National Transportation Safety Board

Office of Railroad, Pipeline and Hazardous Materials

Washington, DC 20594

DCA22FM001

PIPELINE OPERATIONS

Group Chair's Factual Report

August 28, 2023

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ACCIDENT

Location: Newport Beach, California
Date: October 2, 2021
Time: 08:09
Pacific Daylight Time

PIPELINE OPERATIONS GROUP

Group Chair	Kim West National Transportation Safety Board Federal Way, Washington
Group Member	[redacted] United States Coast Guard San Pedro, California
Group Member	Brian Pierzina Pipeline and Hazardous Materials Safety Administration Oklahoma City, Oklahoma
Group Member	Junaid Ashfaq Bureau of Safety and Environmental Enforcement Camarillo, California
Group Member	Jeff Ortloff Amplify Energy Corp. Houston, Texas

SUMMARY

On Saturday, October 2, 2021, at 08:09 pacific daylight time, Beta Offshore confirmed that their 16-inch diameter San Pedro Bay Pipeline released crude oil into the waters of the Pacific Ocean about 4.75 nautical miles off the coast of Huntington Beach, California [1] The pipeline failure resulted in a 588-barrel release of crude oil which contaminated portions of the nearby California shoreline. A unified command (UC) was formed consisting of local, state, and federal agencies and Amplify Energy Corp who responded to the scene. Including amongst the agencies was the Coast Guard, Bureau of Safety and Environmental Enforcement, National Oceanic and

[1] All times referenced in this report are Pacific Daylight Time unless otherwise noted.

Atmospheric Administration, Pipeline and Hazardous Materials Safety Administration, California Department of Fish and Wildlife (CDFW), and local law enforcement.

Beta Offshore sent a dive team 95 feet below the water surface, who discovered the source of the leak stemmed from a 21 – 3/8-inches linear crack on the pipeline near where the crude oil was leaking. The crack was located near the top of the pipe, and a gouge crossing over the weld seam. The pipeline was found to be dented around the crack location and the concrete weight coat had broken off in the vicinity of the crack location. An underwater survey over the effected portion of the pipeline showed a 4,025-foot section of pipeline had a maximum displacement of 105 feet over a portion of the pipeline from its original position on the right-of-way, and there was evidence of seabed scars/scouring adjacent to, and in the vicinity of the damage. After determining that the leak was potentially caused by anchors being dragged over the pipeline by vessels subjected to strong winds, the US Coast Guard declared the incident a Major Marine Casualty.

In response to the release, Beta Offshore created a negative pressure that suctioned the crude oil in the pipeline and slowed the rate of release. Clean up efforts continued after the release, whereby over 132 barrels were recovered. Twenty-four wildlife and sea life species were impacted by the spill. A second release was discovered on November 20, 2021, when Beta Offshore divers re-inspected the crack, and they found a 30-foot x 70-foot oil sheen on the water that leaked from a previously applied wrap over the crack area.

There were no injuries or fatalities as a result of the release.

ACCIDENT LOCATION

The release of crude oil occurred on the 16-inch diameter San Pedro Bay pipeline about 4.75 miles off the California coastline in federal waters.[2] At this location, the pipeline is in about ninety-five feet of water and sits on the ocean floor. The damaged portion of the pipeline was outside of the 3-Nautical Mile Coastal Boundary. Where the release occurred, a portion of pipeline had deviated from its original position in the right-of-way by 105 feet to the east. The crude oil that had been released from the pipeline and migrated to the water surface, where an oil sheen was discovered in an

[2] Submerged Lands Act (SLA) of 1953, 43 U.S.C. § 1301 et seq., is a U.S. federal law that recognized the title of the states to submerged navigable lands within their boundaries. Submerged navigable lands include navigable waterways, such as rivers, as well as marine waters within the state's boundaries, generally three geographical miles (3 nautical miles or 5.6 kilometers) from the coastline. There is now a fixed boundary approximately 3 nautical miles off the coast of California extending from Mexico to Oregon, providing certainty to state and federal lessors, regulators, lessees, and operators of federal and state mineral and renewable-energy leasing programs. USA v. State of California, 135 S. Ct. 563; 190 L. Ed. 2d 514; 2014 U.S. LEXIS 8436 (2014).

area about 60-foot wide by 1-1/2-miles, located about 4.5 miles south of the *Platform Elly*.[3] See the pipeline release location in shown Figure 1.

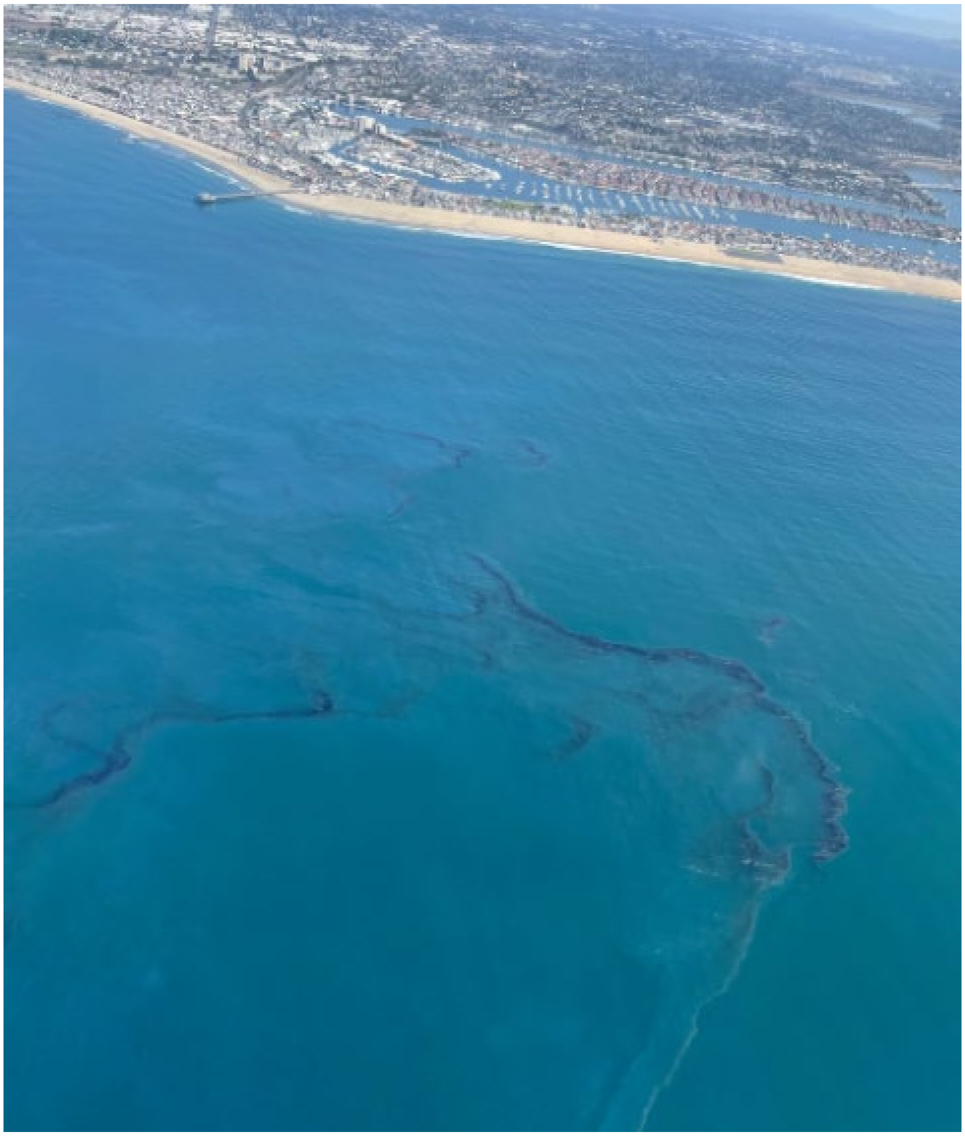

Figure 1. Crude oil is shown in the Pacific Ocean offshore of Orange County, Oct. 3, 2021. Photograph courtesy of U.S. Coast Guard.

[3] *Platform Elly* is a processing platform that separates the oil, gas, and water and pumps the oil through the San Pedro Pipeline, which originates on the Outer Continental Shelf off the California coastline. It is operated by Beta Offshore.

PIPELINE OPERATOR

The San Pedro Bay Pipeline Company is a corporation that owns the San Pedro Bay Pipeline (SPBPL) under the ownership of Amplify Energy Corp (Amplify), the parent company. Amplify is an independent oil and natural gas company engaged in the acquisition, development, exploration and production of crude oil and natural gas properties. Amplify has assets in Oklahoma, the Rockies, the Eagle Ford, East Texas / North Louisiana, and federal waters offshore in southern California. Amplify is headquartered in Houston, Texas.

Beta Operating Company, LLC (d.b.a. "Beta Offshore" or "Beta") is a wholly owned subsidiary of publicly traded Amplify Energy Corp. Beta Offshore is a local oil and gas production company (upstream) based out of Long Beach, California, and an oil sales facility in the Port of Long Beach. Beta Offshore has operational assets located on three offshore fixed platforms in the federal Outer Continental Shelf about twelve miles south of Long Beach and nine miles west of Huntington Beach. Beta Offshore operates the SPBPL.

In the 1980s, Shell Oil Company developed the Beta Offshore oil field, and it has been in operation since. Shell California Production Inc. assumed operation in 1984, following up with Shell Western E&P Inc., who assumed operation in 1987. In 1993, Shell assigned its rights as a rate structured and prorated system in the San Pedro Bay Pipeline Company and the pipeline became a common carrier pipeline.[4,5] In 1995, CalResources LLC assumed operation of SPBPL in 1997, then CalResources became Aera Energy LLC and continued as the operator. The business was acquired by Pacific Energy Resources, Ltd. on November 1, 2006, when the office of the State Fire Marshal, Pipeline Safety Division, was notified that Pacific Energy Resources Ltd. (PERL) took ownership of the SPBPL, three delivery pipelines, and a breakout tank in Long Beach, California. On March 1, 2007, PERL assumed operation of these facilities. In 2010, Beta Offshore took over the business and employees of its predecessors and has continued the operations since. In 2012, the controlling interest in Beta Offshore was acquired by Memorial Production Partners, a corporate predecessor of Amplify Energy Corp. See Table 1.

Table 1. Operatorship History for the San Pedro Bay Pipeline

[4] Shell Oil Company had a rate structure and proration system with commitments with shippers under contract for specific volumes of product. In addition, a percentage of pipeline capacity would be set aside for committed shippers and non-contract shippers.
[5] Common carrier refers to any pipeline that offers transportation services to any third party under a standard set of terms. This contrasts with a private or proprietary pipeline that is either used by the owner for internal purposes or contracted to only a limited set of users.

San Pedro Bay Pipeline	Operatorship Date Range
Shell Oil Company	1980 (Original construction)
Shell California Production Inc.	1984
Shell Western E&P Inc.	1987
Shell assigned it rights to the SPBPL to be a common carrier	1993
CalResources LLC assumed operatorship	1995
CalResources LLC became Aera Energy LLC	1997
Pacific Energy Resources acquired SPBPL	2006
Pacific Energy Resources Ltd. (PERL)	2007
Beta Offshore took over the business and employees	2010
Memorial Production Partners acquired Beta Offshore	2012
Amplify Energy Corp.	2017

Beta Offshore's crude oil is pumped from oil wells located near *Platforms Ellen* and *Eureka* where drilling rigs on each platform have been in operation since the 1980s. Oil, water, and associated natural gas are pumped through production wells from the subsurface petroleum reservoirs and transferred via production pipelines to *Platform Elly*, where the fluids are separated. Crude oil is dehydrated and sent to shore. The produced water is filtered, treated, and transported across a bridge to *Platform Ellen* and *Platform Eureka* via the water injection pipeline. *Platform Elly* burns all of the production gas for fuel needed for the platform and pumps the crude oil through the SPBPL to the Beta Pump Station at the Port of Long Beach. There the oil is metered and distributed through two onshore delivery pipelines, which connect to the Crimson Pipeline system.

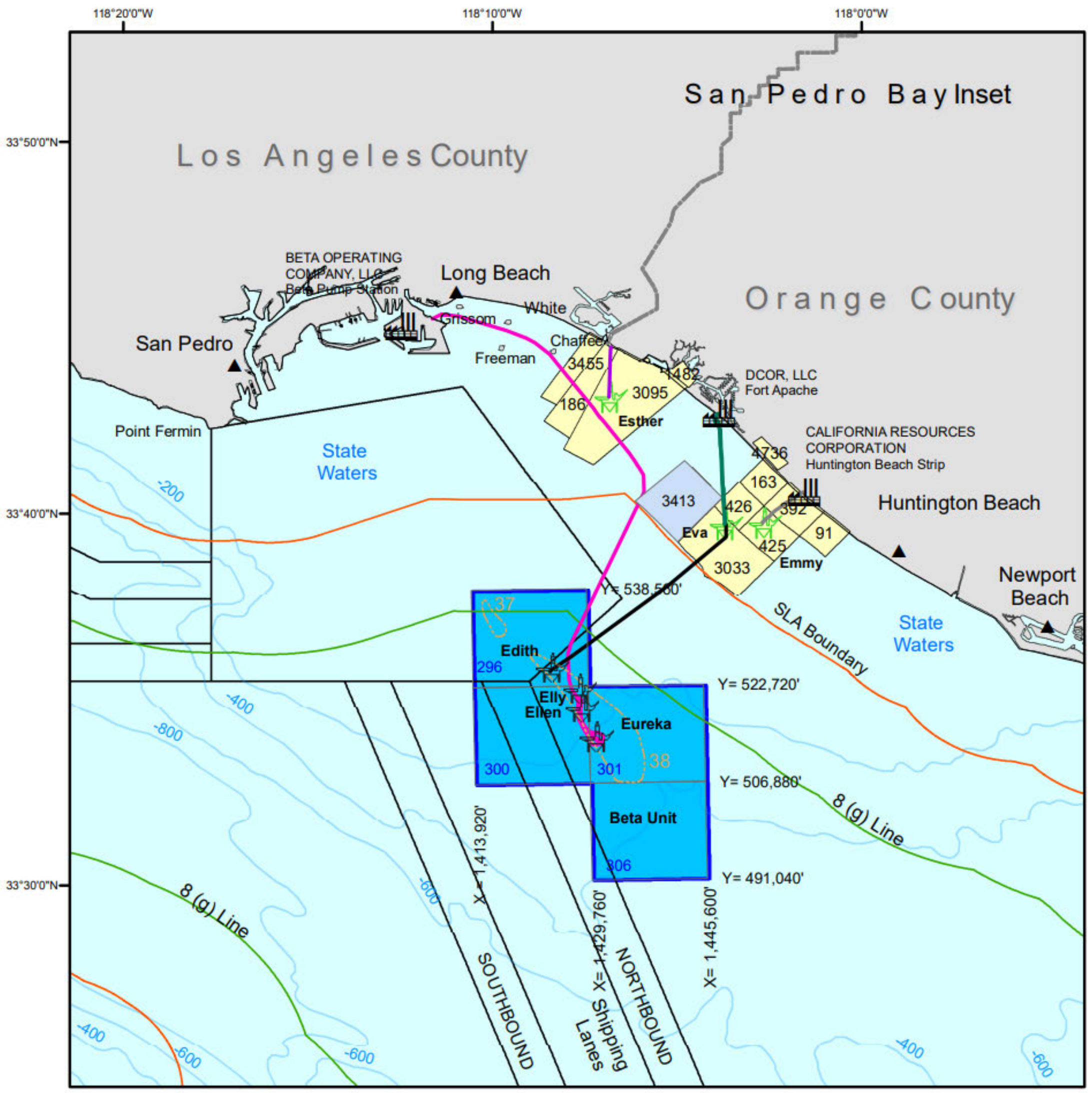

Figure 2. Crude Oil Delivery Process Platforms through the San Pedro Bay Pipeline. Area map created by Bureau of Safety and Environmental Enforcement (BSEE) POCSR Map October 2020.

PIPELINE SYSTEM

1.0 Pipeline Description

The San Pedro Bay Pipeline is a16-inch diameter interstate transmission, common carrier pipeline that transports crude oil about 17.5 miles (33,521 feet) from the *Platform Elly* to the Beta Pump station located onshore at the Port of Long Beach, California.[6][7] The pipeline transports about 4,000 barrels per day of heavy crude oil from Beta Offshore production oil fields as well as Platform Edith, which is owned by DCOR LLC. The crude oil is shipped using positive displacement pumps.[8] The pipeline has a maximum operating pressure (MOP) of 1,152 pounds per square inch gauge (psig), determined through a hydrostatic test. The SPBPL typically operates at 300 to 600 psig. The total volume in the pipeline is 20,228 barrels.[9]

The pipeline begins at the 16-inch mainline ball valve (ML-1) located on *Platform Elly,* considered the point of custody transfer from offshore production to pipeline transportation, and terminates at the Beta Pump Station. During normal operations, the pipeline flows south to north.

At *Platform Elly*, the pipeline transitions from aboveground to subsea piping through two 90-degree bends. The first 10.9 miles of the pipeline lies on top of the ocean floor. The remainder of the offshore pipeline (4.4 miles) was originally buried 10-to-15 feet below the ocean floor until it reaches the shoreline. The pipeline then continues onshore where it was buried 5-to-15 feet below grade for about 2.2 miles to the Beta Pump Station in Long Beach, California. Table 2 describes the pipeline specifications of each pipeline segment beginning at the platform and ending at the facilities onshore (Figure 3).

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[6] Pump stations are industrial facilities that maintain the flow and pressure of the crude oil by receiving oil from the SPBPL. Due to the friction loss created by liquids moving through the length of the pipeline, the pipes are subject to pressure losses over the length of the piping. Pump stations bolster (re-pressurizing) the pressure and send back into the pipeline system for further delivery to reach its customers.

[7] An interstate pipeline is a pipeline or that part of a pipeline that is used in transportation of hazardous liquids in interstate or foreign commerce. An interstate pipeline is a pipeline that extends beyond the boundaries of one state.

[8]A positive displacement pump moves crude oil by repeatedly by enclosing a fixed volume and moving it mechanically through the pipeline system.

[9] Hydrostatic testing refers to the process of testing pipelines to examine the strength pipeline using water or other medium. Hydrostatic testing also allows you to identify and locate leaks, which can weaken the vessel’s strength. Pressure tests are used by pipeline operators to determine the integrity of the pipeline immediately after construction and before placing the pipeline in service, as well as during a pipeline’s operating life. The post-construction pressure test verifies the adequacy of the pipeline materials and construction methods.

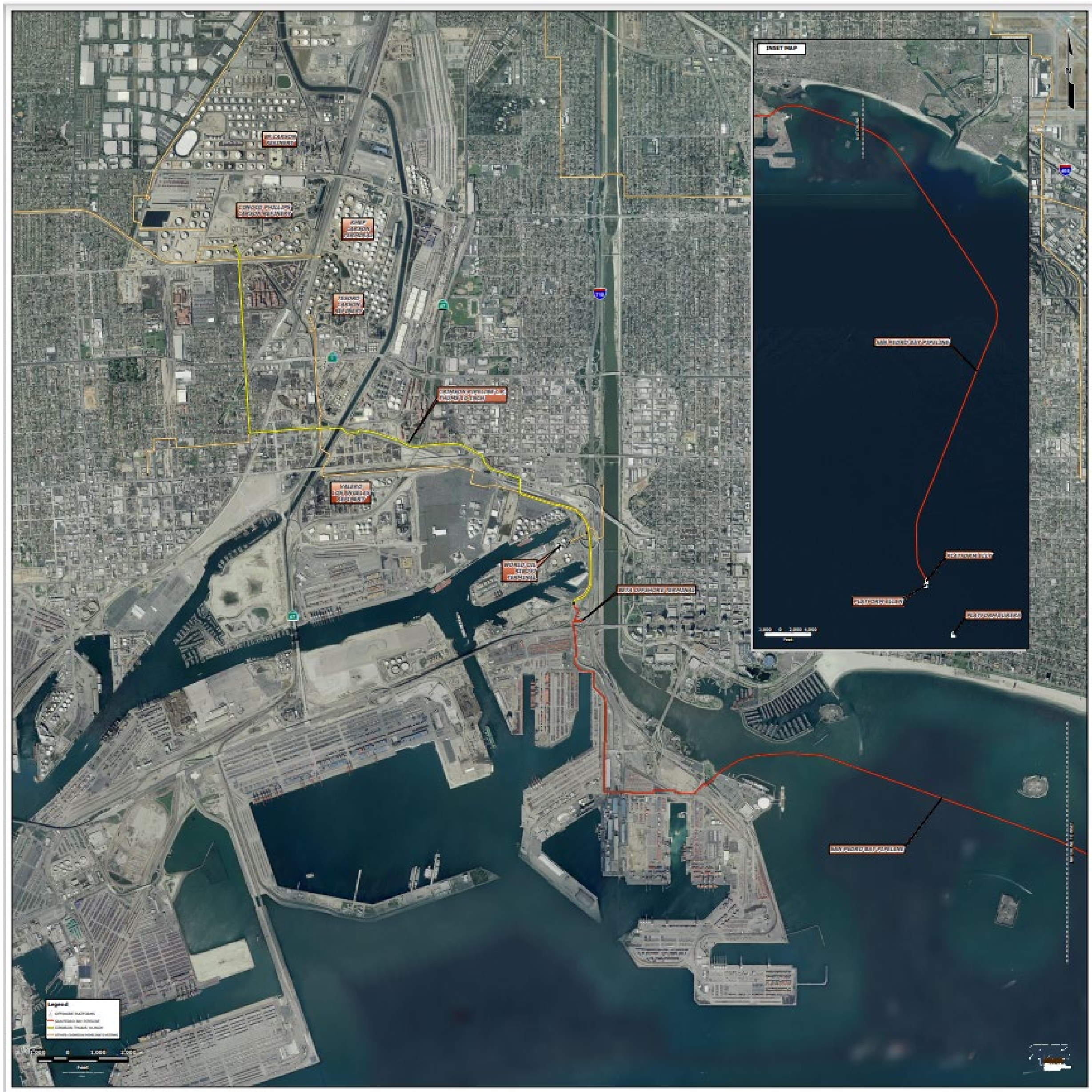

Figure 3. Crude Oil Delivery Process Platforms through the San Pedro Bay Pipeline. Area map created by the BSEE.

The SPBPL was fabricated from a 16-inch external diameter, 0.375-inch to 0.844-inch wall thickness, API-5L X-42 to X-52 grade steel pipe with a specified minimum yield strength (SMYS) of 35,000 to 52,000 psi, depending on the locations of the section of pipe. Table 2 shows the pipe specifications along the length of the pipeline. A small portion of the pipeline seam type is seamless with a majority of the pipeline has double submerged arc welded (DSAW) of unknown frequency.[10] In the vicinity of the

[10] Double submerged arc welding is a process that involves two submerged arc welding passes. One pass of submerged arc welding takes place on one side of the material, and another pass takes place on the opposite.

release, the pipe was coated with a felt outer wrap, over which a 1-inch-thick concrete coating was applied.

Table 2. Pipeline Specifications of San Pedro Bay Pipeline

Segment	Grade	Wall Thickness, in.	Diameter in.	% SMYS	length, ft	Seam
***Platform Elly* Riser**	ASTM A-106 Grade B	0.844	16	31	411	Seamless
Approach Pipe	API 5L X42	0.844	16	26	413	DSA, Cold Expanded
Sub-Sea	API 5LX52	0.500	16	35	80,206	DSA, Cold Expanded
Onshore	API 5LX52	0.375, 0.500	16	47	10,811	DSA, Cold Expanded

2.0 Pipeline Design and Construction

The Shell Oil Company originally designed the SPBPL. The US Army Corps of Engineers (USACE) issued the original permit, number 78-178, to construct the SPBPL on December 11, 1979. When the pipeline was built, the USACE Permit specified that the pipeline was to be placed and it was installed at least 500 yards outside of the anchorage area that is seaward of the Long Beach Breakwater and located adjacent to the pipeline in compliance with the permit. About 15.28 miles of the SPBPL pipeline is designed to be offshore, with 6.37 miles in federal waters and 8.91 miles in State waters. The landfall is at Pier H, in Long Beach. The beginning of the line starts at the riser on *Platform Elly*, where there is a 16-inch diameter seamless steel pipe with 0.844-inch wall thickness. The remainder of the offshore portion is constructed of 16-inch diameter steel pipe with a 0.500 wall thickness, 82.77 lb./ft, double submerged arc welded seam with welded pipe joints. The external coating is by Ameron-Price, which consists of a double coat system, with felt outer wrap. The system consists of two coats of fully plasticized coal tar enamel and glass reinforcement covered with an outer wrap of 15lb. felt. A concrete weight coating was applied prior to installation. It consists of 1-inch thick, 190 pound per cubic foot concrete, installed over the external.

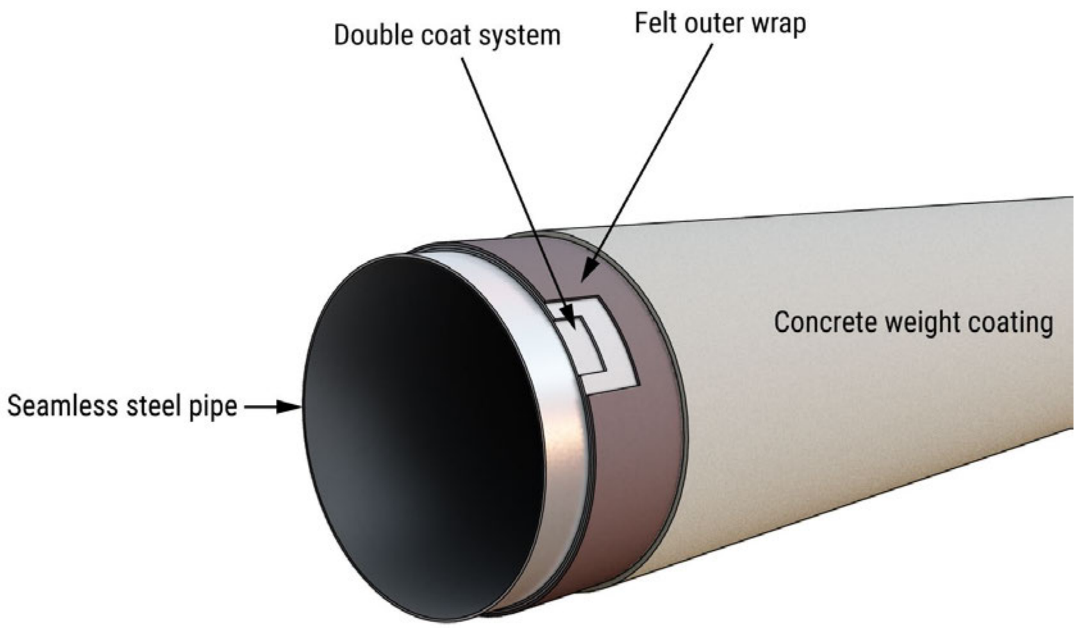

Figure 4. Illustration of the San Pedro Bay Pipeline external layers of pipeline coatings.

Kaiser manufactured the pipe in 1979. The pipeline was constructed between 1979 through 1980. The offshore portion of the pipeline that is past the breakwater is not buried. The offshore pipeline inside the breakwater was laid from the shoreline into the ditch and backfilled to ten feet of cover after a successful 6-hour hydrostatic test. The initial hydrostatic test was conducted with water to 2160 psig for 24 hours. The onshore portion of the pipeline was tested on April 22, 1980, and the offshore portion of the pipeline was tested on June 1, 1980. The entire offshore pipeline was successfully hydrostatically tested at 2160 psig for 24 hours from *Platform Elly* to the shoreline.

3.0 San Pedro Bay Pipeline and Pump Station

The downstream end of the pipeline is located at the Beta Pump Station where the crude oil is delivered. The Beta Pump Station is staffed seven days a week, 12 hours per day by a pipeline technician, and is otherwise remotely monitored. The facility also has a control room that can monitor the pipeline. The facility was installed in 1980, on one acre of land, between Pico Avenue and the Long Beach Freeway. It consists of a pipeline pig receiver, custody transfer meters, a 10,000-bbl surge tank (breakout), pumps, and manifolds.[11],[12] The current average daily throughput is about 4,000 barrels per day (BPD); the maximum throughput capacity is 9,600 BPD.[13]

The primary function of the surge tank is to store or provide the oil volume necessary to account for the differential flow rate between the *Platform Elly* shipping pumps and the onshore pump station shipping pumps. SPBPL onshore facilities consist of a pipeline right-of-way, marine supply and equipment storage yard, and a one-acre crude oil distribution site. At the Beta Pump Station, the crude oil is pumped through one of two sales Lease Automatic Custody Transfer units, and then through a 10-inch diameter delivery pipeline to the off-site THUMS manifold. The two pipelines leave the pump station, and they connect to the off-site THUMS manifold where they connect to the Crimson 8- and 10-inch pipelines.

4.0 Common Carrier Crude Oil Type

The SPBPL is a common carrier transporting crude oil to customers onshore from the platforms. The crude oil is considered heavy crude oil, ranging from 14.0 – 15.7 API gravity oil and a sour crude oil.[14,15] Crude oil specifications were tested and identified in Table 3.

Table 3. Crude Oil Specifications	
Gravity, API	14 – 15.7
Specific Gravity	0.96
Sulfur, % Wt.	3.5
H2S gas/100cc	0.0003
Flash Point, F°	<70 - 76
Pour Point, F°	37.4

[11] Pig is a generic term for any independent, self-contained device, tool, or vehicle that is inserted into and moves through the interior of a pipeline for inspecting, dimensioning, or cleaning. These tools are commonly referred to as 'pigs' because of the occasional squealing noises that can be heard as they travel through the pipe.
[12] A pig receiver is a device to remove a pig out of a pipeline without interrupting flow when a pig is launched. The valve or pump station has equipment to retrieve pigs from the mainline pipeline, referred to as pig receivers.
Custody Transfer Systems are highly accurate metering systems that move petroleum or any other fluid product between two owners. These systems are engineered to maintain extreme accuracy while pumping hundreds of gallons of product per minute.
The surge tank is a welded steel tank protected by a containment wall and provides surge control for the San Pedro Bay Pipeline shipping system. It is also referred to as a breakout tank.
[13] Average daily throughput based on September 2021 values.
[14] The American Petroleum Institute gravity, or API gravity, is a measure of how heavy or light a petroleum liquid is compared to water: if its API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks.
[15] Crude oil is defined as "sour" if its sulfur content exceeds 0.5%, or if it does not meet the required thresholds for hydrogen sulfide and carbon dioxide levels. Sweet crude, on the other hand, is defined by the New York Mercantile Exchange (NYMEX) as petroleum with sulfur levels below 0.42%.

Viscosity, cp	2500 (at 59°F)

PIPELINE OPERATIONS ON THE DAY OF THE ACCIDENT

5.0 Events Leading Up to the Accident

October 1, 2021

Based on interviews from the control room crews on duty the day of the incident, the day started off normally when they were preparing to launch cleaning pigs down the pipelines as scheduled.[16] Prior to the crude oil release, Beta Offshore employees had several operations and maintenance activities occurring at the same time: Hotwork permits were created for splicing wire on *Platform Ellen*, crews were conducting maintenance on the water filter, and they were launching three cleaning pigs for the 10-inch intrafield pipeline that runs from Platform Eureka to Platform *Elly*. At 00:30, dry oil tank SO2B levels started rising. The valve that controls the heat treater vessel began sticking, which caused an upset on the oil/water separator system, as the mainline pumps were not designed to push a lot of water or a mixture of hydrocarbons, gas, and water. Because they were not able to remove "wet oil" from the Dry Oil Tank SO2B, control room staff shutdown some wells and variable speed drives (VSDs) at *Platforms Eureka* and *Ellen*.

The dayshift controller had worked from about 06:00 on September 30 until about 01:00 on October 1, and was at the console for the SPBPL from about 05:00 to about 18:00 on October 1. He notified the person-in-charge (PIC) around 12:30 that there was an upset in the system, and his assistance was needed at the control room.[17]

The following timeline indicates the certain actions taken by Beta Offshore employees to address the increasing levels in Tank SO2B, loss of communication, instrumentation anomalies, and leak detection system (LDS) alarm activation. By about 16:00 on October 1, the tank levels started coming down and they had to wait to make sure the tank was lowered enough so that the wells and VSDs had been shut down. Shipping pump C was depressurized and shut down in preparation for the cleaning pig launches in the SPBPL to Beta Pump Station at 08:31. Pump C was restarted at 08:29 to start the pig run, indicated by a flow change on the Supervisory Control and Data Acquisition (SCADA) system. Later in the morning on October 1, Platform Elly began to receive cleaning pigs from Platform Eureka. Tank SO2B levels

[16] Cleaning pig refers to a technique of maintaining the internal pipeline free of debris buildup such as paraffin and wax without stopping operation. It is done through inserting a device known as scraper (cleaning) pig into the transportation pipelines.

[17] Person-In-Charge is the employee who will coordinate all field activities. The control room operator designates one person at the remote locations as the person in charge. The controller communicates with the person-in-charge to keep them informed about operation of devices including verification that all devices work as designed.

began to rise later in the day, which triggered an alarm, indicating the tank level had exceeded 85 percent. The crude oil stream coming from the wells was floating, which can create mechanical and efficiency problems with pumps. By 15:00, crews were able to bring the water content from the processing train that was carried over to a normal system level. The upset forced a significant amount of high-water content oil into the SPBPL. The mixture of crude oil and water comprised of about 50% water, rather than the usual 0.5% water entering the pipeline.

Around 16:00, the dayshift controller observed that the SPBPL mainline pressures on the console indicated normal operating pressure and flow patterns (shown in Figure 5) until 16:05, when the pattern changed from normal behavior as shown in Figure 6. At that time, there was a mainline pipeline pressure spike of 829-psig, which is below the maximum operating pressure of the pipeline, but above the normal operating pressure of the system. Figure 6 shows the pipeline operating flow and pressure changed from normal to erratic patterns.

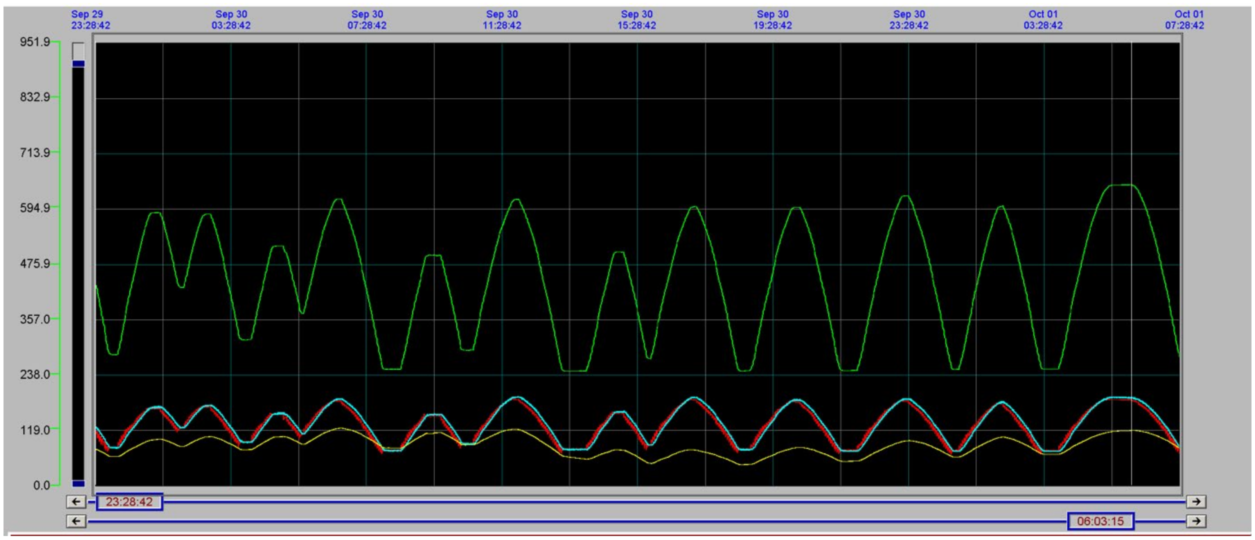

Figure 5. San Pedro Bay Pipeline Normal Operating flow and pressure. The green line indicated the mainline pipeline pressure, the red line indicates the mainline total flow rate, the blue line indicates the raw flow rate into the pump station, and the yellow line indicates the pipeline inlet pressure.

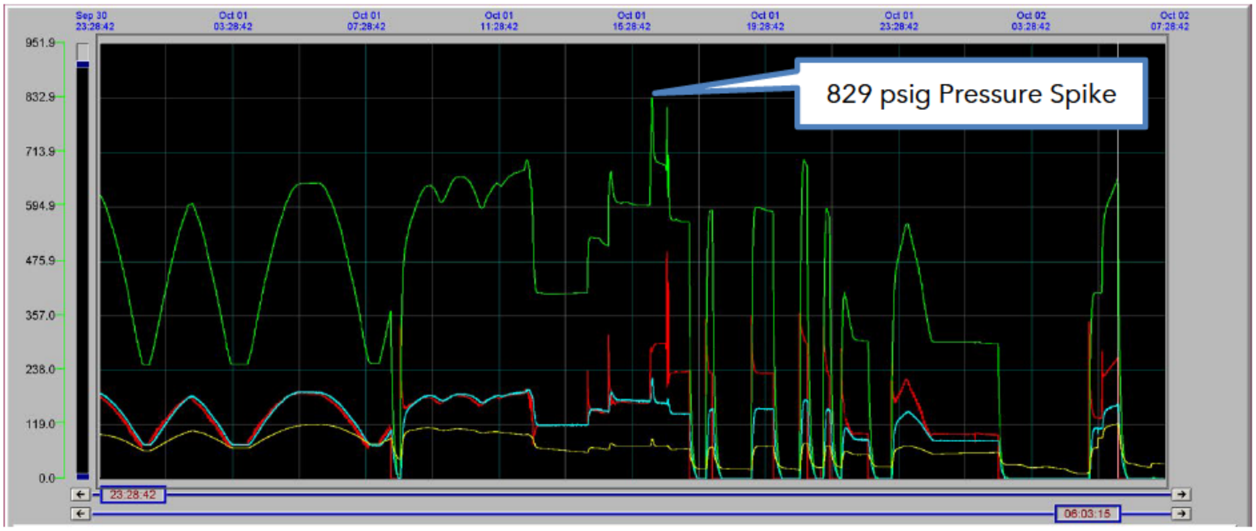

Figure 6. SCADA data showing the normal pattern up until about 07:28 on October 1 and the 829-psig pressure spike. The green line indicated the mainline pipeline pressure, the red line indicates the mainline total flow rate, the blue line indicates the raw flow rate into the pump station, and the yellow line indicates the pipeline inlet pressure.

The controller was running shipping pump C when the first Atmos leak detection system (LDS) alarm occurred at 16:10 and was acknowledged by the controller at 16:11.[18] A "Mile 0" was shown on the control room console, indicating a leak occurred at the beginning of the pipeline, at Platform Elly. Each time the LDS issued a leak alarm on October 1, it indicated that the leak was at Mile 0, or at Platform Elly. The Senior Pipeline Technician was called at 17:37. See Figure 7, which shows the general layout of the SPBPL beginning at Platform Elly and delivering into the Beta Pump Station on shore. About 30 minutes later the SPBPL was restarted. The dayshift controller stated to the NTSB investigators that he assumed the alarm was erroneous and activated due to upset conditions in the pipeline from shipping wet crude oil. The senior pipeline technician was called at 19:37 and told to head toward Beta Pump Station to assist in troubleshooting the leak detection alarms.

[18] A controller acknowledges an alarm by pressing the red alarm indicator on his HMI screen, which may result in the alarm disappearing or changing to a green color if the condition has been resolved. Otherwise, the alarm remains active on the screen. A Human-Machine Interface (HMI) is a user interface or dashboard that connects a person to a machine, system, or device. The HMI provides a visual display of the data screens.

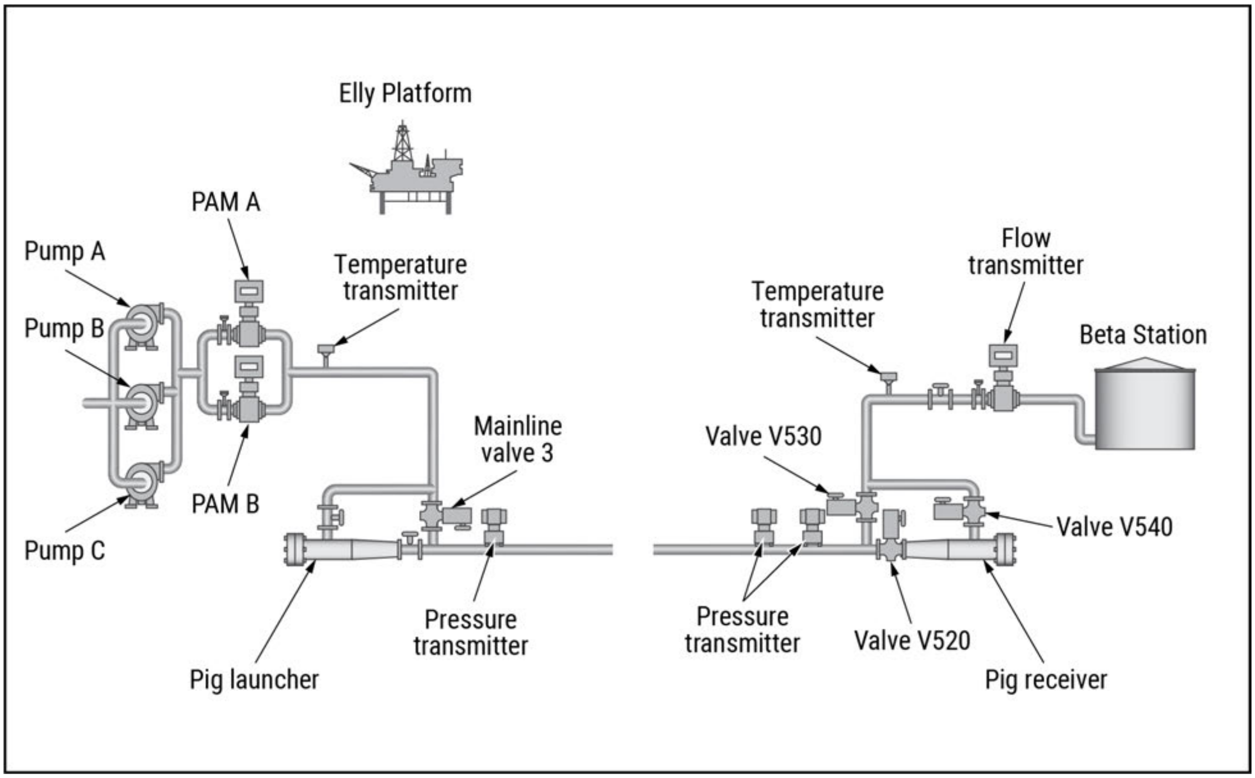

Figure 7. San Pedro Bay Pipeline simplified component layout beginning at Platform Elly to the Beta Pump Station.

A second alarm activated at 17:52. A minute later, the dayshift controller shut down shipping Pump C and reset the LDS alarm and resumed the oil shipment until a third alarm activated at 19:15. The controller called the PIC and notified him of the situation and requested the pipeline technician reboot his computer at the Beta Pump Station to begin troubleshooting.

At 18:13, Colonial Compliance Systems, Inc., discovered an unknown sheen in the water three miles offshore near their vessel ([redacted]"N [redacted]"W) and reported to the National Response Center (NRC).[19] The vessel location was identified as approximately 3 miles from the failure location.

At 19:42, the controller shut down the pipeline and then resumed shipping using Shipping Pump A at 20:29 until a fourth alarm activation occurred at 20:39. The controller called the senior pipeline technician to inform him that they were getting leak detection indications and notified the PIC. Pump A was shut down a minute later. The Beta Pump Station technician notified the pipeline superintendent that they were experiencing leak alarms and metering issues and were shutting down the pipeline to

[19] The National Response Center is a continuously staffed communications center that receives telephonic notification of all oil, chemical, radiological, biological, and etiological discharges into the environment, anywhere in the United States and its territories.

clear and reset the leak detection system. The pipeline superintendent informed the control room they should shutdown shipping in response to the leak alarms to let the pipeline settle. By 21:12, the dayshift controller restarted shipping Pump A through production allocation meter (PAM) B for 12 minutes. At 21:23, a fifth alarm activated and the controller shutdown Pump A one minute later. Twenty minutes later the controller restarted running the pipeline and resumed shipping. During the shipment, a sixth alarm activated at 21:53, and the controller stopped shipping at 22:33 and restarted at 23:15.

On October 1 at 19:58, the National Oceanic and Atmospheric Administration (NOAA) NOAA/NESDIS/satellite analysis branch observed an oil anomaly on satellite imagery and reported it to the NRC at 01:15 on October 2.[20] See Figure 8. NOAA did not characterize this anomaly as oil on water at that time.[21] At 23:30, a seventh Atmos LDS alarm was activated while the pipeline was running.

[20] For significant spills, the Office of Response and Restoration (OR&R) is responsible for providing scientific support to the federal on-scene coordinator overseeing the response. OR&R provides situational awareness to the Unified Command. OR&R is provided on-scene and remote scientific support. NOAA's National Weather Service provided weather briefings and decision support to the Unified Command. Weather conditions will change how the oil moves and where it might strand on beaches.

[21] Synthetic Aperture Radar (SAR) used in the NOAA NESDIS pollution reports detects differences in surface water roughness, as oil dampens waves and creates a smooth area or "slick". [Source: Aerial-Viewing-of-Oil-Spill-Fact-Sheet_NOAA-2021.pdf (amazonaws.com)]

Figure 8. Dark areas in this radar image captured by NASA Earth Observatory/Joshua Stevens at 18:49 on Oct. 2, 2021.

In an interview with the nighttime controller, the pipeline superintendent was informed on October 2, at about 02:20, that a manual leak detection was needed.[22] The manual leak detection operations were run for a couple of hours. The pipeline superintendent compared the flow reading using the PAM instrumentation. He found there was an eight-to-10-barrel per hour difference where normally the difference was two-to-three-barrels per hour. They continued to monitor the situation with almost identical results taken over two hours, taking readings every 30 minutes. Crude oil has a different density from water and when blended with water, it can

[22] The manual leak detection compares readings on 30-minute intervals to assess flow in and flow out. A manual leak detection test is where the employee measures the flow meter data at the Platform and concurrently at the Beta Pump Station, in order to compare the amount of oil shipped from *Platform Elly* to the amount received at Beta Pump Station.

change the measured flow rate through the meters. Shipping was shut down immediately.

Refer to Appendix A for more information about the pipeline operations chronology of events on the day of the accident.

6.0 The Release Discovered

October 2, 2021

SoCal Ship Services ("SCSS"), the Beta Offshore right-of-way patrol contractor was called at 02:34 to perform a pipeline right-of-way inspection via the vessel *Nicholas L,* starting from shore and working toward *Platform Elly*. At 05:10, they reported they had not found anything. After the report from the right-of-way inspection, the controller resumed shipping at 05:11. At 05:28, an eighth alarm activated at the SCADA console indicating a leak was detected.

At 06:04, the controller stopped shipping, called out for an additional pipeline right-of-way survey when it was light out, and waited for the results. Sunrise occurred at 06:47. The vessel *Nicholas L* crew started inspecting the pipeline right-of-way at 07:10, starting from *Platform Elly* and traveling toward shore. At 08:09, the vessel crew confirmed there was oil on the water. They estimated a 60-foot-wide x 1 ½ mile long oil sheen that could be seen on the water, located about 4.7 miles from the shoreline. See Figure 9.

Once the oil was confirmed, Beta Offshore responded to the release with resources and notifications. At 08:11, Beta Offshore mobilized their crews and contractors and initiated an oil spill response. *Platform Edith* was notified of the leak in the pipeline and shut down production. Notifications of the leak went out to their oil spill removal organization (OSRO), SCSS, and the Marine Spill Response Corporation (MSRC). SCSS notified Beta Offshore they had mobilized a reconnaissance team. At 10:02, while the San Pedro Bay Pipeline's valves were closed at the Elly Control Room, Beta's pipeline superintendent started the shipping pumps at Beta Station to pull pressure off the pipeline. This process creates a vacuum in the pipeline, which alleviates pressure at the leak site, pulls any remaining product out of the pipeline along with sea water through the leak to prevent any further crude oil from leaking into the ocean. Negative pressure was achieved before noon on October 2.

Witt O'Briens (regulatory reporting contractor for Beta Offshore) reported to the NRC (Report No.1318463) of an unknown discharge of crude oil into the Pacific Ocean. They reported a discharge was observed in the vicinity of a pipeline after a drop in pressure was noticed of unknown causes. On October 1, the pipeline mainline pressure averaged about 443 psig.

Figure 9. The unified command responded to and cleaned the crude oil spill off the California coast. Oil spill removal organization (OSROs) are shown towing skirted oil boom to contain the oil spill. Oct. 3, 2021. Photograph by U.S. Coast Guard.

Refer to Appendix A for more information about the pipeline operations chronology of events on the day of the accident.

7.0 Pipeline Isolation

Emergency isolation from the upstream side of the release required the flow from each gathering production supply to stop and to close the mainline valve, ML1 on *Platform Elly* to stop further flow into the pipeline. Pipeline shutdown and isolation is monitored and operated by the *Platform Elly* control room operator. In the event of a leak, the control room operators can close the platform discharge shutdown valve (ML3), which isolates the pipeline between *Platform Elly* and the Beta Pump Station. Closure of this valve automatically shuts down the shipping pumps. However, to prevent further release into the ocean, crews started pumping from the Beta Pump Station to pull the crude oil and any sea water to relieve pressure on the pipeline, which created a negative pressure and stopped the rate of release. Prior to the indications of a leak, the crews had loaded a maintenance cleaning brush pig that had remained in the pipeline about 17,500 feet downstream from *Platform Elly* and upstream of the failure location.

EMERGENCY RESPONSE

On October 3 at 09:10, the Coast Guard received an initial report an oil sheen that was identified off the coast of Newport Beach. Coast Guard Pollution Responders began mapping the sheen to identify a source and estimate size. A Coast Guard aircraft flew over the sheen and estimated it to be 13 square miles in size, 3 miles off the coast of Newport Beach. At 11:38, the Coast Guard Sector Command Center issued a Marine Safety Information Broadcast for a large oil spill in the vicinity of Newport Beach, California.[23] At 12:00, Sector Command Staff arrived at the first Incident Command Post that was held at the Beta Offshore offices in Long Beach, California, and established a Unified Command (UC).[24]

The UC was led by the Coast Guard Sector Los Angeles / Long Beach (LA-LB) as Federal On-Scene Coordinator (FOSC), California Department of Fish and Wildlife Office of Spill Prevention and Response's (CDFW) as the State On-Scene Coordinator and Amplify as the Responsible Party. Other agencies consisting of local, state, and federal agencies, including the National Transportation Safety Board (NTSB), BSEE, NOAA, Pipeline and Hazardous Materials Safety (PHMSA), and local law enforcement responded to the oil spill (identified as incident "Pipeline P00547"). Amplify funded the response and were fully involved in the efforts to clean up the spill and executed the requirements of the UC. The initial incident management team (IMT) consisted of the deputy sector commander as FOSC, a deputy incident commander, operations section chief, and several qualified Coast Guard pollution responders. Shoreline impacts were reported in Orange and San Diego Counties. Local government on-scene coordinators from the Orange and San Diego Counties were added to the Unified Command.

The USCG declared the incident a Major Marine Casualty, due to the potential involvement of vessels dragging anchor and the resulting damages estimated in excess of $500,000.[25] Refer to the Federal and State Jurisdiction section of this report for more detail on the USCG authority of this incident.

[23] The U.S. Coast Guard broadcasts coastal maritime safety warnings to ensure coverage of different ocean areas for which the United States has responsibility. All ships of every size and nationality can receive this safety information, however, ships in U.S. waters over 20m in length are required to monitor VHF channel 16 and must have radios capable of turning to the VHF simplex channel 22A. All broadcasts except those over VHF and MF radiotelephone are made by computer. Urgent marine navigational and weather information is broadcast over VHF channel covering the coastal areas of the U.S.

[24] A unified command is an authority structure in which two or more individuals share the role of incident commander, each already having authority in a different responding agency. Typically, a unified command is needed for incidents involving multiple jurisdictions or agencies for the incident manage the response from a single incident command post. Under a unified command, a single, coordinated incident action plan will direct all activities.

[25] Major marine casualty means a casualty involving a vessel, other than a public vessel, that results in:(1) The loss of six or more lives: (2) The loss of a mechanically propelled vessel of 100 or more gross tons; (3) Property damage initially estimated at $500,000 or more; or (4) Serious threat, as determined

The crude oil release impacted beaches starting from Huntington Beach to beaches in northern Mexico, including activation of the LA-LB and U.S. Coast Guard Sector San Diego Area Contingency Plans (ACP), and the MEXICO-U.S. oil spill response plan (MEXUS). The USCG worked with the Orange County Sheriff's Harbor Patrol to investigate the source of the sheen. Sector LA-LB staff began briefing stakeholders to activate an IMT. The shoreside response was conducted by 105 government agency and non-government personnel. The response was conducted as a round-the-clock operation until the oil was recovered.

Initial estimates of the crude oil released were based on maximum potential discharge of the of the amount of crude oil that remained in the pipeline of 3,440 barrels (144,480 gallons). The amount was later refined down to 588 barrels that was confirmed by PHMSA, BSEE, and California State Fire Marshal. There were no fatalities or injuries associated with the release.

8.0 Monitoring And Tracking the Spill

The UC established an oil spill response that encompassed about 13 square miles in size, three miles off the coast of Newport Beach, California. The USCG and Huntington Beach Police Department continually dispatched aircraft to visually assess the oil spill. On October 3, 2021, Beaches were closed, starting from Seapoint Drive south to the Santa Ana River. The UC announced a request for the public to stay out of the water from Tower 44 north to the Santa Ana River. Specific beach openings and closing statuses were managed by local government.

The Oiled Wildlife Care Network was activated.[26] Oil-impacted animals were collected and received veterinary care. Other reports of oiled wildlife were investigated. A public telephone number was set up to report impacted wildlife.

Air monitoring efforts were conducted under the UC South Coast Air Quality Management District, in coordination with the U.S. Environmental Protection Agency, the OC Health Care Agency, and a contracted environmental consulting firm, conducted community air monitoring through mobile air surveys and air sampling at 12 sites located along the Orange County coastline. By October 7, 2021, air samples from areas potentially impacted by the oil spill were within background levels (air quality on a typical day) and below California health standards for the pollutants

by the Commandant and concurred in by the Chairman, to life, property, or the environment by hazardous materials.

[26]Oiled Wildlife Care Network (OWCN) is an organization that provides regional, national, and international readiness and response activities to oil spills. OWCN is a statewide collective of trained wildlife care providers, regulatory agencies, academic institutions, and wildlife organizations working to rescue and rehabilitate oiled wildlife in California.

measured. On October 18, 2021, the UC reported that segments of beach were recommended for no further clean-up activities.

The UC lead clean-up efforts for the oil spill. At its peak, more than 1,800 responders from around the country supported the IMT. Over a four-month period, responders recovered 8,063 gallons of on-water oil, 964 gallons of on-land oil and 549,658 pounds of oily debris. In total: 13 Geographic Response Strategies were deployed which contributed to the protection of 32 environmentally sensitive sites, a cumulative 624 miles of shoreline were assessed, 764 miles cleaned, and 271 recreational vessels were impacted and decontaminated.

On November 30, 2021, the UC released a waste stream management report that indicated 132 barrels (5,544 gallons) had been recovered. Additionally, 68,620 pounds of oily sand and 74,040 pounds of oily water were collected. A total of 12,860 feet of oil containment boom was deployed to contain the oil and protect intercoastal areas such as the inlet to the desalination plant in the Agua Hedionda Lagoon. See Table 4.

Table 4. Oil Spill Response Statistics

Total spilled	588 barrels (24,696 gallons)
Total recovered	132 barrels (5,544 gallons)
Oil boom deployed	12,860 feet
Wildlife impacted	24
Injures	0
Fatalities	0
Volunteers	116
Total Costs	$160,000,000
Response personnel	1,800
Tar balls recovered	13.5 barrels[27]
on-water oil	8,063 gals
on-land oil	964 gals
Oily debris recovered	549,658 pounds
oily water	74,040 pounds
oily sand	68,620 pounds

On November 30, the UC announced that no free-floating oil had been observed on the water since October 5, 2021. On February 2, 2022, with "no further indications of shoreline oiling have been reported since Jan. 4," the UC stood down and concluded its response and monitoring efforts.

[27] About 57 percent of tar balls collected and tested did not match Amplify' s crude oil. Six of 265 samples from the most impacted areas—Talbert Marsh, Huntington Beach, and the Santa Ana River Delta—tested as Amplify oil.

Figure 10. Shoreline crews conduct cleanup operations on Huntington Beach, Calif., October 4, 2021. Photograph courtesy U.S. Coast Guard.

9.0 Fisheries and Health and Safety

The Office of Environmental Health Hazard Assessment (OEHHA) is the lead state agency for the assessment of health risks posed by environmental contaminants. On October 2, 2021, the OEHHA was notified of an oil spill off the coast of Orange County, California, and responded to the release, working through the UC. The contaminants of concern, relating to human consumption of seafood following an oil spill, are specific polycyclic aromatic hydrocarbons (PAHs) that are considered to have the potential to cause cancer.

OEHHA sampled seafood in the area from October 14 to November 3, 2021, to measure and evaluate levels of certain chemicals found in crude oil, such as PAHs. According to OEHHA, PAHs can accumulate in species caught for human consumption, posing an increased risk for cancer and other adverse health conditions.

The CDFW issued a notice on October 4, 2021, that taking of all fish and shellfish was immediately prohibited from Huntington Beach, California to Dana Point, California, to include about 650 square miles of marine waters and about 45 miles of shoreline (Figure 11). On November 30, 2021, the CDFW lifted the affected area closure.

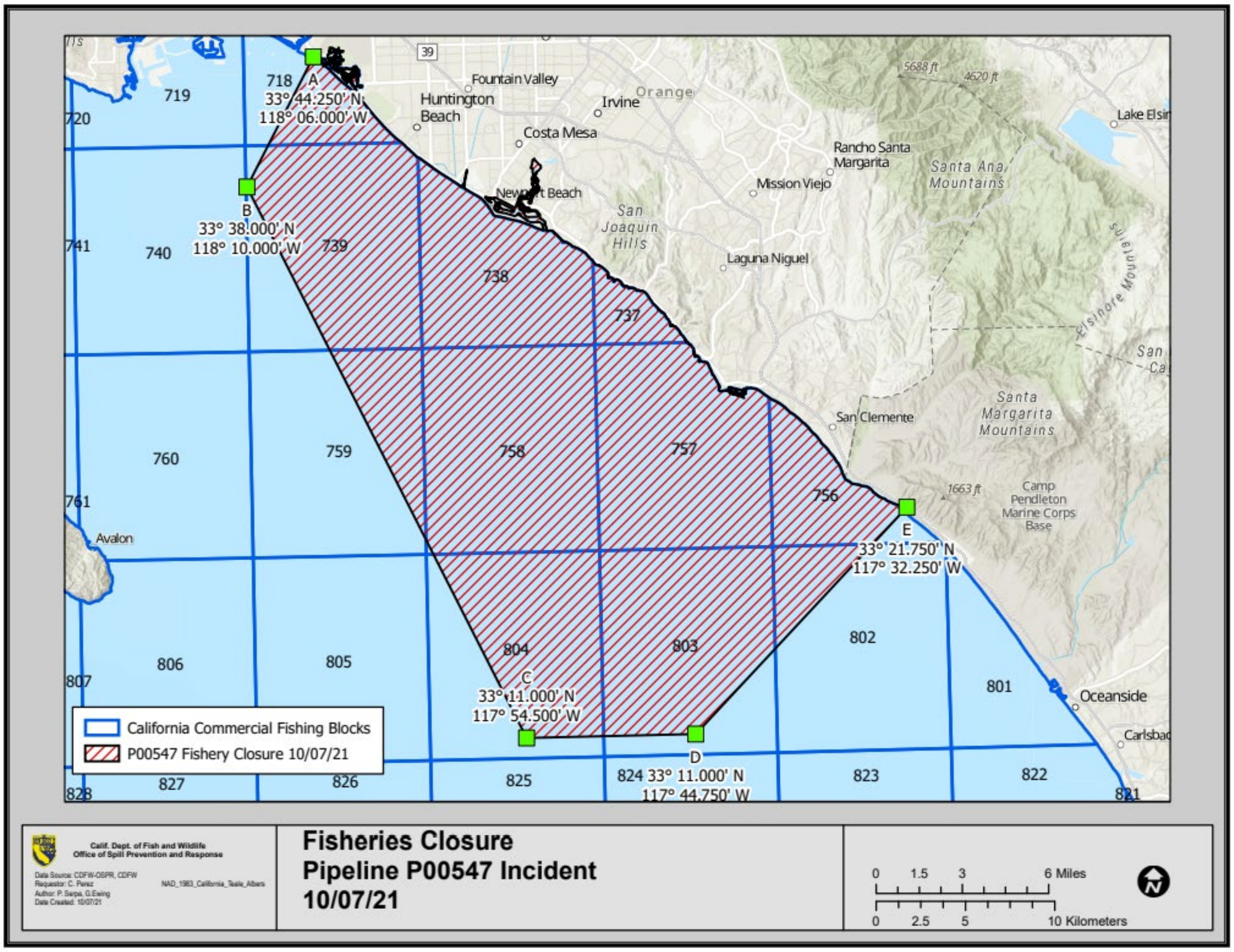

Figure 11. Detailed map of initial closed areas on October 7, 2021. Map by California Department of Fish and Wildlife.

DETAILS OF THE INVESTIGATION

The USCG was the lead federal agency for this investigation. The PHMSA and BSEE conducted regulatory investigation of the pipeline operators' actions, respective of their jurisdictions. The CDFW was the state's lead agency conducting a separate investigation into the circumstances of the crude oil release.

Beta Offshore continued to remove any residual hydrocarbons from the pipeline. While the source of the oil sheen was unknown in the initial days of the release, all of the production and pipeline operations at the Beta Offshore fields were shut down as a precautionary measure. In order to control the crude oil coming from the pipeline breach, Beta Offshore began drawing crude oil and seawater toward the Beta Pump Station via a vacuum pump, so they could prevent further release into the ocean and determine the source of release.

On October 3 and 4, 2021, Beta Offshore sent a remotely operated vehicle (ROV) and a diving crew to the suspect area to conduct a post-accident examination of the pipeline and confirm the location of the source of the release. Beta Offshore's initial contract diver observed a linear indication on the pipeline, a crack running longitudinally along the top of the pipeline. Using a 0.008-inch feeler gauge, the diver found an area in the linear indication that penetrated the pipe and hydrocarbons were observed on the feeler gauge when it was retracted from the pipe. The diver also observed bright shiny metal and a deformed area 24 inches in length and 8 inches wide. The pipe appeared out-of-round and had a flat spot at the 6 o'clock position against the mudline. See Figure 12. The flat spot strip was measured at 7-1/2 inches from the start of the linear indication (Figure 12 and 13). The diver confirmed there was no external coal tar enamel coating in the area around the indication by placing a magnet on the pipe. There was a 7–8-foot section of concrete coating missing south of the indication. There was concrete rubble found near the pipeline area. The diver found linear disturbances in the seabed near the pipe.

Figure 12. San Pedro Bay Pipeline linear indication with a Flat Spot in situ. Concrete rubble can be seen adjacent to the pipeline. Photograph by Beta Offshore, October 4, 2021.

Figure 13. San Pedro Bay Pipeline linear indication at the release location with the coating in place. Marine growth is shown over the damaged portion of the pipeline. Photograph by Beta Offshore, October 4, 2021.

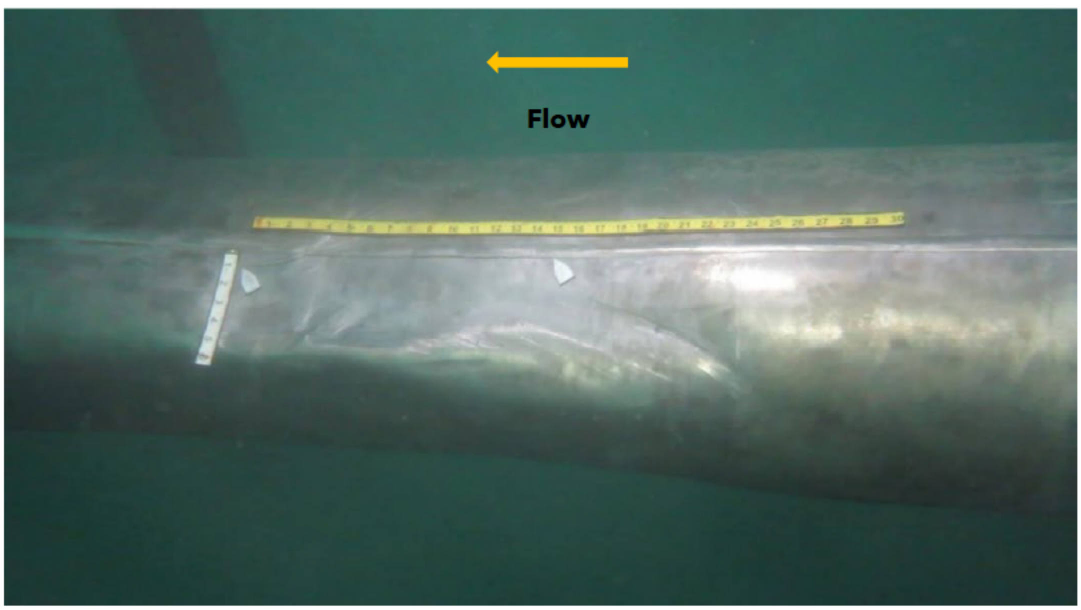

Figure 14. Underwater view of the San Pedro Bay Pipeline with the coating removed showing damage to the pipe. A flat spot was indicated that measured at 7-1/2 inches from the start of the linear indication. Photograph by Aqueos, October 19, 2021.

The ROV survey showed seven areas where the concrete coating had come off the pipe and bare steel was exposed. The survey covered 8,000 feet of pipeline, with no indications of oil released in those other areas. The previous ROV survey conducted in May 2020 showed no significant damage to the concrete casing along the fulllength of the pipeline. The ROV contractor found the pipeline to be 'in good condition with no visible damage or anomalies.

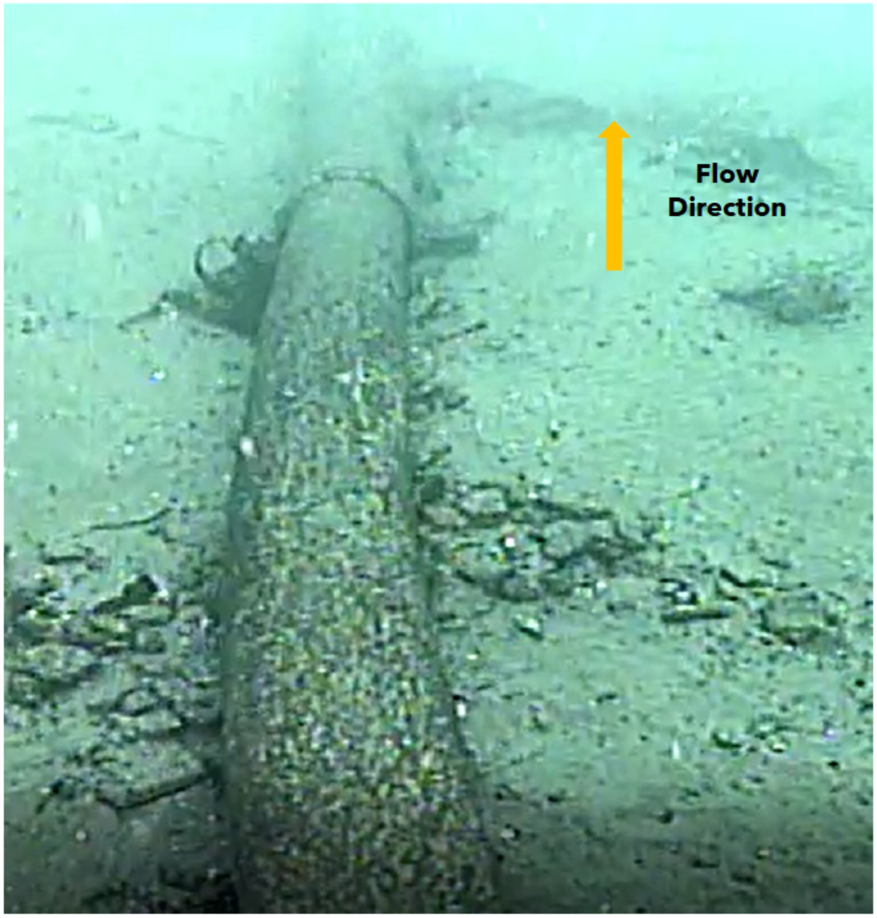

Figure 15. San Pedro Bay Pipeline with coating damage. Concrete coating can be seen sitting on the sea floor adjacent to the pipeline on both sides of the pipeline. Photograph by Beta Offshore.

On October 9, 2021, the pipeline remained under a slight vacuum to prevent further crude oil release, allowing the installation of an initial mitigative measure using SynthoGlass XT fiberglass composite wrap™ over the area of the crack. The crack repair is further described in Section 10.1.

On October 12, 2021, Beta Offshore contracted for a multibeam echosounder (MBES) survey over the effected portion of the SPBPL.[28] The purpose of the survey was to identify and map displacement of the pipeline and indicate how the pipeline was damaged. The survey showed a 4,025-foot section of pipeline had a maximum

[28] A multibeam echosounder (MBES) is a type of sonar that is used to map the seabed. It emits acoustic waves in a fan shape beneath its transceiver. MBES uses beamforming to extract directional information from the returning soundwaves, producing a swath of depth soundings from a single ping.

displacement of 105 feet over a portion of the pipeline from its original position on the right-of-way, and there was evidence of seabed scars/scouring adjacent to and in the vicinity of the damage (Figure 16). In the previous ROV survey the pipeline was positioned in the ROW.

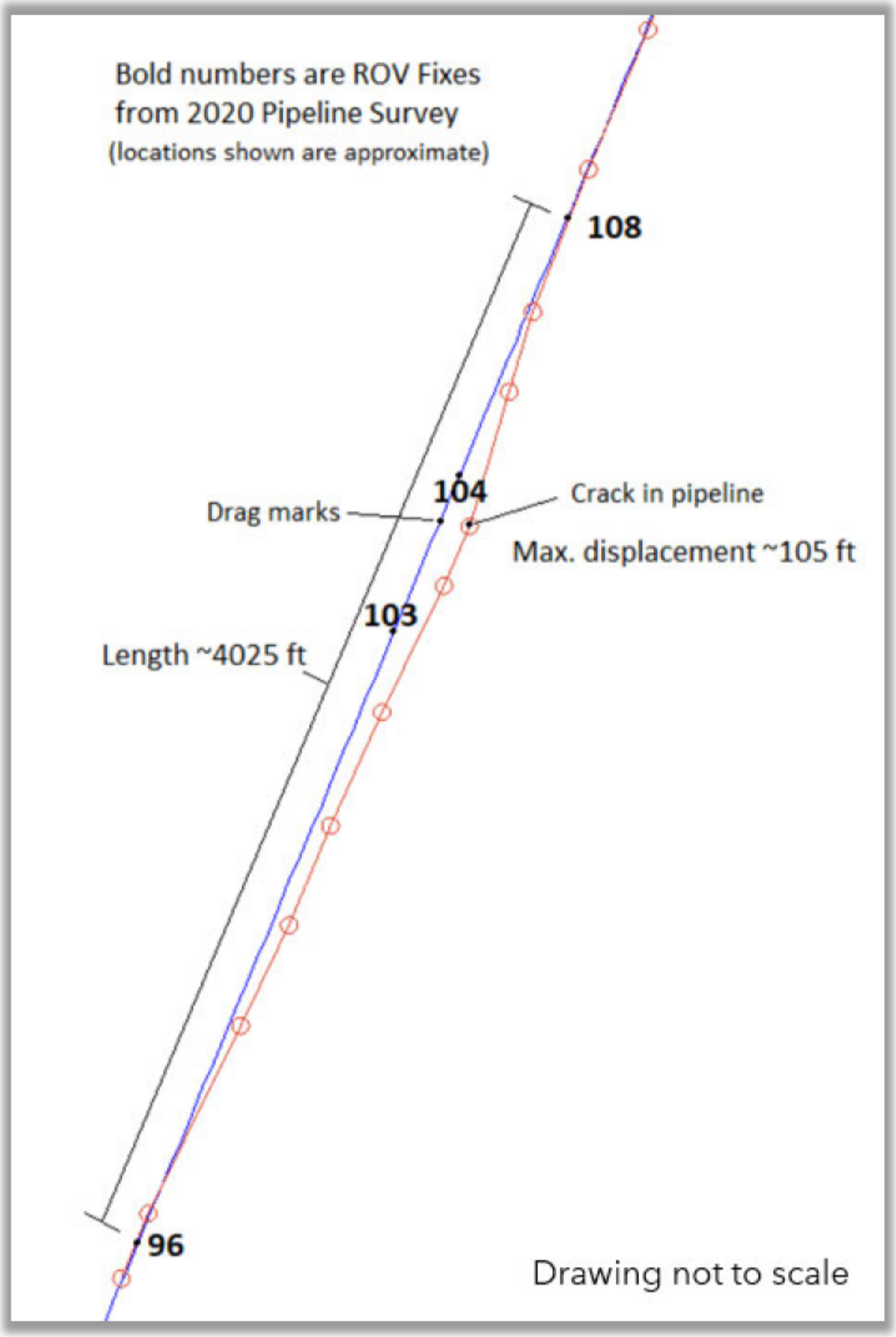

Figure 16. Drawing of the San Pedro Bay Pipeline showing a 105-foot displacement from its original position on the Right-Of-Way. Illustration by Beta Offshore.

The survey identified several instances of seabed scarring/scouring at and near the pipeline as illustrated in Figure 17.

Figure 17. San Pedro Bay Pipeline original location and displacement. Scarring is noted by the dotted line in this graphic. Graphic by Beta Offshore.

10.0 Pipeline Crack

Beta Offshore's contractor completed a detailed underwater pipeline survey on October 22, 2021, that reviewed the crack and pipe damage. They visually inspected over 4,000 feet of pipeline that had been displaced from its original location out to the end of the ROW limits. Crews conducted nondestructive testing utilizing ultrasonic and magnetic particle inspection of the failed section of pipeline.[29] They found indications of a crack with an overall measured length of 21- 3/8-inches. The longitudinal weld was located at the 11:00 o'clock position relative to the pipe at the failure location.[30] The circumferential profile showed the pipeline was out of round with a convex (dented) segment at the crack location. The crack was found at 10:30 through 11:00 o'clock position relative to the pipe facing north, and below the weld seam. See Figure 18. A punch mark was added to south side of linear indication to prevent further cracking and denotes the end of indication.

[29] Aqueos 16-inch Pipeline Damage Assessment, Aqueos Project No. BET01-21-257, October 2021.
[30] The 12:00 o'clock position on the pipe is the center and top of the pipe as found on the seabed floor. The 11:00 o'clock position would be found on the west side of the pipeline.

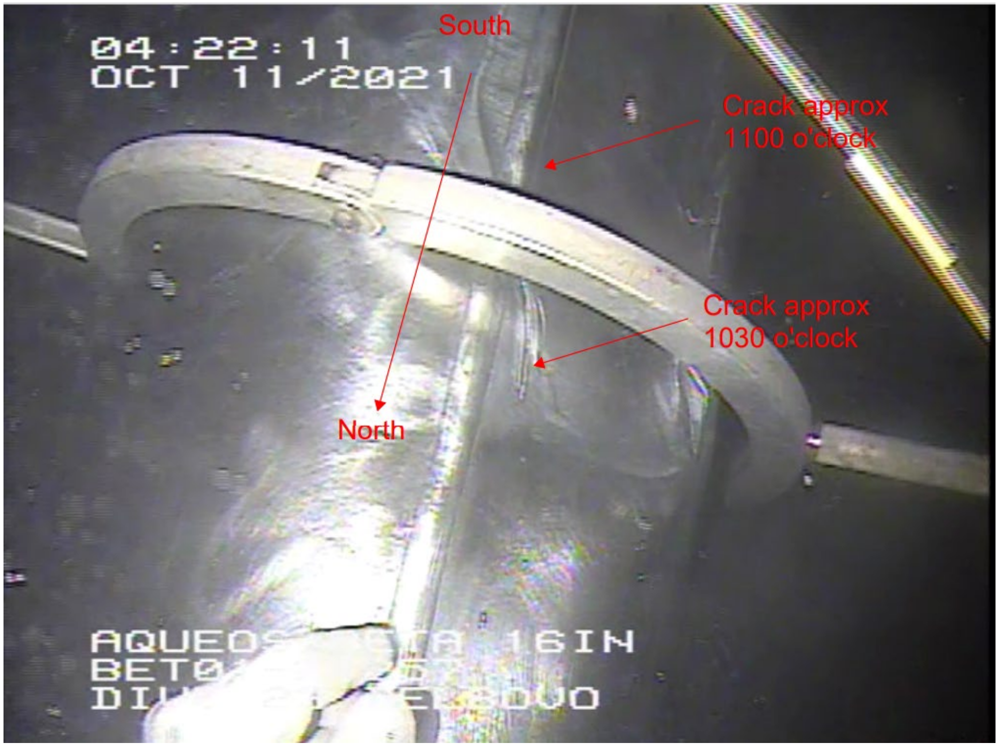

Figure 18. San Pedro Bay Pipeline Non-Destructive testing showing the crack location on the pipe. Photograph by Aqueos, October 11, 2021.

The contractor originally identified the crack required a repair and replacement. Inspectors found other anomalous indications during the review. On the other locations to the south of the crack, they conducted engineering analysis on the pipeline to prepare for temporary and permanent repairs.

On November 20, 2021, when Beta Offshore divers re-inspected the crack, they found a 30-foot x 70-foot oil sheen on the water. Beta Offshore notified the UC and submitted an updated report to the NRC (Report No. 1322578 and update NRC No. 1322586). The divers inspected the previously applied wrap on the crack area and found small crude oil droplets that had moved around the wrap and were migrating to the surface. They removed the composite wrap and installed an epoxy and wrap over the crack. They then placed a pollution dome, which captures any oil released, over the crack area, as well as a camera for ongoing monitoring 24 hours 7 days per week.[31] The dome (Figure 19) remained in place until all hydrocarbons were removed from the pipeline and the threat of pollution eliminated.

[31] A Pollution Dome is a subsea oil containment system, comprising of a subsea collector apparatus positioned subsurface to collect leaking oil and transfer it to the surface.

Figure 19. Pollution Dome Design and Fabricated and Ready for placement with a 53 Barrel Capacity. Photograph by Beta Offshore.

10.1 Crack Repair

Given the 95-foot depth of the pipeline and the out-of-roundness of the pipe, Beta Offshore fabricated a pressure containing steel repair vessel for securing the pipeline until it could be cut out and permanently replaced. PHMSA consulted Oak Ridge National Laboratories, who reviewed and did not oppose the proposed repair design.[32]

The fabricated pressure containing steel repair vessel consisted of several circumferential welds connecting end caps to a short nominal 10-inch diameter pipe section. See Figure 20.

[32] Oak Ridge National Laboratory (ORNL) is a U.S. multiprogram science and technology national laboratory sponsored by the U.S. Department of Energy and administered, managed, and operated by UT–Battelle as a federally funded research and development center under a contract with the DOE, located in Oak Ridge, Tennessee. PHMSA contracted services to evaluate the fabricated temporary patch vessel designed for the crack of the failed section of pipe.

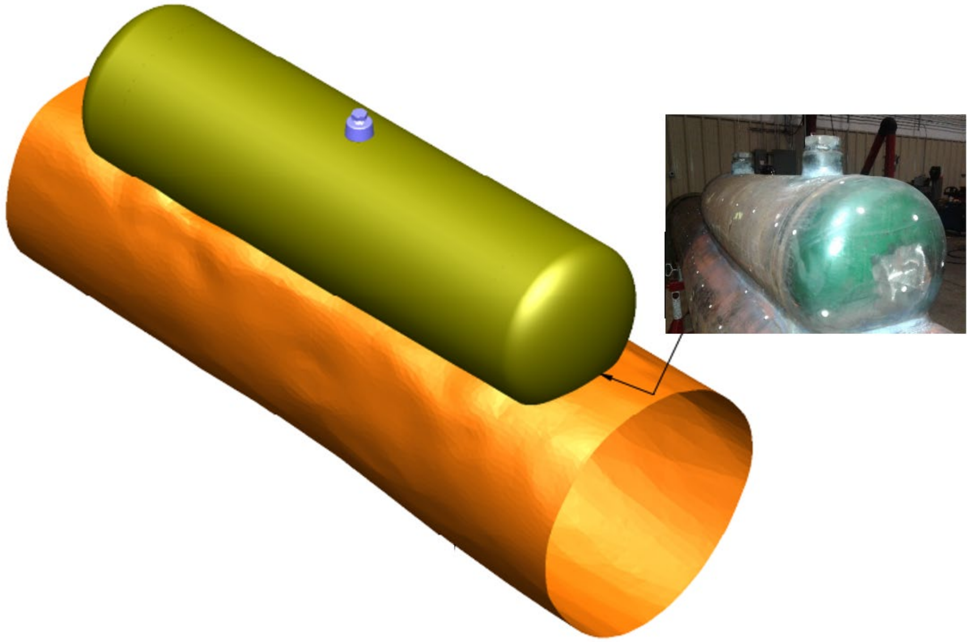

Figure 20. San Pedro Bay Pipeline Fabricated Temporary Repair Patch Model and Fabricated Vessel.

Amplify began the offshore portion of the temporary repair work on December 16, 2021. On December 16 through 18, 2021, Beta Offshore verified the leak had ceased. The pollution dome showed no evidence of crude oil. They welded the temporary patch over the pipe and installed ⅜ inch drill stops on each end of the crack to function as a crack arrestor to prevent further crack development.[33]

With the temporary repair in place, on January 4, 2022, Beta offshore inserted an ultra-seal pig into the pipeline to remove the residual crude oil. The ultra-seal pig that remained in the pipeline prior to the release was estimated to be 1,900 feet upstream from the crack. On January 8, 2022, the brush cleaning pig was received at Beta Pump Station. On January 10, 2022, crews started reverse flushing the residual contents in the pipeline from Beta Pump Station back to *Platform Elly*.

On October 26, 2022, six segments of damaged pipeline were removed from the SPBPL and brought to the surface and were scheduled for replacement. They

[33] Crack arrestor are a structural engineering device that is typically shaped into ring composed of a strong material, It serves to contain stress corrosion cracking or fatigue cracking, helping to prevent the catastrophic failure of a device such as a pipeline. Stress concentration of a crack can be relaxed by drilling a hole (drill stop) at the crack tip. The repair method is called a stop drilling procedure and is often used to reinforce the pipeline wall to protect it against bursting and exterior damage.

replaced two pipe sections that contained the rupture site. Beta Offshore installed 357 feet of new replacement pipe, including a new structural clamp. On the north section, they had replaced over 261 feet of pipe and a south section had replaced over 95 feet. A nine-foot segment of pipe was removed from the section labeled number five and was preserved as evidence for laboratory evaluation at the NTSB Materials Laboratory (Washington, DC). The section removed from pipeline segment number five contained the rupture site – with a welded repair patch still intact. See the Materials Laboratory Factual Report 23-045 for further details. The NTSB laboratory discovered the failed pipe segment showed generally flattened areas at the 6 and 12 o'clock position relative to the pipe flow direction and appeared elongated on the 3 and 9 o'clock positions in the vicinity of the rupture site. An indentation was observed on the lower surface of the pipe segment diametrically opposite of the rupture site. The fracture surface at the rupture site exhibited a flat region extending radially through a portion of the pipe wall near the seam weld. Features resembling radial marks and ratchet marks were observed in the flat fracture region emanating from the outer surface, which indicated progressive crack propagation occurred from multiple origin locations along the outer surface of the pipe wall and migrated toward the inner surface. Finer fracture features were not resolvable due to general corrosion and smearing damage from mechanical contact after separation.

A visible crack, approximately 18 inches long, was observed on the outer surface along the toe of the seam weld and extended through the pipe wall a maximum of 0.3 inch locally. A secondary crack, which arrested at the crack along the seam weld toe, was observed extending through the pipe wall along a gouge in the outer surface. The fracture surface did not exhibit intergranular separation characteristics. No evidence of crack branching was observed. Mechanical and chemical testing found no apparent material defects in the pipe and were consistent with the API standards.

The pipeline was successfully hydrostatically tested on December 19, 2022. The pipeline held pressure above 2220 psig for a period of 15 minutes with no pressure deviations.

On April 8, 2023, the pipeline was restarted.

PIPELINE CONTROL CENTER

The San Pedro Bay Pipeline is monitored and controlled by a SCADA system. The control room is located offshore on *Platform Elly* where a pipeline controller monitors and controls crude oil movements. *Platform Elly* control room is operated 24 hours per day, 7 days a week. In addition, the pipeline can be monitored from onshore at the Beta Pump Station. The facility is a secured facility.

The SCADA system allows the pipeline controller to monitor pipe pressures and crude oil flow rate from one point to another along the pipeline system. The system also provides the pipeline operator the capability of manipulating the remotely controlled pipeline valves, monitoring leak detection of the line, reviewing safety related conditions, monitoring, and acting on alarms, and receiving reports of any detected anomalies to the controls. The pipeline operator can remotely control the automated mainline motor-operated valve and close the emergency shut down mainline valves located at the Beta Pump Station. Control room operators are responsible for operating the entire pipeline and facility operators are responsible for the equipment associated with the pipeline.

Beta Offshore Start Up and Shutdown of Pipeline SPBPL 16" – Platform Elly procedures identified the following control room operator and facilities operator responsibilities for starting up and shutting down the SPBPL:

The control room operator is responsible to:

- Ensure that all personnel follow platform safety and procedural guidelines,
- Operations of the pipeline system,
- Verify radio communications with facilities operator,
- Verify if any "Lock Out Tag Out" exist on involved equipment,
- Verify with the facilities operator that the pump preparation and line ups have been completed and the lube system has been reset,
- Switch the permissive toggle on the master shutdown panel (MSP) for the selected P-05 starting to the "NORMAL" position, this will start the pump.
- To shut down the P-05 pump (s) that is/are online switch the "Permissive" toggle to the "SHUTDOWN" position on the MSP and this will de energize the pump.
- Shut down to verify that the run light on the CCP and SCADA/HMI are out and monitor for a drop in the pipeline pressure and flows.

The facilities operator is responsible to:

- Start up outside operations of the pipeline system,
- Perform operational requests at the direction of the control room operator,
- Monitor pipeline equipment and operational status,
- Verify radio communications with control room operator, and
- Verify if any "Lock Out Tag Out" exist on involved equipment.

11.0 Shifts

The normal hours-of-service are 8-, 10-, and 12-hour shifts (day or night). Controllers normally work 12-hour shifts. During the day, there are two operators working on

Platform Elly, a well bay operator working on *Platform Ellen,* and a well bay operator working on *Platform Eureka*. At night, they have one outside operator for *Platform Elly*, one outside operator for *Platform Ellen* (well bay operator), and one outside operator for *Eureka*. There is a 36-hour minimum time off after a work set and 48-hour work set of 4 or more-night shifts. There are provisions for extended work hours in the event of an outage or unplanned safety critical task, this includes exceptions for unplanned shifts or callouts. The procedures require that controllers have an opportunity for eight hours of continuous sleep between shifts.

Prior to the release, the dayshift controller was on duty on *Platform Elly*, when he had just completed an extended 18-hour shift until midnight on September 30, 2021, due to another controller experiencing unforeseeable travel delays and not arriving on time. The dayshift controller had worked until midnight before another controller could be brought in to take over the console. On October 1, 2021, he went to bed around 02:00 and then awoke around 04:30 and returned for another shift starting around 05:00 that same day. This shift also coincided with his first day of a rotational shift. He was relieved by a nightshift controller after the first LDS alarm was received.

12.0 Abnormal Operations

An abnormal operating condition exists outside the normal operating limits such as a fall in pressure, rise in flow rate symptomatic of a break in, or major leak from the pipeline since the resistance to flow presented by the line is reduced. If the operator notes that there is a significant decrease in discharge pressure from *Platform Elly* and/or a rise in the flow rate that is above normal, the pipeline will be shut down while actions are taken to determine the cause. If no obvious explanation is apparent, then the procedure for providing notification of a possible leak must be initiated immediately.[34]

The procedures call for immediate pipeline shutdown and notification of the platform supervisor or PIC if any of the following occurs:

- Discharge of fluids,
- High discharge pressure (exceeds MOP of pipeline),
- Mechanical malfunction,
- Leak warning on LDS, and
- No flow, pumps on but no flow indication.

Any abnormal operating conditions that occur, are immediately reported to pre-designated on-call personnel for further investigation.

[34] An abnormal operation is a non-emergency condition on a pipeline facility which occurs when the operating design limits have been exceeded due to pressure, flow rate, or temperature change outside the limits of normal operation. [source: Beta Offshore Pipeline Specific Operations and Maintenance (PSOM) Procedure 17.08 Procedure 17.08]

13.0 Leak Detection

SPBPL computational pipeline monitoring (CPM) Leak detection system is monitored through a SCADA operating system.[35] Control room operators monitor all leak detection operational events monitored and recorded by ATMOS Pipe® software and Quantum® operating systems. Communication with *Platform Elly*, in addition to close coordination with facility operations, is maintained via telephone, intranet, cell and radio with the onshore receiving Beta Pump Station. The SPBPL has no history of leaks.

The leak detection system is a volumetric comparison that occurs in two ways to detect leaks and limit the amount of crude oil spilled in the event of a leak. It is intended to detect leaks smaller than a rupture.[36] In the event that this sensor detects an abnormally low pressure caused by a pipeline break, all crude oil shipping pumps will be automatically stopped. The time elapsed between detection and pump shutdown will be less than five seconds. The leak detection system repeatedly scans the PAM devices at each end of the pipeline. A scan calculates the volume of crude oil which has entered the pipeline, change in crude oil volume in the shore surge tank due to level changes, volume shipped to customers, and pressure and temperature changes since the last scan. A net volume imbalance for the bounded system is then calculated. Under normal conditions, the net imbalance at each scan should be either plus or minus the crude oil volume and the cumulative imbalance will drift about zero. If a leak occurs, the cumulative imbalance will grow steadily larger. Alarms are initiated if volume balance discrepancies vary beyond specific short term and long-term limits of the inlet and outlet flow meters. When an alarm limit is exceeded (25-50) barrels per hour, a leak is indicated. See Figure 21 that shows the pipeline pressure, temperature, flow rate, rotating equipment and valve position status are continuously monitored. It uses field flowmeters that measure vibration/harmonics, and pressure.

The leak location indication is shown on the programmable logic controller (PLC) as a leak location in miles from the *Platform Elly* to shore. The range of values are 0 to 17.3 where a 0 value is at the beginning of the line located at *Platform Elly* and a 17.3 value is located at Beta Pump Station.

[35] Computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline must comply with API RP 1130 (incorporated by reference, see § 195.3) in operating, maintaining, testing,

[36] A very large leak (i.e., pipeline rupture) will be detected by a high/low pressure sensor (switch) on the pipeline from *Platform Elly*.

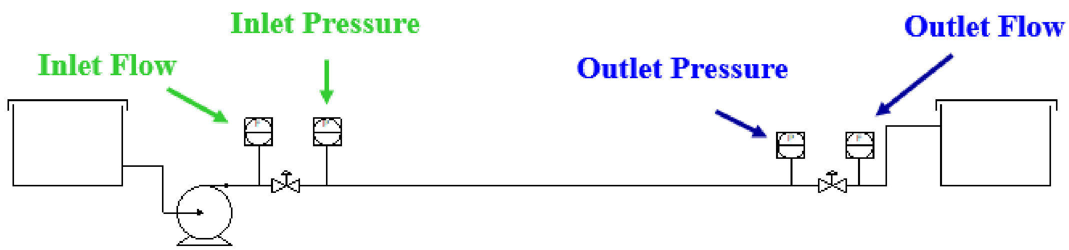

Figure 21. San Pedro Bay Pipeline Meter Configurations, courtesy of Atmos Pipe Operator Training, 2010.

The LDS uses the Atmos Pipe ® a computer-based PLC software program to analyze pressures and flows in order to characterize a leak. The software uses fluid property changes such as crude oil flow and pipeline pressure data that is collected and sent to the SCADA and the PLC systems for processing the data. The software identified a percentage of variation in flow and pressure shown as lambdas. To raise an alarm, at least one lambda must be above the threshold value of 4.6. The lambdas provide controllers with a quick indication of a potential leak on the pipeline system. As long as the potential leak condition is present, the lambda value will remain high.

Controllers are supposed to be trained to review the lambda values and look at the system parameters for indications of a leak. As shown in Figure 22, this involves recognizing that a leak is indicated when the inlet flow increases, as the inlet pressure, outlet flow, and outlet pressure are decreasing. In an interview with dayshift controller, he explained that that they had on-the-job training but had not received formal training on the Atmos CPM process.

	Inlet flow	Inlet Pressure	Outlet Flow	Outlet Pressure
Pump Stop	↓	↓	↓	↓
Pump Start	↑	↑	↑	↑
Outlet Valve ↑			↑	↓
Outlet Valve ↓			↓	↑
Inlet Valve ↑	↑	↑		
Inlet Valve ↓	↓	↓		
Leak	↑	↓	↓	↓

Figure 22. Pattern Recognition and Operational Changes. Courtesy of Atmos Pipe Operator Training, 2010.

When a leak is detected, an alarm will be sounded, a report summarizing pipeline conditions are printed, and a cumulative imbalance versus time trend plot is generated for the last 200 scans. By reviewing the report and plot, the pipeline controller can make a judgment as to the validity of the alarm. The alarm will indicate the location of the leak. A location of mile 0, for example indicates the leak occurred at mile post zero at the beginning of the pipeline at *Platform Elly*.

On October 1, 2021, the first Atmos leak alarm occurred at the control room console at 16:10 and the controller acknowledged the alarm at 16:11 and shutdown the pipeline. The controller noted a "Mile 0" was shown on the control room console, indicating a leak occurred at *Platform Elly*. A second alarm activated at 17:52 where the controller shut down the pipeline, followed by a third alarm at 19:15. The control room operator can shut down the pipeline if a leak is believed to exist and at 19:42, the controller shut down the pipeline and resumed shipping until a fourth alarm activation occurred at 20:39 and the pipeline was shutdown. Over four minutes later, a fifth alarm activated, then a sixth alarm activated at 21:53 when the controller stopped shipping down the pipeline and restarted again. At 23:33, a seventh Atmos LDS alarm activated then shipping was stopped. At 05:28 on October 2, 2022, an eighth alarm activated at the SCADA console indicating a leak was detected and the pipeline was shutdown.

The sensitivity of this system, and hence the maximum amount of oil that could leak before an alarm was sounded, is about 25 to 50 barrels of oil. The estimated detection of a leak based on the percent of nominal flow is found in Table 5. The following leak size and detection time should be achievable by the ATMOS software.

The repeatability for the instrumentation is set at 0.5 percent and the flow meter accuracy at 1 percent of nominal flow.

Table 5. San Pedro Bay Pipeline Leak Rates

Leak Rate (%)	Detection Time (min)	Leak Size (barrels/day)
1.3	50	4
2.7	25	8
4	10	12
6.7	5	20
13.3	4	40
20	3	60
>26.7	2	80

13.1 Leak Location Accuracy

As a general rule for the SPBPL, the leak detection system source location error decreases exponentially as the leak size increases. Leak location estimation depends on the quality of the measurements. For large leaks (greater than 20% of flow), an accuracy of ±5% of the distance from nearest two pressure meters is achievable. Table 6 shows the estimated leak size based on the detection time in minutes.

Table 6. Estimated Detection Times

Leak Size (% of nominal flow)	Detection Time
1%	50 min
1.67%	25 min
3.33%	10 min
≥ 10%	4 min

14.0 Alarms

Beta Offshore' s Alarm Management Plan procedures are based on the alarm system designed to notify the controller of events requiring a response in a timely manner. Alarms are used to indicate the need for controller action to return the pipeline to normal and safe operation, or to avoid automated shutdowns. Alarms may also indicate the need for controller action in response to operational changes in hydraulics, volume measurement, or product quality operating situations. Controllers are supposed to be trained on the alarm management strategy. The procedures require controllers to respond to all alarms, regardless of priority.

The procedures require that pipeline controllers are responsible for the following alarm management tasks:

- Ensuring that the alarm system design meets the required operational performance,
- Ensuring alarms are properly documented,
- Ensuring proper controller response to alarms,
- Ensuring that performance is assessed in accordance with Beta Offshore policy and actions are taken to respond to anomalies, and
- Ensuring they participate in or are a part of the development of the management of change (MOC) process.

All alarm records are logged electronically by the Wonderware software system®.[37] Examples of alarms are high pressure rush of fluids from production wells, and routine weekly tests. Alarms are identified as normal or abnormal events. Normal events are notifications, while abnormal events are alarms that require action. Abnormal alarms are audible and/or visual indications that require at least two actions by the operator, acknowledgement of the alarm and reset, where the operator adjusts the process to resolve the abnormal condition or flags the alarm for repair or maintenance of the process equipment.

Beta Offshore' s procedure, Section 608 *Operations, Maintenance, Assessment, and Monitoring* indicates that false alarms occur occasionally, so any alarm that is presented to the controller that did not accurately reflect the actual operational parameter or condition, or an alarm that can mislead a controller to believe a condition exists that does not exist, is a false alarm. The controller (nightshift controller) on duty, prior to the leak told investigators that he had experienced, "false leak detection before." The controller (dayshift controller) was on duty when the leak was discovered in the field. In an interview with dayshift controller, he explained that the microwave communication signals can be affected by fog or flat water coming in from Beta Pump Station. He explained, "we know that sometimes when there's fog, which there was, messes up our communication, which is our leak detection, and that's the reason why we shut down shipping sometimes." He went on to say, "that was kind of the first indication, but it didn't really dawn on me that it was actually a leak because it happens to us all the time."

PIPELINE INTEGRITY MANAGEMENT

Amplify' s Integrity Management Program (IMP) describes how the integrity of SPBPL will be monitored and maintained. Integrity management is a process that identifies,

[37] Wonderware software system platform acts as an "Industrial Operating System" by providing common services such as configuration, historical trending, deployment, communication, security, data connectivity with field units, people collaboration, and other applications.

assesses, and manages pipeline risks. Amplify's Integrity Management Program describes the process by which Amplify monitors and maintains the integrity of the Pipeline. It consists of a documented set of policies, processes, and procedures that include the required elements pursuant to 49 C.F.R. § 195.452(f).
Beta Offshore has an integrity management plan that identifies risk in high consequence areas (HCA) and those that could affect an HCA. The entire pipeline falls within an HCA.[38] The SPBPL Integrity Management Plan identifies risk factors such as:

- Design (e.g., wall thickness, seam type)
- Operations (e.g., maximum operating pressure, pressure cycle)
- Maintenance and surveillance (e.g., patrolling frequency, valve maintenance practices)
- Previous integrity assessment and repair results
- Operation experience (e.g., leak history, cathodic protection history)
- Commodities being transported.
- Emergency response procedures and preparedness
- Proximity to and geo-physical features separating the pipeline from populations.
- Unusual sensitive environmental resources
- Commercially navigable waters

The program includes the integration of information from inline inspection (ILI), pressure testing, ROV or other technologies.[39] The assessment methods for the integrity of the pipeline are by ROV, ROW inspections, hydrostatic testing, and ILI inspections tools capable of assessing seam integrity, cracking, corrosion, and deformation anomalies.

Beta Offshore' s integrity management program considers at a minimum the following information:

- Previous assessment results
- Surveillance, testing, and other monitoring and inspection data (e.g., internal corrosion coupon monitoring, fluid analysis, and cathodic protection survey results)
- Historical maintenance and repair information
- Root cause analysis or metallurgical analysis
- Inspection tool accuracies or tolerance
- Information about how a failure would affect an HCA
- Consideration of new technology and previous incident report

[38]A high consequence area means a waterway where a substantial likelihood of commercial navigation exists and is an unusually sensitive area, an ecological resource as defined in Title 49 Part 195.450 as defined in 49 C.F.R. § 195.450 and an ecologically unusually sensitive area as defined in § 195.6.
[39] Smart pigs are an internal In-line inspection (ILI) device that evaluates pipelines utilizing non-destructive examination techniques to detect and size internal and external damage. ILI measures and records irregularities in pipelines including corrosion, cracks, deformations, or other defects.

Applicable standards used in the assessment of pipeline risks include:

- API Recommended Practice (RP 1160), Managing System Integrity for Hazardous Liquid Pipelines, for selecting the proper inspection tool,
- API Standard 1163 In-line Inspection Systems Qualification,
- NSI/ASNT ILI-PQ, for inline inspection personnel qualifications, and
- NACE SP0102-2010 In-Line Inspection of Pipelines.

Regulatory oversight of the Beta Offshore' s pipeline integrity management program falls under the requirements of Title 49 Code of Federal Regulations (CFR) Part 195, regulated by PHMSA and Title 30 CFR Part 250 Subpart S Safety and Environmental Management System (SEMS) and Subpart J Pipelines and Pipeline Right-of-Way, regulated by the BSEE.

15.0 Pipeline Right-of-Way Surveillance

The integrity management program included offshore pipeline surveillance. The BSEE ROW permit requires that Beta Offshore inspect the ocean surface along the pipeline route for leakage a minimum of once week by boat or aircraft. The results were maintained at the field location and submitted annually by April I.[40]

The San Pedro Bay Pipeline received a right-of-way permit for the Pacific Outer Continental Shelf region from the BSEE. The permit allows a 200-foot width for the maintenance and operation of the pipeline from *Platform Elly* to state waters, a distance of about 6.37miles.[41]

The Permit requires that the San Pedro Bay Pipeline Company:

- Provide open and nondiscriminatory access to the pipeline to both owner and nonowner shippers,
- Inspect the ocean surface along the pipeline route for leakage a minimum of once every week by boat or aircraft and submit the records of these inspections to BSEE,
- Conduct external surveys using a ROV with video and sonar, a high-or ultra-high resolution side scan sonar, or other acceptable methods to identify burial

[40] A right-of-way grant is an authorization issued by Bureau of Ocean Energy Management for the construction and use of a pipeline for the purpose of gathering, transmitting, distributing, or otherwise transporting energy product generated or produced from renewable energy under 30 CFR Part 585. Under the October 1, 2018, memorandum of agreement, BSEE's functions include all field operations, including permitting, inspections, technology assessment and research, offshore regulatory programs, oil spill response planning, and training.

[41] BSEE Permit number OCS-P 0547 became effective on June 24, 1998.

conditions, protrusions, structural integrity, damage, or corrosion to the pipeline. The external survey should include inspection of the pipeline risers and riser clamps; any grout bags, spans, debris or any other object which might constitute a pipeline safety concern or hazard to commercial fishermen or other users; identification of any weight or any other coating damage; identify any third-party activity, such as anchor scars; observations of the rectifiers or anodes; and visual inspection above the splash zone. Also, side scan sonar shall be used at least once every 6 years as an external survey,

- Internal surveys shall be conducted to identify corrosion and/or damage *using* an internal smart pig survey tool,
- For continuity, pipelines entering State waters should be internally and externally inspected, including rectifier or anodes, as far as possible towards shore when conducting inspection procedures,
- Visually inspect the oil pipeline upon the report of any equipment being dropped overboard which might damage a pipeline or construction occurring within its vicinity and a report submitted to the Camarillo District Supervisor describing the incident and the results of the investigation,
- Inspect the pipeline protected anodes annually within an interval not to exceed thirteen months by taking measurements of pipe-to-electrolyte potential measurements and submit the results and maintain the pipeline to be compatible with fishing and shipping.

16.0 ROV Surveys

Beta Offshore conducts ROV surveys biennially. Under BSEE ROW Permit OCS P 0547, Beta Offshore is required to conduct external assessments using a ROV with video and sonar, a high-or ultra-high-resolution side scan sonar, or other methods acceptable to identify burial conditions, protrusions, structural integrity, damage, or corrosion to the pipeline. The external survey should include inspection of the pipeline risers and riser clamps; any grout bags, spans, debris or any other object which might constitute a pipeline safety concern or hazard to commercial fishermen or other users; identification of any weight or any other coating damage; identification of any third-party activity, such as anchor scars; observations of the rectifiers or anodes; and visual inspection above the splash zone.[42] In addition, an internal inspection of the pipeline is made every two (2) years to Identify corrosion and/or damage using an internal “smart” pig survey tool.

On October 15 through 17, 2021, Beta Offshore performed an ROV subsea pipeline inspection on the SPBPL. The survey provided a visual external inspection and included a video documentation of the pipeline. The survey included inspection for excessive scour and pipeline spans in excess of 50 feet, a continuous pipeline-to-

[42] The splash zone is the area on the pipeline above and below the mean water level where it may be exposed to changing water influence and subject to corrosion. The areas well above the splash zone are exposed only to atmosphere, while the areas below the sea water.

electrolyte cathodic potential survey and anomaly documentation (debris on or near the pipeline such as fishing net, metal objects, cylinders, and automobile tires). The survey found the majority was in good condition with no visible external damage except for:

- Section of the pipeline had multiple sections missing weight coating and the surrounding seafloor showed markings consistent with possible anchor and chain contact with the pipeline.
- A section of the pipeline had moved from its original as built position. That section had multiple sections of missing weight coating and the surrounding seafloor exhibit marking consistent of possible anchor and chain contact with the pipeline.
- Multiple dents on the pipeline that were inspected and confirmed by divers after the ROV survey.
- One (1) cathodic protection test point was installed in 2014 was found to be displaced from its position. It was also noted on the 2018 and 2020 surveys. No damage was found at the test point.

Figure 23. The October 2021 ROV survey showed a possible dent with missing coating. Photograph by Aqueos, October 15, 2021.

17.0 Inline Inspections

Beta Offshore's integrity management uses a combination of ILI and direct assessments to support the results of the hydrostatic pressure testing and provide data for integration as part of continuous evaluation.[43] The purpose of the assessment is to determine if the condition meets Title 49 CFR Part 195.452, special requirements for scheduling remediation. According to Beta Offshore' s *San Pedro Bay Pipeline Integrity Management, Section 2.3.1 Internal Inspection*s procedures, a magnetic flux leakage (MFL) metal loss tool will be run first. If dents, gouges, or grooves are detected, the procedures call for a geometry/deformation tool or physical inspection to identify dents, gouges, and grooves. The BSEE ROW permit requires Beta Offshore to conduct an internal and external inspection by a third party in alternating years within an interval not to exceed thirteen months. Internal surveys must identify corrosion and/or damage using a smart pig survey tool.

In the four years before the release, there were two ILI runs conducted. On November 10, 2017, Baker Hughes, a pipeline ILI contractor for Beta Offshore, ran a CPIG high resolution magnetic flux leakage (MFL) caliper combination tool (CPIG MFL/CAL) ™ the entire 17.5-mile pipeline length. The inspection showed nine metal loss anomalies were all also less than 30% wall thickness loss, as reflected by the 2017 ILI report. Additionally, a more recent ILI (2023 Post Incident ILI) was performed in January 2023, which showed 0 internal metal loss anomalies and 0 external metal loss anomalies. There are 12 anomalies which are categorized as "Mill/ Manufacturing Features" of <30%. There were three (3) previous repairs that had sleeve repairs at 7.6 miles and two (2) at 15.3 miles (15 feet apart) downstream of *Platform Elly* within the breakwater area.

On October 26, 2019, ROSEN, an ILI contractor for Beta Offshore, ran a RoCorr UTWM tool™ on portions of the SPBPL beginning at *Platform Elly*. The RoCorr UTWM is a high-resolution metal loss detection and sizing ultrasonic inspection technology tool that identified metal loss and is a characterization tool. The inspection found no metal loss anomalies equal to or greater than 60 percent of the wall thickness, no dents with metal loss, and three laminations representing the locations of the dents previously repaired with sleeves.

On November 3, 2019, Baker Hughes ran a CPIG MFL/CAL tool on the SPBPL. No pipeline anomalies were found that met the criteria of metal loss equal to or greater than 80 percent of the nominal pipe wall thickness. There were no deformation anomalies with metal loss. One deformation anomaly that was predicted to be greater than or equal to 6 percent of a nominal outside diameter appeared under a previous repair. The three laminations previously identified as dents with no metal loss anomalies sleeve repairs were again identified.

18.0 Corrosion Prevention

The offshore portion of the SPBPL is under "Galvanic" cathodic protection using sacrificial anode bracelets attached to the pipeline. The pipeline was installed with 84 – 315-pound zinc anode bracelets at 100-foot intervals to provide cathodic protection for the subsea portion of the pipeline.[44] Impressed current from Beta Pump Station also provides cathodic protection to the offshore portion of the pipeline. Onshore segments use an impressed current system consisting of rectifiers and buried sacrificial anodes. A pair of rectifiers and an anode ground bed located at the Beta Pump Station facility provides protection for the pipeline.

Cathodic protection surveys are to be performed annually to determine adequacy of protection. Beta Offshore procedures require the SPBPL cathodic protection system provide a level of protection that complies with either at least a negative 850 millivolt (mV) (for offshore 800 mV) or a minimum of 100 mV of cathodic polarization between the structure surface and the stable reference electrode contacting the electrolyte.

Beta Offshore conducted surveys of the offshore portion of the pipeline annually to assure that cathodic protection potentials were within specification to prevent corrosion. A visual inspection of the line is also made with a ROV to inspect for mechanical damage to the line, the coating, and the anode bracelets.

In April 2018, pipe-to-electrolyte potential values recorded were more negative than 903 mV on the SPBPL. No visible damage or anomalies were found on the pipeline. One (1) cathodic protection test point was found to be displaced from its location on the pipeline, and no damage was noted at the location.

Internal inspection of pipe segments removed during 1991, 1993 and 2000 found no evidence of corrosion. These inspections involved onshore segments of the SPBPL or piping at the Beta Pump Station.

In May 2020, the cathodic protection survey was conducted. SPBPL was found to have all test points exceeded the minimum structure-to soil potential with no visible damage or anomalies. One (1) cathodic protection test point was found to be displaced from its location on the pipeline (this was also noted in the 2018 survey), and no pipeline damage was noted at the location.[45] The pipe-to-electrolyte potential values recorded were more negative than 906 millivolts.

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[44] A zinc anode is a type of sacrificial anode used to prevent corrosion through cathodic protection. It is also classified as a galvanic anode, with the other galvanic anodes being made from aluminum or magnesium.
[45]On March 11, 2014, Aqueos a contractor for Beta Offshore installed four (4) RetroClamp Stab test points, two (2) RetroSleds, and four (4) Submar mats.

On November 11 - 12, 2021, Farwest Corrosion, a corrosion contractor conducted a corrosion biannual survey on onshore section of the SPBPL. The survey showed:

- Structure-to-soil Potentials – All measured potentials exceed -850 mV instant off when measured against a reference electrode.[46]
- Dielectric Insulating Flanges – All dielectric insulating flanges were found to be functional and in good repair.
- Anode Beds – The anode beds for Rectifier BS-1 had 17 of the 21 anodes operational and BS-2 had 11 anodes operations out of 16. Both rectifiers were operating as designed and at historical levels.
- Shoreline bond test station was damaged and repaired. The bonds at the pump station were intact, however, a redistribution of current was measured and recorded. This was repaired.

PIPELINE MAINTENANCE AND REPAIRS

19.0 U.S. Army Corp of Engineers

Although the USACE has no authority to approve pipelines, certain pipeline segments and their construction required USACE authorizations. To complete the permanent pipeline repair, the USACE reviewed the existing permit (No. 78-178).[47] A Nationwide permit (NWP) for the emergency and final pipeline repairs was needed to replace the damaged and failed sections of the SPBPL. As part of the permit, the US National Marine Fisheries reviewed the proposal and did not oppose the construction. An NWP verification letter for the SPBPL permanent repairs was issued on September 30, 2022, because the construction involved structures and/or work in or affecting navigable waters of the United States.[48]

Beta Offshore was permitted to remove and replace in-kind the two damaged sections of 16-inch-diameter pipeline at the northern (255 feet of pipe) and southern (76 feet of pipe) sites in two phases based on location. The damaged (cracked) area of pipeline was removed with the northern pipeline section on October 26. Beginning on November 29, 2022, new pipeline sections, consisting of 16-inch

[46] Instant off refers when the structure-to-soil potentials are measured when the cathodic protection current (rectifier) is turned off.

[47] USACE Regulatory program, regulates work and structures that are located in, under or over navigable waters of the United States under Section 10 of the Rivers and Harbors Act of 1899, the discharge of dredged or fill material into waters of the United States under Section 404 of the Clean Water Act, and the transportation of dredged material for the purpose of disposal in the ocean (regulated by the Corps under Section 103 of the Marine Protection, Research and Sanctuaries Act). "Waters of the United States" are navigable waters, tributaries to navigable waters, wetlands adjacent to those waters, and/or isolated wetlands that have a demonstrated interstate commerce connection.

[48] Department of the Army permit is required pursuant to Section 10 of the Rivers and Harbors Act of 1899 (33 USC 403).

diameter concrete-coated, API 5L X-52, 0.500-inch wall thickness seamless steel pipe, were lowered to the seafloor in spool sections ranging from 35 to 45 feet in length.

20.0 Overpressure Protection

At *Platform Elly*, the pipeline is protected from over-pressure by means of a pressure switch set to shut down the pumps at 1043 psig pressure. Pressure relief valves are located at *Platform Elly* set at 1100 psig. At least once each calendar year (at intervals not exceeding 15 months), inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.[49]

21.0 Pipeline Free Span Survey

Beta Offshore surveyed the SPBPL to ensure the support under the pipeline was reviewed and documented. Several pipeline spans (unsupported pipe) have been documented over the years. Pipeline spans range from a few feet to over 50 feet in length can exhibited growth or shrinkage as subsea currents add or remove bottom material near the pipelines. All spans listed in Table 7 below and all spans greater than 50 feet in length are noted, for future tracking. Vortex induced vibration (VIV) is a major cause of fatigue failure in submarine oil and gas pipelines and steel catenary risers especially in the vicinity of the girth welds. Even moderate currents can induce vortex shedding, alternately at the top and bottom of the pipeline, at a rate determined by the flow velocity. [50]

Table 7. San Pedro Bay Pipeline Free Span table

16" OIL PIPELINE SPAN TABLE					
CHAPTER	TIME	DATE	DEPTH	FIX #	DESCRIPTION
1	8:46:36	5/5/2020	251.65	MFX 3	END SPAN 50' X 12"
1	8:51:04	5/5/2020	242.39	MFX 8	END SPAN 100' X 8"
1	8:54:56	5/5/2020	237.71	MFX 13	END SPAN 15' X 6"
1	8:56:10	5/5/2020	235.20	MFX 16	END SPAN 22' X 6"
1	8:58:14	5/5/2020	231.79	MFX 16	END SPAN 21' X 4"
1	9:05:37	5/5/2020	218.82	MFX 21	END SPAN 75' X 4"
1	9:07:16	5/5/2020	216.13	MFX 23	END SPAN 25' X 4"

Two spans greater than 50 feet in length were found on the SPBPL. Neither were unsupported spans greater than 50 feet in the vicinity of the release location.

[49] Title 49 CFR Part 195.428.
[50] Fatigue Analysis of Free Spanning Pipelines Subjected to Vortex Induced Vibrations, Conference: ASME 2013 32nd International Conference on Ocean, Offshore and Arctic Engineering, Van den Abeele, F. Boel, M. Hill, June 2013.

22.0 Damage Prevention Program

The SPBPL is required to have and carry out a written damage prevent program for the pipeline. Beta Offshore Operations and Maintenance Manual, Damage Prevention Procedure 3.01 *Passage of Hurricanes* reminds pipeline operators to, among other things, identify and caution marine vessel operators in offshore shipping lanes and other offshore areas that deploying fishing nets or anchors and conducting dredging operations that may damage underwater pipelines, their vessels, and endanger their crews when there is a hurricane passage.

The procedures do not specify how to identify and caution marine vessel operators in offshore shipping lanes.

The pipeline is charted on the National Oceanic and Atmospheric Administration (NOAA) nautical charts of the San Pedro Channel. The NOAA nautical charts notify mariners about submarine pipelines and cables identified with specific symbols. The notice states, "CAUTION SUBMARINE PIPELINES AND CABLES. . . Additional uncharted submarine pipelines and submarine cables may exist within the area of this chart. Not all submarine pipelines and submarine cables are required to be buried, and those that were originally buried may have become exposed. Mariners should use extreme caution when operating vessels in depths of water comparable to their draft in areas where pipelines and cables may exist, and when anchoring, dragging, or trawling."

Following an extreme weather event or natural disaster that has the likelihood of damage to infrastructure by the scouring or movement of the soil surrounding the pipeline, an operator must inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline within 72 hours after the cessation of the event.[51] To avoid damages from hazardous pipeline incidents that may be prevented through earlier detection of threats to pipeline integrity from extreme weather events, and through enhancing the ability of PHMSA and pipeline operators to evaluate risks, pipeline operators are required to follow an extreme weather event or natural disaster that has the likelihood of damage to infrastructure, such as a named tropical storm or hurricane; or an earthquake in the area of the pipeline. Such an extreme weather event occurred on January 25, 2021, at 03:30. The windspeed at the VTS LA-LB facility in San Pedro, California, was observed to rise from 15 to 28 knots, with gusts up to 47 knots.[51] On January 27, 2021, Beta Offshore conducted a right-of-way inspection over the pipeline.

An operator must inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.[52] An

[51] A) See Nautical Operations, Group Chair Factual Report, VTS LA-LB *CMA CGM New Jersey-Ever Front* Incident Report. B) Vessel Traffic Service Los Angeles-Long Beach (VTS LA-LB)
[52] Federal regulations require pipeline operators to comply with hazardous liquid regulations under

operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments. An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection.

22.1 Coastal and Marine Operators Pipeline Industry Initiative

Coastal and Marine Operators Group (CAMO) is an industry initiative engaging marine vessel operators to promote public safety. The CAMO Group is a private organization consisting of industry consortium comprised of pipeline operators and industry stakeholders. Their mission includes educating marine stakeholders and the public about the risks that damage to offshore utilities and pipelines can pose to personal safety and the environment.[53]

On August 2012, CAMO initiated its joint pilot project for marine pipeline damage prevention and awareness with the USCG. The pilot system was developed using Oceaneering's PortVision AIS-based vessel monitoring service through a grant partnership with Port Fourchon, Louisiana and PHMSA. The transmission of AIS safety messages was approved by the FCC and USCG as part of an experimental AIS transmission.

In 2015, CAMO group partnered with Port Fourchon to provide a test area for vessel and port operators to collaborate on protecting mariners from the risk of pipeline strikes. The AIS Vessel Safety Initiative system provides a safety message transmission making it easier for mariners to know where and when to take protective measures as they transit or operate near submerged pipelines. The system works by allowing a vessel navigating inside a pipeline safety corridor below at a speed of less than 0.5 knots for three minutes or greater to provide a one-time alert stating: "PIPELINE BELOW," depending on the equipment installed onboard the vessel and the configuration of its equipment. Most AIS hardware will alert the vessel operator via an audible alarm, and chart displays will display the AIS safety message.

23.0 Public Awareness Program

Beta Offshore's Public Awareness program includes a schedule for notifications: annually to emergency officials and excavators, once every two years to the public, and once every three years to public officials. A majority of the SPBPL pipeline is located offshore. Amplify' s Public Awareness program includes a schedule for

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Title 49 CFR Part 195.414.

[53] For more information about CAMO, visit http://www.camogroup.org/ or follow CAMO at https://www.linkedin.com/company/coastal-and-marine-operators-camo-.

notifications: annually to emergency officials and excavators, once every two years to the public, and once every three years to public officials. The Coast Guard and Long Beach Harbor Patrol are among others that receive mailers. Amplify' s outreach to community is through a mailer, notification about the location of the Pipeline consisting of publicly available information, and markings on the NOAA charts. The *Public Awareness Procedure 18.00* covers the public awareness program for the SPBPL. The communications procedures related to offshore operations are not covered by these procedures, nor is it intended to provide guidance to operators for communications about operator-specific performance measures that are addressed through other means of communication or regulatory reporting. The procedure referring to offshore public awareness do not have provisions to educate the public, and appropriate government organizations. It does not address the possible hazards associated with unintended releases or what physical indications that such a release may have occurred.

PHMSA PIPELINE INSPECTIONS

In the past ten years, the PHMSA Office of Pipeline Safety (OPS) conducted five standard and specialized inspections of the SPBPL.

24.0 September 24 through 27, 2012

On September 24 through 27, 2012, a standard inspection was conducted of the SPBPL, and Beta Pump Station included a review of baseline procedures, field observations, records review, operator qualification protocol, and liquid integrity management field verifications. The inspection identified no areas of concern or probable violations.

25.0 November 3, and December 7, 2016

On November 3, and December 7, 2016, a PHMSA OPS inspector conducted a standard inspection of the SPBPL and Beta Pump Station resulting in a Letter of Concern. The inspection identified two potential safety concerns related to external construction activity and security that could affect the Beta Pump Station.

26.0 February 2019

PHMSA Office of Pipeline Safety (OPS) conducted a specialized inspection of the Beta Offshore' s drug and alcohol program in February 2019, which included a review of the combined Beta Operating Company Anti-Drug and Alcohol Misuse Prevention Plan. The audit revealed that the drug and alcohol plans were last updated in 2011 and were found to be years out of date. However, the company provided an Addendum, dated January 1, 2018, with updates. The audit identified that, "the plan is mostly a regurgitation of the regulations with little to no information on how Beta Offshore Operating actually manages their drug and alcohol program."

PREVIOUS NTSB INVESTIGATIONS

27.0 Sabine Pass, Texas, 1989

On October 3, 1989, the United States fishing vessel *Northumberland* struck and ruptured a 16-inch-diameter natural gas transmission pipeline, about 1/2 nautical mile offshore, in the Gulf of Mexico, and near Sabine Pass, Texas.[54] When the crews completed their work, the vessel was preparing to leave the area when it started moving backward at 2 to 3 knots, when it struck and ruptured the Natural Gas Pipeline Company of America (NGPL) 16-inch natural gas transmission pipeline. Of the 14 crewmembers, 11 died as a result of the accident.

The NTSB determined that the probable cause of the accident was the failure of NGPL to maintain the pipeline at the burial depth required by the permit issued by the USACE. Contributing to the accident was the failure of the Office of Pipeline Safety of the Research and Special Programs Administration (predecessor to PHMSA), after its 1977 study, to require pipeline operators to inspect and maintain submerged pipelines in a protected condition.

The following safety issues were discussed in the report:

1. The adequacy and enforcement of Federal and State regulations for the maintenance, inspection, surveillance, and protection of submerged pipelines.
2. The need for commercial fishing vessel operators to recognize submerged pipelines as a potential hazard to fishing operations.
3. The marking of submerged pipelines on large scale navigation charts.
4. The knowledge of U.S. Coast Guard Captains of the Port of the number, type, location, and operator of all submerged pipelines within their zones.
5. Emergency preparedness planning of offshore pipeline operators with emergency response agencies and with offshore producers.

As a result of this investigation, the NTSB issued the following safety recommendations:

P-90-2 To the U.S. Department of the Interior:
Assist the Department of Transportation, to determine effective methods of inspection, maintenance, and protection for offshore pipelines located in the Gulf of

[54] National Transportation Safety Board. Pipeline Accident Report. *Fire on Board the F/V Northumberland and Rupture of a Natural Gas Transmission Pipeline in the Gulf of Mexico near Sabine Pass, Texas, October 3, 1989* (NTSB/PAR-90/02). Washington, DC: TSB 9-11-1990, 79

Mexico to depths of water comparable to the maximum drafts of marine vessels that may operate outside of established sea lanes.
Status Closed--Superseded by Safety Recommendation P-90-34

P-90-5 To the U.S. Department of Transportation:
To the U.S. Determine, with the assistance of the Department of the Interior, effective methods of inspection, maintenance, and protection for offshore pipelines located in the Gulf of Mexico to depths of water comparable to the maximum drafts of marine vessels that may operate outside of established sea lanes.
Status: Closed-Superseded by Safety Recommendation P-90-29

28.0 Gulf of Mexico, Galveston, Texas, 2014

The articulated tug and barge (ATB) unit Valiant/Everglades lost propulsion and drifted within about 20 yards of the East Cameron 321A production platform in the Gulf of Mexico, forcing the shutdown of the platform and evacuation of its 35 crewmembers, at about 0600 on November 17, 2014. The captain of the Valiant ordered the anchor dropped to slow the vessel until propulsion was restored, and in the process of backing away, the anchor ruptured a subsea pipeline, causing an estimated $2 million in damage and the release of about 249,800 thousand cubic feet of natural gas. Neither the platform nor the vessel was damaged, and no one was injured.[55]

The NTSB determined that the probable cause of the damage to the subsea natural gas pipeline was the anchor from the Valiant/Everglades dragging across the pipeline after the vessel lost starting air pressure and propulsion due to the opening of an unprotected air system valve on deck.

29.0 Matagorda Bay, Texas, 2018

On April 17, 2018, the cutter suction dredge *Jonathon King Boyd* punctured a submarine natural gas pipeline with a spud during dredging operations in Matagorda Bay, Texas. A gas plume ignited and engulfed the dredge and its accompanying towboat, the *Bayou Chevron*. All ten crew members abandoned the vessels uninjured.[56]

The NTSB determined that the probable cause of the fire aboard the cutter suction dredge *Jonathon King Boyd* was RLB Contracting's failure to inform the crew about

[55] *Subsea Pipeline Damage by Tug and Barge Valiant/Everglades, Marine Accident Brief Report* NTSB/MAB-15/15, (Washington D.C., National Transportation Safety Board, 2014).
[56] *Pipeline Breach and Subsequent Fire Aboard Cutter Suction Dredge Jonathon King Boyd and Towboat Bayou Chevron,* Marine Accident Brief Report NTSB/MAB-19-19, (Washington D.C., National Transportation Safety Board, 2019).

utilities in the area due to ineffective oversight, which led to dropping a spud onto a buried submarine pipeline, causing natural gas to release and ignite.

30.0 Corpus Christi, Texas, 2020

On August 21, 2020, about 0802 central daylight time, the US-flagged dredge *Waymon Boyd* struck a submerged 16-inch liquid propane pipeline during dredging operations in Corpus Christi, Texas. A geyser of propane gas and water erupted adjacent to the vessel. Shortly thereafter, propane gas engulfed the vessel and an explosion occurred. Fire damaged the vessel and surrounding shoreline. A total of 18 personnel employed by Orion Marine Group were working or resting on the dredge and assist boats (tender boats, anchor barges, booster barges, and a supply barge) on the day of the accident. Three crewmembers aboard the *Waymon Boyd* and one on an adjacent anchor barge died in the explosion and fire. Six crewmembers aboard the dredge were injured, one of whom later died from his injuries.[57]

The NTSB determined the probable cause was Orion Marine Group's inadequate planning and risk management processes, which failed to identify the proximity of their dredging operation to Enterprise Products' pipeline TX219 and resulted in the absence of effective controls to prevent the dredge's cutterhead from striking the pipeline. Contributing to the accident were deficient dredging plans, which resulted in incomplete and inaccurate information communicated to Enterprise Products by Orion Marine Group during the one-call process, which resulted in insufficient measures to protect the pipeline from excavation damage.

Refer to Appendix B for other pipeline accidents involving marine vessels. The accident descriptions were provided by pipeline operators who are required to submit an accident report to PHMSA.[58]

PERSONNEL QUALIFICATIONS

Beta Offshore adopted an electronic system to fulfill the requirements for PHMSA/DOT 49 CFR 195, also Beta Offshore provides in house training as supplemental. The company policy requires training every three years and is tracked electronically by Beta Offshore' s electronic training management system.

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[57] *Hazardous Liquid Pipeline Strike and Subsequent Explosion and Fire aboard Dredging Vessel Waymon Boyd,* Marine Accident Report NTSB/MAR 2105, (Washington D.C., National Transportation Safety Board, 2021).

[58] Title 49 CFR Part 195.50 Reporting Accidents.

31.0 Pipeline Dayshift controller

The pipeline controller who was on duty at the time of the accident had over 13 years' experience with the Beta Offshore. He had prior experience in construction and started working in 2008 for Pacific Energy. He gained experience starting as a well bay operator, gaining experience on operations on *Platform Elly* and *Ellen* platform control rooms. He was qualified as a pipeline controller for 3 years. Testing required a handwritten test and a verbal test to certify for different positions. After about three months, he passed the Well Bay test to become a well bay operator, receiving his T2 certification, which authorized the controller to work on offshore pipeline systems. His training involved the review by a Platform, Well Bay, and Safety Trainers.

32.0 Pipeline Nightshift Controller

The controller who was on duty at the time the release was identified had over 43 years of experience in offshore production. He started working in 1978 when Shell owned the pipeline. He began his employment as a roustabout crew member and progressed to a well pulling crew member for six years. He then became a lead for three years. He started working offshore on the platform around about 1996, as a facility operator. In 2006 he went to work for Pacific Energy as a facilities operator for about 3 to 4 years. He trained and became a control room operator on *Platform Elly* for the last eight years.

FEDERAL AND STATE JURISDICTION

Offshore transmission and gathering pipelines in federal waters on the Outer Continental Shelf are regulated by the PHMSA OPS and by BSEE.

33.0 Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety and California Office of State Fire Marshal

The PHMSA OPS has authority over the SPBPL through Section 60112 of Title 49, United States Code. PHMSA regulates Offshore transmission and gathering pipelines in federal waters on the Outer Continental Shelf. PHMSA OPS monitors operator compliance through field inspections of pipeline facilities and construction projects; inspections of operator management systems, procedures, and processes; and incident investigations. PHMSA deployed investigators to the site of the release to review and monitor the pipeline release and review the emergency response plan. PHMSA additionally issued a corrective action order that required Beta Offshore to take immediately corrective actions to the SPBPL to:

- Shutdown of the Affected Pipeline
- Verify the records for the Affected Pipeline that were used to establish the MOP

- Review of prior Inline Inspection Results
- Conduct an ILI of the Affected Pipeline using a geometry tool, a high-resolution axial magnetic flux leakage (MFL) tool
- Mechanical and metallurgical testing and failure analysis of the failed pipe
- Complete and submit a root cause failure analysis
- Develop and follow a remedial work plan
- Review and assess the effectiveness of the emergency response plan and training Review
- Review and assess the effectiveness public awareness program review.
- CAO documentation review
- Provide a written restart plan.
- Twenty percent (20%) pressure reduction of the affected pipeline
- Perform an aerial survey (off-shore) and ground leakage survey (on-shore) of the affected pipeline right-of-way.

Additionally, PHMSA monitored compliance with the federal regulations.[59]

The California Office of State Fire Marshal (OSFM) regulates offshore hazardous intrastate liquid transmission and gathering pipelines in state waters. PHMSA OPS grants the OSFM exclusive regulatory authority over intrastate hazardous liquid pipelines under a certification issued through OPS.[60] Identified non-compliance issues and unsafe conditions are addressed through a variety of means, including an assortment of enforcement tools, such as corrective action orders, safety orders, notices of violation, warning letters, and notices of amendment.[61] As interstate agents, OSFM provides assistance to PHMSA as needed.

OSFM regulates the safety of intrastate hazardous liquid pipelines in California. OSFM Pipeline Safety Division staff inspect pipeline operators to ensure compliance with federal and state pipeline safety laws and regulations. PHMSA maintains exclusive federal authority over interstate pipelines, which are pipelines that cross over state borders or begin in federal waters. However, the OSFM was granted an agreement authorizing the OSFM to participate in the oversight of interstate hazardous liquid pipeline transportation, special investigations involving incidents, new construction,

[59] Federal regulations require pipeline operators to comply with hazardous liquid regulations under Title 49 CFR Part 195.
[60] Pipeline safety base grants are authorized by Title 49 of the United States Code (49 U.S.C.) Chapter 601 §60107 – State Pipeline Safety Grants. To qualify for federal grant funds a state agency must participate in the pipeline safety program either under certification in accordance with 49 U.S.C. §60105 or under an agreement in accordance with §60106.
[61] Title 49, Part 190, Subpart B "Enforcement" in the Code of Federal Regulations. Part 195 does not apply to pipelines upstream of the flange outlet of a production facility on the Outer Continental Shelf.

and other activities overseeing interstate pipeline transportation.[62] [63] The agreement does not allow OSFM the authority to issue enforcement actions on interstate hazardous liquid pipelines that remain under the purview of PHMSA OPS.

Additionally, these California state agencies are responsible for the following aspects of petroleum production:

- The California Geologic Energy Management Division (CalGEM) regulates oil and natural gas production pipelines and wells.
- The State Lands Commission manages offshore oil and production within three miles of the coast.

34.0 Bureau of Safety and Environmental Enforcement

BSEE has the authority and responsibility to conduct investigations as outlined in the Outer Continental Shelf Lands Act (OCSLA), and its implementing regulations.[64] BSEE is the lead federal agency charged with investigating incidents related to the offshore energy industry, primarily oil and natural gas, and most recently renewable energy, on the U.S. Outer Continental Shelf. BSEE's Safety and Incident Investigations Division and the Regional Office of Incident Investigations collect data to determine compliance with their regulations, which includes the Safety and Environmental Management System (SEMS II) rules. The SEMS II rule established performance-based standards at 30 CFR Part 250, Subpart S for managing offshore operations and Subpart J for managing pipeline right-of-way.[65]

The district investigation report includes a determination of probable cause(s) of an accident, list the contributing cause(s) of an accident, recommendations to prevent recurrence, and a narrative that includes OCS violations related to accident.

On October 4, 2021, the BSEE issued a preservation order (Order) to Amplify.[66] The Order required that Amplify take all steps necessary to immediately identify, retain, and preserve, in their present condition, all potentially relevant information related to the pipeline leak that occurred, October 1, 2021, between Amplify' s *Platform Elly* and the Beta Station in Block 6438 of the LB area, surface lease P-0300.

[62] An intrastate hazardous liquid pipeline is a pipeline that is located entirely within the borders of the State of California, including offshore state waters.
[63] The pipeline safety statutes allow for States to assume safety authority over interstate hazardous liquid pipelines Agreements with PHMSA under 49 U.S.C. §§ 60106.
[64] Title 30 Part 250
[65] See 78 *Federal Register* 20423, April 5, 2013.
[66] Section 22 of the Outer Continental Shelf Act (43 U.S.C. section 1348)

35.0 United States Coast Guard

The Coast Guard investigates the causes of marine casualties and analyzes investigation data in an effort to identify measures that will promote safety, protect the environment, and to prevent future accidents. Under the ACP, the USCG Captain of the Port is pre-designated the federal on-scene coordinator (FOSC), with primary responsibility for incidents originating in navigable waters within the coastal zone.[67][68] The USCG Sector Los Angeles-Long Beach maintains IMTs for response to discharges of oil in the coastal zone. FOSC's are responsible for determining the source, cause, and responsible party, as well as initiating source control and enforcement actions as appropriate. The FOSC coordinates and directs on-scene response resources and efforts during a pollution incident. Through the support of the National Response Team, Regional Response Team, state representatives, area committees, special teams, contractor resources, and responsible parties, as necessary, to supply the needed personnel, equipment, and scientific support, respond to discharges of oil and hazardous substances.[69]

Whenever a vessel is involved in a marine casualty with significant harm to the environment, the owner, agent, master, operator, or person in charge of a vessel they must notify the nearest USCG Sector Office, Marine Inspection Office.[70] Upon receipt of information of a marine casualty, the USCG will initiate an investigation to determine its cause and may initiate appropriate proceedings against the credentials of persons for misconduct, inattention to duty, negligence, or willful violation under 46.U.S.C. 6301.

OPERATOR POST-ACCIDENT ACTIVITIES

36.0 Post-Accident Drug and Alcohol Testing

In accordance with 49 CFR 199.105(b), an operator must drug test each surviving covered employee whose performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident and may elect not to test if a decision based on specific information that the covered employee's performance had no role in the cause or severity of the accident. Beta Offshore procedures state, "All employees who are governed by the DOT regulations, including testing on a random or periodic basis." At the time of the

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[67] Los Angeles-Long Beach Area Contingency Plan (v. 2019-3), June 2022. The Area Contingency Plan is the primary guidance manual for responders to oil spills and hazardous substance releases and is intended to promote coordination for orderly and effective implementation of response actions.
[68] The Captain of the Port area of responsibility is specified in 33 CFR 3.55-10.
[69] The U.S. National Response Team is an organization of 15 federal departments and agencies that are responsible for providing technical assistance, resources, and coordination on preparedness, planning, response, and recovery for emergencies of national significance involving hazardous substances, pollutants, contaminants, oil, and weapons of mass destruction. See https://www.nrt.org.
[70] In accordance 46 CFR 4.05-1

release, the cause was unknown therefore the controllers on duty and field staff were not drug and alcohol evaluated.

37.0 Operations post-accident Actions

In response to NTSB investigator's request for the Beta Offshore to identify post-accident policy or best-practice changes, Amplify responded that they had conducted several activities to improve their operations and to enhance public safety across both its Beta Offshore operations in California and its affiliated, onshore assets.

Evaluation of Amplify' s Existing Pipeline-Related Procedures and Trainings
Amplify updated its existing operational procedures. Amplify conducted a desktop evaluation of procedures for Beta's operations of the offshore facilities including a month-long review of control room procedures. They revised the following procedures:

- *Platform Elly* – Power Generation / Emergency Power Procedure. Removed redundant information and items no longer required due to process changes.
- *Platform Elly* – Power Failure Procedure. Added additional procedures, clarified existing procedures, and updated equipment names.
- *Platforms Elly, Ellen, Eureka* – Start-up Procedure. Updated list of responsible personnel and specified available power sources.

Additionally, they are evaluating revisions to more procedures, including about 150 non-critical procedures. Amplify reports that the crew will be trained and tested on all revisions before restart of the SPBPL, subject to PHMSA approval.

Amplify Increased Staffing
Amplify is evaluating staffing levels for each element of its pipeline-related operations and is attempting to make additions to its employee and contractor roster. For example, Amplify evaluated the need for an addition, redundant control room operator and one redundant *Platform Elly* plant operator to increase personnel knowledge and strengthen the employee base.

Changes to Pipeline-Related Technology and Equipment
Beta Offshore installed a new leak detection system to improve the accuracy of its leak detection alarm locations. Amplify began the project in December 2021. On March 31, 2022, Amplify selected the KROHNE system, which uses independent remote terminal unit (RTU) packages for direct point data gathering.[71] In the event of a communications failure, redundant RTUs and sensors are available for immediate

[71] A remote terminal unit (RTU) is a microprocessor-controlled electronic device that interfaces to a SCADA system by transmitting telemetry data to a master system. An RTU converts electrical signals from (field) instrumentation to data, and to make that data available to the SCADA Host.

deployment, with equipment stored locally in California. RTUs also provide redundant 4G communications if there is a primary communications failure. In addition, KROHNE provides a visual mapping display of identified leak points.

The new leak detection system is a site-specific, engineered product that fits the type of product in the line, viscosity, gravity, temperatures, and volumetrics, among other things. Beta Offshore will then perform three tests to ensure the system and related communications infrastructure are functioning properly.

Once operational, Amplify will have KROHNE personnel train the crews before Amplify restarts the SPBPL and then annually thereafter.

ACCIDENT WITNESS INTERVIEW SUMMARIES

38.0 Dayshift controller

The following information about the accident was compiled from the transcript of the control room operator's interview by NTSB investigators on October 9, 2021.

The dayshift controller was on duty at the console when the crude oil release was discovered. Prior to the incident, the dayshift controller had worked from about 06:00 on September 30 until about 01:00 on October 1, and was at the console for the SPBPL from about 05:00 to about 18:00 on October 1. The dayshift controller worked until midnight before another controller could be brought in to work the shift. On October 1, he went to bed around 02:00 in the morning. He woke up around 04:30. and returned for another shift around 05:00. This shift also coincided with his first day of rotational shift.

There was a lot of activity occurring on Friday but a normal day. They sent a cleaning pig out on the SPBPL and received pigs on *Platform Eureka* to *Platform Elly* 10-inch pipeline. He had walked around *Platform Elly* and completed his rounds to ensure all the levels were where they were supposed to be. They were receiving the three cleaning pigs from *Platform Eureka* with a chemical pill[72] between pigs. They also scheduled to send a cleaning pig to the Beta Pump Station.

When they received the chemical pill, they were having problems blending the mix because the oil was received on the bottom and water floating on top. As the crews were dealing with the *Platform Eureka* to *Platform Elly* 10-inch pipeline pigging activities, he was running the water content "water cut" analysis on SPBPL delivery. The amount of water "cut" is usually about 0.6 – 2.0 percent water in oil and the "cut"

[72] A chemical pill is the application of corrosion inhibitors and other chemical that coats the internal surface of the pipe and assists with the removal of debris and removal of sand or wax buildup in the pipeline. The chemical pill is placed between cleaning pigs.

values were starting to get higher about 4 or 5 percent water in oil then he started seeing Dry Tank S02B level start to rise. He sent the water carried over with the crude oil to Dry Tank S02B.

He called the PIC around 12:30, letting him know conditions. The well bay controller started shutting down some of the production wells on *Platform Ellen* to reduce more fluid rushing in, and he noticed it was not really helping. He called over to *Platform Eureka* to have them shut down the variable speed drive pump units. By that time, *Platform Ellen* was halfway shut down, the PIC instructed the controller at *Platform Ellen* to shut the remaining wells down to "let everything calm down."

Dayshift controller was having problems with the disposal pump, used to move the separated water. He continued to ship with a higher water content. At that point, the system became stable, meaning the water levels were dropping and the pumps were able to push the fluid through the pipeline. the upset was eventually resolved around 4:00 p.m., large amounts of water remained in the pipeline. The crew was aware that there continued to be unusually large amounts of water in the pipeline throughout the afternoon and evening of October 1. The increased water content meant the shipping pumps were having to pump at a higher-than-normal rate to clear the dry tank because they were pumping water in addition to the crude oil.

The LDS had lambda variables that were rising. Normally they would shut down the shipping pumps and "let them calm down." the dayshift controller acknowledged the alarm on the screen and shutdown the pump. he gave it 15 minutes then restarted the pumps around 17:00.

After restarting the pumps, they received another alarm, and dayshift controller shut down the pumps again. This time, they gave it 30 minutes to an hour to reset and clear. The controllers thought the high lambda values were responsible for the alarm, and therefore they shut the shipping pumps off. He observed a zero-value displayed on the console for the meter counter. In his experience, when a zero is displayed on the console, it means a leak was located at *Platform Elly.* By this time, dayshift controller was tired and asked to have nightshift controller to take over the console desk, and he went to bed at 17:30.

The dayshift controller came back on duty at 05:50 on October 2. There were five control room operators in the control room including the well bay controller. The nightshift controller had experienced leak detection alarms going off all day long, starting at 16:10 on October 1. The right-of-way inspection-boat arrived, and they were preparing to conduct another pipeline right-of-way survey run. Around 08:15, dayshift controller was notified there was a sheen in the water. He telephoned the right-of-way survey boat who confirmed there was oil was on the water. His next call was to the *Platform Ellen* and *Platform Eureka* controllers to shut down everything. He started to shut down the rest of the systems, including the water injection Saturn pump turbine recovery unit, and the Centaur gas driven turbine generator since they were not producing gas.

39.0 Pipeline Superintendent

The following information about the accident was compiled from the transcript of the control room operator's interview by NTSB investigators on October 9, 2021.

The pipeline superintendent had the day off on October 1, 2021. About 21:00, he received a call from senior pipeline technician informing that they were having metering issues. Around midnight, he received another call from nightshift controller that they were still having metering problems and leak alarms, so they were shutting down the pipeline to diagnose the trouble. He was informed the HMI was displaying zero. He knew the senior pipeline technician had worked the day before, so believing he was tired, therefore the pipeline superintendent drove into the station to try and remedy the situation himself.

On October 2, 2021, at about 01:30, the pipeline superintendent arrived at the Beta Pump station. Upon arrival, the nightshift controller told him that they had a huge upset on the platform starting with the water processing equipment, metering, and communication between *Platform Elly* and Beta Pump Station. Dry Oil Tank SO2B (dedicated to sales quality crude oil) was contaminated with a lot of water and entrained gas, which made a frothy mixture. The pipeline superintendent believed the froth had therefore entered the pipeline and it was being pumped to shore.

Around 02:30, while the operator was troubleshooting, the pipeline superintendent called Quantum Solutions, a contracted company that works with metering and instrumentation issues and are familiar with the PLCs and the omni flow computers He told investigators that he thought some of the software parameters had been changed since earlier that day, an IT technician was verifying some of the items displayed on the HMI screens. He was working on the network which includes the LDS but that was determined not to be the problem.

About 02:30, the pipeline superintendent called the Vice President of Operations to explain what was happening. He called the PIC, but the control room was occupied with responding to alarms. He suggested to the controller to put the pipeline to sleep while they were still trying to address the problem.[73] When the system is placed in the

[73] The ATMOS software has a "sleep mode" that disables the leak detection audible alarm but the visible alarm remains. It can be activated selecting "sleep" from the ATMOS Panel which can be used during maintenance work. The software warns that ATMOS will remain in the sleep mode until the command is removed.

sleep mode, it does not stop the system. The controller can receive and acknowledge alarms but pauses the audio alarm.

The pipeline superintendent had previous experience when the pipeline is shut down and restarted again, the LDS mysteriously would function normally. In an interview with the pipeline superintendent, he stated, “We were also running it at a little bit lower rate, so the delta between onshore and offshore wasn't nearly as severe as it was before, and honestly we thought we were kind of on the right track for a moment there, but we didn't feel comfortable.” this was not the case the day of the incident, but the volumetric difference was closer after the reset, so the control room staff, and pipeline superintendent thought their actions were getting to a resolution to the volumetric difference.

The pipeline superintendent left for home about 06:15 after the pipeline was shut down and returned immediately when he saw the pictures of the spill in the media.

40.0 Nightshift Controller

The following information about the accident was compiled from the transcript of the control room operator’s interview by NTSB investigators on October 9, 2021.

When working the night shift, nightshift controller begins work around 16:30. The day of the incident was the first day of his shift. He coordinated a shift change with the dayshift controller which is typically is a verbal exchange covering some items written in the logbook and anything happening during the shift. Normally, the night shift runs from 16:45 to 05:00. He was awakened around 14:00 on Friday, October 1 to assist with the upset on Platform Elly.

On October 1, shortly before 14:00, the nightshift controller came on duty and found the knockout unit valve not working correctly (sticking). It was the first-time nightshift controller had seen the valve sticking in a couple of years. It was not a common for the valve to stick but when it did, it made shipping difficult. The technician exercised the valve a few times and cleaned it, which caused it to work again.

When it came to reacting to an alarm, the nightshift controller was trained to shut down the shipping pumps and let the crude oil sit and settle out in the pipeline started shipping through pump B. The nightshift controller stated to investigators that he kept the shipping pumps shut down for a half hour to an hour, depending on where the levels of the dry tank. His experience told him by shutting down and restarting the pumps, it fixes the problem and clears the alarms.

When the leak alarm first went off, the nightshift controller noticed leak location displayed only zeros. A zero display meant the leak was located at *Platform Elly*. He continued receiving leak alarms until about 05:28 on October 2.

The night of October 1, the nightshift controller did not use the trending capabilities or the lambdas. He based his information on the pipeline pressure and the crude oil flow entering the meter. The pipeline was shut down, so he called the PIC about the ongoing leak detection.

He started shipping through pump B, which raised the pipeline pressure but did not help much. He tried adding another pump for 10 minutes to see it could move the crude oil mix, when mechanic called the control room for assistance. The nightshift controller discovered the pumps were cavitating. The discharge gauges on the two running pumps read zero, so he instructed the dayshift controller to shut off the pumps.

About 19:30, he called the Beta Pump station senior pipeline technician who arrived at the Beta Pump Station about 20:00. The senior pipeline technician rebooted his computer thinking it would clear the problem. He restarted the pipeline for about 12 – 15 minutes, then the pipeline went back into a leak detection alarm mode. The nightshift controller shut down the pipeline again. He was unsure of the time when he had the facility operator look outside the control room at the PAM meter unit, shipping pumps around the tank, and the pipeline on *Platform Elly*. The facility operator had climbed down to the 12-foot level and conducted a visual review. It was dark outside, but he was able to see the pipeline all the way to the point where it entered the water and did not observe oil on the water.

The nightshift controller ran the manual leak detection until 02:20. The pipeline superintendent instructed him to restart shipping to see if they could rebalance the system. They put the pipeline to sleep mode around 21:00 on October 1. The nightshift controller was not aware the sleep function was an option on the console. He thought at the time the three pumps running and a cleaning pig in the line may have caused gas and other debris to mix in the line, and the combination may have caused the leak detection alarm. They started the pipeline after a 25-minute period to let it settle, believing it would allow the Beta Pump station meter to coordinate with the PAM meter, however he noticed the strategy did not work.

About 03:35, after discussions with the nightshift controller and the PIC. The PIC called for the boat to conduct a ROW inspection, which took about 45-minutes to complete. No evidence of an oil spill was seen by the boat. About 05:00, the pipeline superintendent decided to do a meter check, so the controllers restarted the shipping pumps while pipeline superintendent the meters.

The nightshift controller remained at the console until 05:50 until his replacement dayshift controller arrived in which he conducted a shift change with him. It was not until he woke up at 16:00 that he learned there was a leak on the pipeline.

APPLICABLE INDUSTRY GUIDANCE AND CONSENSUS STANDARDS

41.0 API Recommended Practice 1160

API Recommended Practice 1160 (RP 1160), Managing System Integrity for Hazardous Liquid Pipelines is used to assist in the determinations of the proper inline inspection tool.

The RP provides guidance to the pipeline industry for developing and managing a pipeline integrity program.[74] The guidance recommends identifying threats to the integrity of pipelines and pipeline facilities, assessing the risk of a release from one pipeline segment to another, and mitigating the risk by removing identified threats.

PHMSA provides additional guidance to help an operator implement the requirements of the integrity management program rule in CFR Part 195 Appendix C to Part 195 - Guidance for Implementation of an Integrity Management Program.

42.0 API Standard 1163 In-line Inspection Systems Qualification

API Standard 1163 In-line Inspection Systems Qualification is used when conducting inline inspection of pipelines. This standard provides performance-based requirements for ILI systems, including procedures, personnel, equipment, and associated software. It provides guidance for the qualification, selection, reporting, verification, validation, and use of ILI systems for onshore and offshore hazardous liquid pipelines.

43.0 NACE SP0102-2010 In-Line Inspection of Pipelines

The National Association of Corrosion Engineers (NACE) Publication NACE SP0102-2010 In-Line Inspection of Pipelines is a standard that provides recommendations to the pipeline operator of industry-proven practices in ILI. This standard is specific to the inspection of line pipe installed along a right-of-way, but the general process and approach may be applied to other pipeline facilities such as gathering systems, water

[74] API Recommended Practice 1160, 3rd Edition, (Washington, DC, American Petroleum Institute, 2019).

injection systems, station piping, and isolated crossings of railroads, highways, or waterways.

44.0 ANSI/ASNT ILI-PQ-2017 In-line Inspection Personnel Qualification and Certification

The American Society for Nondestructive Testing (ASNT) in-line inspection personnel qualification and certification standard was developed by ASNT and approved by the American National Standards Institute (ANSI). This is an employer-based standard to assist the operator in determining qualifications of personnel working on ILI. It provides the minimum requirements for qualification and certification of in-line inspection personnel whose jobs demand specific knowledge of the technical principals of in-line inspection technologies, operations, regulatory requirements, and industry standards as applicable to pipeline systems.

Submitted by:
Kim West

Pipeline Operations Group Chair

APPENDIX A: PIPELINE OPERATIONS TIMELINE OF EVENTS

Date	Description	Source
10/1/21 6:00 AM	Morning operational meeting held.	Controller Interview
10/1/21 8:00 AM	The shipping pump was depressurized and shut down in preparation for pig launch from Eureka.	Controller Interview
10/1/21 8:25 AM	Pig Run Started the original SCADA data indicated flow change	3
10/1/21 8:29 AM	Pump C running	3
10/1/21 9:30 AM	The second cleaning pig shipped.	Controller Interview
10/1/21 10:30 AM	Third cleaning pig was shipped	Controller Interview
10/1/21 10:40 AM	The first pig was received.	Controller Interview
10/1/21 10:40 AM	Beta started making decisions to close the water out of the heater treater (BO2B) float it off water and stabilize the system.	Controller Interview
10/1/21 11:45 AM	Received the second pig while Tank SO2B levels were getting high.	Controller Interview
10/1/21 12:30 PM	Tank SO2B levels start rising. The pumps are not designed to push water or a mixture.	Controller Interview
10/1/21 2:10 PM	First alarm *Platform Elly* Dry Tank S02B Level Exceeded 85 percent.	6
10/1/21 4:00 PM	Tank SO2B levels start coming down	Controller Interview
10/1/21 4:05 PM	Mainline pressure spike to 829-psig. MOP is 1152-psig	4
10/1/21 4:10 PM	First Atmos Leak Detection alarm. Leak Detection System alarm activated following a major high water upset at *Platform Elly* Plant in wake of receiving 3-pig train with chemical pill from *Platform Eureka* in the 10-inch diameter bulk line. Beta assumed the alarm was erroneous and activated due to upset conditions in the pipeline from shipping wet. There was low to no plant residence time. A "Mile 0" was shown on the LDS indicating there was a leak is at the *Platform Elly* location (mile zero). Local checks were performed, and the LDS was reset. Shipping was resumed.	1, 3
10/1/21 4:11 PM	Atmos Leak Detection acknowledged by the dayshift controller	3
10/1/21 5:00 PM	Operator shift change over	Controller Interview
10/1/21 5:10 PM	Shipping pumps turned off	3
10/1/21 5:40 PM	Shipping pump C was resumed.	3

10/1/21 5:52 PM	Second leak detection alarm activated. Local checks were performed, and the LDS was reset.	3
10/1/21 5:53 PM	Pump C stopped	3
10/1/21 5:56 PM	Atmos Leak Detection acknowledged by Controller	3
10/1/21 7:03 PM	Shipping on Pump C was resumed.	3
10/1/21 7:15 PM	Third leak detection alarm activated with 'Mile 0'. Local checks were performed, and the LDS was reset.	5
10/1/21 7:15 PM	The control room operator called the Person In Charge and notified them of the situation and requested to call out Beta station employee.	5
10/1/21 7:15 PM	Atmos Leak Alarm Acknowledged in SCADA by controller	3
10/1/21 7:37 PM	Sr. Pipeline Technician was called and told to head to Beta Station to begin manual LDS monitoring.	1
10/1/21 7:42 PM	Shipping was shut back down.	5
10/1/21 8:00 PM	Sr. Pipeline Technician arrived at Beta Pump Station to troubleshoot the leak alarms.	1, 5
10/1/21 8:29 PM	Shipping was resumed on pump A.	3
10/1/21 8:39 PM	Fourth leak detection alarm activated with a "Mile 0" indicated. The LDS was reset.	1
10/1/21 8:40 PM	Kept getting leak detection problems called out to Sr. Pipeline Technician. Notified PIC	2
10/1/21 9:00 PM	Pipeline Superintendent notified there were metering issues.	Interviews
10/1/21 9:12 PM	Started shipping pump C was resumed through PAM A.	5
10/1/21 9:23 PM	Fifth leak detection alarm activated with a "Mile 0" indicated.	3
10/1/21 9:24 PM	Stopped shipping.	5
10/1/21 9:44 PM	Shipping was resumed. Pump A running	5
10/1/21 9:53 PM	Sixth leak detection alarm activated. LDS alarm activated with a "Mile 0" indicated.	3
10/1/21 9:59 PM	*Platform Eureka* starting shipping to *Platform Elly* with one pump.	2
10/1/21 10:01 PM	Atmos Leak Alarm Acknowledged in SCADA by controller	3
10/1/21 10:33 PM	Stopped shipping through Pump A.	3
10/1/21 10:59 PM	Colonial compliance systems, Inc., a private enterprise submitted a report (NRC Report No.1318437) of an unknown sheen three miles offshore (HB2 Anchorage 33 38.32N 118	NRC Report No. 1318437

	04.09) in the water near their vessel in the Pacific Ocean.	
10/1/21 11:15 PM	Started shipping through PAM A.	5
10/1/21 11:25 PM	Stopped *Platform Eureka* shipping to *Platform Elly* to lower S06 level.	2
10/1/21 11:30 PM	Seventh Atmos leak detection alarm activated with "Mile 0" indicated.	1
10/1/21 11:31 AM	Atmos Leak Alarm Acknowledged in SCADA by the controller	3
10/2/21 12:15 AM	Manual leak detection begins, resume shipping.	5
10/2/21 1:30 AM	Pipeline Superintendent arrives at Beta Pump Station.	1
10/2/21 1:46 AM	Switched PAM from A to B while shipping.	5
10/2/21 1:58 AM	NOAA/NESDIS/satellite analysis branch reported (NRC Report No.1318442): A possible oil anomaly was observed in satellite imagery. Discovered on 10/01/2021. This anomaly is unconfirmed as oil.	NRC Report No. 1318442
10/2/21 2:27 AM	Stop shipping.	3
10/2/21 2:34 AM	SoCal Ship Services called to perform line ride.	5
10/2/21 3:30 AM	Line ride performed. Patrolled the right-of-way and nothing noted.	5
10/2/21 4:00 AM	SPBPL run start 0400 end 0510 all is ok vessel *Nicholas L* [redacted]	2
10/2/21 5:11 AM	Resume shipping to perform meter check.	5
10/2/21 5:28 AM	Eighth Atmos leak detection alarm activated	3
10/2/21 6:00 AM	Morning meeting	Controller Interview
10/2/21 6:04 AM	Pump A stopped	3
10/2/21 6:04 AM	Stop shipping. Called for additional line ride and waited for the results.	1, 5
10/2/21 6:10 AM	*Nicholas L* started pipeline run, wait for day light	2
10/2/21 6:30 AM	Loaded 16-inch diameter pig to run second pig.	3
10/2/21 6:47 AM	Sunrise	https://www.timeanddate.com/sun/usa/newport-beach?month=10&year=2021)
10/2/21 7:10 AM	The vessel *Nicholas L* left the platform traveling toward the shore.	Controller Interview, 2
10/2/21 8:08 AM	Contacted the vessel *Nicholas L*	3
10/2/21 8:09 AM	Vessel *Nicholas L* crews confirmed oil on the water.	3
10/2/21 8:10 AM	Contacted Company Vice President notified of oil on water findings.	3
10/2/21 8:11 AM	Mobilized crew and initiated spill response.	3
10/2/21 8:18 AM	Found leak @ 0818 near our pipeline.	2

10/2/21 8:21 AM	Called platform Edith and notified them of Leak in pipeline and to shut down production.	3
10/2/21 8:23 AM	Possible 60-foot-wide oil sheen actual size of length was not determined.	3
10/2/21 8:30 AM	Called Witt O'Brien group and initiated spill response.	3
10/2/21 8:34 AM	Platform Edith called to notify that shipping pumps were off.	3
10/2/21 8:35 AM	Contacted SCSS and notified of possible leak in 16" pipeline to shore.	3
10/2/21 8:36 AM	MSRC was notified of 16" pipeline to shore leak.	3
10/2/21 8:48 AM	Vessel *Nicholas L* crews reported a 60-foot-wide x 1 ½ mile length sheen oil on the water.	3
10/2/21 8:52 AM	SCSS dispatch notified Beta they were mobilizing a recon team.	3
10/2/21 8:57 AM	Called BSEE and notified them of 16" pipeline to shore leak.	3
10/2/21 9:07 AM	Witt O'Briens (regulatory reporting contractor for Amplify) reported (NRC Report No.1318463) a discharge of an unknown amount of crude oil into the Pacific Ocean at the coordinates (33 38 59 N, 118 6 W) provided. Discharge was observed in the vicinity of a pipeline after a drop in pressure was noticed, due to unknown causes.	NRC Report No. 1318463
10/2/21 9:54 AM	Called SCSS was notified vessel *Nicholas L* was on site and Ocean Guardian, Recon #3 and Recon #4 were in route.	3
10/2/21 10:02 AM	Beta Pump Station started pump to relieve pressure on the pipeline.	3
10/2/21 10:11 AM	Control Room was notified that sheen was nine miles out.	3
10/2/21 10:25 AM	Call out to vessel *Nicholas L* who reported mostly sheen and spotty oil observed.	3
10/2/21 10:25 AM	U.S. Coast Guard (USCG) called Officer Stew.	3
10/2/21 8:43 PM	Pump A stopped	3
10/3/21 4:41 PM	USCG - Sector LA/LB - Command Center reported to the NRC (NRC Report No.1318540) of a caller, who reports a potential major pollution incident associated with oil *Platforms Elly* and Ellen in Newport beach. The release is due to a crack in the line between the 2 platforms. The caller states crude oil has release but could not quantify an amount at this time. There are reports of oiled wildlife and dead fish.	NRC Report No. 1318540

10/3/21 5:20 PM	USCG - Sector LA/LB - Command Center received a report from a caller, who reports a major pollution incident associated with oil *Platforms Elly* and Ellen in Newport beach. The release is due to a crack in the line between the 2 platforms. The maximum potential discharge amount is 3,440 barrels (144,480 gallons). There are reports of oiled wildlife and dead fish. The caller states the platform information is losfpl15 this is in conjunction with report #1318540. Repair pending to the pipeline, 3,700 feet of boom deployed. 29 barrels (1,218 gal) of separated oil has been Recovered. Air flights to be conducted.	NRC Report No. 1318543
10/4/21 11:42 PM	Witt O'Brien's provided an update (NRC Report No.318463) of NRC Report No. 1318463: Beta Offshore has joined the US coast guard and California OSRO to establish a unified command to respond to this oil spill. Beaches along Huntington beach, Laguna shorelines and Newport beach have been impacted on water and shore side. Spill response personnel and aid resources have been deployed to contain and recover the spilled oil. Protection strategies have been Implemented along the coast to protect environmental sensitive areas. Original report: caller is reporting a discharge of an unknown amount of crude oil into the Pacific Ocean at the coordinates provided. Discharge was observed in the vicinity of a pipeline after a drop in pressure was noticed, due to unknown causes.	NRC Report No. 1318656

Source:
1 - Elly Shipping Ops Timeline Long Beach Incident 02 10 2021.docx
2 - Control Room Event Log Red Book Covering 24 Sept to 3 Oct 2021.pdf
3 - Misc Events and Alarms.xlsx
4 - SCADA Data_10.06.21.xlsx
5 - Raw Notes from Control Room.pdf
6 - Beta Platform -Ellen Pipeline Oil Spill chain of Events.pdf

APPENDIX B: OTHER PIPELINE ACCIDENTS INVOLVING MARINE VESSELS

Empco Pipeline, Louisiana, October 16, 2012

Empco was notified by an oil production operator that a sheen was observed by their aerial patrol near Empco pipelines. Divers were deployed who discovered the Empco pipeline had been damaged (struck) by some outside force - possible spud barge, lift boat or anchor.

Young Lady, East of Teesport, England, June 25, 2007

When the tanker *Young Lady* started to drag her anchor in Tees Bay during high wind, the master decided to weigh anchor and depart. During the operation the windlass hydraulic motor exploded, and the cable ran out to the end. The vessel continued to drag anchor until passing over and snagging the Central Area Transmission System (also known as CATS) natural gas pipeline. See Report No 3/2008, Marine Accident Report on the investigation of *Young Lady Dragging anchor 5 miles east of Teesport and snagging the CATS gas pipeline, resulting in material damage to the pipe*, June 25, 2007.

High Island Pipeline System, Texas – December 14, 2006

The High Island Pipeline system control center detected a pressure loss and immediately shut down the pipeline. They discovered the pipeline had been severed by an unknown outside force about 30 miles offshore southeast of Galveston at a water depth of about 100 feet causing a release of 568 barrels of crude oil. After further investigation, High Island Pipeline determined that the pipeline was severed by a ship's anchor, which was dragged across the pipeline.

VR255 TO SMI58 8" Line, Central Gulf of Mexico – November 12, 2005

Hurricane Rita moved through the Central Gulf of Mexico around September 23, 2005, causing the drill rig *Therald Martin* to break loose and drift. As a result, the VR255 to SMI58 8-inch diameter pipeline was found to be fully severed in block VR249 where the *Therald Martin* drug an anchor across the pipeline, releasing 862 barrels of crude oil.

Chevron Pipeline, South Timbalier Gulf of Mexico, April 28, 1998

On April 28, 1998, while operating in the South Timbalier 52 field, *Amcdermott* vessel loss power and began drifting in heavy seas and high winds. To prevent the vessel from drifting, the anchors were dropped. The anchors hooked and severed the pipeline causing the line to be ruptured causing a one-barrel spill and oil sheen 2 miles long, 15 feet wide.

Marathon, East Cameron Gulf of Mexico, December 24,1997
Oryx Operating Company, IIC. informed Marathon that an incident on their east Cameron 338 to East Cameron 321 8-inch crude oil line segment. An outside force (possibly a ship anchor or drilling rig) dragged the pipeline causing damage at the point of contact as well as to piping, vessels and decking on Oryx platform. Piping and equipment on the platform were displaced several feet causing a 4-inch section of the platform piping to separate, releasing an estimated 5 to 15 barrels of crude oil.

Marathon, East Cameron Gulf of Mexico, 3/24/1997

On March 24, 1997, a slight rainbow sheen (estimated at 1.5 gallons) was observed in the vicinity of the subsea assembly of Marathon 8-inch east Cameron pipeline system in vermilion block 299. The minor leak was found to be coming from a 4-inch blind flange joint. The spool piece appeared to have been slightly bent by a fisherman's net or anchor cable.

Amoco Production Co, June 17, 1993

A contract seismic boat was anchored over the pipeline. When the boat attempted to retrieve the anchor, the line was severed. The boat captain noticed the sheen on the water and notified the Amoco foreman.

Exxon Pipeline Co, Ascension Parish, Louisiana, August 31, 1992

During Hurricane Andrew in August 1992, while the pipeline was shut in due to the storm, the semisubmersible drilling rig *Treasure 75* owned by Wilrig (U.S.A.) Inc., drifted from the east side of the affected pipeline to the west side, dragging 4 - 30,000 lb. anchors. The anchors were attached to the rig with 3 1/8" chain weighing 90 lb./ft. The anchor that hit the pipeline had about 1500' of anchor chain, which dragged across the pipe cutting three grooves in the outer surface. The anchor finally hit the pipe causing a dent which concentrated stress at the longitudinal weld seam. When the pipeline came back near normal operating pressure, a fracture occurred along the longitudinal weld.

Unocal Corp, OCS, June 17, 1991

On June 17, 1991, an oil sheen was spotted near the southwest corner of platform *Edith* located in OCS P-0296. Investigation and testing of the 6-inch oil pipeline serving the platform confirmed it to be the source of the spill. The pipeline had been snagged by a ship's anchor (or grappling device) and severely buckled. The pipeline system continued to operate at normal pressure until progressive pigging operations to prepare for an internal inspection created a pressure surge. This surge resulted in a failure at the buckle where pipe wall thinning occurred. A crack formed at the top of the buckle where the pipe wall had thinned. Spill response efforts were subsequently mobilized, and the pipeline was secured. Subsequent investigation identified the vessel and activities that caused the mechanical damage.

Amoco Pipeline Co., Galveston, TX February 8, 1988

The HIPS control center completed calculations indicating a shortage in the oil measured into the Texas City operations control center. A helicopter was dispatched to make an aerial patrol of the offshore pipeline. An oil slick about 1 - 3 miles wide x 15 - 20 miles long was located about 21 miles southeast of Galveston. A ship's anchor pulled about 110 ft. of the 14-inch pipeline out of its trench.