considered incapable of flow or after-flow, once artificial lift is stopped. Therefore, subsurface safety valves (SSSVs) or other automated shut down 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. The electrical submersible pumps (ESPs) can be shutdown remotely via the tank farm lease emergency shutdown (ESD).

Production and injection wells are located within large volume multi-well cellars. They are secured by reinforced concrete walls and provide secondary containment against potential oil spills. An inspection of the cellar walls was performed, and they were found to have visible damage, generating concern regarding their condition. This condition was found to be consistent throughout all well cellars both on and offshore. Damage varied from minor to severe cracking, rebar exposure, and loose top metal edges of the concrete walls. In some instances, sections of concrete were missing. (See Freeman / All Location EFI – 2.4.5.01) Engineering was notified and began looking into the situation immediately.

2.4.6 Firefighting Detection Systems: There are no fire detection systems installed at any CRC Islands or Onshore facilities except for the Pier J-6 Tank Farm. The five flame detectors at J-6 are located within the tank farm retaining walls and alarm at the J-2 control center upon activation. The position of the detectors provides the required coverage to protect the most critical areas of the tanks. The current protection provides the level of protection mandated by building codes and local authorities at the time the Tank Farm was constructed. Additional protection and resources are provided by the local fire department located less than two miles from the J-6 facility.

2.4.7 Firefighting Equipment: CRC Onshore and Offshore facilities have an assortment of portable firefighting equipment that includes 150# wheeled AFFF (Aqueous Film Forming Foam) units and handheld portable extinguishers. Equipment inspections occur monthly by a contractor and equipment appears in good condition. CRC LBU also uses an approved contractor for annual hose and hydrant inspection/testing, foam tank service, foam tests, and annual fire extinguisher service.

Each Island facility also has a fixed fire main and hydrant system with the primary source of water supplied by the water injection booster pumps. A manually activated secondary electric fire pump is located by each boat dock and can be powered by the auxiliary generator.

The City of Long Beach fire department has primary authority regarding firefighting requirements at the facilities. The firefighting equipment installed at all locations meets current Long Beach City Fire requirements. This equipment conforms to National Fire Protection Association (NFPA) standards and appears to be properly maintained with a few minor exceptions. A number of minor concerns include equipment that was not located according to the drawing, missing protective covers, and outdated "Evacuation / Equipment Site Plan" billboards.

2.4.8 Emergency Shutdown Device (ESD): CRC Island facilities are equipped with a manually activated block and bleed system that provides an emergency shutdown switch on the control panel in the Production Office. In addition, activation of other critical alarms will also initiate an Island shut-in. Specifically, activation of Lower Explosive Limit (LEL), water-receiving tank high level, and vent scrubber high level shutdown alarms will also cause an Island shut-in. The shut-in system is tested and documented semi-annually.

2.4.9 Safety and Personal Protective Equipment (PPE): CRC has a written workplace safety program for identifying, evaluating, analyzing, and controlling workplace safety and health hazards. This program has systematic policies, procedures, and practices that are fundamental to creating and maintaining a safe and healthy working environment. CRC prioritizes the importance of preventing occupational injury and illness over production.

CRC regularly assesses the workplace to determine if hazards are present that require the use of PPE when engineering and administrative controls are not feasible or effective in reducing these exposures to acceptable levels. Hazards are communicated to the employees, appropriate PPE is selected, and workers are trained in its use. Employees were observed to be using appropriate PPE as required by company policy or where hazards are known to exist. PPE commonly used includes hard hats, steel-toed boots, fire resistant clothing, hearing protection, safety glasses, and other specialty items like face shields, rubber gloves, aprons, and fall protection as needed. An inspection of the Portable Eyewash stations and fixed Safety Showers on Island White generated some safety concerns. Multiple Eyewash stations had low fluid levels and one station was found empty. It was also determined that not all Safety Shower stations are within line of sight or standard distance from multiple chemical totes. (EFI – 2.4.9.01) At B&M, a combined eyewash/shower station located near Amine Storage Tank (TK-8000) was missing the foot actuator linkage for eyewash activation, but the hand paddle was still functional.

2.4.10 Instrumentation, Alarm, and Paging: Major equipment, process controls, and process control alarms are graphically displayed on a Human Machine Interface (HMI) that is integrated with the Siemens automation system. In addition, the status of safety systems such as the cellar gas detection system and Hydrogen Sulfide (H_2S) detection system at Chaffee, can be seen on the instrument air/block and bleed screen of the HMI. Electronic gas sensors are spaced throughout each cellar to detect combustible gas accumulation. Event logging (errors, alarms, and system messages) is performed by the Siemens Process Control and Safety Systems and can be printed on demand.

The facility instrumentation is tested, maintained, and calibrated on a regular schedule. Records are readily available, and the device history can be tracked through the maintenance database program. All local instrumentation (e.g., pressure gauges, temperature gauges, and recorders) appeared to be properly maintained and in good operating condition.

2.4.11 Auxiliary Generator / Prime Mover: The emergency generators on each Island location are installed to supply electrical power to the fire pump, barge ramp, and some area lighting at or near barge ramp/boat landing. CRC has established a schedule of maintenance and service based on recognized and generally accepted good engineering practices. The frequency of inspection and tests of the emergency generator are consistent with applicable manufacturers' recommendations and NFPA standards.

2.4.12 Spill Containment: Spill containment appeared to be more than adequate throughout the Island facilities. The well cellars and pipe trenches have adequate capacity to prevent discharged oil from reaching navigable waters. The well cellars and pipe trench capacities range from a low of 26,000 barrels on Island White to a high of 33,500 barrels on Island Grissom. Cellar pumps and vacuum trucks are used to reintroduce any liquid accumulation back into the process stream.

Each Island facility was constructed with a 54-inch retaining wall in addition to utilizing berms, curbing and grade to allow for effective drainage of rainwater. The total surface area containment as shown in the Oil Spill Contingency Plan (OSCP) ranges from 69,350 barrels on Island Grissom to 78,700 barrels on Island Freeman.

In addition to the spill booms maintained on each Island, initial spill response supplies such as sorbent pads and hand tools are available. These supplies are inventoried and readily accessible by operating personnel in the event of a spill.

2.4.13 Spill Response: Oil spill response for the Long Beach Unit is outlined in CRC LBU's OSCP dated June 2017. The plan satisfies both federal and state regulations and is discussed in more detail in the Safety Management Programs Audit. The response equipment that is located on the Islands is checked monthly for condition and to satisfy the quantities specified by the response plan. All equipment and its storage appeared to be in good order during the safety audit.

CRC is a member of a cooperative of oil producers, refiners, transporters and shippers that provide funding to Marine Spill Response Corporation (MSRC). MSRC is an independent, non-profit, national spill response company dedicated to rapid response. MSRC's capabilities include a large inventory of vessels, equipment, and trained personnel. MSRC operates three oil spill response vessels (OSRV), two boom boats, two deployment boats, and a shallow water barge from Berth 57 at the Port of Long Beach. MSRC will respond to any oil spill reaching the water at CRC's request. In the event oil reaches the water, operating personnel on the Island facilities will deploy their boom to contain the spill until MSRC arrives to assume control of the spill and clean up. Boom deployment drills are conducted with MSRC annually and may be witnessed by various participating agencies. The drill schedules include both announced and unannounced drills. In addition to the MSRC drill, CRC schedules Qualified Individual notification checks, facility deployment drills, and tabletop drills to test the Incident Command System (ICS). 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 in the same three-year period.

2.5 Mechanical Integrity / Preventive Maintenance Program

The Preventive Maintenance and Mechanical Reliability section provides a general overview of CRC's corporate philosophy and approach to implementing a successful reliability program. The evaluation of CRC LBU's maintenance activities also ensures mechanical equipment is operating to designed parameters and maintained in a manner appropriate for its intended application.

The computerized maintenance management system utilized is called Maximo, which is used to manage and track maintenance activities. Operating personnel have the capability to 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 manufacturer's recommendations, operating history, and recognized and generally accepted good engineering practices. Operating personnel conduct preventative maintenance on all critical processes and operational equipment. Major pieces of process equipment (i.e. vessels, tanks, piping, and machinery) can be scheduled within the preventative maintenance program based on manufacturer's recommendations and operating history.

In addition, a risk management system called CREDO is being implemented to augment Maximo. Once implemented, facility engineers will be able to view risk levels established for the various sections of piping and pressure vessels based on service and consequence of failure. When the risk for a particular section of piping or shell thickness of a pressure vessel reaches an unacceptable level, engineers can implement a corrective or mitigating action on the asset to lower the risk to an acceptable level. This proactive approach to piping integrity and risk control has been enhanced in recent years and has produced positive results.

Baker Hughes provides the facility with a chemical treatment program that satisfies operational needs. A main component of the program is the introduction of 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.

Cathodic protection (e.g., impressed current and sacrificial anodes) is used in conjunction with other forms of corrosion control such as protective coatings wherever systems are exposed to an aggressive environment. This means of corrosion control is provided for sub-sea pipelines, select pressure vessels, and tanks. Appropriate recordkeeping provides historical data and often provides signs as to the source of a detected deficiency. The maintenance program records monthly measurements and data initiated by a Maximo generated work order. A cathodic protection specialist reviews and records the information as part of system maintenance. The specialist also determines the cause and necessary corrective measures should any deficiencies be detected.

2.6 Production Safety Systems

The audit team reviewed each Island as the starting point for evaluating the automated safety systems. All process components, their installed safety alarms and shutdown features, detection and monitoring systems, other emergency support features, equipment, and their functions were reviewed. Study of these systems and devices provided an overall view of the design of the Island safety systems. From there, the specific logic or function of each system could be evaluated. Due to each Island's containment capability, the necessary safety features to suit the risks are different from offshore platforms. As such, the Islands show some difference in installed safeguards compared to offshore platforms equipped with specific Mineral Resources Management Division (MRMD) required features. The Islands have been evaluated to ensure they provide at least equivalent safeguards, based on the pollution risk.

CRC LBU has designed processes to be inherently safe through the implementation of simpler process designs and by conducting Process Hazards Analyses (PHAs) early in the design process. If this is not practical, then non-Safety Instrumented Systems layers of protection are applied to reduce risk to an acceptable level. CRC uses a hierarchy of health and safety controls (e.g., elimination/substitution, engineering controls and warnings) when hazards cannot be eliminated or controlled through design.

Additional design and reliability improvements include the transition from pneumatic and relay-based safety systems to software based Programmable Logic Controllers (PLC). These PLCs have diagnostic and failsafe capabilities, offer self-documentation, and effective levels of redundancy. In addition, the "hot backup" switching mechanism between the Central Processing Units (CPUs) ensures there is no loss of data in the event of a main CPU failure.

Each Island has a compatible integrated safety control system. The audit team review revealed the updated automated control and safety systems were designed following appropriate industry standards. They feature an upgraded HMI with dramatically improved status information for the operator, improved process controls, and include a set of safety sensors and controls for the Island facility. The design incorporates all the controls and safety features that have been historically provided at the Islands, coupled with modern and reliable control equipment that is common to facilities with similar risk. Each Island possesses multiple layers of protection for the oil and gas production streams that are provided by the basic automated control system as well as additional safety controls or systems determined as necessary by Hazards Analysis (HA). These multiple layers achieve appropriate levels of corrective action or safeguarding for the specific risk or hazard addressed. The consequences from operational upsets and other undesirable events are minimized using these additional safety layers. The automated control system provides for reliable and coordinated operation of the major production equipment. An initial set of production control alarms and the capability for operator originated corrective actions act as the first level of safeguard within this automated control system. For critical deviations in pressure or level, a safety or emergency shut-in action typically provides the next level of protection. Relief valves and/or other mechanical devices provide physical protection to prevent rupture from overpressure or overflow. Substantial overcapacity in containment volume provides a final safeguard that makes the risk of a spill on these facilities significantly less than that on a platform. The safety features and system of each Island provide the necessary safeguards and features as determined by staff personnel. The substantial safe operating history of these facilities also attests to the adequacy of the safety features provided.

The specific design considerations for the safety systems installed on pressure vessels, and subsea pipelines focus on preventing releases, stopping the flow of hydrocarbons to a leak if one occurs, and minimizing the effects of such releases. Pressure vessels on the Islands contain hydrocarbons under pressure for liquid-gas separation, dehydration and surge handling, while tanks process and store produced water and liquid hydrocarbons. The majority of safety devices on the pressure vessels consist of alarms and pressure safety valves (PSVs). Shut-in sensors are provided on the FWKOs and vent scrubber. The safety systems for the FWKOs, water-receiving tank, and subsea pipelines that handle the main production stream of crude oil provide appropriate levels of protection to minimize the effects of equipment failure. As an example, a Level Safety High-High (LSHH), Pressure Safety High-High (PSHH), and PSVs protect FWKOs and the water-receiving tank from overflow and overpressure. Safety devices on these pieces of equipment are capable of shutting down the Island when the automated control system fails. Subsea pipeline low-pressure and high-pressure safety shutdowns protect against leaks on the subsea pipelines in the same way that platform safety systems operate.

Process tanks and their control systems are designed with sufficient safety devices and redundancy to prevent and/or isolate any accidental release of flammable gas or liquid. An integrated detection and protection system senses and activates appropriate high and low-level alarms. In addition, mechanical devices such as level indicators and valves are incorporated into the design to provide for an additional level of protection.

Pressure vacuum/vent relief valves prevent rupture of the tank from overpressure or collapse of the tank from under pressure. These adequately sized vacuum/vent valves handle maximum inflow or outflow safely. A gas make-up system is also in place to prevent the introduction of air into the tank and a resulting explosive mixture. All systems (e.g., sensors, valves, equipment) are designed to be fail-safe upon a signal or power failure.

Stock tanks (30M-1, 30M-2, and the 87M-2) at the J-6 site are equipped with pressure-vacuum/vent relief valves, a vapor recovery system, and high and low-level alarms. The concrete firewall surrounding the stock tanks provides secondary containment. The level alarm highs and lows are displayed on Pier J computers via the PLC and HMI display. Additional spill protection is provided by operator surveillance and operating procedures once the high-level alarm (18-feet) is reached. Finally, Facilities Operations Supervisor (FOS) notification and approval is needed to exceed 24-feet when the high high-level alarm sounds.

Facility HMI control systems are designed to allow easy access, so operators can make required changes. Conversely, because of strict safety systems procedures, access to the program control code is limited to the automation team. This policy prevents inadvertent changes and maintains uniformity among the Islands. In addition, changes to the control system will not prevent the safety system from functioning properly. This assurance is made possible through the use of separate systems. Bypass switches for functional testing provide "no interruption" to the normal process operation. System safety integrity is maintained when a device is placed in bypass by procedures and the use of an alarm to indicate an active bypass.

The emergency shut-in switch for the Island is clearly indicated and easily accessible in the control room. The switch provides a means for personnel to initiate a facility shutdown when an abnormal condition is observed. In addition, the PLC will trip the solenoid on the Island's block and bleed system if a shut-in condition is present. This condition electrically shuts down the well controllers and closes diverter valves on the flow lines. The Island controls and safety features are designed to be fail-safe and have redundant capabilities. The block and bleed system has this capability.

Electrical System Audit

California Resources Corporation
Long Beach Unit

June 2019

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) Long Beach Unit (LBU) facilities including Islands Grissom, Freeman, Chaffee, and White, onshore Pier J Well areas J-1, J-3, J-4, J-5, onshore J-6 tank facility, and the onshore production and transportation facilities at J-2 and Broadway & Mitchell to determine if they conform to recognized and appropriate electrical Codes and industry standards.

References used in 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 Regulations. The ELC Team review comments are based on those publications, which primarily include API RP 500, API RP 540, CEC documents and industry standards. The drawings used in support of the audit were Electrical Single-lines and Area Classification Drawings provided by CRC for the facility.

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

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

3.2 Hazardous Area Electrical Classification Drawings

The API recommended practices and CEC requirements provide specific guidelines for the electrical classification of hazardous areas and installation practices for electrical equipment and materials within classified areas. The basis for observations and review comments for all hazardous areas are API RP 500, CEC Articles 500, 501, and 504, and NFPA 70E. The hazardous area electrical classification drawings are generally representative of the existing conditions and area class elements. However, the drawings for the LBU facilities need to be updated to include process and equipment additions and deletions made since the last revision on December 2015.

The purpose of a Hazardous Area Electrical Classification Drawing is to define the locations of boundaries and areas where specific electrical materials and installation practices are required to manage risks associated with the explosive properties of flammable liquids, vapors, and other volatile materials. Installation and maintenance of electrical systems requires attention to the type of hazard and the level of the hazard in order to ensure compliance with CEC requirements. Hazardous Area Electrical Classification Drawings are required to include the information necessary for designers, electricians, and other personnel to perform work in and around classified areas. There have been equipment changes made at Islands Grissom, Freeman, Chaffee, and White, onshore Pier J Well areas J-1, J-3, J-4, J-5, onshore J-6 tank facility, and the onshore production facilities at J-2 and Broadway & Mitchell since December 31, 2015, that necessitate an update of the Hazardous Area Electrical Classification Drawings.

Portable chemical tanks are used for treatment and injection and are located throughout the facilities. However, the locations of the tank installations are, by definition, permanent and they have pumps that operate continuously. Since 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.

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 area classification. All areas known to contain flammable liquids or vapors are required to be identified on a Hazardous Area Electrical Classification Drawing. The area classification plans require the addition of details to more clearly define and illustrate the facility area class boundaries, elevations, and extents.

General-purpose electrical enclosures (Load Centers, MCC's, control panels, etc.) are only suitable for use in unclassified areas. In general, electrical equipment installed in Classified areas was found to be explosionproof, NEMA 4, purged, or otherwise suitable for use in Classified areas. Purged enclosures must have purge systems monitored and equipped with an alarm when purge pressures drop below a minimum level.

Some junction box and conduit fitting covers are missing or not properly seated against box flanges to provide 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. Conduits must be sealed at devices, enclosures, and area classification boundaries.

After updating and revising the Hazardous Area Electrical Classification boundaries as required by the matrix and as described in this report, additional equipment may be identified as unsuitable. Electrical equipment that is not suitable for installation in a classified area will need to be relocated, replaced with equipment that is suitable, purged, or non-permeable barriers will need to be installed. Enclosed and gasketed fittings are suitable for Division 2, but not Division 1. NEMA 3R enclosures are suitable for unclassified areas, but not Division 1 or Division 2. When non-explosionproof enclosures with arc producing devices are located in Class I areas, they are required to be purged and pressurized per NFPA 496.

3.3 Electrical Power Distribution System, Normal Power

Electrical System Configuration: Electric utility service is supplied by Southern California Edison (SCE) for all of the facilities. The Islands receive power at 66kV from two SCE oil-filled submarine cables. The Onshore facilities receive power at 12.47kV from SCE over a single power line. All facilities utilize power at 4160V or 480V through a radial distribution system to supply plant loads.

3.3.1 Electrical Single-Line: The electrical single-line drawings provided by CRC were used for review of the LBU facilities electrical system. During the audit, sizes and rating of the equipment were recorded for comparison to existing drawings. The audit focused on 12.47kV, 480V, and 240V power distribution systems. CRC will need to add missing information and incorporate the corrected information into updated single-line drawing per each site matrix.

3.3.2 Electrical Service Capacity: The normal power system capacity appears to be adequate for present usage and loads based on observation of equipment connected for each site. The 4160V main switchgear on the Islands appears to be approaching full capacity. It is recommended that the serving utility be contacted regarding any service capacity and motor starting limitations and to determine the peak load. Electrical system utility short circuit duty data was not available for the LBU sites. The information is needed to verify the adequacy of existing interrupting equipment, at all voltage levels, can withstand the fault currents as well as isolating the faulted area. The data is required and must be included on the single-line diagram. Utility short circuit duty should be verified every five years when the facility arc flash hazard assessment is updated as required by NFPA 70E.

A physical inspection of motor starters and circuit breakers revealed that, in general, overcurrent protection was appropriate. The application of overcurrent devices with respect to equipment rating is generally satisfactory.

3.3.3 Electrical System Design: Power for the Islands is delivered from SCE Pico Substation over two 66kV submarine oil-filled power cables. Two submarine cables are installed to each Island where two 66kV transformers step down and supply three-phase power at 4.16kV to the main switchgear. The SCE transformers are sized so that one transformer can supply the entire load of each Island. One transformer could be taken out of service and the load would continue to be served. Load may be transferred between the SCE transformers through primary switching as well as secondary switching at the 4160V main switchgear.

Electric power from Broadway & Mitchell to Pier J shore facilities is supplied by SCE from the Pico Substation on one of several SCE lines. Pier J and Broadway & Mitchell receive power from SCE at 12.47kV. CRC-owned step down transformers supply three-phase power at 4.16kV and 480V to the facility loads. Facility loads requiring a 208/120V supply are served by CRC owned transformers located near the loads.

Broadway & Mitchell receives SCE power at 12.47kV at Distribution and Metering Switch Center B. Two main step down transformers supply power to the 4.16kV switchgear. The 4.16kV transformer windings are delta connected and undergrounded.

Pier J receives power from SCE at 12.47kV at the JWP-SWGR-1 distribution center located at J-4. Power is distributed from J-4 via a primary selective distribution system to J-1, J-2, J-3, J-4, J-5, and J-6 Load Centers. The rig feeders at each shore location are rated 12.47kV. Water injection pumps located at Pier J-1 operate at 4160V. All other loads at each location on Pier J are served at 480V or less. The 480V systems are solidly grounded.

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. A sound maintenance and inspection program, properly implemented, is key to assuring the highest level of reliability. Electrical preventative maintenance and repair has been integrated into the MAXIMO computer database where it is tracked.

Electrical systems shall be designed to minimize the risk of hazards to operating personnel. CEC Article 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 is, in general, provided on all energized equipment at the LBU. It was confirmed with CRC that the studies for arc flash hazard are being updated every five years.

Circuit identification nameplates are 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.

3.4 Electrical Power Equipment Condition and Functionality

3.4.1 Equipment Condition: Given the harsh environmental conditions near the seashore, the overall condition of the electrical equipment can be rated as fair. The rating condition of fair can be attributed to age, 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 Article 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 of electrical equipment, cables, and materials needs to be consistently addressed and managed throughout the island and onshore facilities.

3.4.2 Equipment Maintenance Practices: Safety Standards in the Operations Manual are provided to cover the electrical equipment lockout/tagout/blockout program. CRC has implemented a hazards identification program that requires personnel to complete a Job safety Analysis (JSA) prior to performing any work on equipment or facilities. The JSA includes hazards identification, PPE, and other measures to mitigate hazards. All JSAs must be closed out at the completion of the tasks.

Personnel were unfamiliar with the applicable requirements for extension cord and portable equipment testing programs. CEC Article 509 identifies a maximum time constraint of 90 days for temporary installations. It is recommended that CRC implement an Assured Equipment Grounding Conductor Program that includes a testing schedule and marking system for temporary power extension cords and a method to identify when cords were last inspected. This program should also apply to contractors performing work on premises.

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.

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 together, 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 all the way back to the power transformer grounding electrode system. The best way to achieve ground circuit continuity is to include properly sized (CEC Article 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 on the liquid-tight conduits where needed.

3.6 Emergency Electrical Power

3.6.1 System Configuration: Islands Grissom, Freeman, Chaffee, and White each have standby power generators for the fire pumps and barge ramp. There are also small local uninterruptible power supply (UPS) units and battery power provided in the Control Building Telecom Rooms with capacity for ride-through in the event of a short power outage. Broadway & Mitchell has a standby generator to power a 125VDC panel and a 20kVA UPS. Sites J-1 through J-6 do not have permanently installed emergency or standby power generators. The control buildings on each Island, Broadway & Mitchell, and J-2 include manual transfer switch provisions to allow connection of a portable temporary generator to supply critical control building loads.

3.6.2 Equipment and Component Ratings: Individual battery backup power is provided within the Control Building telecom and telecommunications system enclosures. The capacity of the UPS systems installed on the Islands is adequate based on the load.

3.6.3 Electrical System Design Safety: No life safety systems are installed that require permanent emergency electric power sources.

3.7 Electric Fire Pumps

Islands Grissom, Freeman, Chaffee, and White each have a fire pump and emergency generator. The purpose of the Electric Fire Pump is to provide backup to the water injection booster pumps. If the water injection booster pumps fail to operate during an emergency the Electric Fire Pump can be used. The Electric Fire Pump has a normal source of power and an emergency generator supply. Manual switching is necessary to run the Electric Fire Pump. The emergency generator can provide power to the fire pump or the barge area but not to both simultaneously. The pumps utilize sea water to supply the deluge system. Sites J-1 through J-6, and Broadway & Mitchell do not have a fire pump. Fire protection is supplied from the local fire department.

3.8 Process Instrumentation

Process control is managed on a daily basis by operating personnel. Communications regarding process operating parameters is managed through direct communications and cellular phone. A microwave data link is maintained on Islands Grissom, Freeman, Chaffee, and White for the Wonderware HMI operations management software. The microwave data link is supervised by the IT department and maintenance is performed by CRC electricians.

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

Process monitoring is accomplished through the use of control terminal screen displays located in the Main Control Room on each Island, Pier J, and Broadway & Mitchell. Additionally, operators will tour the facilities to conduct daily monitoring and verification of local instrument readings and record them on a regular basis.

Process alarms are either discrete or result in a single point alarm. Annunciation at the Main Control Room or with a local alarm and beacon or a combination of local and Control Room alarms will result from a process alarm. Single point alarms annunciated in the Control Room require an operator to go to the source of the alarm to determine the actual cause. Local annunciators or displays are then used to troubleshoot the cause of a general alarm or shutdown.

3.9 Standby Lighting

Standby lighting is installed for wayfinding and consists of battery powered lights installed inside of buildings and walk-in structures. Facility area and work lights require normal and utility power.

Area and work lights are installed throughout the Islands, Pier J, and Broadway & Mitchell. Light sources are being converted from High Pressure Sodium and Metal Halide to LED. Illumination levels should comply with API RP 540.

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 or operation of equipment in a fail-safe condition.

Emergency shutdown (ESD) stations, referred to as “Island Shut In”, are installed at various locations throughout the Island facilities. Electric power can be manually turned off at the main breaker of each service substation. The Onshore facilities at Pier J and Broadway & Mitchell do not have systems that would be considered ESD.

3.10.2 Gas Detection Systems: Combustible gas detection systems, LEL and H_2S type, are employed to detect combustible gas leaks in equipment and piping, and to warn personnel of explosive and toxic concentrations in order to initiate remedial action. Several H_2S sensors on Island Chaffee were tagged as having bad sensors that require repair. The Islands have permanently installed cellar LEL detectors that activate the ESD system. Pier J and Broadway & Mitchell facilities rely on portable detectors. All personnel are required to wear a personal H_2S detector and to carry a 4-way detector when entering confined space, cellars, and the J-6 tank farm.

3.10.3 Fire Detection Systems: Fire detection and smoke detection is employed to detect and warn personnel of fire and smoke conditions and to initiate remedial action. No fire detection equipment is installed in any of the facilities. The only exception is the fire eyes installed at the J-6 tank farm.

3.10.4 Aids to Navigation: The U.S. Coast Guard requires Aids to Navigation in offshore facilities close to the shore to include obstruction lights. The navigation beacons are equipped with an automatic lamp feature which stays lit even if a bulb burns out. The transfer feature automatically detects when the currently active lamp has ceased to function and moves the next lamp into place. It was noted during the audit that Island Chaffee has one (1) navigation beacon that is out-of-service. The beacons require periodic maintenance to confirm proper operation and should be included in MAXIMO.

3.10.5 Communication: Communications systems are established to provide reliable communication during normal and emergency operations. Systems used for emergency communication have battery-operated supplies good for at least four-hours continuous operation as required by API RF 14F. UPS systems are installed on the Islands that provide power for communications during a power outage. Landlines, microwave, wireless radio, and cellular phones are available and are used for communication between facilities.

3.10.6 General Alarms: General alarms shall be audible in all parts of the facility to notify personnel to abandon the facility or respond to an emergency. Red lights can be used in conjunction with the audible alarms. All general alarm sounding devices shall be identified by a sign at each device in red letters at least 1-inch high describing the required personnel response. It is recommended the central paging system be used to supplement instruction of a general alarm. Audible alarms on the Islands were verified to be operational.

3.10.7 Cathodic Protection: Cathodic protection systems are installed on the Islands, Pier J, and Broadway & Mitchell facilities. It was noted during assessments that many of the cathodic protection rectifier panels were painted over and that electrodes were not being reinstalled on piping, tanks, or vessels after being repaired or replaced. All cathodic protection system equipment required to protect vessels, tanks, and pipelines should be evaluated for proper operation and repaired as necessary.

Safety Management Audit

California Resources Corporation
Long Beach Unit

June 2019

4.0 SAFETY MANAGEMENT AUDIT

4.1 Goals and Methodology

The goal of the Safety Management Program Audit was to verify that CRC has the required regulatory programs, plans, and manuals in place and uses a safety management approach to manage workplace hazards to 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 OSHA and the EPA. Operating Manuals, emergency and spill response plans, training and qualification programs, and other key elements were reviewed for accuracy and content. Additionally, Staff reviewed programs specific to CRC addressed in their Health, Safety, and Environmental Manual.

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 in prior Safety Audit reviews were found to be clearly written and not overly complicated.

The SOPs are maintained and available via the company intranet system to all CRC personnel with hard copy versions located on each island and onshore operating facility control room. However, State Lands Commission staff haven't received up-to-date Operation Manuals for CRC Islands and Pier J facilities (SMP – 4.2.01). A comprehensive review of the SOPs is performed to determine that pertinent operating information is readily available within the different manuals. The SOPs should be systematically reviewed annually, with hard copies and/or electronic files being updated by authorized CRC personnel every 1-2 years, to ensure that the policies and procedures remain current. It does not appear as though this is occurring. When applicable, a review date is added to each SOP that has been reviewed and 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

CRC's Oil Spill Contingency Plan (OSCP) was developed under the 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 lessen damage to the environment, natural resources, and facility installations. 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

Within the OSCP are operating procedures the facility uses to prevent oil spills. Included are control measures to prevent oil from entering navigable waters and adjoining shorelines. The countermeasures contain, clean up, and mitigate the effects of an oil spill. The OSCP was reviewed and meets Federal requirements (40 Code of Federal Regulations (CFR) Part 112) and the State Office of Spill Prevention and Response requirements. CRC staff is familiar with the OSCP and holds annual spill drills to test the effectiveness of their spill response. No action items were identified for this plan.

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 EPA Rule compliance. The plan is prepared following good engineering practices and provides operation, maintenance, and management strategies to lessen the potential of a spill or release of oil products. A licensed professional engineer and company management have approved the SPCC Plan. No action items were identified for this plan.

4.4 Training and Drills

CRC has a policy requiring all employees, contractors, and visitors to receive safety orientation training, be issued a security badge, and to sign-in upon entering an operating location. This policy provides a record that is used to account for personnel during an evacuation and enhances safety awareness and accountability.

CRC has an ongoing regulatory required training program for facility personnel and contractors. This training includes confined space entry, oil spill drills, hazard communication, HAZWOPER, hot/safe work permitting, H_2S, lockout / tagout, and personal protective equipment. The program appears to include all mandatory training as required by OSHA and the Office of Spill Prevention and Response. The training matrix appears to be well defined and effective for each particular job description. A refresher course on fire extinguishers is part of CRC's "Block Training". Firefighting is encouraged only if the fire is small and can be safely done until the fire department arrives and takes over.

Drills, exercises, and safety meetings are conducted following an appropriate schedule. Facility personnel conduct morning safety meetings that include all persons performing work onsite. A range of general to specific safety subjects are addressed throughout the month and these training and pre-job safety meetings are recorded. The records are retained for a predetermined amount of time. The Safety Audit Team has observed that CRC's personnel recognize the importance of personal protective equipment and that the requirements are strictly enforced. There were no action items identified regarding personal protective safety devices or equipment.

4.5 Safety Management Programs

A CRC corporate program that parallels the OSHA Process Safety Management (PSM) regulation (29 CFR 1910.119) is used to control workplace hazards. The majority of CRC facilities, with the exception of the Broadway & Mitchell gas processing facility, are not bound by PSM; CRC has voluntarily integrated their 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. Safety 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.

CRC has a number of regulatory agency required plans available on electronic file and hard copy. These documents include a Business Emergency Plan (BEP), Emergency Response Plan (ERP), and Safety and Health Manual. The manuals referenced were reviewed for content, accuracy, and compliance with regulatory requirements. The Long Beach Fire Department approves CRC's BEP. This document is current and meets the Hazardous Materials Disclosure Program requirements of the city by providing the chemical inventory and other hazards on the lease to fire personnel. The Los Angeles County Environment Health Division retains chemical inventory data and other hazards on the lease. The BEP is available at each facility.

CRC's ERP was developed to provide guidelines for management and employees who respond to abnormal events at the facility (California Code of Regulations, Title 8, 3220 & 3221; Health & Safety Code, Title 19, 2729). The focus of the manual is to provide structure and guidance in the response actions required to effectively mitigate emergencies. The manual appears to have the required information and is organized in a logical manner.

Human Factors Audit

California Resources Corporation
Long Beach Unit

June 2019

5.0 HUMAN FACTORS AUDIT

5.1 Goals of the Human Factors Audit

The primary goal of the Human Factors Team 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 be conducted following audits of the Long Beach Unit (LBU) lease facilities. Interview results are considered confidential between CSLC and LBU 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), and
- Investigation and Audit (9).

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

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

5.2 Human Factors Audit Methodology

The Commission's MRMD staff will schedule the SAMS interviews with a cross-section of CRC staff and sub-contractors after completion of the Safety Audit. The assessors will evaluate the responses based on SAMS guidelines and develop a separate confidential report. The MRMD staff will provide the confidential report accompanied by a formal presentation that summarizes the report to CRC's management.

Action Item Matrix

California Resources Corporation
Long Beach Unit

June 2019

Appendices

California Resources Corporation
Long Beach Unit

June 2019

Appendix A
Acronyms

AFFF	Aqueous Film Forming Foam
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
B&M	Broadway and Mitchell facility
BAP	Best Achievable Protection
BEP	Business Emergency Plan
Cal OSHA	California Occupational Safety and Health Administration
CEC	California Electrical Code
CPU	Central Processing Unit
CRC	California Resources Corporation
CSLC	California State Lands Commission
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	Facilities Operations Supervisor
FWKO	Free Water Knock Out
GOV	California Government Code
HA	Hazards Analysis
HF	Human Factors
HMI	Human Machine Interface
H_2S	Hydrogen Sulfide
ICS	Incident Command System
IT	Information Technology
JSA	Job Safety Analysis
kVA	KiloVolt Amperes
LBERD	Long Beach Energy Resources Department
LBU	Long Beach Unit
LED	Light Emitting Diode
LEL	Lower Explosive Limit
LSHH	Level Safety High-High
MAWP	Maximum Allowable Working Pressure
MCC	Motor Control Center
MCF	Thousand Cubic Feet
MOC	Management of Change
MRMD	Mineral Resources Management Division
MSRC	Marine Spill Response Corporation
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Association

OSCP	Oil Spill Contingency Plan
OSHA	Occupational Safety & Health Administration
OSPR	Office of Spill Prevention and Response
OSRV	Oil Spill Response Vessel
P&ID	Piping and Instrumentation Diagram
PFD	Process Flow Diagram
PHA	Process Hazard Analysis
PLC	Programmable Logic Controller
PM	Preventative Maintenance
PPE	Personal Protective Equipment
PRC	Public Resources Code
PSHH	Pressure Safety High-High
PSI	Pounds per Square Inch
PSM	Process Safety Management
PSV	Pressure Safety Valve
RP	Recommended Practice
SAMS	Safety Assessment of Management Systems
SCE	Southern California Edison
SDS	Safety Data Sheet
SMP	Safety Management Programs
SOP	Standard Operating Procedures
SPCC	Spill Prevention, Control, and Countermeasure
SSSV	Subsurface Safety Valve
UFC	Uniform Fire Code
UPS	Uninterruptible Power Supply
UT	Ultrasonic Thickness
V	Volt

Appendix B
Best Practices

1.0 INTRODUCTION

1.1	Safety Audit Background	PRC 8750, 8755, 8757
1.2	Facility History	
1.3	Facility Description	

2.0 FACILITY CONDITION AUDIT

2.1	Goals and Methodology	
2.2	General Facility Conditions	
2.2.1	*Workplace Housekeeping*	CSLC 2123 & 6539
2.2.2	*Stairs, Walkways, Gratings, & Ladders*	CAL OSHA Title 8 CCR
2.2.3	*Escape/ Emergency Egress/ Exits*	CAL OSHA 22, 25, 3215 & 6577
2.2.4	*Labels, Color Coding, and Signs*	CAL OSHA & API RP 14J
2.2.5	*Security*	CSLC 2123
2.2.6	*HAZMAT Handling and Storage*	OSHA 29 CFR 1910.1200
2.3	Field Verification of Plans	
2.3.1	*Process Flow Diagrams*	CSLC 2132(a)(2) & API 51R
2.3.2	*Piping & Instrumentation Diagrams*	CSLC 2132(a)(2) & API 51R
2.3.3	*Fire Protection Drawings*	CSLC 2132(g)(4)(G) & API 51R
2.4	Condition and Integrity of Major Systems	
2.4.1	*Piping*	CSLC 2129(b)&(c), CAL OSHA 6533, API 570, OSHA1910.106(c)(4) ANSI 31.3
2.4.2	*Tanks*	CSLC 2129(b)&(c), API 653&RP 572
2.4.3	*Pressure Vessels*	CSLC 2129(b) & (c), ASME B&PV Code Sect. VIII, API RP 510 & 572, CAL OSHA 6551(c), 46 CFR 53
2.4.4	*Relief Systems*	CSLC 2132(g)(3), API RP 520, 521, 576
2.4.5	*ESP, Pump Units, Wellhead Equipment & Well Safety Systems*	CSLC 2132(a)(4)
2.4.6	*Firefighting Detection Systems*	NFPA 30
2.4.7	*Firefighting Equipment*	CSLC 2132(g)(4)(A) & NFPA 25 -10.2.5.1
2.4.8	*Emergency Shutdown Device*	CSLC 2132(g)(1)
2.4.9	*Safety and PPE*	CAL OSHA
2.4.10	*Instrumentation, Alarm, & Paging*	CSLC 2132(g)(1)&(2), CAL OSHA 5189
2.4.11	*Auxiliary Generator/Prime Mover*	CSLC 2132(g)(7)
2.4.12	*Spill Containment*	CSLC 2139 & 2140, 40 CFR 112.7(c) & GOV 8670
2.4.13	*Spill Response*	CSLC 2139 & 2140, GOV 8670
2.5	Mechanical Integrity	CSLC 2129(c) & CAL OSHA 5189(j)
2.6	Production Safety Systems	DOG 1747 OSHA 1910.119 API RP 75

	Onshore Production Safety System	CAL OSHA 5189 OSHA 1910.119 DOG 1712 - 1724 API RP 51
2.7	Process Hazards Analysis	CAL OSHA 5189(e) API RP 75 PRC 8758 GOV 8670.28 (a)(7)

3.0 ELECTRICAL AUDIT

3.1	Goals and Methodology	
3.2	Hazardous Area Electrical Classification Dwgs	API RP 500, NFPA 70
3.3	Electrical Power Dist. System, Normal Power	API RP 540, NFPA 70
	3.3.1 Electrical Single Line	
	3.3.2 Electrical Service Capacity	
	3.3.3 Electrical System Design	
3.4	Elec. Power Equip Condition and Functionality	API RP 540, NFPA 70
	3.4.1 Equipment Condition	
	3.4.2 Equipment Maintenance Practices	
3.5	Grounding	
3.6	Emergency and Standby Power (batteries, chargers, UPS)	NFPA 70, NFPA 110
	3.6.1 System Configuration	
	3.6.2 Equipment and Component Ratings	
	3.6.3 Electrical System Design Safety	
3.7	Electric Fire Pumps	NFPA 20, NEC 696
3.8	Process Instrumentation Wiring Methods, Materials and Installation	API RP 540, NFPA 70
3.9	Standby Lighting	DOG 1743 (a)-(c)
3.10	Special Systems	
	3.10.1 Safety Control Systems	DOG 1743 & 1747 API RP 75, GOV 8670 ISA RP 7.1, 12.1 & 12.2 ISA S7.4, S12.4
	3.10.2 Gas Detection Systems	DOG 1747.6
	3.10.3 Fire Detection Systems	DOG 1743 & 1747 API RP 75 & 2001
	3.10.4 Aids to Navigation	USCG 33 CFR Subcp. C, Part 67
	3.10.5 Communication	
	3.10.6 General Alarms	
	3.10.7 Cathodic Protection	API RP 651, NACE RP 01-76 & 0675

4.0 SAFETY MANAGEMENT AUDIT

4.1	Goals and Methodology	API RP 75 OSHA 1910.119 CAL OSHA 5189
4.2	Operations Manual	PRC 8758
4.3	Spill Response Plan	GOV 8670
	4.3.1 SPCC Plan	40 CFR 112.7

4.4	Training and Drills	DOG 1747.5 GOV 8670
4.5	Safety Management Programs	CAL OSHA 5189, API RP 75

5.0 HUMAN FACTORS AUDIT

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

CSLC regulations: California Code of Regulations, Title 2
CAL OSHA regulations: California Code of Regulations, Title 8
DOG regulations: California Code of Regulations, Title 14
OSHA regulations: Code of Federal Regulations, Title 29

Appendix C
References

GOVERNMENT CODES, RULES, AND REGULATIONS

Cal OSHA	California Code of Regulations, Title 8
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*
CSLC	California Code of Regulations, Title 2
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 14B	*Design, Installation and Operation of Sub-Surface Safety Valve Systems*
RP 14H	*Use of Surface Safety Valves and Underwater Safety Valves Offshore*
RP 14J	*Design and Hazards Analysis for Offshore Production Facilities*
RP 51	*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*
RP 520	*Design and Installation of Pressure Relieving Systems in Refineries, Part I and II*
RP 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 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 Steve Staker Ryan Horton
CRC – LBU	Ester Brawley
LBERD	Carlos Carrion

ELECTRICAL TEAM

CSLC – MRMD	David Rodriguez
PES	Doug Effenberger
CRC – LBU	Ester Brawley
LBERD	Carlos Carrion

TECHNICAL TEAM

CSLC – MRMD	David Rodriguez David Calderon Steve Staker Ryan Horton
CRC – LBU	Ester Brawley
LBERD	Carlos Carrion

SAFETY MANAGEMENT TEAM

CSLC – MRMD	David Rodriguez David Calderon Steve Staker Ryan Horton
CRC – LBU	Ester Brawley
LBERD	Carlos Carrion