California State Lands Commission

Safety and Oil Spill Prevention Audit

Long Beach Unit

Oxy Long Beach, Inc. (OLBI)

March 2013

TABLE OF CONTENTS

Executive Summary

Oxy Long Beach, Inc.
Long Beach Unit

March 2013

Executive Summary

Safety Audit of the Long Beach Unit

A Safety and Oil Spill Prevention Audit of the Long Beach Unit (LBU) was started in January 2012 at the request of the State Lands Commission with an anticipated duration of 15 months. Field work for the audit was completed in January 2013 and a draft report was prepared in March 2013. 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. The audit followed the established procedures that have been used by CSLC for many years. An agreed upon list of Best Achievable Protection Criteria was developed between CSLC, the City of Long Beach, and THUMS personnel and is included in Appendix A.4. Audit findings are based on these criteria.

Company Background

Occidental Oil and Gas Holding Corporation (Oxy) purchased the Field Contractor interest of the LBU oil and gas development contract from ARCO in 2000. The THUMS Long Beach Company is the agent for the field contractor, Oxy Long Beach, Inc. (OLBI). THUMS operates the LBU on behalf of the State of California and the City of Long Beach. OLBI is a wholly owned subsidiary of Oxy with corporate headquarters in Los Angeles. Oxy's oil and natural gas operations are worldwide. In addition to OLBI, Oxy's California operations include Elk Hills in Kern County and Vintage Production California, LLC with operations in the San Joaquin, Ventura and Sacramento basins. THUMS is a name that has been retained from the original consortium of operators: Texaco, Humble, Union, Mobil, and Shell.

Description of the Oil Field

The LBU is located within the Wilmington Oil Field in California. The Wilmington Oil Field is part of the larger, 22-mile northwest by southeast Torrance-Wilmington structural trend that reaches from the Pacific coast near Hermosa Beach to the Pacific coast off Seal Beach. The Wilmington Field 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) and uplands (private lands). It has produced over two and one-half billion barrels of oil through primary production and secondary water flooding from a total of 6,150 wells, of which about 1,200 remain active wells including 753 producers and 465 injectors. The City of Long Beach operates the LBU using THUMS as field contractor.

Description of the Facilities

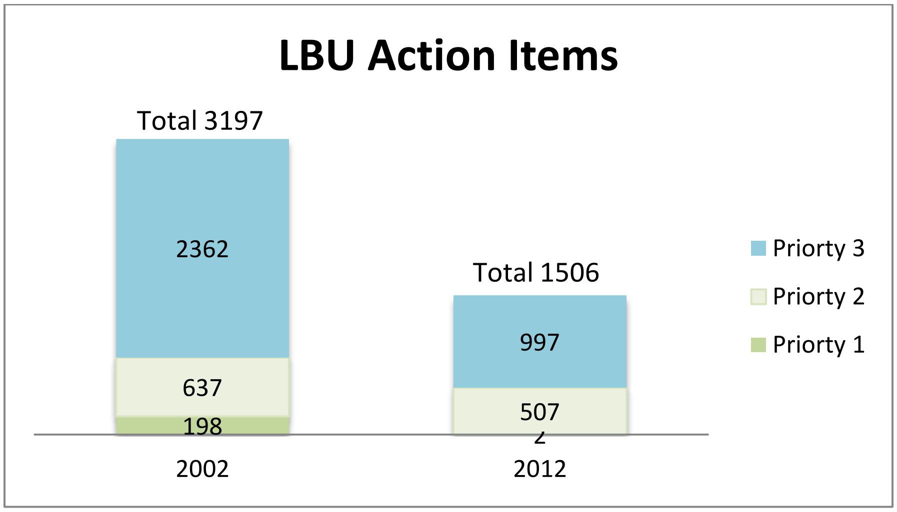
The LBU has drilling and production facilities on four offshore islands, and drilling, production, and dehydration facilities onshore. Crew boats are used to transport employees, contractors, and visitors to and from the islands while materials and supplies are shipped by barge and tugboat. The islands and onshore areas are interconnected by a number of subsea and onshore pipelines. The islands and onshore facilities remain very much as originally designed and constructed. The four islands are named after four American astronauts who died in the line of duty in the early years of the United States Space program. Each island is about ten to twelve acres in size.

The onshore facilities that are part of the LBU are located within the Pier J area of the Port of Long Beach. Well sites are located at J-1, J-3, J-4, and J-5 locations. Oil and gas from the islands and from onshore well areas arrives at the J-2 process facility via pipelines. At J-2, gas and water are further separated from the oil. The Broadway and Mitchell gas processing facility dehydrates and processes the gas to meet Long Beach City Gas specifications. Processed gas is then delivered via existing pipelines either to the THUMS LBU Electric Power Plant on Pier D to be used as fuel, to the Long Beach Gas and Oil Pipeline, or to a flare at the THUMS Pier J4 location during emergencies. Custody transfer of crude oil to the individual shipping companies also takes place at the Broadway and Mitchell facility.

Safety Audit Results

The Safety and Oil Spill Prevention Audit found the LBU to be in good condition and free of conditions that may present undue risk to personnel, the facility, or to the environment. The condition assessment activities found the LBU facilities, systems, and equipment to be in an improved state of repair compared to the previous audit completed in 2002. This audit identified about 53% fewer action items with a total of 1506 compared to the total of 3197 identified during the previous audit, a substantial decrease. In the 2002 audit, there were a total of 198 priority one action items that posed a significant risk to personnel, the facility, or the environment versus two priority one items in this audit. The number of priority two action items dropped from 637 to 507 and the priority three items dropped from 2362 to 997 items, posing low potential risks. The two priority one action items were rapidly addressed and have already been resolved by THUMS personnel. As of the time of this report, THUMS has been very responsive in assigning work orders for many of the action items and has already completed 10% of the 1506 action items (11% of the priority two items have been completed and 9% of the priority three items have been completed). Resolution of the remaining priority two action items is required within 120 days, and resolution of the remaining priority three actions items is required within 180 days.

The following chart displays the total number of action items from the 2002 safety audit report (3197) versus the total number of action items identified on the 2013 safety audit (1506). This substantial decrease demonstrates THUMS's continuing commitment and resolve to further risk management efforts for both facility and personnel safety, and to optimize safety management program strategies.



The Safety and Oil Spill Prevention Audit found the LBU facilities, safety systems, and equipment design to be based on sound engineering principles and accepted industry practices. The condition of the LBU was found to be to be in an adequate state of repair, clean, and well organized. A comprehensive mechanical integrity program is in place with equipment being maintained and operated properly. Oxy and THUMS have well established safety policies, health and environmental programs, and operate the LBU facilities in a manner that protects the health of the public, the environment, and its employees. A high spirit of plant ownership is evident in THUMS employees that enhances reliability, performance, and team work. Personnel are knowledgeable, demonstrate responsibility for the environment, and provided valuable assistance to the state lands team with this safety audit.

Introduction

Oxy Long Beach, Inc.
Long Beach Unit

March 2013

1.0 INTRODUCTION

1.1 Safety Audit Background

The California State Lands Commission (CSLC) Mineral Resources Management Division (MRMD) staff conducts detailed safety audits of operators and/or contractors for lands in which the State has an interest. The primary goal of the safety audits is to ensure that all 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/permits, as well as industry standards and practices.

The safety audit includes a comprehensive facility site review that evaluates physical condition, design features, and observes safety, spill prevention measures, and environmental management practices. The audit team evaluates each facility and its systems following a practical division of effort in these areas:

- Equipment Functionality and Design (EFI)
- Electrical Systems (ELC)
- Safety and Environmental Management Programs and Systems (SEMP/SEMS)
- Human Factors (HF)

The audit team reports progress and findings to the operator periodically throughout their audit evaluations based on these categories. Action items are recorded in a tabular matrix along with recommended corrective actions and a priority ranking reflective of risk or significance. This audit report details these results with written discussion that conveys to facility management, operations and maintenance personnel, a general evaluation of the operation and provides more discussion on any significant issues that cannot be fully developed in an action item description. Draft copies of the matrix of action items are provided to the company periodically throughout the audit. This practice affords the opportunity to discuss the action items and the appropriate course of action. Action item completion is tracked by MRMD and if necessary, the safety audit group will assist the operator with follow-up assessments.

The audit program could not be successfully undertaken without the full cooperation and support of the operating company. It is designed to benefit both the company and the State by reducing hazards in the workplace and preventing environmental accidents. Previous experience shows that safety assessments aid operating efficiency and lower cost. Good practice in health and safety creates a high-quality working environment and makes sound business sense.

1.2 Facility Background

1.2.1 Description of the Oil Field: The Long Beach Unit (LBU) is located within the Wilmington Oil Field in California. The Wilmington Oil Field is part of a larger, 22-mile 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) and uplands. It has produced over two and one-half billion barrels of oil through primary production and secondary water flooding from a total of 6,150 wells drilled to date.

The LBU encompasses the eastern portion of the Wilmington Field. It includes the combined working interest of the City's granted tidelands (Tract I – 86.4%), the State's tidelands (Tract II – 3.8%) and the upland areas (Townlot Tracts – 9.8%). 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, but resulting in water cuts that are now typically high. Oil is mostly produced from intervals ranging in depths from 2,000 feet to 8,500 feet, with just a handful of wells that measure over 11,000 feet in measured depth. The configuration of the LBU's islands and onshore well areas provide excellent containment against potential oil spills. The wellheads are located in large volume multi-well cellars and the islands and onshore well sites have perimeter berms to provide secondary containment for large volumes of spilled oil.

1.2.2 Company History: Legislation enacted in 1964 had allowed the City of Long Beach to contract out the operation of the eastern offshore portion of the field. 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 and operated the islands and well areas that formed the LBU. Occidental Oil and Gas Holding Corporation (Oxy) acquired THUMS from ARCO in 2000 creating Oxy Long Beach, Inc. (OLBI). THUMS continues to be the agent for the field contractor (OLBI) operating the LBU on behalf of the State of California and the City of Long Beach.

OLBI is a wholly owned subsidiary of Oxy with corporate headquarters in Los Angeles. In addition to OLBI, Oxy's California operations include Elk Hills in Kern County and Vintage Production California, LLC with operations in the San Joaquin, Ventura and Sacramento basins. The THUMS islands were named after four astronauts who died in the line of duty in the early years of the United States space program.

1.3 Facility Description

The LBU is engaged in the 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 facilities. Both the islands and onshore facilities remain very much as originally designed and constructed.

Wells at the LBU employ downhole electric submersible pumps to produce the crude oil. The wells are grouped in large cellars at each island and well site. 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 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 associated natural gas produced at each island production facility is passed through a scrubber to remove any liquids before being routed to the subsea pipelines.

Oil and gas pipelines from the islands and underground pipelines from the onshore well sites arrive at the J-2 production facility. The J-2 production facility is the main facility that 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 also 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 the gas 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 transfers custody 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 LBU power plant to generate power directly for the local electric utility grid.

The daily production of oil from the LBU is over 28,000 bbl per day with an additional 1500 bbl per day produced by state lease PRC 186 wells that have been drilled into PRC 186 from Island Chaffee. The daily gas produced by the LBU is about 6,500 Mcfd with an additional 375 Mcfd produced by the state lease PRC 186 wells on Chaffee.

Facility Condition Audit

Oxy Long Beach, Inc.
Long Beach Unit

March 2013

2.0 FACILITY CONDITION AUDIT

2.1 Goals and Methodology

The primary goal of the facility condition portion of the Safety and Oil Spill Prevention Audit was to evaluate the current functional performance and maintenance conditions of the Long Beach Unit (LBU) islands and associated facilities. The facilities audit used a planned method of collecting accurate information about each of the four islands (Grissom, Freeman, White, and Chaffee) and onshore pier facilities. Onshore facilities, e.g., Pier J-1 thru 6 sites, the Pier G Warehouse and the Broadway and Mitchell (B&M) facility were examined in similar fashion. Specific tasks to accomplish this goal included field verifications of key drawings/plans, a review of system and equipment maintenance histories, applicable codes and standards, facility condition checklists, and technical review of safety systems design. The layout of the audit report generally reflects a "system by system" method and includes a detailed assessment of the facilities and any significant observations. The powerplant was not included within the scope of this audit.

2.2 General Facility Conditions

2.2.1 Workplace Housekeeping: The facility work areas appeared neat and orderly, free of slip and trip hazards, waste materials (e.g., refuse, oilfield wastes) and possible fire hazards. Material storage areas were adequately sized, appeared organized, and were located to minimize interference with work activities. There was an adequate supply of clearly marked refuse containers throughout each facility. Refuse appeared to be well controlled. The regular collection and sorting of waste contributes to good housekeeping practices. It also makes it possible to separate materials that can be recycled from those going to waste disposal facilities. Drip pans and guards are placed where possible spills might occur. When substances drip on the ground, personnel clean the material up immediately. Absorbent materials are available for wiping up greasy, oily or other liquid spills. Tools are stored in suitable fixtures with marked locations to provide orderly arrangement. Employees return them promptly after use and regularly inspect, clean and take any damaged or worn tools out of service. Employee facilities are adequate, clean and well maintained. Washrooms are cleaned once per shift and have a good supply of soap and hand towels. Organizational policies throughout the LBU require workers to pay attention to good housekeeping practices as a basic part of accident and fire prevention.

2.2.2 Stairs, Walkways, Gratings and Ladders: Stairs, walkways, gratings and ladders throughout the facilities appeared to be of a safe design and construction. Safeguards protect workers from equipment where needed or required. Aisles have adequate width to accommodate the movement of people, materials and vehicles safely. The walkways, stairs, and gratings appeared to be in good repair, and were typically clear of obstructions that could create a hazard. The skim basin is one area of exception, yet hazards there are marked and the effort to safeguard personnel in this area is apparent. Portable ladders and other necessary work equipment appeared in good working order and free from oil and grease. Fixed metal ladders and appurtenances were painted to resist corrosion. Safe work practices cover the use and care of ladder equipment on the facility.

2.2.3 Escape / Emergency Egress / Exits: Escape / Emergency Egress / Exits are clearly posted and accessible. Each facility has a primary and secondary evacuation point to allow evacuation of employees and other personnel during an emergency. Evacuation routes are explained during initial worker orientation and are clearly identified on emergency site plans and signs posted in the field.

2.2.4 Labeling, Color Coding and Signs: The design, application, and use of signs and symbols within the facilities define specific workplace hazards and adhere to OSHA and ANSI recommendations. Employees receive instruction on what the signs signify 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 red.

Signs were posted at the entrance of each island or facility, are clearly visible, and identify safety hazards as well as the emergency site plan. Cellar warning signs were in good condition and posted at the entrance to each well cellar. Signs are also posted to identify the well number and type of well at each wellhead.

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

2.2.5 Security: Physical and operational security measures are in place to prevent unauthorized entry into LBU facilities. Process facilities are manned twenty-four hours a day, seven days a week with at least two operators present. 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 THUMS issued identification card for crew boat and barge access.

2.2.6 Hazardous Material Handling and Storage: Flammable and combustible liquids were found properly stored in safety cans and drums in accordance with CAL-OSHA and NFPA 30 regulations. The bulk chemical totes were correctly labeled, appeared structurally sound, and had adequate containment in the event of a leak. No loose combustible material or empty drums were present within the containment areas.

Flammable, combustible, toxic and other hazardous materials are stored in approved containers in designated areas that are appropriate for the different hazards that they pose. Storage of materials appeared to meet requirements specified in the fire codes and the regulations of environmental and occupational health and safety agencies.

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

Material Safety Data Sheets (MSDS) containing information on all chemicals used in the workplace were up-to-date and accessible to all employees.

2.3 Field Verification of Plans

2.3.1 Process Flow Diagrams (PFD): The PFD drawings are considered a part of the necessary design documentation for a facility. The PFD drawings for the islands and other production facilities of the LBU were generally up to date and showed the flow through the plant processes and equipment. However, the mass balances for one location were not up-to-date. There were also just a couple minor inconsistencies on flow path identified when compared to P&ID's or actual operation.

2.3.2 Piping and Instrumentation Diagrams (P&ID): The P&ID's for the Islands 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 2002. Virtually all of the P&ID's are now in electronic format and kept up to date with as built arrangements shown. The minor corrections that were identified by safety auditors 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.

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 most piping systems at each facility was performed in conjunction with P&ID's verification. This visual inspection and evaluation work observed the outside condition of the piping, painting and coating, signs of misalignment, vibration, and leakage. The evaluation included the condition of pipe hangers and supports as well as any field modifications or temporary repairs not recorded on the piping drawings. The evaluation also considered other key information such as material selection, piping design and maintenance practices. Any significant deficiency generated an action item and any recurring items common to all locations were grouped together. The piping evaluation found the condition and maintenance of piping throughout the facility to be good, with very few action items. The selection of piping materials and components, e.g., valves, flanges, bolts, welds are compatible with the process, operating variables and environment.

The LBU 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., API RP 570 and 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.

2.4.2 Tanks: Facility tanks are subject to THUMS's written inspection and maintenance program. The program conforms to applicable safety and industry standards, complies with Federal and State regulations, and uses appropriate work practices and procedures. Routine external/internal maintenance inspections occur on a five-year cycle and more often if conditions require it. Tank documentation includes inspections, repairs, alterations and reconstruction records. In addition, tank shell ultrasonic thickness data showing locations and results are completed as part of the inspection process. This inspection method searches for flaws and service induced damage as part of determining the suitability of the tank for the intended service.

Tank coatings, piping, valves, walls, anchor bolts, and labeling appeared to be in good condition with no evidence of recent damage or active leaks. However, in one particular case involving an island water-receiving tank, signs of past upper coarse buckling and bottom plate/shell leakage were discovered. Repairs were in process at the time of the audit and it appears these problems did not pose a significant risk to facility personnel or the environment.

To help prevent liquid overflow and leaks, safety instrumentation for the process tanks consists of high and low level alarms and switches only. The exception to this control logic is the facility water-receiving tanks. These tanks have overflow protection switches in the form of Level Switch High-Highs (LSHH) that can shut down island or pier facilities in the event of an abnormally high water level. A high water level alarm in these tanks will trigger an attempt by the process computer to control the level by initiating staged cellar shut-ins. This action consists of shutting in high water-cut wells in stages by cellar. Any further rise in level will result in a complete location shut in. Receiving Tank staged cellar shut in selections are made by operations via computer terminal. Field Operations Supervisor (FOS) log-in is required to make any changes to the tank level control set points.

2.4.3 Pressure Vessels: The facility contains a number of pressure vessels ranging from air receivers to two and three phase separators. These pressure vessels are built according to ASME Codes and have appropriate controls and safety devices. In order to improve efficiency, the LBU has tailored inspection cycles to match the safety risks posed by particular classes of pressure vessels. THUMS uses pressure vessel management software (CREDO) to determine vessel inspection frequencies. These frequencies are based on calculations within CREDO that take into consideration required vessel wall thickness, available corrosion allowance and the corresponding minimum thicknesses (t-mins). The operating temperature and pressures are also considered in establishing the inspection frequency. Vessel inspections do not exceed 5 year intervals and can be external, internal, or both and use non-destructive examination techniques.

External inspections found no evidence of leakage, distortion or cracks at welds (structural attachments), corrosion or defects of vessel connections. Internal inspection records show corrosion to be low and at a predictable rate with no major concerns. The visual inspection of the pressure vessels found no major problems or defects with only minor concerns.

A review of vessel records found that the required information was available with the exception of some missing U1-A's (manufacturer's data report). This condition was due to manufacturer's data not being available. To alleviate the problem, THUMS reengineered the thickness, corrosion rates and thickness minimums (t-mins) using ASME, Section 8, Boiler and Pressure Vessel Code for the pressure vessels that were missing U1-A's.

2.4.4 Relief System: The primary purpose of the islands pressure relief system is to ensure protection for facility personnel and equipment 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 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 sumps (3) 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 12-inch dump valve to the pipe trench.

Recent increases in Island Grissom's production required resizing of FWKO pressure safety valves and vent line. PSV's and discharge piping were resized based on relieving capacity calculations and were the principle basis for the redesigned vent line and scrubber. The calculation procedures were well documented and the MOC reflected accepted practices with no concerns noted.

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

The maintenance and servicing records for PSV's comply with applicable regulations and recommended standards, as well as, record keeping within a preventive maintenance system, API RP 520, 521 and Cal OSHA 6551. PSV's are tested using OSHA guidelines and serviced by an outside contractor. There were several administrative discrepancies between listed PSV's and process drawings. (TEC - 2.4.4.01 thru 05) When brought to the attention of THUMS personnel, these differences were corrected immediately.

2.4.5 Fire Detection Systems: There are no fire detection systems installed at any LBU 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-6 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 minimum 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.

2.4.6 Fire Fighting Equipment: Each LBU island and facility has an assortment of portable fire-fighting equipment that includes wheeled units and hand carried portable extinguishers. Equipment inspections occur monthly by a contractor and are in good condition. The 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 firemain 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 NFPA standards and appears to be properly maintained.

2.4.7 Combustible Gas and H_2S Detection Systems: The islands are equipped with automatic combustible gas detection and alarm systems in each cellar. The sensors activate at 10% of the lower explosive limit (LEL) and at 60% LEL, which will activate the emergency shutdown (ESD) system. Currently LBU utilizes fixed H_2S detection on the wellheads of several high H_2S content wells located on Island Chaffee and along the East perimeter of the J-3 processing facility due to proximity to public areas. In contrast, the Pier J facilities have no combustible gas detection systems in place. When personnel are in the well cellars or the processing and storage facilities at Pier J, they must carry personal protective gas detection monitors. This includes the J-6 tank farm which is located a considerable distance from the other facilities.

On Island Chaffee staff observed that the control center was not equipped with a positive pressure air system. The control center is located adjacent to the Master Gas Scrubber and upwind of the automatic well test units (AWT's). No fixed LEL or H_2S detection exists to provide early warning to personnel inside the adjacent Control Center in the event of a gas release. An action item was issued to evaluate early warning for personnel in the Control Center or provide engineering justification for the lack of such protection. (TEC - 2.4.9.15) A window in the Control Center also appeared to be a potential blast hazard. An action item was issued to evaluate the potential hazard to personnel posed by the window. (TEC - 2.4.9.16)

LBU provided staff with a Facility Siting Study by Baker Engineering & Risk Consultants, Inc. dated November 2008. The Island Chaffee portion of the study showed that the blast hazard had been addressed and TEC - 2.4.9.16 was marked as cleared.

Although radius of exposure (ROE) calculations had been performed for H_2S as part of the siting study on the island locations, the audit team suggested that, as part of addressing action item TEC - 2.4.9.15, that the risks posed be fully evaluated using some type of hazard analysis so that the likelihood of exposure would be addressed. Some locations such as the Control Center, or areas where there is a concentration of personnel or frequent personnel transit in the vicinity of the identified ROE's should be evaluated for risk.

The island cellar combustible gas detection systems are tested on a monthly basis. CSLC and Long Beach Department of Oil Properties (LBDOP) staff witness all tests. Quarterly tests are also performed which include a witness from the Department of Oil, Gas, and Geothermal Resources (DOGGR). The sensors activate at 10% LEL for alarm and 60% LEL, whereupon they actuate the block & bleed system and shut down the wells in that particular cellar. There were no issues identified with these systems.

The Broadway & Mitchell Gas Plant (B&M) falls under OSHA and Cal OSHA Process Safety Management (PSM) regulations and must meet additional requirements to prevent or minimize the consequences of catastrophic releases of toxic or explosive chemicals. One requirement is that a process hazard analysis (PHA) is required to identify hazards in the process and must be revalidated every five years. The PHA revalidation, which used the HAZOP guideword method, dated September 2011 was reviewed as part of the audit. Recommendations from the revalidation were still being addressed. It appears that PSM regulations are being met.

2.4.8 Emergency Shutdown System (ESD): The LBU 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 LEL, fire detection, 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): LBU 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. LBU also considers the prevention of occupational injury and illness to be of such importance that it is given precedence over production.

OLBI 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 using appropriate PPE as required by company policy or where hazards are known to exist. PPE commonly used at these facilities include 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.

In reviewing the H_2S hazard and the response equipment provided on the islands, the audit team identified a difference in the first aid equipment available for treatment of H_2S inhalation compared to offshore platforms. For offshore platforms, where emergency medical assistance is not proximate or rapidly available, an oxygen resuscitator is required. LBU operating personnel advised that several years ago the company removed the emergency oxygen from the islands. Oxygen is a commonly recommended first aid treatment for H_2S inhalation. Although this decision may have been based on the capability of the Long Beach Lifeguard paramedics, it appears that response time may be significantly different from onshore locations. Onshore, OSHA permits companies to rely on trained emergency professionals located close to their facility; however, OSHA interpretation of “near proximity” is on the order of 3 to 4 minute response time. Response time to Chaffee appears to be at least 10 minutes or more. An action item was issued to re-evaluate providing oxygen resuscitation equipment based on this information. (TEC - 2.4.9.01) This equipment should also be considered for any of the island facilities posing similar H_2S danger, as well as provisions for training of personnel in the use of the oxygen resuscitation equipment and CPR.

2.4.10 Lighting: Fixtures installed throughout the facilities appear to be placed in a manner that provides adequate lighting levels for safely performing tasks. Pole-mounted fixtures with high-pressure sodium vapor lamps provide the area lighting. This method of artificial light appears to conform to work area lighting and hazardous conditions requirements. The electrical (ELC) portion of the safety audit evaluates lighting levels as sampled in several locations.

2.4.11 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 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.

2.4.12 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. LBU 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 manufactures’ recommendations and NFPA standards.

2.4.13 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 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.

2.4.14 Spill Response: Oil spill response for the LBU is outlined in the Long Beach Unit's Oil Spill Contingency Plan (OSCP) dated August 2010. The plan satisfies both federal and state regulations and is discussed in more detail in the Administrative Audit. The response equipment that is located on the islands is checked at periodic inspections throughout the year 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.

LBU 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 LBU's request. In the event that oil reached the water, operating personnel on the island facilities would deploy their boom to contain the spill until MSRC arrived 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, LBU schedules Qualified Individual notification checks, facility deployment drills and tabletop drills to test the incident command system. The entire response plan is tested on a triennial basis by either conducting a worst-case discharge drill or by ensuring that other portions of the plans components are exercised at least once during other drills occurring in the same three-year period.

2.5 Preventive Maintenance and Mechanical Reliability

The mechanical integrity section provides a general overview of management's philosophy and practices in controlling the maintenance function. The evaluation of LBU's maintenance activities also ensures mechanical equipment is operating to designed parameters and maintained in a manner appropriate for its intended application.

One of the most effective practices in use to manage the maintenance function is the utilization of a computer based maintenance program (Maximo) to schedule and track activities. All 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 LBU the flexibility to schedule and record these activities based upon manufacturer's recommendations, operating history, and recognized and generally accepted good engineering practices. LBU maintains tank and pressure vessel 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. LBU advises that commonly used parts and supplies are stocked on each island facility while critical spare parts are located in the warehouse.

LBU facility engineering has developed a risk management system for the various piping systems. These piping systems or sections of piping connect the wells via headers to the processing equipment yielding the various process streams that ultimately tie into the subsea lines. A risk level is established for the various sections of piping based on service and consequence of failure. When the risk level for a particular section of piping reaches an unacceptable level, engineers implement a corrective or mitigating action on that section of piping to lower the risk level to an acceptable level. The piping systems are re-evaluated yearly as the risk levels change with mitigation. This proactive approach to piping integrity and risk control has been enhanced in recent years and has produced positive results. A number of different methods are being used to improve the life of the various piping systems that include:

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

Baker Hughes provides the facility with a chemical treatment program that satisfies the operational needs of the LBU. A main component of the program is 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 anode system) 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 record keeping 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.

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 in diameter 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 routinely evaluated via periodic electronic smartpig inspection. Utility and inspection pigs are used as a maintenance tool for the in-service oil and gas-shipping lines from the Islands to onshore locations. 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 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.

The maximum allowable operating pressure of each pipeline is established based on these results and 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.

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 determine the effectiveness of the corrosion inhibitors. Because the subsea lines are buried, an external inspection is not possible; however, weekly visual line surveys by crew boat 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. OLBI has demonstrated that is has a very well managed pipeline maintenance program that takes appropriate actions to ensure a high degree of reliability from these lines.

2.6 Production Safety Systems

The audit team reviewed individual cause and effect charts for 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 MRMD required features. The islands have been evaluated to ensure they provide at least equivalent safeguards.

Oxy has designed processes to be inherently safe through the implementation of simpler process designs and by conducting PHA's early in the design to allow for inherent safety 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. Oxy 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 PLC's 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 (CPU) 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 recently updated automated control and safety systems were designed following appropriate industry standards. They feature an upgraded Human Machine Interface 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. 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 substantial 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 (PSV). Shut-in sensors are provided on the FWKOs and vent scrubber. The safety systems for the FWKO’s, 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 Switch High High (LSHH), Pressure Switch 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 Varec level indicators and valves are incorporated into the design to provide for an additional level of protection.

Pressure/vacuum valves prevent rupture of the tank from overpressure, or collapse of the tank from under pressure. These adequately sized 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 a pressure-vacuum relief valves, vapor recovery systems and high and low level alarms. The concrete firewall surrounding the stock tanks also provides secondary containment and is preferable to a low-level sensor when the normal flow of liquids prevents the sensors ability to detect a leak. Additionally, the level alarm highs and lows are displayed on Pier J computers via the PLC and Human Machine Interface 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 Human Machine Interface 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. 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

Oxy Long Beach, Inc.
Long Beach Unit

March 2013

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 Long Beach Unit (LBU) off shore and onshore facilities to determine if they conform to recognized and appropriate Codes and industry standards. The ELC System Audit included the electrical equipment located at onshore sites (Pier J1, 2, 3, 4, 5 and 6) and Broadway and Mitchell (B&M) gas processing facility. The offshore facilities included Islands Grissom, White, Chaffee, and Freeman.

Specific tasks to accomplish this goal on each location included a proven process of field verification of electrical single-line diagrams, plan drawings, area classification drawings, and a comprehensive use of inspection checklists, code and standard compliance checklists, and review of electrical system design for conformance to codes and standards. This report includes a summary of the electrical systems included in the audit.

3.2 Hazardous Area Electrical Classifications Drawings

The API recommended practices and California Electrical Code (CEC) requirements provide specific guidelines for the electrical classification of hazardous areas and installation practices for electrical equipment and materials within classified areas. The hazardous area electrical classification diagrams (HAECD) are generally representative of the existing conditions and have been revised when process systems were modified.

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

Portable chemical injection totes for oil and water treatment are located throughout the facilities. The totes are portable, but the locations of the tote installations by definition, are permanent. The lines, pumps, and fittings associated with the tanks are a source of hazard and require classification of the areas affected. (White - 3.2.28, 3.2.48)

General-purpose electrical equipment (Load Centers, MCC's, control panels, etc.) have been found to be located in classified areas. Electrical equipment that is not suitable for installation in a classified area will need to be relocated, and replaced with equipment that is suitable, purged, or non-permeable barriers will need to be installed. After updating and revising the area classification boundaries as required by the matrix and as described below, additional equipment may be identified as unsuitable and requires replacement. (White - 3.2.41, Freeman - 3.2.01, 3.2.07, B&M - 3.2.03, 3.2.15) As a result, the action items involving purged equipment and the use of a powered industrial truck used to lift and transport materials within classified areas at B&M have been resolved.

Edges or small portions of several buildings overlap the boundaries of classified areas requiring the buildings to become classified. The electrical equipment within the buildings is typically not suitable for classified areas. Some buildings, such as a Battery House, should be purged. Purged enclosures and buildings require UL listed purge systems and loss of purge alarms. Some buildings can avoid reclassification by ensuring natural ventilation is not restricted. Non-permeable barriers such as walls may be constructed to prevent transmission of hazardous concentrations into the building. (Grissom - 3.2.07)

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.

Conduit seals are required at classification boundaries. Locations where conduits originate outside of classified areas and travel through classified areas without the use of a box, fitting, or coupling may cross boundaries of Division 2 areas without a seal. Some required conduit seals are provided but not poured. Seals may need to be verified that they are poured. (Grissom - 3.2.01, Freeman - 3.2.22, B&M - 3.2.10)

3.3 Electrical Power Distribution System, Normal Power

3.3.1 Electrical Single Line: The electrical single-line drawings used for this audit of the facilities have been kept up-to-date and revised as system modifications have been made. The drawings represent the electrical power system well. The audit focused on the 12,000V, 4160V and 480V distribution systems and excluded lower voltage systems. The drawings were generally available and located in the electrical foreman's office and on the facility network.

3.3.2 Electrical Service Capacity: The onshore and offshore facilities receive power from Southern California Edison (SCE). The islands receive power at 66kV from two (2) SCE oil-filled submarine cables. The shore facilities receive 12.47kV from SCE over a single power line. All facilities utilize power at 4160V or 480V through a LBU operated and maintained radial distribution system to supply plant loads.

Emergency power is limited to one or two generators at each location that provide backup power for specific loads such as the Barge Ramp or Fire Pump and do not support production or process equipment. Emergency power systems are discussed in Section 3.6.

The power system capacity, in general, appears to be adequate. Transformers have been replaced with new fan-cooled units that have higher kVA ratings. The new transformers have been installed to address prior audit findings regarding excessive operating temperatures and because of increased loads. The Gear and Williams (G&W) oil switches that are used to supply power to rig feeders should be replaced. The switches no longer comply with code and standard functional requirements and have been recalled by the manufacturer. Since this is a recommendation only, no action item was generated.

3.3.3 Electrical System Design: Power for the islands is delivered from SCE Pico Substation over two (2) 66kV submarine, oil-filled power cables. The two lines run into each island where two step-down transformers 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.

Electrical power for B&M and Pier J shore facilities is supplied by SCE from the Pico substation on one of several SCE lines. Pier J and B&M receive power from SCE at 12.47kV. Step-down transformers owned by the LBU supply three-phase power at 4.16kV and 480V to the facility loads. Facility loads requiring a 208/120V supply are served by LBU owned transformers located near the loads.

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 maintenance has been integrated into the MAXIMO computer database and tracked. LBU has performed extensive maintenance and inspection activity during scheduled shutdowns. (White - 3.4.02)

The original installation included the installation of power factor correction capacitors to improve power factor and increase system power capacity. These capacitors are not readily accessible and, as installed, would result in a lengthy outage if they failed. It is recommended they be removed and relocated if needed. Consequently, the capacitors are being removed when the transformers are de-energized during the Island shut-ins. (White - 3.4.58)

The electrical equipment is labeled with arc flash hazard warning labels. Each label is specific to each piece of equipment. LBU has implemented a comprehensive training program to educate and inform all workers of the hazards associated with electrical systems and also train them with the proper and mandatory use of personal protective equipment (PPE). (White - 3.3.3.28, 3.7.01, Freeman - 3.4.03)

3.4 Electrical Power Equipment Condition and Functionality

The overall condition of the electrical equipment can be rated as good. The existing equipment is a mix of original and new. The original equipment is being maintained in good working order. There were a few instances noted where equipment had deteriorated as a result of the harsh marine environment and operating conditions, but overall, the equipment is being adequately maintained. (White - 3.4.27) There were also several instances of missing covers that required replacement to eliminated shock hazards. (White - 3.4.22)

The cellars include explosion-proof junction boxes that have been in service for many years. The boxes are subject to damage as a result of drilling activity. The damage noted is typically related to the detachment of the box from the cellar wall, where the mounting tabs are broken. This is an ongoing condition and is being addressed by LBU.

The electrical conduit manholes on the islands require repair. LBU has completed an assessment of all manholes, prioritized replacement and repair based on condition, and is in the process of completing the necessary repairs. The repairs have been designed by a structural engineer to assure the manholes will withstand the physical forces imposed on them. (Grissom - 3.4.87, 3.4.88, Pier J1 - 3.4.04)

The electricians follow a mandatory set of procedures designed to enhance personnel safety and reduce the potential for shock and injury. Electricians are responsible to complete a task checklist prior to beginning any work. The checklist includes identification of hazards that might be associated with the task and the measures to be employed to minimize the hazard, including PPE.

A lock-out tag-out program is well documented and implemented. The use of three-way and four-way gas detectors is required for entry to cellars and confined spaces and for hot work in classified areas. All electrical equipment is labeled with arc flash hazard labels. The labels identify the required personal protective equipment based on the incident energy available at each location.

The working clearance required around electrical equipment is maintained, however, there were a few instances where trip hazards or inadequate clearance was maintained.

There were a number of instances where either outdated or missing panel schedules were observed. LBU has made a concerted effort to update the panel schedules. This is an ongoing effort. It is also recommended that equipment identification labels be consistent with the electrical single-line diagrams, as well as the established naming convention. (White - 3.3.3.20)

3.5 Grounding

Three specific types of grounding are required at the facilities; power system grounding, safety or equipment grounding, and static grounding. Separately derived systems at 480Y/277V, 240/120V, and 208Y/120V are either ungrounded or solidly grounded and satisfy Code requirements for power system grounding. Equipment and static grounding conductors are generally adequate except as noted in the matrix.

The panelboards installed in the Auxiliary Motor Control Center (AMCC) equipment do not have a ground conductor bus bar. As a result, panelboards should be verified for the installation of ground bus bars to avoid code noncompliance. (Chaffee - 3.5.12, White - 3.5.2)

Chemical dispensing and storage areas require a ground bonding conductor connection to the grounding electrode system and the plant ground grid as well as a ground loop around all chemical storage areas for temporary bonding and static bonding of individual tanks and delivery trucks. The ground bonding provisions for chemical storage tanks require regular verification. (Freeman - 3.5.01, 3.5.17, Chaffee - 3.5.05, Pier J5 - 3.5.05) While there is a written procedure in-place for regular verification of temporary and static bonding on chemical totes, it appears that the chemical contractor may not consistently follow the safe work practice.

3.6 Emergency Electrical Power

Emergency generator power is provided on the islands for a few electric driven loads such as a backup fire pump and the barge ramp. Pier J and B&M production and process equipment have no auxiliary electrical power supply and are not provided with standby or emergency power API RP 14J and 14F recommends that AC electrical safety control systems for offshore platforms, be supplied through a battery charger-inverter system, or UPS, and that DC controls have a reliable DC supply.

CSLC MRMD regulation 2132 (g)(7) requires “an auxiliary electrical power supply shall be installed to provide sufficient emergency power for all electrical equipment required to maintain safety of operation in the event the primary electric power supply fails”. However, the uniqueness of the Oxy islands, facility design, risk management and provisions for emergency power render the present arrangement adequate and not subject to the regulation.

Present generators on the islands are sized to provide backup power for either the boat ramp loads or the fire pump but not both simultaneously. The transfer switch for selection between the normal and auxiliary sources is manual. Generator startup is automatic on loss of the normal source but the transfer from the normal source to the emergency source is manual. The control rooms at each facility have UPS units installed to provide limited PLC operation during a power outage.

It was noted during the audit that the switching procedures and wiring configuration for the island generator installation are not consistent with the single-line diagram. The single-line diagram requires revision. (White - 3.3.1.09, 3.6.02, B&M - 3.6.01, 3.6.03)

Area lighting, communication, fire alarm, smoke detection, combustible gas, and general alarm systems are not, in general, supplied by emergency power systems. Battery supplied UPS systems and DC control systems are not backed up by a standby or emergency power generator, but do have manual transfer switch provision for the connection of temporary portable generators. Upon loss of normal power, the connected loads are de-energized. Where UPS systems are installed, they should continue to supply the load throughout the disturbance and have a capacity adequate for the discharge rate of the load served. Furthermore, Oxy facilities have experienced total utility outages without any impact to surrounding areas or air quality.

Generator testing records reviewed show that load and routine tests are being performed. The generators should continue to be tested on a routine basis and operated under full load periodically.

3.7 Electric Fire Pumps

The purpose of the Electric Fire Pump on each island is to supply water to fire hydrants strategically located around the island. 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 ramp but not both simultaneously. (Freeman - 3.7.01)

3.8 Process Instrumentation

The process control system uses a combination of pneumatic, hydraulic and electrical instruments and controls. It includes the use of computers, Programmable Logic Controllers (PLC) and relay logic to control and interface with valves, solenoids and pump controllers.

Alarms from level, temperature, pressure and flow sensors, report to a PLC, advising operators of process conditions.

Process monitoring is accomplished using computer terminal screen displays and the annunciator panel, which are located in the Main Control Room on each island, Pier J, or B&M. Additionally, operators routinely conduct process 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.

A SCADA system is installed for the remote monitoring of producing wells. The SCADA system monitors voltage, amperage, power factor, and pump status with annunciation for over/undervoltage and overload conditions. Data acquisition for a 30-day period is available for trend analysis of individual wells. This system provides enhanced capability for operator surveillance of producing wells. The process control wiring generally complies with the code. Intrinsically safe systems comply with CEC Article 504 requirements. (Chaffee - 3.3.3.01)

3.9 Standby Lighting

The recommended illumination levels are provided in API RP 540, Electrical Installations in Petroleum Processing Plants. The light levels in the Cellars should be a minimum of five foot-candles for manifolds, pump-rows and valves. Active stairs, operating platforms, gauge glasses, instruments, and separators should have a minimum of five foot-candles per API RP 540. LBU staff should conduct a comprehensive lighting audit and take corrective action to eliminate areas with low lighting levels.

Emergency lighting is limited and there are very few area lights that are connected to a standby or emergency source. A HAZOP may be used to evaluate the need for improved emergency lighting. Additional perimeter lighting should also be considered for improved security at Pier J1, 2, 3, 4, 5, 6 and B&M. A mix of incandescent, fluorescent, high-pressure sodium, and metal halide lighting is used throughout the facility. A large number of work or task lamps were found to be burnt out, requiring replacement.

Wiring between the final junction box and the light fixture must have a temperature rating at least as high as the light fixture nameplate requirement. Numerous light fixtures require wire to have insulation with a 125°C rating but have 75°C wiring installed. Oxy should verify wire insulation rating during fixture installation and include the requirement to use properly rated wire in work orders.

3.10 Special Systems

3.10.1 Safety Control Systems: Safety control systems are required to be a collection of devices arranged to effect plant 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. The island emergency shutdown system logic is programmed in a PLC system. Additional documentation is needed to evaluate Alarm and Shutdown systems for compliance with applicable industry standards. (B&M - 3.10.1.01 - 3.10.1.03)

3.10.2 Gas Detection Systems: Combustible Gas detection systems, LEL and H_2S, are employed to detect combustible gas leaks in equipment and piping, to warn personnel of possible toxic concentrations and to initiate remedial action. LEL and H_2S detectors are installed in the island cellars and tested on a regular basis.

3.10.3 Fire Detection Systems: Fire detection and smoke detection is normally employed on offshore facilities to detect and warn personnel of possible fire and to initiate remedial action per API RP 14J. Pier J6 tank farm is equipped with fire-eye detectors. No other fire-eye detectors are installed at any of the facilities. Smoke detectors and alarms are not provided for most buildings and structures in the facility except for the sleeping quarters of drilling crews and well work supervisors. The Long Beach Fire Department conducts annual inspections to verify that the facilities meet the local requirements. Except as noted, fire detection systems are not required nor present at the facilities. Since there are many unmanned or essentially unmanned areas in all of the facilities, fire detection depends primarily on operators and contractors to report a fire.

3.10.4 Aids to Navigation: The US Coast Guard requires aids to navigation in offshore facilities close to the shore to include obstruction lights. The four-lamp navigation beacon is equipped with an automatic lamp transfer feature. All beacons appeared to be functioning properly at the time of this audit. The beacons require periodic maintenance to confirm proper operation and are included in MAXIMO.

3.10.5 Communication: Communications systems are established to provide for normal and emergency operations. Systems used for emergency communication should have battery-operated power supplies good for at least four hours of continuous operation as required by API RP 14F. Landlines, microwave, wireless radio, cellular phones, and computer networks are available 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 are used in some cases with the audible alarms. A sign in red letters at least one inch high describing the required personnel response at each device shall identify all General Alarm sounding devices. It is recommended the central paging system be used to supplement instructions of a general alarm. Alarms were tested and found to demonstrate adequate performance.

3.10.7 Cathodic Protection: The majority of cathodic protection equipment at various locations appears to be out-of-service. Many of the Cathodic Protection rectifiers were out-of-service with electrode lead wires not terminated. In addition, some of the meters were found to be broken. Systems that are not functional should be repaired or removed.

Safety Management Audit

Oxy Long Beach, Inc.
Long Beach Unit

March 2013

4.0 SAFETY MANAGEMENT AUDIT

4.1 Goals and Methodology

The goal of the safety management programs audit was to verify that THUMS uses safety management programs similar to API RP 75 SEMP, OSHA Process Safety Management, or other commonly used or industry recommended safety management programs to identify and mitigate environment, health and safety risks. The audit began with the review of the Operations Manual, other required emergency and spill response plans, training programs, and other key elements before considering the specific other programs that THUMS uses to fill out the remaining areas that are addressed by their Safety and Environmental Management Program for the Long Beach Unit (LBU).

4.2 Operations Manual

THUMS has a system in place for determining what procedures or processes need to be documented. These Standard Operating Procedures (SOPs) are written by individuals knowledgeable with the process and its hazards. These individuals are also familiar with the subject-matter and have actually performed the work or operated the process. The SOPs are written in a concise, step-by-step, easy-to-read format with sufficient detail so that someone with limited experience with or knowledge of the procedure can successfully carry out the process when unsupervised. In addition, the information presented was clearly written and not overly complicated. Illustrations are also used to help understand the procedures being described. THUMS SOPs appear to fulfill the requirements of MRMD Regulation 2175 and OSHA's PSM standard.

The SOPs are maintained via the company intranet system with hard copy versions located in island and pier control rooms. These SOPs are reviewed for accuracy by individuals possessing the appropriate training and experience with the process. Whenever procedures are changed, SOPs are updated and re-approved with the change date/revision number for that section in the Table of Contents and a document control notation. SOPs are also systematically reviewed annually, with hard copies being updated every 1-2 years, to ensure that the policies and procedures remain current. 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

THUMS Oil Spill Contingency Plan (OSCP) was developed in accordance with Federal and State Facility Response Plan requirements. The document defines procedures and plans for responding to discharges of oil into navigable waters and seeks to minimize damage to the environment, natural resources, and facility installations. The plan covers LBU's four islands, onshore facilities and pipelines. The following elements are addressed within the plan:

- Facility description
- Hazards Evaluation Study and potential worst case spill scenario evaluation
- On-water containment and recovery procedures
- Shoreline protection and clean-up

- Wildlife Care and Rehabilitation Procedures
- Response procedures

Also contained within the OSCP are operating procedures the facility implements to prevent oil spills, control measures installed to prevent oil from entering navigable waters or adjoining shorelines; and countermeasures to contain, cleanup, and mitigate the effects of an oil spill that could have an impact on navigable waters or adjoining shorelines. THUMS OSCP has a long approval history and meets federal (40 CFR Section 112.5) and State Office of Spill Prevention and Response (OSPR) requirements. THUMS staff is familiar with the OSCP and conducts annual spill drills to increase the effectiveness of their spill response.

4.3.1 EPA Spill Prevention Control and Countermeasure (SPCC): The SPCC Plan is an Environmental Protection Agency (EPA) requirement. Electronic versions of the SPCC Plans were reviewed for compliance and found to meet the EPA Rule. Oxy's SPCC Plan is prepared in accordance with good engineering practices and includes spill prevention procedures, control measures installed to prevent a spill from reaching navigable waters, and countermeasures to contain, clean up, and mitigate the effects of an oil spill that reaches navigable waters. The SPCC Plan is also approved by THUMS management and is certified by a licensed professional engineer.

4.4 Training and Drills

Annual training in hazard communication, incipient firefighting, personal protective equipment (PPE), Control of Hazardous Energy (Lockout/Tagout), confined spaces, hot work, respiratory protection, hydrogen sulfide, and first aid/CPR is conducted to satisfy Cal OSHA safety and health training requirements.

Facility training combines classroom activities with on-site facility instruction. Computer based instruction alerts personnel to upcoming training requirements and maintains a history of all training activities. Some of the basic training provided includes: Confined Space Entry, DOT Pipeline Operations, Oil Spill Drills, First Aid/CPR Medic Inclusive, incipient firefighting, Hazardous Communications, Hazardous Waste Operations and Emergency Response (HAZWOPER), Hot Work Permitting, H_2S, Control of Hazardous Energy (Lockout/Tagout), and Process Safety Management. Mandatory OSHA and spill response training is also provided. Each level of training requires successful completion and a field competency demonstration before advancement to the next level can occur.

Spill response team members receive training to perform the tasks required of them based upon their job description and responsibility. This training consisting of classroom instruction, field briefings, exercises, tabletop drills and equipment deployment drills. Drills, safety meetings, evacuation and environmental training are conducted throughout the year. These drills are used to gauge functionality, maintain readiness and are documented and reviewed by management.

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

4.5 Safety Management Programs

In order to control workplace hazards, Oxy has a corporate program that parallels the OSHA Process Safety Management (PSM) standard. The major additional elements brought by Oxy's program consist of a detailed mechanical integrity program for all process equipment, a system for operating procedures, training, emergency response, compliance audits, contractor safety and process hazards analysis programs. While the majority of THUMS facilities, with the exception of the Broadway & Mitchell gas processing facility, are not bound by PSM, THUMS has voluntary integrated their corporate program into its non-covered sites. This practice has improved their operating reliability, system operating efficiency and reduced incidents involving the release of hazardous materials beyond its facility boundaries.

THUMS safety policy sets a clear direction for the organization to follow and contributes to all aspects of business performance as part of a commitment to continuous improvement. The objective of their safety policy is to set down in clear-cut terms its management's approach and commitment to health and safety at their facilities. The organization's senior management has defined, documented and endorsed its safety policy which includes a commitment to:

- Recognizing health and safety in the workplace as an essential part of its business performance
- Achieving a high level of occupational health and safety performance in compliance with regulatory requirements as the minimum
- Providing adequate and appropriate resources to implement the safety policy
- Making the management of health and safety one of the prime responsibilities of all employees and contractors

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 Oxy's safety policy; and the measuring, auditing or reviewing of the performance of those functions.

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

Human Factors Audit

Oxy Long Beach, Inc.
Long Beach Unit

March 2013

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 a benchmark for future assessments.

5.2 Human Factors Audit Methodology

The CSLC Mineral Resources Management Division will schedule the SAMS interviews with LBU staff and sub-contractors after completion of the safety and oil spill prevention audit. Interview responses will be evaluated according to SAMS guidelines and a separate confidential report summarizing the results will be generated. The MRMD staff will provide the confidential report accompanied by a formal presentation that summarizes the report to LBU management.

Appendices

Oxy Long Beach, Inc.
Long Beach Unit

March 2013

TEAM MEMBERS

FACILITY CONDITION TEAM

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry Steve Staker
LBU	Clint Harris Bill O'Toole Julian English Kathye Griffis
LBGO	Carlos Carrion

ELECTRICAL TEAM

CSLC – MRMD	Mark Steinhilber David Rodriguez
PES	Doug Effenberger
LBU	Rey Navarro Julian English
LBGO	Carlos Carrion

TECHNICAL TEAM

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry Steve Staker
LBU	Clint Harris Bill O'Toole Julian English Kathye Griffis
LBGO	Carlos Carrion

SAFETY MANAGEMENT TEAM

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry Steve Staker

LBU	Clint Harris Bill O’Toole Julian English
LBGO	Carlos Carrion

ACRONYMS

ADM	Administration
ANSI	American National Standards Institute
API	American Petroleum Institute
BAT	Best Achievable Technology
CEC	California Electrical Code
CFC	California Fire Code
CSLC	California State Lands Commission
EFI	Equipment Functionality and Integrity
ELC	Electrical
ESD	Emergency Shutdown
ESP	Electric Submersible Pump
FSL	Flow Safety Low
FSV	Flow Safety Valve
HF	Human Factor
H_2S	Hydrogen Sulfide
kVA	KiloVolt Amperes
kW	Kilowatts
LACT	Lease Automatic Custody Transfer
MOC	Management of Change
MRMD	Mineral Resources Management Division
NEC	National Electrical Code
NFPA	National Fire Protection Association
OSHA	California Occupational Safety & Health Administration
OSPR	Office of Spill Prevention and Response
P&ID	Piping and Instrumentation Diagrams
PHA	Process Hazard Analysis
PM	Preventative Maintenance
PPE	Personal Protective Equipment
PRC	Public Resources Code
PSH	Pressure Safety High
PSHL	Pressure Safety High-Low
PSI	Pounds per Square Inch
PSL	Pressure Safety Low
PSM	Process Safety Management
PSV	Pressure Safety Valve
RP	Recommended Practice
SAFE	Safety Analysis Function Evaluation
SAC	Safety Analysis Checklist
SAMS	Safety Assessment of Management Systems
SCADA	Supervisory Control and Data Acquisition
SCBA	Self Contained Breathing Apparatus
SCE	Southern California Edison
SSV	Surface Safety Valve
TEC	Technical
UBC	Uniform Building Code
UFC	Uniform Fire Code
VSD	Variable Speed Drive

REFERENCES

GOVERNMENT CODES, RULES, AND REGULATIONS

Cal OSHA — California Occupational Health and Safety

3215	*Means of Egress*
3222	*Arrangement and Distance to Exits*
3225	*Maintenance and Access to Exits*
3308	*Hot Pipes and Hot Surfaces*
3340	*Accident Prevention Signs*
5189	*Process Safety Management of Acutely Hazardous Materials*
6533	*Pipe Lines, Fittings, and Valves*
6551	*Vessels, Boilers and Pressure Relief Devices*
6556	*Identification of Wells and Equipment*

CCR — California Code of Regulations

1722.1.1	*Well and Operator Identification*
1774	*Oil Field Facilities and Equipment Maintenance*
1900-2954	*California State Lands Commission, Mineral Resources Management Division Regulations*

CFR — Code of Federal Regulations

29 CFR	*Part 1910.119 Process Safety management of Highly Hazardous Chemicals*
30 CFR	*Part 250 Oil and Gas Sulphur Regulations in the Outer Continental Shelf*
33 CFR	*Chapter I, Subchapter N Artificial Islands and Fixed Structures on the Outer Continental Shelf*
40 CFR	*Part 112, Chapter I, Subchapter D Oil Pollution Prevention*
49 CFR	*Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standard*
49 CFR	*Part 195, Transportation of Liquids by Pipeline*

INDUSTRY CODES, STANDARDS, AND RECOMMENDED PRACTICES

ANSI — American National Standards Institute

B31.3	*Petroleum Refinery Piping*
B31.4	*Liquid petroleum Transportation Piping Systems*
B31.8	*Gas Transmission and Distribution Piping Systems*
Y32.11	*Graphical Symbols for Process Flow Diagrams*

API — American Petroleum Institute

RP 14B	*Design, Installation and Operation of Sub-Surface Safety Valve Systems*
RP 14C	*Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms*
RP 14E	*Design and Installation of Offshore Production Platform Piping Systems*
RP 14F	*Design and Installation of Electrical Systems for Offshore Production Platforms*
RP 14G	*Fire Prevention and Control on Open Type Offshore Production Platforms*
RP 14H	*Use of Surface Safety Valves and Underwater Safety Valves Offshore*

RP 14J	*Design and Hazards Analysis for Offshore Production Facilities*
RP 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*
RP 570	*Piping Inspection Code*
RP 651	*Cathodic Protection of Aboveground Petroleum Storage Tanks*
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

BEST ACHIEVABLE PROTECTION CRITERIA

1.0	**CODE AND REGULATIONS FOR BEST ACHIEVABLE PROTECTION**	
1.1	Best Achievable Protection/ Best Achievable Technology	PRC 8750
	Inspection of Marine Facilities	PRC 8757
	DOG Oil & Gas Regulations	DOG 14 CCR 1740-1779
2.0	**FACILITY CONDITION AUDIT**	
2.1	Methodology for Audit	
2.2	General Facility Conditions	
2.2.1	*Housekeeping*	DOG 14 CCR 1740.1 & 1743
2.2.2	*Stairs, Walkways, Gratings, & Ladders*	CAL OSHA Title 8 CCR
2.2.3	*Escape/ Emergency Egress/ Exits*	CAL OSHA 3215, 22, 25, 6577
2.2.4	*Labels, Placards, & Signs*	CAL OSHA & API RP 14J
2.2.5	*Security*	DOG 14 CCR 1743 (b), 1774, 1778
2.2.6	*HAZMAT Storage*	
2.3	Field Verification of Plans	
2.3.1	PFDs	API RP 14J
2.3.2	P&ID	API RP 14J
2.3.3	Fire Protection Drawings	API RP 14J (6.4.3)
2.4	Condition and Integrity of Major Systems	
2.4.1	*Piping*	ANSI 31.3
2.4.2	*Tanks*	API Spec 12 R1 API RP 653, DOG 14 CCR 1747.1
2.4.3	*Pressure Vessels*	ASME Boiler & PV Code Sect. VIII API RP 510 PV Insp Code DOG 14 CCR 1747.1
2.4.4	*Pressure Relief, PSVs and Flare Sys*	API RP 14J API RP 520 API RP 521 API RP 576, DOG 14 CCR 1747.1
2.4.5	*Fire Detection*	DOG 14 CCR 1747.5 & NFPA
2.4.6	*Fire Fighting Equipment and Systems*	DOG 14 CCR 1747.5 & NFPA
2.4.7	*Combustible Gas & H_2S Detection*	DOG 14 CCR 1747.6
2.4.8	*Emergency Shutdown Device*	DOG 14 CCR 1747.2 & API RP14J
2.4.9	*Safety & Personnel Protective Equip*	CAL OSHA
2.4.10	*Lighting*	CAL OSHA
2.4.11	*Instrumentation, Alarm, & Paging*	DOG 14 CCR 1747, API RP 14J, & 8CCR 5189
2.4.12	*Auxiliary Generator Prime Mover*	DOG 14 CCR 1747.4
2.4.13	*Spill Containment*	40 CFR 112.7 (c), DOG 14CCR 1750-1779, GOV CODE 8670
2.4.14	*Spill Response*	GOV CODE 8670
2.4.15	*Cranes*	API RP 2C & 2D
2.4.16	*Blow Out Prevention*	DOG 14 CCR 1747
2.4.17	*Compressors*	CAL OSHA 8 CCR 461-465

2.5 Mechanical Integrity	CAL OSHA, 8 CCR 5189 (j), DOG 14 CCR 1747
2.5.1 ESP, Pump Units & Wellhead Equip	DOG 14 CCR 1747
2.6 Offshore Production Safety Systems	DOG 14 CCR 1747 API RP 14C* API RP 14J 29 CFR 1910 API RP 75 **as applicable to Island Facilities*
Onshore Production Safety System	CAL OSHA 8 CCR 5189 29 CFR 1910 DOG 14 CCR 1712 - 1724 API RP 51
2.7 Process Hazards Analysis	CAL OSHA 8CCR 5189 (e) API RP 75 API RP 14J PRC 8758 Gov Code 8670.28 (a)(7)

3.0 ELECTRICAL AUDIT

3.1 Goals and Methodology

3.2 Electrical Hazardous Area Classification Dwgs — API RP 500, NFPA 70

- *Level of classification*
- *Extent of classification*

3.3 Electrical Power Dist. System, Normal Power — API RP 540, NFPA 70

3.3.1 System Configuration

3.3.2 Equipment and Component Ratings

3.3.3 *System Electrical Design Safety*

- *System protection*
- *Operational safety*
- *Reliability*

3.3.4 Grounding (system and equipment)

3.4 Elec. Power Equip Condition and Functionality — API RP 540, NFPA 70

3.4.1 Wiring Methods and Enclosures materials and installation)

- *Classified locations*
- *Unclassified locations*

3.4.2 Safety Procedures

- *Lockout tagout procedures*
- *Electrical safety training*
- *Extension cord and portable equipment testing*

3.5 Emergency and Standby Power (including batteries, chargers and uninterruptible power supplies) — NFPA 70, NFPA 110

3.5.1 System Configuration

3.5.2 Equipment and Component Ratings

3.5.3 Electrical System Design Safety

- *System protection*
- *Operational safety*

3.6 Electric Fire Pump System — NFPA 20, NEC 696

- *Starter equipment and controls*
- *30 minute fire rated wiring*

3.7 Process Instrumentation Wiring Methods, Materials and Installation — API RP 540, NFPA 70

- *Classified locations*
- *Unclassified locations*

3.8 Standby Lighting — DOG 14 CCR 1743 (a)-(c)
IES RP 7

- *Fixture locations, type*
- *Operation*
- *Lighting levels*

3.9 Special Systems

3.9.1 Safety Control Systems, Electrical Shutdowns — DOG 14 CCR 1743&1747
API RP 14J
API RP 75
Gov Code 8670
ISA RP7.1, RP 12.1, 12.2
ISA S7.4, S12.4

- *System configuration*
- *System component types and locations*
- *System devices and wiring*
- *Review testing records*

3.9.2 Gas Detection System — DOG 14 CCR 1747.6
API RP 14J

- *System configuration (SD devices normally energized, fail safe)*
- *System component types and locations*
- *System devices and wiring*
- *Review testing records*

3.9.3 Fire Detection System — API RP 14J,
DOG 14 CCR 1743&1747
API 2001
API RP 75

- *System configuration (8 hour backup power)*
- *System component types and locations*
- *System devices and wiring*
- *Review testing records*

3.9.4 Aids to Navigation — USCG 33 CFR Subcp. C, Part 67

- *System component types and locations*
- *Suitable enclosures*
- *Circuit voltage drop less than 2.5%*
- *Coast Guard records*

3.9.5 Communication Equipment

- *4 hour battery operation*

3.9.6 General Alarm System

- *System configuration*
- *System component types and locations*
- *System devices and wiring*
- *Review testing records*

3.9.7 Cathodic Protection API RP 651, NACE RP 01-76, NACE RP 0675

- *System components*
- *Equipment and wiring complete / operational*

4.0 SAFETY MANAGEMENT AUDIT

4.1	Goals and Methodology	API RP 75 SEMP OSHA 29 CFR 1910.119 CAL OSHA 8 CCR 5189
4.2	Operations Manual	OSPR PRC 8758
4.3	Facility Oil Spill Response Plan	OSPR GOVC 8670
	4.3.1 Spill Prevention Control & Countermsr Plan	40 CFR 112.7
4.4	Training and Drills	DOG 14 CCR 1747.5 OSPR GOVC 8670

5.0 HUMAN FACTORS AUDIT

5.1	Process Safety Management	CAL OSHA 8 CCR 5189 API RP 75 CSLC Safety Audit of Mgmt Systems (SAMS)