environmental
DEFENSE CENTER

June 9, 2023

Mr. John Parke, Chair
Planning Commission
123 East Anapamu Street
Santa Barbara, CA 93101
Submitted to: dvillalo@countyofsb.org

Re: Change of Owner, Guarantor, and Operator for the Las Flores Pipeline System (Formerly AAPL Lines 901/903)

Dear Chair Parke and Honorable Commissioners:

On behalf of Get Oil Out! ("GOO!"), Santa Barbara County Action Network ("SBCAN"), and the Environmental Defense Center ("EDC"), I urge the Planning Commission to deny the requested change of owner, operator, and guarantor of former AAPL Lines 901 and 903. The application for a Change of Owner from Plains Pipeline L.P. ("Plains") to Pacific Pipeline Company ("PPC"), Change of Guarantor from Plains to ExxonMobil Corporation, and Change of Operator from Plains to ExxonMobil Pipeline Company ("EMPCo") is inconsistent with Chapter 25B of the County Code, would perpetuate risks caused by the corroded condition of the pipelines, and would allow Plains to avoid liability for future accidents, leaks, spills, and remediation obligations.

GOO! was formed in the wake of the 1969 Santa Barbara Oil Spill and continues to work to protect California from further oil and gas development and exploitation. SBCAN is a countywide grassroots organization that works to promote social and economic justice, to preserve our environmental and agricultural resources, and to create sustainable communities. EDC is a nonprofit public interest law firm that protects and enhances the local environment through education, advocacy, and legal action.

Our clients were involved in the immediate response to the 2015 Plains pipeline oil spill and efforts to prevent future spills. Our clients remain concerned about the condition of Lines 901 and 903, the failure of Plains to remediate the damage to the pipelines, and the potential restart of the pipelines. For these reasons, we urge the Planning Commission to deny the requested transfers.

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I. Background

2015 Pipeline Spill

On May 19, 2015, Line 901 ruptured due to the failure of the cathodic protection system and the longstanding failure of Plains to properly maintain the pipeline. The oil spill resulted in the release of more than 450,000 gallons of crude oil that damaged approximately 150 miles of the California coast, from Refugio State Beach Park to Los Angeles County.[1] The spill destroyed 1,500 acres of shoreline habitat and 2,200 acres of benthic subtidal habitat, killed at least 558 birds, injured 156 pinnipeds and injured or killed 76 cetaceans, closed 138 square miles to commercial and recreational fisheries, and caused over 140,000 lost recreational user days in Santa Barbara and Ventura Counties, including recreational activities such as camping, sunbathing, beach combing, exercising, swimming, wildlife viewing, fishing, diving, boating, and surfing.[2] The spill closed State and County parks and impacted Marine Protected Areas.

The federal report prepared by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") following the pipeline rupture determined that Plains failed to adequately maintain, inspect, and operate the pipeline, and that the improper design of the pipeline resulted in corrosion throughout the pipeline system.[3] Specifically, PHMSA determined that Plains' cathodic protection system failed to prevent corrosion on the pipelines.[4] The damaged condition of the pipeline was exacerbated because Plains failed to detect and mitigate the corrosion.[5] Moreover, the pipeline's leak detection system was inadequate and Plains' employees did not identify or respond to abnormal conditions once the release occurred.[6] PHMSA issued a Corrective Action Order ("CAO") that was amended twice.[7] Plains was found

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[1] Expert Report of Igor Mezic, Ph.D., *Andrews v. Plains All American Pipeline, LP*, October 21, 2019, pp. 16-17.
[2] Refugio Beach Oil Spill Final Damage Assessment and Restoration Plan/Environmental Assessment, prepared by California Department of Fish and Wildlife, California State Lands Commission, California Department of Parks and Recreation, University of California, U.S. Fish and Wildlife Service, and National Oceanic and Atmospheric Administration (June 2021), see Summary.
[3] Pipeline and Hazardous Materials Safety Administration ("PHMSA"), *Failure Investigation Report, Plains Pipeline, LP, Line 901, Crude Oil Release, May 19, 2015, Santa Barbara County, California* (May 2016), pp. 3, 13-17 (hereinafter referred to as the "PHMSA Report"). Available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/PHMSA_Failure_Investigation_Report_Plains_Pipeline_LP_Line_901_Public.pdf. Report without appendices attached hereto.
[4] *Id*. at 14.
[5] *Id.*
[6] *Id.* at 15-17.
[7] PHMSA Corrective Action Order, CPF No. 5-2015-5011H. May 21, 2015, amended on June 3, 2015, and November 12, 2015. Available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/Corrective_Action_Order_Plains_Pipeline_LP.pdf, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/520155011H_Amendment_to_the_Corrective_Action_Order_06032015_0.pdf, https://primis.phmsa.dot.gov/comm/reports/enforce/documents/520155011H/520155011H_Amendment%20No.%202%20Corrective%20Action%20Order_11122015.pdf

criminally liable for the spill and has been subject to several civil actions by the County of Santa Barbara, State of California, property owners, fishers, and businesses.[8]

The pipeline's corroded condition has not been remediated. In fact, the County recently confirmed that "Plains cannot meet the current cathodic protection requirements outlined in PHMSA's Corrective Action Orders (CAOs) due to deficiencies in the existing pipeline coating."[9]

The Office of the State Fire Marshal ("OSFM") assumed regulatory oversight of Lines 901 and 903 through a Consent Decree.[10] The Consent Decree requires Plains to apply to the OSFM for a State Waiver "for the limited effectiveness of cathodic protection" on Line 901 and the non-operational segment of Line 903 prior to restarting the pipelines.[11]

Plains Replacement Pipeline Project

Due to the pervasive corroded state of the pipeline, Plains applied to the County for permission to construct a new replacement pipeline.[12] The County published a Notice of Preparation ("NOP") of a Draft Environmental Impact Report ("EIR") on February 14, 2019, and a Revised NOP on April 26, 2022. The County is in the process of preparing a Draft EIR in combination with a Draft Environmental Impact Statement ("EIS").[13]

Plains Valve Upgrade Project; Potential Restart of Lines 901 and 903

In the meantime, Plains applied for permission to install valves in existing Lines 901 and 903. This project may facilitate restarting the existing pipelines. On April 26, 2023, the Planning Commission denied the application, citing concerns about the risk of another oil spill. Even with the proposed installation of additional valves, the Commission found that oil spills may still occur "due to several factors that have acted in combination to cause degradation of the line including inadequate inspection intervals, a lack of adequate anomaly repairs, internal corrosion, and corrosion under insulation (external corrosion)."[14]

On May 8, 2023, PPC submitted an appeal to the Board of Supervisors.[15] In the appeal, PPC claimed vested rights to restart the pipeline.[16]

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[8] See, e.g., *The People of the State of California v. Plains All American Pipeline, L.P.*, Santa Barbara County Superior Court Case No. 1495051; *United States of America v. Plains All American Pipeline, L.P.*, U.S. Central District of California Case No. 2:20-cv-02415.
[9] Revised Notice of Preparation of a Draft Environmental Impact Report / Environmental Impact Assessment re Plains Replacement Pipeline Project, SCH #2019029067 at p. 2. April 26, 2022.
[10] *United States of America, et. al. v. Plains All American Pipeline, L.P., et., al.*, United States District Court, Central District of California, Civil Action No. 2:20-cv-02415, Consent Decree (March 13, 2020).
[11] *Id.*, Appendix B, Article I, Section 1.
[12] Conditional Use Permit application, Coastal Development Permit application, Development Plan application, August 14, 2017.
[13] Revised NOP.
[14] Planning Commission Action Letter, March 3, 2023, at p. 5.
[15] Available at https://cosantabarbara.app.box.com/s/qgounp6sva8f1mlp9u9a8iozhrze0wrc.

Plans to Transfer Pipelines to Sable Offshore

In addition to PPC's stated interest in restarting Lines 901 and 903, the company plans to sell the pipelines to Sable Offshore, which has also stated its intention to restart the existing pipelines.[17]

II. The Proposed Transfer is Inconsistent with Chapter 25B.

The purpose of Chapter 25B is to "*protect public health and safety, and safeguard the natural resources and environment of the county of Santa Barbara*, by ensuring that safe operation, adequate financial responsibility, and compliance with all applicable county laws and permits are maintained during and after all changes of owner, operator or guarantor of certain oil and gas facilities." Chapter 25B, Sec. 25B-1 (emphasis added). As explained in PHMSA's report, Lines 901 and 903 remain severely damaged. This Planning Commission has already determined that even with facility upgrades, the risk of another oil spill is unavoidable and unacceptable. The Consent Decree and current OSFM requirements recognize that cathodic protection is not a viable way to prevent further corrosion on the pipelines. Therefore, the proposed transfer and potential restart of the pipelines will not protect the environment or public health and safety. Moreover, the current and proposed owners cannot demonstrate compliance with all applicable County laws and permits.

A. PPC has not Demonstrated Compliance with Permit Conditions.

Section 25B-4(h) requires that any owner, operator, or guarantor must comply with all conditions of the permit. Similarly, Section 25B-9(a)(5) prohibits the County from approving a change of owner unless the current owner(s) are in compliance with all requirements of the permit. The permit conditions included in the Final Development Plan ("FDP") for Lines 901 and 903 incorporate the project description included in the AAPL application.[18] The project description stated that the entire pipeline would be protected from corrosion with cathodic protection systems.[19] The Staff Report acknowledges that the Environmental Impact Report / Environmental Impact Statement ("EIR / EIS") for the AAPL project described the project as including a cathodic protection system. (Staff Report at 12-13) The EIR / EIS relied on the

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[16] PPC Appeal at pp. 7-8.

[17] Flame Acquisition Corp., *Flame Acquisition Corp. (FMLE) to Combine with Sable Offshore in $883M Deal*. November 3, 2022. ("Sable Offshore is set to purchase the Santa Ynez Unit (SYU) offshore oil field and its associated onshore facilities off the coast of California," "the new Sable entity predicts it could achieve a restart by the first quarter of 2024, but that will first require that the existing pipeline – which Exxon has since bought – will be approved by local regulators. Exxon has applications in with the California Fire Marshal and has received some clearances.")

[18] FDP, Conditions A-7, A-20.

[19] See Draft EIR/EIS for the Proposed Celeron/All American and Getty Pipeline Projects, State Clearing House No. 83110902 (August 1984), pp. 2-5, 2-14, 4-106. The Final EIR/EIS consists of the Draft EIR/EIS; a summary of the projects, areas of controversy, major impact conclusions, and the Federal preferred alternatives; comments and responses; changes in the text of the Draft EIR/EIS; and appendices. State Clearing House No. 83110902 (January 1985) ("AAPL Draft EIR / EIS").

cathodic protection system to protect the pipeline from corrosion, thereby mitigating the risk of an oil spill.[20]

The staff report recommends finding compliance with the applicable permit conditions because a cathodic protection system was installed as part of the construction of Lines 901 and 903. (Staff Report at 13-14, 16-17) The report further states that "[t]he pipelines maintain a cathodic protection system…" (Staff Report at 25) However, that system failed and resulted in a catastrophic oil spill. The system is defunct and no longer provides mitigation for the risk of an oil spill. As noted in PHMSA's Failure Investigation Report,

> Plains' CP [cathodic protection] system was ineffective in protecting thermally insulated underground pipeline systems from external corrosion. Industry practices recognize that an impressed current system like the one utilized on Line 901 cannot protect an insulated steel pipeline should the coating (tape wrap over insulation) become compromised. The external coating in the area of the rupture had allowed moisture to enter the insulation adjacent to the steel pipe. Corrosion under insulation (CUI) cannot be prevented on insulated lines where the coating system has been compromised.[21]

The Report further noted that cathodic protection "is not effective on buried insulated underground structures."[22] The Report identified extremely high rates of metal loss in the pipeline, ranging from 40% to *greater than 80%.*[23] The external corrosion thinned the pipeline wall, causing the leak.[24]

Accordingly, contrary to the assertion in the staff report, the pipeline does <u>*not*</u> maintain a cathodic protection system as required in the project description and permit conditions. The failure of the system caused pervasive corrosion on the pipeline which exists to this day.

Because of this deficiency, the Consent Decree requires the owner and operator to apply for a State Waiver for the "limited effectiveness of cathodic protection."[25] Therefore, the Planning Commission cannot find that PPC is in compliance with the County's permit conditions.

B. PPC has not Completed a County-Conducted Safety Audit.

Section 25B-9(a)(4) requires the current owner or operator to provide "a copy of the most recent county-conducted comprehensive safety audit of the physical facility, along with a description of the status of implementing its recommendations." The staff report states that an

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[20] AAPL Draft EIR / EIS at 2-5, 2-14, H-35.
[21] PHMSA Report at 14.
[22] *Id*., Appendix E, at 2.
[23] *Id*. at 13
[24] *Id*. at 14.
[25] Consent Decree, Appendix B, Article I, Section 1.A.

agreement with a prior owner waived the requirement for a County-conducted safety audit, and that the County relies on PHMSA and OSFM to conduct audits. (Staff Report at 9)

According to Sec. 25B-9(a)(4), the safety audit must include recommendations and a description of the status of implementing such recommendations. According to the staff report, however, "[t]he County is not required to oversee or monitor state and/or federal pipeline audits." The staff report lists recent PHSMA and OSFM audits but lacks a description of the audits. (Staff Report at 23) The staff report does not provide any information regarding the damaged and corroded condition of the pipelines, recommendations to address such corrosion, or a description of the status of implementing such recommendations. Without this information, there are no assurances that the dangerous condition of Lines 901 and 903, or the ability of the new owner to remedy such condition, will be addressed as part of the transfer. Given the history of the pipeline, the County must either conduct its own audit or at least provide details about the current status of OSFM's audits, inspections, investigations, and recommendations regarding the corroded condition of the pipeline.

III. Plains Must Remain Liable for the Safe Maintenance, Operation, and Abandonment of the Pipelines.

As discussed above, Plains has been found criminally and civilly liable for its failures to properly maintain and operate Lines 901 and 903. The pipelines have not been repaired and remain unsafe. Plains should not be allowed to transfer pipelines that are known to be damaged and pose a serious threat to the environment and to public health and safety.

Accordingly, in the event the Planning Commission decides to approve the transfers, Plains must (1) provide financial guarantees to ensure safe operation and maintenance of Lines 901 and 903; (2) retain liability for any future accidents, leaks, or oil spills that result from the current corroded condition of the pipeline; and (3) remain responsible for remediating the corroded condition of the existing pipelines. In addition, in accordance with Section 25B-4(i), Plains must retain liability for the abandonment of the pipelines.

The staff report states that "[n]either County Code or the FDP Permit requires that previous owners/operators maintain liability for a new owner/operator's operation or abandonment of the facilities as the permit transfers." (Staff Report at 25) The County's Code does, however, allow the County to hold a prior owner or operator liable for abandonment if the current owner or operator lacks the necessary financial resources. Sec. 25B-4(i). Even if the Code does not *require* that a former owner or operator be held liable for abandonment, or for future accidents caused by the owner's or operator's malfeasance, it does not *prohibit* the County from holding such prior owner or operator liable. In this case, the risk of another oil spill is simply too great to let Plains off the hook.

IV. Conclusion

In closing, this application must be considered in the context of Plains' responsibility for the damage to the pipelines, and PPC's intention to sell the lines to Sable Offshore. In this shell

game, the County must remain vigilant and protect the interests of its residents, our unique environment, and the businesses that rely on access to healthy coastal resources. We urge the Planning Commission to deny the proposed transfer because PPC cannot comply with the AAPL permit conditions. In addition, the Commission should reject any proposal for Plains to relinquish its duties and responsibilities for the damaged pipelines until adequate assurances are made that appropriate remedial and safety measures have been taken.

Sincerely,

Linda Krop
Chief Counsel

cc: Get Oil Out!
SBCAN

Atts: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *Failure Investigation Report: Plains Pipeline, L.P., Line 901 Crude Oil Release*, *May 19, 2015, Santa Barbara County, California*. May 2016 (without appendices).

U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

Failure Investigation Report

Plains Pipeline, LP, Line 901
Crude Oil Release, May 19, 2015
Santa Barbara County, California

May 2016

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Executive Summary

At approximately 10:55 a.m. Pacific Daylight Time (PDT) on May 19, 2015, the Plains Pipeline, LP (Plains), Line 901 pipeline in Santa Barbara County, CA, ruptured, resulting in the release of approximately 2,934 barrels (bbl) of heavy crude oil.[i] An estimated 500 bbl of crude oil entered the Pacific Ocean. Line 901 is a 24-inch diameter buried, insulated pipeline which extends approximately 10.7 miles in length and transports heated crude oil from Exxon Mobil's storage tanks in Las Flores Canyon westward to Plains' Gaviota Pumping Station. On May 21, 2015, the Pipeline and Hazardous Materials Safety Administration (PHMSA), a regulatory agency within the U.S. Department of Transportation, issued a Corrective Action Order (CAO) that required the operator to shut down Line 901. Concurrent with the issuance and implementation of the CAO, PHMSA conducted an investigation to identify causal factors that contributed to the occurrence and size of the crude oil release. As the failure investigation progressed, the CAO was amended to address additional safety concerns that were identified. On June 18, 2015, Line 901 was purged and filled with inert nitrogen to enhance safety during the investigation and development of a remedial action plan.[ii] No fatalities or injuries occurred as a result of this rupture and release. The spill resulted in substantial damage to natural habitats and wildlife.

PHMSA's findings indicate that the proximate or direct cause of the Line 901 failure was external corrosion that thinned the pipe wall to a level where it ruptured suddenly and released heavy crude oil. PHMSA's investigation identified numerous contributory causes of the rupture, including:

1) Ineffective protection against external corrosion of the pipeline

- The condition of the pipeline's coating and insulation system fostered an environment that led to the external corrosion.
- The pipeline's cathodic protection (CP) system was not effective in preventing corrosion from occurring beneath the pipeline's coating/insulation system.

2) Failure by Plains to detect and mitigate the corrosion

- The in-line inspection (ILI) tool and subsequent analysis of ILI data did not characterize the extent and depth of the external corrosion accurately.

3) Lack of timely detection of and response to the rupture

- The pipeline supervisory control and data acquisition (SCADA) system did not have safety-related alarms established at values sufficient to alert the control room staff to the release at this location.
- Control room staff did not detect the abnormal conditions in regards to the release as they occurred. This resulted in a delayed shutdown of the pipeline.
- The pipeline controller restarted the Line 901 pipeline after the release occurred.
- The pipeline's leak detection system lacked instrumentation and associated calculations to monitor line pack (the total volume of liquid present in a pipeline section) along all portions of the pipeline when it was operating or shut down.
- Control room staff training lacked formalized and succinct requirements, including emergency shutdown and leak detection system functions such as

alarms.

The consequences of the spill were additionally aggravated by an oil spill response plan that did not identify the culvert near the release site as a spill pathway to the Pacific Ocean.

This report contains factual information and analysis regarding the events leading up to the release, information collected during PHMSA's failure investigation to date, and the technical analysis of that information known at the time of the completion of this report. PHMSA used this information to mandate remedial measures on Line 901, Line 903, and associated stations and tankage. PHMSA will also use the information to determine whether violations of the federal pipeline safety regulations occurred.

Final Report Methodology

PHMSA conducted relevant interviews, gathered and reviewed numerous historical documents and available records, and performed a thorough review of the Plains Control Room in Midland, TX. An ILI subject matter expert (SME) was hired to review the raw magnetic flux leakage (MFL) data and final vendor reports from the MFL surveys, and evaluated Plains actions as a result of their review of the vendor reports. PHMSA issued a CAO which in part instructed Plains to have the failed pipe examined by a PHMSA-approved metallurgical laboratory and to have a root cause failure analysis (RCFA) performed by a third party independent consultant.

The factual evidence reviewed includes: the Plains Integrity Management Plan (IMP), CP records, ILI reports, anomaly dig information, SCADA event and alarm logs, pressure and flow trends, procedures and reports obtained from the pipeline operator and PHMSA SMEs.

The arrangement of this report provides a general description of the pipeline system, the events that occurred on the day of the release, and acts or omissions of the operator that led to this failure and release of crude oil. Specific evidence is supplied and pertinent statements from each report are excerpted where appropriate.

Facility Background

Plains transports crude oil produced in federal and state waters off the coast of Santa Barbara, CA to inland refineries. Plains' pipeline is composed of two major pipeline sections: (1) Line 901, and (2) Line 903. Lines 901 and 903 were constructed in the late 1980s, hydrostatically tested in 1990, and went into crude oil service in 1992 and 1991, respectively. The pipelines are coated with coal tar urethane and covered with foam insulation which in turn is covered by a tape wrap over the insulation. Shrink wrap sleeves, which provide a barrier between the steel pipeline and soil for corrosion prevention, are present at all of the pipeline joints on Line 901 and multiple locations on Line 903. The pipelines carry high viscosity crude oil at a temperature of approximately 135 degrees Fahrenheit to facilitate transport. Lines 901 and 903 are controlled from the Plains Control Room's (PCR) California console in Midland, TX.

(1) Line 901 is a 24-inch diameter pipeline that extends approximately 10.7 miles in length from the Las Flores Pump Station to the Gaviota Pump Station; and (2) Line 903 is a 30-inch diameter pipeline that extends approximately 128 miles in length from the Gaviota Pump Station to the Emidio Pump Station, with intermediate stations at Sisquoc Mile Post (MP) 38.5 and Pentland (MP 114.57). There is a delivery point into Line 901 from Venoco's Line 96 located approximately 2 miles downstream of the Las Flores Station. All of Line 901 crude oil throughput enters Line 903. Line 901 was manufactured of low carbon steel by Nippon Steel

in Japan in 1986. Line 901's pipe specifications are API 5L, Grade X-65 pipe, 0.344-inch wall thickness, with a high frequency-electric resistance welded (HF-ERW) long seam. The line was hydrotested to 1,686 pounds per square inch gauge (psig) on November 25, 1990.

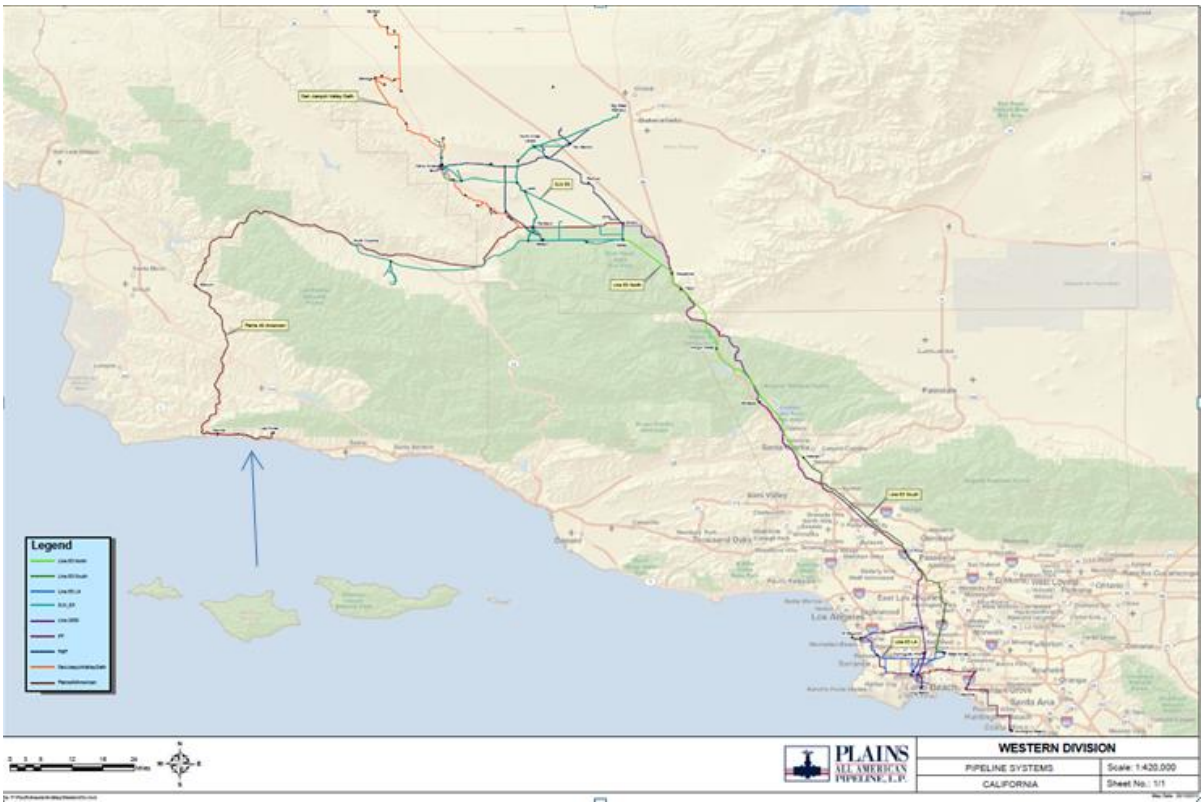

Figure 1. Map of Plains' Western Division Pipelines. The arrow points to the approximate release site on Line 901.

At Sisquoc Station, crude oil can be pumped to one of two locations: a nearby refinery via a 12-inch diameter pipeline operated by Phillips 66, or continue down Line 903 to Pentland Station. There are additional crude oil lines coming in and out of Pentland Station with numerous tanks at that station used to blend different crude oils for delivery further downstream. At Emidio Station crude oil is delivered to above-ground storage tanks for future delivery to Los Angeles refineries in a separate pipeline system.

Prior to the May 19, 2015 release, there had been four small releases meeting PHMSA reportable criteria at pump stations on Lines 901 and 903. No releases were reported to PHMSA on the pipelines outside of pump stations prior to 2015. The operator reported maximum operating pressure (MOP) of Line 901 is 1,341 psig.

At the time of the spill, Plains All American Pipeline (PAAPL) operated Line 901 and Line 903 under a Federal Energy Regulatory Commission (FERC) certificate of economic regulatory jurisdiction that was issued in 1987. Plains Pipeline, LP, is a subsidiary of PAAPL. Based on the FERC filing, Lines 901 and 903 were classified as interstate pipelines, pursuant to 49 U.S.C. § 60101(7), as facilities used to transport hazardous liquid in interstate or foreign commerce, and as such, were regulated by PHMSA as interstate pipelines. Plains cancelled the FERC certificates for Lines 901 and 903 on February 12, 2016 and April 29, 2016,

respectively, stating that the transportation service was no longer available in interstate commerce. Line 903 from Gaviota to Sisquoc to Pentland Stations was purged with nitrogen in accordance with Amendment No. 2 to the CAO, and remains shut down between these stations. The Pentland to Emidio segment of Line 903 is active and operating intermittently at low pressures. This section of pipe between Pentland and Emidio is not directly connected to the Gaviota to Pentland segment and is used to transport crude product from breakout tanks in Pentland Station.

Events Immediately Prior to and During the Crude Oil Release

On the morning of May 19, 2015, Lines 901 and 903 were transporting crude oil with a flow rate setpoint of 1,240 bbl per hour (BPH) leaving the Las Flores Station, and the discharge pressure was approximately 575 psig. Pumps were operating at the Las Flores Station on Line 901 and Sisquoc Station on Line 903. A Plains instrumentation and electrical technician was dispatched that morning to disconnect and remove a motor from a non-operational pump at the Sisquoc Station. While the technician was performing his work, the operational pump (Pump 401) at the Sisquoc Station was shut down unintentionally (i.e., "uncommanded"). When Pump 401 on Line 903 stopped operating, the pressure in Line 901 increased. The pressure rose to a maximum of 696 psig at the Las Flores Station discharge. The controller shut down the pump at Las Flores Station and the pressure remained at 677 psig. Approximately four minutes later, the pump at Las Flores Station was restarted. At approximately 10:55 a.m. PDT, the flow rate at Las Flores Station climbed from zero to 2,042 BPH. Concurrently, the line pressure rose to a high of 721 psig, then dropped to 199 psig, and then slightly increased to approximately 210 psig until the Las Flores pump was shut down a second and final time. Generally, a sudden increase in flow rate accompanied by a decrease in pressure is indicative of a release. PHMSA has determined that Pump 401 going offline in an "uncommanded" manner on the morning of May 19, 2015, was an abnormal event, but that this in itself should not have caused Line 901 to rupture.

PHMSA performed a detailed review of the SCADA event and alarm logs, and pressure and flow records. The review indicated that there was information reported by the SCADA system that indicated a release had occurred by approximately 10:58 a.m., and an alarm was generated on low pressure. The alarm was not set at an appropriate value. The alarm also did not have a major priority/severity or safety-related alarm status. The controller did not recognize the information he received as indicative of an abnormal operation. Evidence indicates that the controller was focused on the events at Sisquoc Station (i.e., restarting the Sisquoc pump that had gone down once uncommanded, and a second time on high case temperature along with other duties).[iii]

Due to the Sisquoc Station maintenance activity resulting in an unplanned pump shutdown, the controller anticipated alarms would be activated from the pipeline leak monitoring (PLM) system. According to interviews and a review of the alarm log, the PLM inhibit was requested by the controller to the step-up shift supervisor between 11:15 and 11:22 a.m.[iv] The step-up shift supervisor then inhibited (shut off) the PLM system alarms.[v] Also, during this time, the controller started an investigation of the SCADA data in an attempt to understand the operational abnormalities that were occurring. After attempting to restart the Sisquoc pump twice, the controller shut down the pipeline. PHMSA requested the operator review the flow imbalance calculations and provide a time when the PLM system would have generated an alarm if not inhibited, and it was determined that alarms would have been generated

approximately two minutes before the controller shut down the pipeline.[vi]

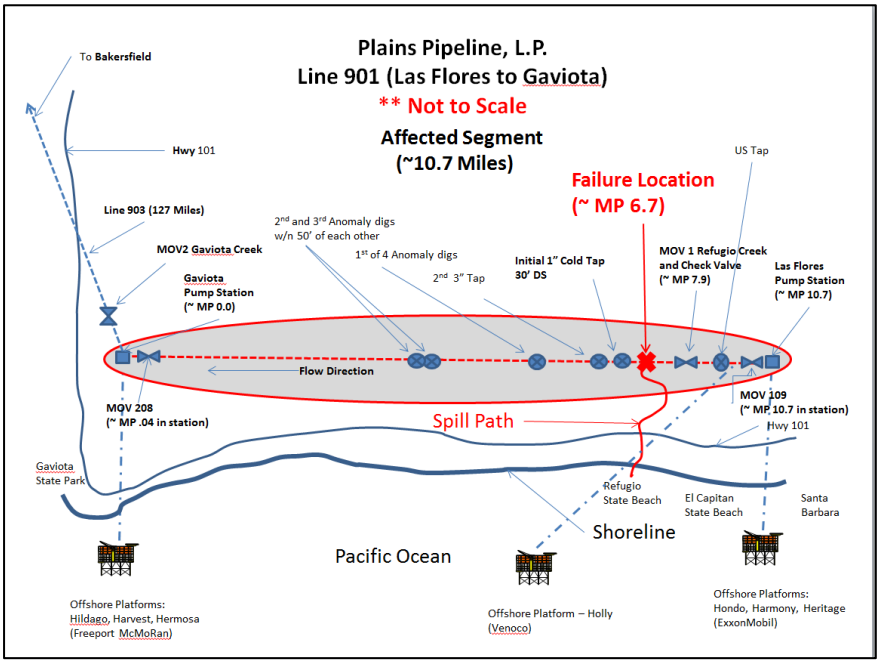

Figure 2. Schematic of Plains Pipeline, LP, Line 901 and spill path.

Plains' Field Response and National Response Center Notifications

The following is a timeline of Plains and emergency responder activities conducted immediately prior to locating the leak site:[vii]

- At 11:42 a.m. a call reporting a petroleum smell was received at Santa Barbara Fire Department (SBFD) Station 18. Engine 18 left the station to investigate the odor complaint near Refugio State Beach.
- At approximately 12:15 p.m., prior to a scheduled tabletop spill drill required by federal regulations 49 C.F.R. §194, the pre-drill meeting was completed and adjourned. A representative from the Santa Barbara Office of Emergency Management (SB-OEM) received a call from the SBFD reporting that there was oil on Refugio Beach. The SB-OEM representative and the Plains representatives left the spill drill and drove separately to Highway 101 at Refugio Beach.
- The Santa Barbara Dispatch notified the National Response Center (NRC #1116950) at 12:43 p.m. PDT of an unknown sheen in the ocean at Highway 101 and Refugio Beach.[viii]
- At approximately 12:55 p.m., the two Plains representatives arrived at the south side of Highway 101 where the SBFD personnel were. They noted oil in the ocean but could not determine the source of the oil. One of the Plains representatives told the assembled group that he did not think the oil was coming from Line 901 because the pipeline is located on the other side of Highway 101, and there would be oil flowing across Highway 101 if Line 901 was leaking.

- The Plains representatives drove to the company's pipeline right-of-way (ROW). At approximately 1:27 p.m., the Plains representatives located the leak site on the Plains ROW. They called the controller to report the leak and to tell the controller to leave Line 901 shut down and to close the Refugio gate valve. The Plains representatives used their cell phones to contact other Plains personnel, the landowner where the leak occurred, Plains' oil spill response contractors, and others. The Plains representatives noted that crude oil from the release site had entered a culvert that crosses under the Highway 101 and railroad tracks and discharges to Refugio Beach. The Plains representatives, along with Fire Department personnel, attempted to stop the flow of oil into the culvert. However, the culvert was too large to stop the flow with shovels, and sand bags were not readily available, so their immediate efforts were unsuccessful. At approximately 3:00 p.m., additional equipment and personnel arrived, the culvert was dammed and oil was prevented from entering the culvert.
- At 2:56 p.m., a representative from Plains called the NRC to report (NRC #1116972) the release of crude oil at 2:56 p.m. PDT. This report indicated that the release was at Latitude: 34° 27' 43" N; and Longitude: 120° 05' 24" W. This NRC report was made 89 minutes after the release site was found by Plains field personnel.[ix]

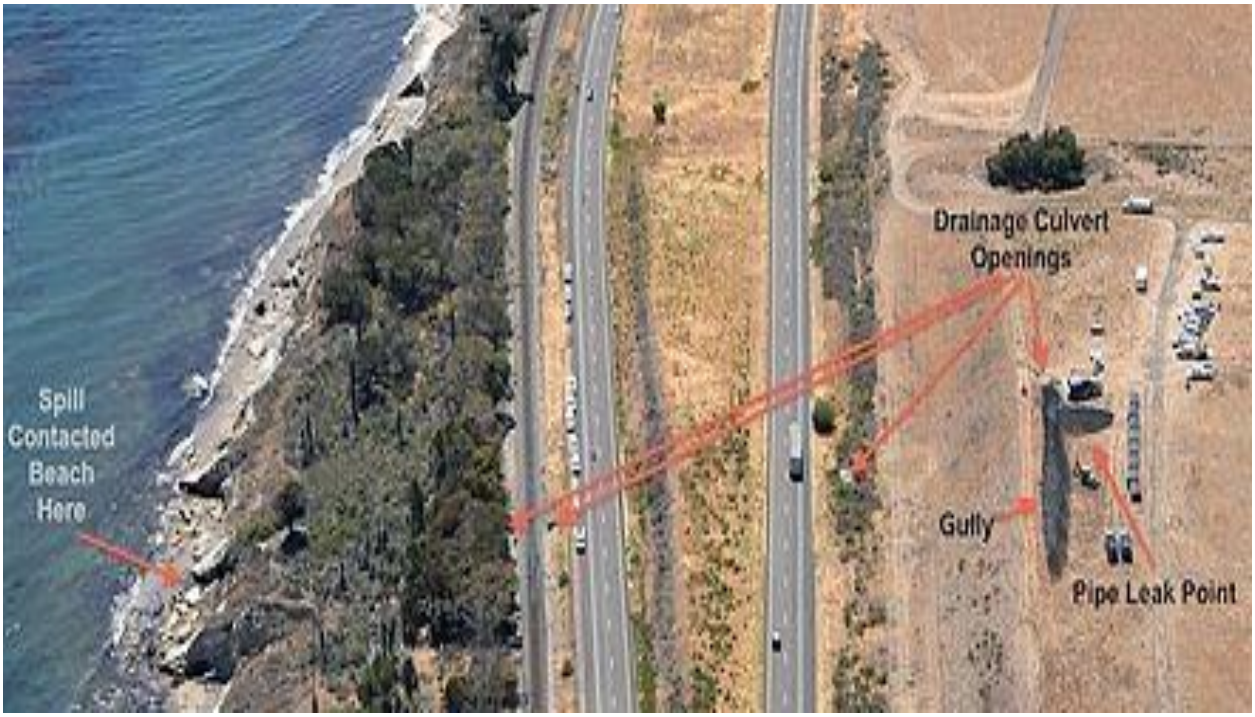

Figure 3. Spill location relative to Refugio Beach in Santa Barbara County, CA. Photo: John L. Wiley http://flickr.com/jw4pix

Federal pipeline safety regulations, (49 C.F.R. § 195.52), require that the NRC be notified at the earliest practicable moment following discovery of a release of a hazardous liquid, including "[a]ny failure that resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality stands, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines." On January 30, 2013, PHMSA issued an

Advisory Bulletin clarifying that this was to be interpreted as within one hour of discovery. Plains reported the rupture to the NRC approximately 89 minutes after discovery, thus notifying the NRC 29 minutes late.

The estimated costs reported by the operator as of December 23, 2015, were $142,931,884. This figure includes all costs the operator spent as a result of this release through the date reported, including commodity lost, the operator's property damage and repairs, operator's emergency response, environmental remediation, and estimated other costs spent including government agency costs and media relations expenses.[x]

PHMSA's Corrective Action Order

On May 21, 2015, PHMSA issued a CAO, CPF No. 5-2015-5011H, to Plains. The CAO required Plains to purge Line 901; review the pipeline's construction, operating, maintenance, and integrity management history; expedite the review of data from the May 5, 2015, ILI tool run; conduct metallurgical evaluation of the failed pipe; repair any integrity-threatening anomalies identified by the ILI survey; and conduct a root cause failure analysis. The CAO requires Plains to purge Line 901 and to keep Line 901 shut down until PHMSA approves the restart of the pipeline. Plains' Line 901 was purged and filled with an inert nitrogen gas on June 18, 2015.

On June 3, 2015, PHMSA issued Amendment No. 1 to the CAO. The amendment was issued to address preliminary findings from the early stages of PHMSA's investigation, and the possibility that the conditions on Line 901 also existed on Plains Line 903. The amendment to the CAO required Plains to conduct additional non-destructive testing of ILI anomalies on Lines 901 and 903; review the construction, operating, maintenance, integrity management, and ILI history of Line 903; and reduce the operating pressure of Line 903 to 80% of the highest pressure sustained for a continuous 8-hour period during the month before the May 19 failure. This pressure reduction was intended to enhance safety until all facets of the line's integrity could be evaluated.

On November 12, 2015, PHMSA issued Amendment No. 2 to the CAO. The amendment required Plains to empty and purge Line 903 between Gaviota and Pentland Stations and fill it with an inert gas. Line 903 was purged between Gaviota and Pentland Stations and filled with inert nitrogen. The complex purging operations began in December 2015, and were completed on April 18, 2016. Both Line 901 and the purged sections of Line 903 will remain shut down until all actions required by PHMSA's CAO and subsequent amendments have been completed. PHMSA may continue to issue additional amendments to the CAO as necessary.

Pipeline Alignment

Las Flores Station to Gaviota Station Line 901 Elevation Description

To fully understand the Line 901 release, it is vital to understand the elevation profile of Line 901 and Line 903 from the Las Flores Canyon to Pentland Station. Line 901 starts at the Las Flores Station at an elevation of approximately 180 feet. There are two large hills downstream of the originating pump station. The first hill has a peak elevation of approximately 740 feet and the second hill has an elevation of approximately 600 feet. The release occurred downstream of the second hill at an elevation of approximately 80 feet. Immediately downstream of the release point, the pipeline rises slightly and then runs relatively level approaching the Gaviota station. This fact is important because as soon as the pump at Las

Flores Pump Station was turned off the second time, the only crude oil that could be released was the height of oil in the pipeline above the release site and not the amount located between the two aforementioned hills.

Gaviota to Pentland Station Line 903 Elevation Description

Line 903 receives all of the crude oil delivered by Line 901. The line elevation at Gaviota is approximately 150 feet. The elevation at Sisquoc is approximately 880 feet. Downstream of Sisquoc, Line 903 rises to 2,420 feet and then to a height of approximately 2,750 feet and ultimately to an elevation of close to 3,000 feet before dropping into Pentland Station at an elevation of approximately 690 feet. Line 903 exhibits many of the same construction and operation conditions as Line 901 and was addressed by the amendments to the CAO. Pump 401 at Sisquoc Station has adequate capacity to push the oil up and over the downstream hills and into Pentland Station but only if it has full suction pressure and full flow coming into the pump. Because of the release, the pump could not push the oil over the downstream hills, and so the oil in the pump became hot and the pump shut down to prevent overheating.

Post-Incident Investigation Results

Metallurgical Evaluation of Failed Pipe

The failed pipe segment has been analyzed by third-party metallurgical experts, Det Norske Veritas (U.S.A.), Inc.'s (DNV-GL) in Dublin, OH. The failed pipe assessment and testing was witnessed by PHMSA, the California Department of Fish and Wildlife, and the U.S. Department of Justice.

Figure 4. The failed pipe and surrounding insulation and coating.

Figure 5. Pipe External Surface at the Line 901 failure site after cleaning.

DNV-GL's draft report was completed and disseminated to Plains and PHMSA on August 6, 2015. The draft report was reviewed by PHMSA engineers, and a number of comments and clarification requests were made. DNV-GL reviewed the comments and revised the report. The Final Report was issued on September 18, 2015.

The Final Report provides a summary of findings, including the following excerpt:

"The results of the metallurgical analysis indicate that the leak occurred at an area of external corrosion that ultimately failed in ductile overload under the imposed operating pressure. The morphology of the external corrosion observed on the pipe section is consistent with corrosion under insulation facilitated by wet-dry cycling."[xi]

In-Line Inspection Survey Review

Plains conducted ILI surveys on Line 901 (10.7 miles in length) to assess the integrity of the pipeline in accordance with PHMSA regulations in 2007, 2012, and 2015. According to 49 C.F.R. § 195.452(j)(3), the pipeline is required to be surveyed at intervals commensurate with the pipeline's risk of integrity threats, but at least every 5 years. Plains changed Line 901 from a 5-year assessment cycle to a 3-year assessment cycle after the 2012 ILI survey.

The data collected during these surveys must be fully evaluated within 180 days of the ILI, and an operator must take action upon discovery of any "immediate repair conditions" as defined in 49 C.F.R. § 195.452(h) unless the operator can demonstrate that the 180-day period is impracticable.

The most recent ILI survey for Line 901 was completed on May 6, 2015. The 2015 ILI survey data for the first 2 miles of Line 901, as measured from the Las Flores Station, was found to be incomplete and not useable for ILI analysis. For the rest of the ILI survey, the correlation digs, which are used to gauge survey data accuracy in the ILI vendor's preliminary report, had not been finished at the time of the May 19, 2015 failure.

PHMSA's independent third-party ILI SME also performed an analysis of the data from past ILI surveys of Line 901. Preliminary data from the results of each of the ILI surveys are summarized below and show a growing number of corrosion anomalies on Line 901.

Number of Anomalies

Metal loss	June 19, 2007	July 3, 2012	May 6, 2015
Greater than 80%	0	0	2
60-79%	2	5	12
40-59%	12	54	80

The May 6, 2015 ILI survey data and subsequent analysis by the ILI vendor predicted external corrosion at the failure site with an area of 5.38 inches by 5.45 inches, and a maximum depth of 47% of the original pipe wall thickness. After the failure, the DNV-GL metallurgical investigators physically measured external corrosion at the failure site to have a maximum depth of 89%.[xii] The dimensions of the corrosion feature were 12.1 inches axially by 7.4 inches in circumference. The maximum depth, as measured using laser scan data, was 0.318 inches or 89% of the measured wall thickness (0.359 inches).

The ILI summary report prepared by PHMSA's SME also examined the "as-called" (ILI-predicted) versus as-found (field measured) lengths, widths and area for the excavated anomalies on Line 901. The report demonstrates that the lengths and widths of the anomalies were under-called (underestimated) in many cases, however many were also over-called. Plains submitted little documentation concerning their analysis of how the field measured anomalies compared to the ILI vendor analysis. Furthermore, Plains did not provide documentation showing that discrepancies between the originally reported anomaly sizes predicted by the ILI vendor and Plain's actual field-measured sizing of the corrosion anomalies were subsequently discussed with the ILI vendor, as required by Plains' IMP.[xiii]

Cathodic Protection Findings

According to 49 C.F.R. § 195.563, CP is required under the federal Pipeline Safety Regulations to prevent external corrosion of buried pipelines. Historical CP records for line 901 have been reviewed and reveal protection levels that typically are sufficient to protect non-insulated, coated steel pipe. Line 901 and Line 903, however, are insulated. An increasing frequency and extent of corrosion anomalies were noted on both Lines 901 and 903 in ILI survey results, anomaly excavations, and repairs. PHMSA inspectors noted moisture entrained in the insulation at four excavations performed by Plains on Line 901 after the May 19 spill and prior to the PHMSA-mandated purging of the pipelines.

Spill Volume Estimate from Plains' Third-Party Consultant

Plains initially estimated the volume of spilled crude oil to be approximately 2,400 bbl, of which 500 bbl was estimated to have reached the ocean. On August 4, 2015, Plains reported to the Unified Command that the 2,400 bbl release estimate was still accurate. However, after Plains completed the PHMSA-mandated purge, the company's calculations indicated that up to 3,400 bbl had possibly been released from the pipeline. Plains notified the Unified Command

that RPS Knowledge Reservoir (RPS), a third-party investigator hired by Plains, was still trying to reconcile the difference.

On November 24, 2015, Plains informed PHMSA that RPS had completed their analysis regarding the release volume and produced a report of findings. RPS used the OLGA simulation software tool to model the behavioral dynamics of the pipeline prior to, during, and immediately after the May 19, 2015 leak. The report concluded that the discharge leak volume was 2,934 bbl. The RPS report was dated November 11, 2015. Plains has reported 1,100 bbl of crude oil have been recovered.

Investigation Findings and Conclusions

Line 901 pipeline ruptured at approximately 56% of the MOP. Although the operational events that occurred on the morning of the release were abnormal, this should not have caused the release if the pipeline's integrity had been maintained to federal standards.

Proximate or Direct Cause

PHMSA determined that the proximate or direct cause of the release was progressive external corrosion of the insulated, 24-inch diameter steel pipeline. The corrosion occurred under the pipeline's coating system, which consisted of a urethane coal tar coating applied directly to the bare pipe, covered by foam thermal insulation with an overlying Polyken tape wrap. Water has been noted in the foam insulation at a number of digs, indicating that the integrity of the coating system had been compromised. The external corrosion was facilitated by the environment's wet/dry cycling, as determined by the PHMSA-approved, third-party metallurgical laboratory. The release was a single event caused at an area where external corrosion had thinned the pipeline wall. There is no evidence that the pipeline leaked before the rupture. There was a telltale "fish mouth" (a split due to over-pressurization) at the release site indicating the line failed in a single event.

PHMSA's investigation identified numerous contributory causes of the rupture. The contributory causes can be grouped into three categories: 1) ineffective protection against external corrosion of the pipeline; 2) failure by Plains to detect and mitigate the corrosion;, and 3) lack of timely detection of the rupture. Below is a summary of the key contributory causes:

Contributory Causes

1) Ineffective protection against external corrosion of the pipeline

   - Plains' CP system was ineffective in protecting thermally insulated underground pipeline systems from external corrosion. Industry practices recognize that an impressed current system like the one utilized on Line 901 cannot protect an insulated steel pipeline should the coating (tape wrap over insulation) become compromised. The external coating in the area of the rupture had allowed moisture to enter the insulation adjacent to the steel pipe.[xiv] Corrosion under insulation (CUI) cannot be prevented on insulated lines where the coating system has been compromised.[xv]

2) Failure by Plains to detect and mitigate external corrosion

   - Plains did not identify CUI as a risk-driving threat in their federally-mandated integrity management program (IMP).

- Plains' did not fully implement their IMP.
    - Plains did not perform suitable analysis of the field measurements of the excavated corrosion anomalies that occurred after ILI surveys were completed in 2007 and 2012.
    - The data reported by the ILI vendor were inconsistent (and did not meet the published accuracy of the ILI tools of +/- 10%, 80% of the time for depth) when compared to the results of the field-measured corrosion anomalies.
    - Plains' as-found field measurements of corrosion anomalies were inconsistent with the as-called vendor-provided ILI data and analytical reports. ILI surveys conducted in 2007 and 2012 revealed inconsistencies in the character of the anomalies. In both of these cases, Plains did not consult the ILI vendor to help resolve the inconsistency.
    - Plains failed to follow written procedures directing the IMP group to perform appropriate statistical analysis after the anomaly dig reports were received from the field, and to discuss any inconsistencies with the ILI vendor.[xvi]
        - Plains' Pipeline Integrity group created a unity plot for depth after the 2012 ILI survey and anomaly digs. There is no documentation detailing what was done with the information from the unity plot.
    - Plains incorrectly added the over-called anomalies in the close-out reports.
        - The close-out reports should have only reported the anomalies that were within the reported accuracy of the ILI tool. The reported tool accuracy is +/- 10 %, 80 % of the time. Adding the overcalled anomalies outside of the tool accuracy skews the data.
- Plains' Pipeline Integrity group was historically focused on pitting corrosion under "shrink sleeves" at the pipeline girth welds (circumferential welds to join pipe segments).
    - The release location was within 6 feet of a corrosion anomaly that was exposed and repaired after the 2012 ILI survey. There was evidence of corrosion and degraded coating systems between the 2012 repair site and the 2015 rupture site.
    - The anomaly that ruptured was called out by the ILI tool at 45% depth in 2012. Plains' IMP specified adding 10% to all anomalies (55% depth in this case) then "growing them" to predicted failure using an anticipated corrosion growth rate. This analysis would provide a predicted failure time. Plains did not excavate the anomaly that failed.

3) Lack of timely detection of and response to the rupture

- The controller did not have information communicated from the SCADA system in such a manner to be successful in detecting abnormal operations. The pipeline SCADA system did not have safety-related alarms on low pressure configured at the

correct value or priority to alert the control room staff of the rupture. When this alarm was provided to the controller, the discharge pressure at Las Flores was 199 psig but, within a minute, pressure elevated above 210 psig, the alarm status cleared, and the discharge pressure remained above 200 psig (approximately 210-211 psig) until the pipeline was purged. The pipeline was still leaking when the discharge pressure at Las Flores was above 200 psig, and continued to do so without additional alarm indications. When the pipeline was down, isolated but still leaking, the minimum pipeline discharge pressure at Las Flores remained at 210-211 psig. The low discharge pressure alarm setpoint value was not set properly as it should have been above 211 psig. This type of alarm should be identified as a high priority safety related alarm. While the controllers and shift supervisors can access historical trend data or continue to monitor a given pressure or flow, when the pipeline was ultimately shut down at 11:30 a.m., neither the controller nor step-up shift supervisor detected any drop of pressure at the specific failure location that would indicate that oil was being released.

- Neither the pipeline controller nor step-up shift supervisor detected the initial abnormal conditions as the release occurred. There was an indication of decreased pressure and increased flow between 10:53 and 10:58 a.m., which is consistent with a pipeline release. This resulted in a delayed shutdown of the pipeline. Adequate alarm setpoint values with correct priorities are essential to controller and shift supervisor recognition of abnormal operations, especially when many pipeline systems are operated from the same console.

- The pipeline controller restarted Line 901 after the release occurred.
- The pipeline leak detection system lacked instrumentation and associated calculations to monitor line pack.
    - The function of the PLM system was a simple line balance calculation based on flow meter values without line pack considerations. The PLM relies on comparing "meter in – meter out" calculations over time. This type of leak detection system without the use of safety-related, high-priority, low-pressure alarms does not provide the controller or shift supervisors with adequate information when the pipeline is down.
    - When the pipeline is not running, even if only due to scheduling and not required maintenance activities, flows will be close to zero and the imbalance calculation will provide little if any value as currently configured. Leak detection on a down pipeline requires a robust system of planned and accurate high-priority alarm types and alarm setpoint values in order for response to occur on critical low pressures.
    - The leak detection system for Lines 901 and 903 consists of two leak detection segments. Additional instrumentation such as pressure and temperature transmitters located at Refugio Gate and Cuyama valve settings (both transmitter types on each side of the valves) would allow additional information about the operating status of the pipeline to be presented and pack calculations pursued.
    - Plains utilizes the SimSuite application for other pipelines in the control

center. This application does allow for pack calculations to be utilized in the leak detection system. According to information obtained during meetings with Plains hydraulic specialists, Lines 901 and 903 were pipeline systems with a low to medium priority defined for future modeling efforts compared to other assets in the Plains operations. The approach utilized by Plains for prioritizing which systems should be modeled first did not appear to take into account all appropriate consequence-based asset impacts (such as culverts providing a pathway to the ocean) associated with these two systems. Existing instrumentation and the need for added instrumentation would factor into this prioritization decision.

- Control room staff training lacked formalized and succinct requirements, including emergency shutdown and leak detection system functions such as alarms.
    - Interviews determined that the step-up shift supervisor and shift supervisor training lacked formalized and succinct requirements, including that for leak detection system functions such as "inhibit" options. The interviews determined that different shift supervisors performed PLM inhibit functions without contacting the console supervisor first as required by procedure.
    - Step-up and shift supervisor responsibilities include emergency shutdown of any pipeline. However, training does not cover a means by which to accomplish this for all relevant pipelines. A general emergency shutdown provision has not been programed for supervisory use on all systems.
- The oil spill response plan required by 49 C.F.R. §194 did not account for a culvert near the release site that traversed the Pacific Coast Highway and Amtrak railroad tracks. This culvert provided a quick flow path between the pipeline ROW and the Pacific Ocean, thereby allowing crude oil to flow easily towards Refugio State Beach and the ocean. The response plan did not have a response strategy that considered the presence of the culverts.

PHMSA Post-Incident Action Chronology

Following the May 19, 2015 Plains Pipeline, LP, Line 901 rupture in Santa Barbara County, CA, PHMSA took the following actions:

- On May 19, 2015, PHMSA deployed inspectors to investigate the Plains Pipeline LP Line 901 pipeline failure in Santa Barbara County, CA. PHMSA also provided information updates to the Unified Command (UC), US Coast Guard, the Federal on Scene Coordinator (FOSC), State Fish and Wildlife, and other agencies on site.
- On May 21, 2015:
    - PHMSA issued a Corrective Action Order (CAO), CPF No. 5-2015-5011H, to Plains Pipeline LP ordering it to suspend operations and to specific safety actions to further protect the public, property, and the environment from potential hazards associated with the recent failure. PHMSA staff reviewed the CAO with the operator and briefed the California State Attorney on the CAO and provided an overview of PHMSA's regulations.
    - PHMSA sent an inspector to Plains' control room in Midland, Texas to collect operational data and interview the control room operators on duty at the time of the incident and their supervisors. The inspector gathered any pertinent logs and information, including electronic copies of relevant data from the Supervisory Control and Data Acquisition (SCADA) system.
    - PHMSA staff worked with the operator to review their plan to expose the pipe and to cold tap it to ensure there was no pressure or crude left in the line at a low spot immediately downstream of the release point. The plan was signed off by the UC at approximately 5 pm PDT.
- On May 22, 2015:
    - PHMSA staff met with representatives from the Assistant U.S. Attorney, DOT Inspector General, EPA Criminal Investigation Division, California Attorney General, and others to brief them on PHMSA's process for securing and transporting the failed pipe to a metallurgical lab for evaluation.
    - PHMSA staff remained on the scene as the operator exposed, tapped, removed any remaining product, and excavated the pipeline downstream of the release site.
- On May 25, 2015:
    - PHMSA issued an approval letter for Plains to excavate, remove and secure the failed joint of pipe under the supervision of two DNV metallurgists (third party contractor) but requested that the coating and insulation not be touched until the failed pipe has been removed because the DNV personnel were interested in in gathering available samples there as well.
    - A PHMSA inspector returned to Midland, TX to interview the controller and the Operations Control Center supervisor and to obtain any handwritten logs created by the controller on the morning of the release.
- On May 28, 2015:
    - A PHMSA investigator was on site when affected pipeline was removed, crated, and transported to secure location for metallurgical evaluation. PHMSA retained a third-party ILI expert to examine the 2012 and 2015 ILI runs. DNV personnel took soil and insulation samples.
- On June 3, 2015, PHMSA amended the CAO to address preliminary findings from the early stages of the investigation (Amendment No. 1). The amended CAO mandated

additional safety requirements on Line 901 and expanded the scope of the CAO to include the 128-mile long Line 903, which is located downstream of Line 901. The amendment reduced the operating pressure of the Lone 903 by 80% of the highest 8 hour continuous pressure between April 19, 2015 and May 19, 2015. On May 30, 2015, Plains voluntarily shutdown Line 903.

- On June 18, 2015, PHMSA staff monitored the Line 901 purge to ensure safety during the purging process. Plains completed the purge and injected inert gas in Line 901.
- On September 18, 2015, PHMSA received the DNV Final Mechanical and Metallurgical Report. PHMSA staff reviewed the document and provided comments.
- On November 12, 2015, PHMSA issued Amendment No. 2 to the CAO, which ordered Plains to purge and shutdown Line 903 from Gaviota to Pentland.
- On December 1, 2015, PHMSA staff monitored Plains moving Freeport McMoRan crude oil from their offshore platforms into Line 903 from Gaviota Station to Sisquoc Station. Movement of the Freeport McMoRan oil was completed on December 10, 2015.
- On December 4, 2015, PHMSA staff received the DNV Root Cause Failure Analysis Report. PHMSA reviewed and commented on the report.
- On December 14, 2015, PHMSA staff monitored the purge process on Line 903 from Gaviota Station to Sisquoc Station. The purge was completed on December 18, 2015 and the line was filled with inert gas.
- On February 17, 2016, PHMSA issued a Preliminary Factual Final Report.
- On April 2, 2016, PHMSA staff monitored the Line 903 Sisquoc to Pentland portion purge that was completed on April 18, 2016. Line 901 and 903 are shutdown, except for the Pentland to Emidio section of Line 903, which is not connected to 903 any longer.

APPENDICES

A. Investigation Summary Detail
B. Supervisory Control and Data Acquisition (SCADA) Log Excerpts
C. Pipeline Leak Monitoring Details
D. Excerpts and Discussion of Plains Integrity Management Plan (IMP) Requirements
E. Corrosion Control and Pipeline Conditions
F. Industry Standards and General Requirements for In-Line Inspection
G. In-Line Inspection Report
H. PHMSA's Independent Analysis of In-Line Inspection Data
I. Maps and Photographs
J. National Response Center Report #1
K. National Response Center Report #2
L. Form PHMSA F 7000.1: Accident Report for Hazardous Liquid Pipeline Systems
M. Det Norske Veritas (U.S.A.), Inc. (DNV GL): Line 901 Release (5/19/15) Mechanical and Metallurgical Testing
N. Det Norske Veritas (U.S.A.), Inc. (DNV GL): Line 901 Release (5/19/15) Technical Root Cause Analysis
O. NACE International: Effectiveness of Cathodic Protection on Thermally Insulated Underground Metallic Structures

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[i] According to the *FRACTURE CONTROL TECHNOLOGY FOR NATURAL GAS PIPELINES CIRCA 2001* (the PRCI report superseding NG-18 Report 208): "The distinction between leak and rupture for the pipeline community is based on the size and configuration of the breach, not how it develops." Based on these calculations and visual observations, the length of the feature is consistent with a leak, arresting within the corrosion feature, and did not propagate outside of the feature into nominal wall-thickness pipe. According to the instructions for completing PHMSA Accident Form 7000-1, this type of accident would be classified as a rupture since PHMSA defines a "rupture" as a "loss of containment that immediate impairs the operation of the pipeline".

[ii] The remedial action plan requires: a) investigation and remediation of anomalies on Line 901 (including anomalies requiring repair per 49 C.F.R. § 195.452(h) and similar anomalies); b) analysis of field measurements taken from anomaly investigations; c) re-grade of previous in-line inspection (ILI) data from 2012 and 2015 ILI surveys using an expanded set of interaction criteria; d) additional integrity assessments using a circumferential magnetic flux leakage (MFL-C) ILI tool and integration of MFL-C ILI data with previous ILI survey results; e) investigation and remediation of anomalies that are identified in the MFL-C tool run (if any); f) based on information collected from remedial work plan and root cause analysis report released by Det Norske Veritas (U.S.A.), Inc., improving the integrity management program; and g) integrity studies to reduce spill volumes, including an emergency flow restriction device evaluation and a surge study. Completion of the remedial work plan is required prior to the PHMSA Western Region Director approving a restart plan and return to service for Line 901.

[iii] High case temperature refers to the oil temperature inside the pump cavity. The case holds the pump impeller

where oil passes through. This was a centrifugal pump that continues spinning whether there is product in the pump or not. When the rupture occurred, there was not enough pressure or flow rate to allow the pump to continue pumping the oil over the hills and into Pentland Station. Therefore, the oil that was in the pump remained in place and as the pump continued to spin, and temperature was reported to the SCADA system. If the pump reaches the high temperature setpoint, the pump shuts itself off to protect itself from burning up.

[iv] The PCR utilizes two shift supervisors to cover the entire set of 22 consoles. The California Console is handled by shift supervisor B. The shift supervisor B position at the time of the failure was filled by a step-up shift supervisor. A step-up shift supervisor is a controller who is currently qualified on a specific console in the PCR and has received some informal training by working on shift with other shift supervisors. Step-up shift supervisors are used to cover the shift supervisor positions when additional personnel are needed due to illness, vacation, training, etc. Plains has indicated that two step-up shift supervisors are not allowed to be on duty at the same time so one shift supervisor is paired with a step-up shift supervisor when additional personnel is needed.

[v] PLM is the SCADA vendor software tool that serves as the leak detection system for PCR.

[vi] *See* Appendix B.

[vii] SCADA Data/Plains Control Room time is local to the Central Time Zone. A two-hour time difference separates Central Time from Pacific Time, with Central Time falling two hours ahead. The release occurred in the Pacific Time Zone which is two (2) hours earlier. All times in this report have been adjusted to Pacific Time.

[viii] *See* Appendix J.

[ix] *See* Appendix K.

[x] *See* Appendix L.

[xi] *See* Appendix M.

[xii] PHMSA has access to this data through a view-only web portal.

[xiii] *See* Appendix G.

[xiv] The inability of an impressed cathodic protection system to protect insulated pipelines was most recently reaffirmed in the National Association of Corrosion Engineers (NACE) Publication 10A392 (2006 Edition) – "Effectiveness of Cathodic Protection (CP) on Thermally Insulated Underground Metallic Structures."

[xv] *See* NACE Report at Appendix O, Background section stating that "[o] n most thermally insulated oil and gas transmission pipelines installed prior to 1980 to 1981, a shop mold-formed thermal insulation was placed directly over the bare steel pipe, with an outer jacket applied to moisture-proof the system. At the field joint, preformed insulation half shells were applied over the joint area to fit between the ends of the shop-applied insulation. After the insulation was fitted, a heat shrink sleeve or a tape wrap was applied over the insulation. When the integrity of the outer moisture barrier was compromised, the space, gap, or void between the edges of the preformed half shells and the shop-applied insulation allowed oxygenated water to diffuse to the bare steel beneath. Damage to the outer moisture barrier has also occurred remote from the joint, allowing oxygenated ground water ingress.

"Thermally insulated pipelines have experienced relatively aggressive corrosion, with some failures occurring within three years of service, although acceptable industry standards of CP had been applied and maintained shortly after line construction. The most predominant failures have been those occurring at joints; however, moisture has migrated along the pipeline steel surface to create electrochemical corrosion cells remote from the field joint, culminating in extensive replacements of substantial lengths of line. An article titled 'Corrosion of Underground Insulated Pipelines' supports this committee's conclusions that sufficient CP current from an external source may not reach the insulated metallic surface in sufficient quantity to establish adequate corrosion control."

[xvi] *See* Appendix D.