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COOK INLET PIPELINE Infrastructure Assessment

FINAL REPORT

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June 2020

Nuka Research and Planning Group, LLC

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This report summarizes the recommendations of an Expert Panel, without whom it would not have been possible to complete the project:
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EXECUTIVE SUMMARY

The Cook Inlet Pipeline Infrastructure Assessment, funded and managed by the Alaska Department of Environmental Conservation (ADEC) and Cook Inlet Regional Citizens Advisory Council (CIRCAC), was carried out by Nuka Research from 2017 – 2020. The Cook Inlet Pipeline Infrastructure Assessment was initiated following a natural gas leak from a sub-sea pipeline into Cook Inlet that was first reported on February 7, 2017, and lasted more than four months before the pipeline could be permanently repaired (ADEC, 2017). The leak raised concerns about the condition of Cook Inlet's pipelines in general, many of which were installed in the 1960s. The purpose of this project was to help maintain the structural integrity of Cook Inlet pipelines by recommending measures to reduce the risk of failures of this aging infrastructure which would, in turn, help protect the environment, economy, communities, and industries in the Cook Inlet region.

The project considered 54 pipelines of the following types in and around Cook Inlet:

- Pipelines transporting crude oil, three phase fluids (oil/water/gas), or natural gas lines that are directly related to oil production activities.
- Abandoned or out-of-service pipelines.

These pipelines extend approximately 350 miles in the Central Cool Inlet area, both on land and offshore, and are operated by five companies. The project scope excludes the following types of pipelines: piping within oil field or processing and refinery facilities; pipelines that carry refined products; and natural gas pipelines that carry processed gas (dry gas), unless providing fuel gas to offshore platforms.

To complete the project, Nuka Research undertook three activities:

- An inventory of in-scope Cook Inlet pipelines,
- A review of state and federal regulatory requirements related to pipeline integrity in Cook Inlet, and
- Convening of an Expert Panel to recommend best practices to enhance pipeline integrity.

The Expert Panel considered the types of pipelines in Cook Inlet, potential threats to the pipelines, Cook Inlet geographic and hydrologic conditions, and state and federal regulations before developing 34 specific and three general recommendations for best practices to mitigate damage to the pipelines. The specific recommendations were grouped by the following threat types:

- External corrosion,
- Internal corrosion,
- Incorrect operations,
- Manufacturing or installation defects,
- Equipment failure,
- Third party/mechanical damage, and
- Weather/outside forces.

Many of the recommendations represent established industry best practices. Some are practices that are already required for some pipelines in Cook Inlet by either state or federal regulations. However, the panel strongly encouraged that the recommended measures should be implemented for all pipelines considered in the project scope regardless of a pipeline's regulatory status or the commodity transported.

TABLE OF CONTENTS

1. INTRODUCTION

This report presents the results of the Cook Inlet Pipeline Infrastructure Assessment, funded and managed by the Alaska Department of Environmental Conservation (ADEC) and Cook Inlet Regional Citizens Advisory Council (CIRCAC) from 2017-2020.

The purpose of this project was to help maintain the structural integrity of Cook Inlet pipelines by recommending measures to reduce the risk of failures of this aging infrastructure. Safe operation of Cook Inlet's pipelines protects the environment, economy, communities, and industry.

The Cook Inlet Pipeline Infrastructure Assessment was initiated following a natural gas leak from a sub-sea pipeline into Cook Inlet that was first reported on February 7, 2017, and lasted more than four months before the pipeline could be permanently repaired (ADEC, 2017). The leak raised concerns about the condition of Cook Inlet's pipelines in general, many of which were installed in the 1960s.

Nuka Research and Planning Group, LLC, implemented the project under contract to the ADEC and CIRCAC who served as the project management team overseeing this project.

1.1. Project Overview

This section describes the project scope and approach.

Project Scope

This project considered the following types of pipelines in and around Cook Inlet:

- Pipelines transporting crude oil, three phase fluids (oil/water/gas), or natural gas lines that are directly related to oil production activities.
- Abandoned or out-of-service pipelines.

The project scope encompasses approximately 350 miles of pipelines operated by five companies: Cook Inlet Energy, LLC (CIE); Furie Operating Alaska, LLC (Furie); Harvest Alaska, LLC (Harvest); Hilcorp Alaska, LLC (Hilcorp); and Marathon Petroleum Company[1] (Marathon). These pipelines are all located in the Central Cook Inlet area, either on land (both the east and west sides of Cook Inlet), or offshore in state waters. Onshore pipelines in the study scope are all in the Kenai Peninsula Borough. See Figure 1.1-1.

The project scope *excludes* the following types of pipelines: piping within oil field or processing and refinery facilities; pipelines that carry refined products; and natural gas pipelines that carry processed gas (dry gas), unless providing fuel gas to offshore platforms.

It should be noted that the map figures included in this report are not intended to depict the exact location of pipelines, but rather to show the general locations and facilities connected by each pipeline.

[1] Formerly Tesoro Alaska and Andeavor

As the goal of the project is focused on the integrity of existing pipelines, it does not address pipeline siting or spill response.

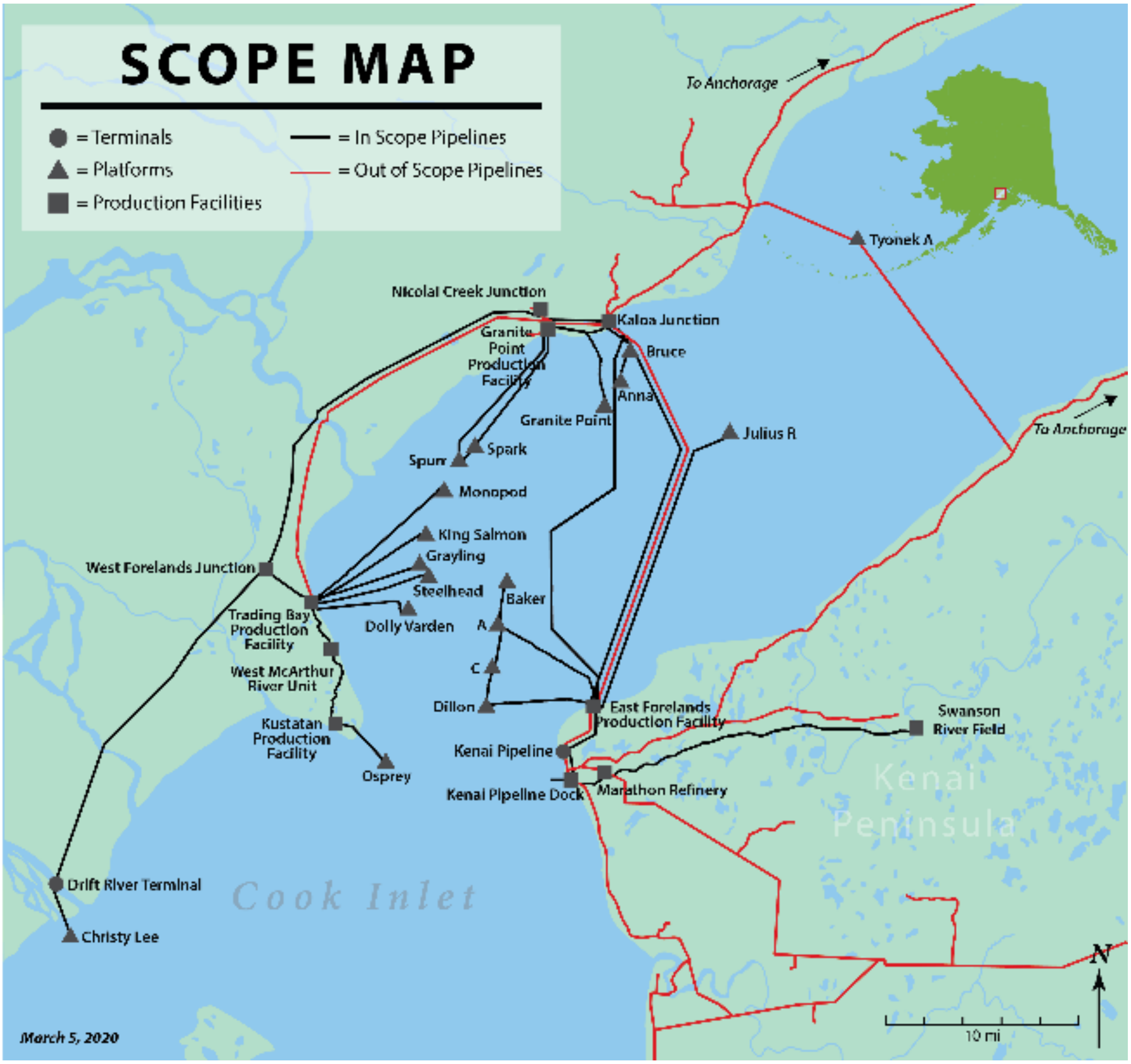

Figure 1.1-1 Pipelines in the Central Cook Inlet area, showing both in-scope and out-of-scope pipelines

Project Approach

The project included three parts:

- Inventory in-scope Cook Inlet pipelines.
- Review state and federal regulatory requirements related to pipeline integrity in Cook Inlet.
- Convene an Expert Panel to recommend best practices to enhance pipeline integrity.

Nuka Research conducted the first two parts of the project in coordination with the ADEC and CIRCAC, along with input from Cook Inlet pipeline operators. These first steps focused on building a current inventory of Cook Inlet pipelines within the project scope, drawing on information from agencies and operators. The regulatory oversight for each line was identified and the applicable regulations summarized (see Section 2.5).

The pipeline inventory, including regulatory information, was provided to an Expert Panel to develop recommended best practices suited to the infrastructure. This project followed the process ADEC used to identify recommended oil spill mitigation measures for the North Slope of Alaska where an independent panel was convened to review available information on the pipeline infrastructure and develop recommendations based on their own experience and the compiled material. That project also focused on preventing pipeline loss-of-integrity events that result in pipeline spills (Nuka Research, 2010).

Expert Panel Selection

A panel of five experts convened to recommend best practices for the operation and maintenance of in-scope pipelines in Cook Inlet, Alaska. (See Appendix A for Panel members and bios.)

The panel was selected by ADEC and CIRCAC from applications submitted in response to an open call for experts. The panel was selected based on their knowledge of oil and gas pipeline operations, pipeline corrosion, integrity management, causal analysis, and general engineering practices. The Expert Panel was charged with providing independent recommendations on mitigation measures, programs, and practices to monitor and address common causes of failures identified in their review of the pipeline infrastructure. (Panel members served in their individual capacities and not as representatives of current or former employers.) The Panel's recommendations described in Section 3 represent the consensus of the group.

During 2019, the Expert Panel implemented their own approach to meet their stated purpose of developing recommendations. In addition to reviewing the pipeline inventory compiled for the project, the Panel met with representatives of Hilcorp to ask questions about the pipelines owned and operated by Hilcorp and its subsidiary, Harvest. On behalf of the Panel, Nuka Research contacted the other operators with in-scope pipelines with the Panels' questions regarding their infrastructure and integrity management practices. Additional information was received from Cook Inlet Energy and Marathon upon request. Furie did not provide information to this project.

Approach to Considering Pipeline Spill Risk

The risk of a pipeline release due to loss-of-integrity is a function of the likelihood of an event leading to a spill and the consequences if it does (Andrews and Moss, 2002). Likelihood varies depending on the range of threats – or hazards – that are possible given the location of a pipeline as well as its age, construction, operation (including contents), and maintenance.

In order to develop a framework for their discussion of risks and associated mitigation measures, the panel first considered a set of potential loss-of-integrity scenarios. Once the expert panel agreed on a list of more than 270 scenarios, each member scored each scenario on a scale of 1 to 5 in four areas: likelihood of occurrence, potential impacts to human safety, potential environmental impacts, and potential socio-economic impacts. These scores were not used to quantitatively rank the scenarios, but to generate discussion of relative risks and mitigation options among the Panel members. The Expert Panel met to review their scenario scores and develop a set of recommendations for best practices for pipeline operators which is tailored to these Cook Inlet pipelines.

The Panel organized their deliberations around hazard types identified in an American Society of Mechanical Engineers (ASME) listing of potential pipeline threats. Although these threats focus on gas pipelines, they were considered applicable for identifying the range of possible hazards applicable to oil pipelines as well (although the consequences would be different). Section 3 of this report is organized around these potential threats, describing the threat, relevant aspects of the Cook Inlet context, applicable regulatory requirements, and Panel recommendations.

1.2. Related Studies

This report builds on previous studies of Cook Inlet pipelines. These include:

- 1993 inventory and risk assessment of both onshore and offshore pipeline infrastructure by Belmar Management Services for the Alaska Department of Environmental Conservation (Belmar, 1993a; Belmar, 1993b).
- 2000 overview of pipeline regulations applicable to Cook Inlet by Tim Robertson and Parker Horn Company (Robertson and Parker Horn Company, 2000).
- 2002 review of Cook Inlet pipeline issues by Lois Epstein for Cook Inletkeeper (Epstein, 2002).
- 2005 pipeline risk assessment by Brown Corrosion Associates for CIRCAC (Brown, 2005).

This report also benefitted from the work of a task force convened in the late spring of 2017 by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and a previous expert-elicitation process focused on North Slope pipelines (Nuka Research, 2010).

2. BACKGROUND ON COOK INLET PIPELINES

This section provides background on Cook Inlet oil and gas production and the pipelines in this study.

2.1. History and Systems Overview

Pipelines are a crucial part of a much larger system that produces, processes, and transports oil and natural gas in Cook Inlet. This section provides a brief overview of this system and its history, which are relevant to understanding the operation of Cook Inlet's pipelines.

Producing oil and gas is a multistep process, including the production, transfer, and processing (or management) of crude oil, natural gas, and produced water. Crude oil, natural gas, and produced water flow from both offshore and onshore wells. This comingled production from the well is sent to production facilities, where the three fluids are separated. Produced water is separated from the oil and gas and is either discharged into Cook Inlet[2] or reinjected into underground formations.

Crude oil and natural gas are then further separated and processed into products that can be sold. Currently, crude oil produced in Cook Inlet is sent by pipeline to the oil refinery in Nikiski where it is refined into various oil products. North Slope crude reaches the refinery via tankers from the Valdez Marine Terminal in Prince William Sound. Refined product (jet fuel, gasoline, and diesel) is loaded into tankers in Nikiski or sent to Anchorage via a pipeline across northern Cook Inlet. Natural gas is transported by pipeline throughout the Kenai Peninsula, the Municipality of Anchorage, and the Matanuska-Susitna Valley for use in homes and industry.

There are 17 fixed platforms operating in Cook Inlet itself and numerous wells on shore. There are five production facilities: Kustatan, West McArthur River, Trading Bay, Granite Point, and East Forelands (also known as Middle Ground Shoals Production Unit). There is also a refinery (Marathon Refinery), two terminals (Drift River Terminal[3] and Kenai Pipeline Terminal[4]), and associated tanker and oil barge traffic.

Approximately 350 miles of in-scope pipelines traverse the Cook Inlet area, moving crude oil, natural gas, and produced water among platforms and on-land storage or processing facilities. These pipelines cross various state, federal, and private lands, as well as resting on the bottom of Cook Inlet.

Brief History of Oil and Gas in Cook Inlet

Oil and gas exploration began around Cook Inlet when Russia owned the area, although it increased substantially immediately before and after Alaska became a U.S. state in 1959. Following discovery of offshore oil in 1962, 14 offshore production platforms were constructed

[2] Discharge of produced water into Cook Inlet is permitted under a National Pollution Discharge Elimination System (NPDES) permit.
[3] The Drift River Terminal was being decommissioned at the time of this project.
[4] Kenai Pipeline is owned by Marathon Petroleum.

by the end of that decade (ADNR, 2009). Additional platforms were installed in 1986 (Steelhead), 2000 (Osprey), and 2015 (Julius R) (Rothe, 2005; DeMarban, 2019).

The original operators of Cook Inlet's platforms and associated infrastructure included Amoco, Arco, Forest Oil, Marathon, Mobil, Phillips Petroleum, Unocal, Shell, and Texaco (Rothe, 2005). Ownership has transitioned over the years, with several changes in the past decade.[5] As of the start of the Cook Inlet Pipeline Infrastructure Assessment, all the production infrastructure was owned by Limited Liability Corporations with the exception of the Marathon Petroleum Company (ADNR, 2017).[6] Similar changes have occurred for many onshore operations, including production, pipelines, and storage. (See Section 2.2.3 for more information on ownership of in-scope pipelines.)

The Marathon (previously Andeavor and Tesoro Alaska) refinery in Nikiski began operations in 1969 and is the oldest and largest refinery in the state (Econ One Research, Inc., 2015). The Marathon refinery processes both Cook Inlet and Alaska North Slope crude oil. Currently Cook Inlet crude oil is delivered via pipelines from the various production facilities on the east and west side of Cook Inlet. Until 2018, oil produced on the west side of Cook Inlet was transported on tankers across Cook Inlet from the Drift River Terminal. In the past there was also a Chevron refinery located near the Kenai Pipeline facility, but it has been decommissioned and removed.

Cook Inlet Oil and Gas Production Systems

Cook Inlet is home to 17 production platforms spanning seven production systems or units. Units are a consolidation of leasehold interests covering a common source of oil and gas. All of them are connected to processing/transport infrastructure by pipelines and shown in Figure 2.1-1. There are four inactive (or "lighthoused") platforms within the Cook Inlet Production Systems: Dillon, Baker, Spark, and Spurr. These platforms are powered by natural gas that is fed to them through pipelines, but they do not produce any crude or natural gas at this time. See Section 2.2 for more information about the pipelines studied.

This report identifies an "East Forelands Production Facility" on the east side of the Inlet. This facility includes the northern terminus of the Marathon Kenai Pipeline crude oil transmission pipeline, Hilcorp Middle Ground Shoals production facility, recently modified Hilcorp cross-Inlet crude oil transmission pipeline, the Cook Inlet Gas Gathering System (CIGGS), and the Furie gas production facility. All of these facilities are located close together and are interconnected by pipelines, but are shown as a single location due to map scale and simplicity.

This report also designates the Kenai Pipeline facility to include the oil storage tanks and dock owned by Marathon at Nikiski. This facility is connected to the Marathon Refinery, the Middle Ground Shoals Production Facility, and Swanson River oil field. This facility is separate from the Kenai Pipeline Junction, which is outside the scope of this project.

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[5] Changes have continued to take place during the course of this project (DeMarban, 2019).

[6] Of these, Cook Inlet Energy and Hilcorp Alaska have pipelines included in the scope of this study. The other companies with pipelines in the study scope, Harvest Alaska, LLC and Marathon, are not oil producers in the region. Harvest Alaska is strictly involved in mid-stream operations, while Marathon operates the refinery and some associated pipelines.

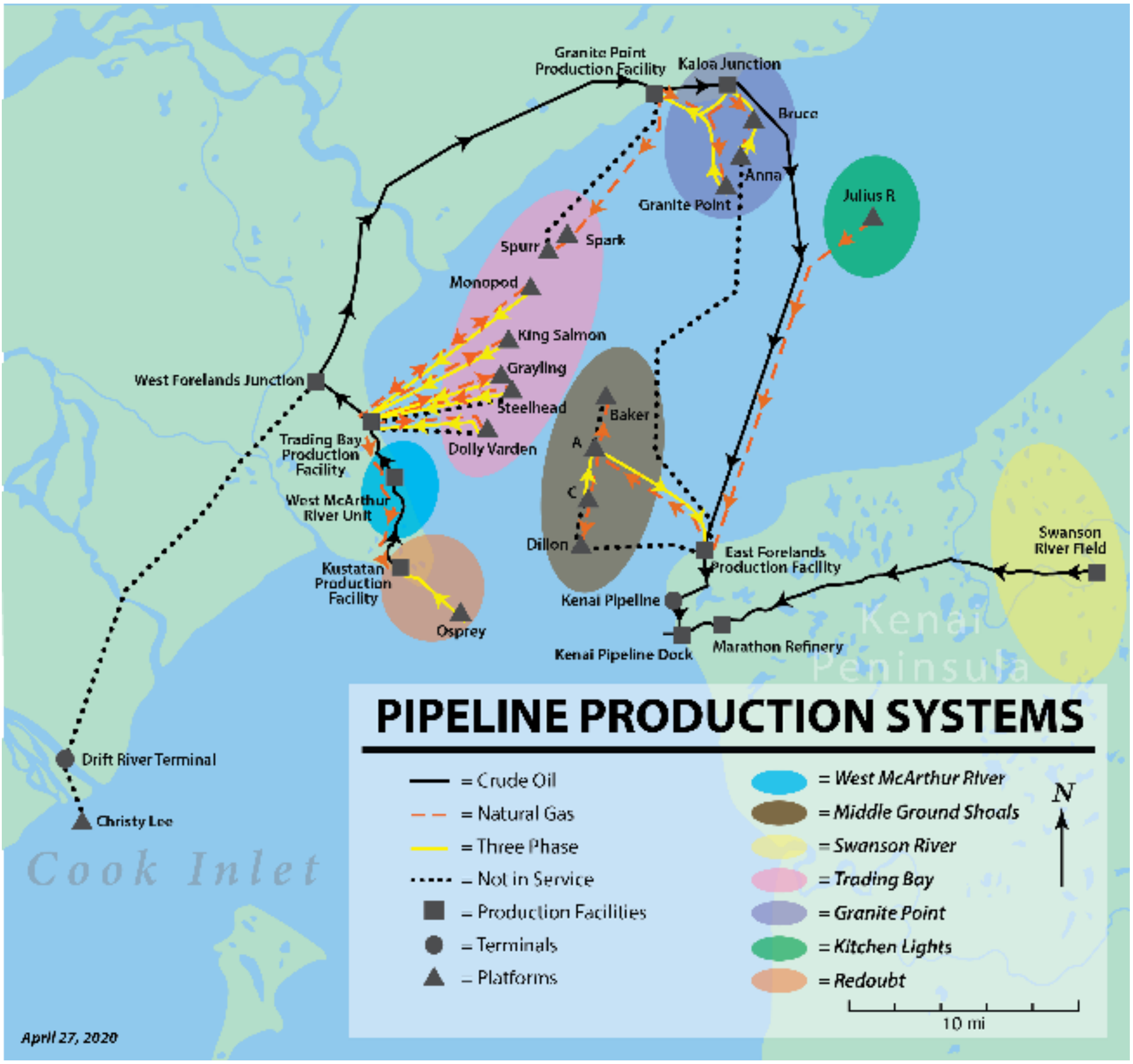

Figure 2.1-1 Cook Inlet production systems, with in-scope pipelines shown by commodity type (or those Not in Service)

2.2. Pipelines

Table 2.2-1 lists the 54 pipelines identified within the project scope, including the operator, operational status, associated facilities, commodity currently transported, and agency(ies) with direct regulatory oversight related to pipeline integrity. Regulations are discussed further in Sections 2.5 and 3 and Appendix B. See Appendices C-H for pipeline system details.

Table 2.2-1 In-scope pipelines (as of 2019); N = not active; A= active)

LINE*	OPERATOR	STATUS	ASSOCIATED FACILITIES	COMMODITY	REGULATORY OVERSIGHT
B1	BP	N	East Forelands Production Facility to Anna Platform	none	none
B2	BP	N	East Forelands Production Facility to Anna Platform	none	none
Redoubt/West McArthur System					
C1	Cook Inlet Energy	A	Kustatan Production Facility to Trading Bay Production Facility	Fuel Gas	PHMSA
C2	Cook Inlet Energy	A	Kustatan Production Facility to West McArthur Production Facility	Crude Oil	ADEC
C3	Cook Inlet Energy	A	Kustatan Production Facility to West McArthur Production Facility	Three Phase	ADEC
C4	Cook Inlet Energy	N	Osprey Platform to Kustatan Production Facility	Gas/Three Phase	ADEC
C5	Cook Inlet Energy	A	Osprey Platform to Kustatan Production Facility	Three Phase	ADEC
C6	Cook Inlet Energy	A	West McArthur Production Facility to Trading Bay Production Facility	Crude Oil	ADEC
Kitchen Lights System					
F1	Furie	A	Julius R Platform to Furie Gas Production Facility at East Forelands Production Facility	Production Gas	none
Cook Inlet Pipeline System					
Ha1	Harvest	N	Christy Lee Platform to Drift River Terminal	none	USCG, ADEC
Ha2	Harvest	N	Christy Lee Platform to Drift River Terminal	none	USCG, ADEC
Ha3	Harvest	N	Drift River Terminal to West Forelands Junction	none	ADEC
Ha4	Harvest	A	Trading Bay Production Facility to West Forelands Junction	Crude Oil	PHMSA, ADEC
Ha5	Harvest	A	West Forelands Junction to Granite Point Production Facility	Crude Oil	PHMSA, ADEC
Ha6	Harvest	A	Granite Point Production Facility to Kaloa Junction	Crude Oil	PHMSA, ADEC

LINE*	OPERATOR	STATUS	ASSOCIATED FACILITIES	COMMODITY	REGULATORY OVERSIGHT
Ha7	Harvest	A	Kaloa Junction to East Forelands Production Facility	Crude Oil	PHMSA, ADEC
Ha8	Harvest	A	East Foreland Production Facility to Marathon Refinery	Crude Oil	PHMSA, ADEC
Swanson River System					
Ha9	Harvest	A	Swanson River Field to Marathon Refinery	Crude Oil	PHMSA, ADEC
Granite Point System					
Hi1	Hilcorp	A	Anna Platform to Bruce Platform	Production Gas	PHMSA
Hi2	Hilcorp	A	Anna Platform to Bruce Platform	Three Phase	PHMSA, ADEC
Hi3	Hilcorp	A	Bruce Platform to Granite Point Production Facility	Production Gas	PHMSA
Hi4	Hilcorp	A	Bruce Platform to Granite Point Production Facility	Three Phase	PHMSA, ADEC
Hi5	Hilcorp	A	Cook Inlet Gas Gathering System to Granite Point Production Facility	Fuel Gas	none
Hi6	Hilcorp	A	Cook Inlet Gas Gathering System to Granite Point Production Facility	Fuel Gas	none
Hi7	Hilcorp	A	Granite Point Platform to Granite Point Production Facility	Production Gas	PHMSA
Hi8	Hilcorp	A	Granite Point Platform to Granite Point Production Facility	Three Phase	PHMSA, ADEC
Hi9	Hilcorp	A	Spark Platform to Granite Point Production Facility	Fuel Gas	PHMSA
Hi10	Hilcorp	A	Spark Platform to Spurr Platform	Fuel Gas	PHMSA
Hi11	Hilcorp	N	Spurr Platform to Granite Point Production Facility	none	PHMSA
Hi12	Hilcorp	N	Spurr Platform to Granite Point Production Facility	none	PHMSA
Middle Ground Shoal System					
Hi13	Hilcorp	N	Dillon Platform to East Forelands Production Facility	none	none
Hi14	Hilcorp	N	Dillon Platform to East Forelands Production Facility	none	PHMSA
Hi15	Hilcorp	A	Dillon Platform to Platform C	Fuel Gas	PHMSA
Hi16	Hilcorp	N	Dillon Platform to Platform C	none	PHMSA
Hi17	Hilcorp	A	Platform A to East Forelands Production Facility	Fuel Gas	PHMSA
Hi18	Hilcorp	A	Platform A to East Forelands Production Facility	Three Phase	ADEC
Hi19	Hilcorp	A	Platform A to Baker Platform	Fuel Gas	PHMSA
Hi20	Hilcorp	N	Platform A to Baker Platform	none	PHMSA

LINE*	OPERATOR	STATUS	ASSOCIATED FACILITIES	COMMODITY	REGULATORY OVERSIGHT
Hi21	Hilcorp	A	Platform A to Platform C	Fuel Gas	PHMSA
Hi22	Hilcorp	A	Platform A to Platform C	Three Phase	ADEC
Trading Bay System					
Hi23	Hilcorp	A	Dolly Varden Platform to Trading Bay Production Facility	Fuel Gas	PHMSA
Hi24	Hilcorp	N	Dolly Varden Platform to Trading Bay Production Facility	none	none
Hi25	Hilcorp	A	Dolly Varden Platform to Trading Bay Production Facility	Three Phase	PHMSA, ADEC
Hi26	Hilcorp	A	Grayling Platform to Trading Bay Production Facility	Fuel Gas	PHMSA
Hi27	Hilcorp	A	Grayling Platform to Trading Bay Production Facility	Three Phase	ADEC
Hi28	Hilcorp	A	King Salmon Platform to Trading Bay Production Facility	Fuel Gas	PHMSA
Hi29	Hilcorp	A	King Salmon Platform to Trading Bay Production Facility	Three Phase	ADEC
Hi30	Hilcorp	A	Monopod Platform to Trading Bay Production Facility	Fuel/Production Gas	PHMSA
Hi31	Hilcorp	A	Monopod Platform to Trading Bay Production Facility	Three Phase	PHMSA, ADEC
Hi32	Hilcorp	N	Steelhead Platform to Trading Bay Production Facility	none	PHMSA
Hi33	Hilcorp	A	Steelhead Platform to Trading Bay Production Facility	Production Gas	PHMSA
Hi34	Hilcorp	A	Steelhead Platform to Trading Bay Production Facility	Three Phase	ADEC
Kenai Pipeline System					
K2	Marathon	A	Kenai Pipeline Tank Farm to Kenai Pipeline Dock	Crude Oil	USCG, ADEC
K1	Marathon	A	East Forelands Production Facility to Kenai Pipeline	Crude Oil	PHMSA, ADEC

** Alphanumeric identifiers in column 1 were developed for this project only. They are used through this report narrative and appendices.*

Pipelines by Commodity

Pipelines in the project scope transport three different types of product: crude oil, three phase production (a combination of produced water, crude oil, and natural gas), and natural gas. There are two types of natural gas pipelines: unrefined natural gas (wet gas), and sales quality natural gas (dry gas). The only dry gas pipelines included in this study are the pipelines providing fuel gas to offshore platforms.

Pipeline use can change as production changes, so a pipeline may carry different commodities over its operational life, or may be unused for a period of time but brought back into operation. Also, the direction of flow can change in a pipeline due to reconfiguration of products and processes. Many such changes have occurred in Cook Inlet as production has shifted from being primarily focused on oil to a growing emphasis on natural gas.

The pipelines studied include roughly 95 miles of gas pipelines, 90 miles of crude oil lines, and 53 miles of three phase pipelines. There are also 105 miles of pipelines currently not in service. See Figure 2.2-1 for a map of pipelines by product carried.

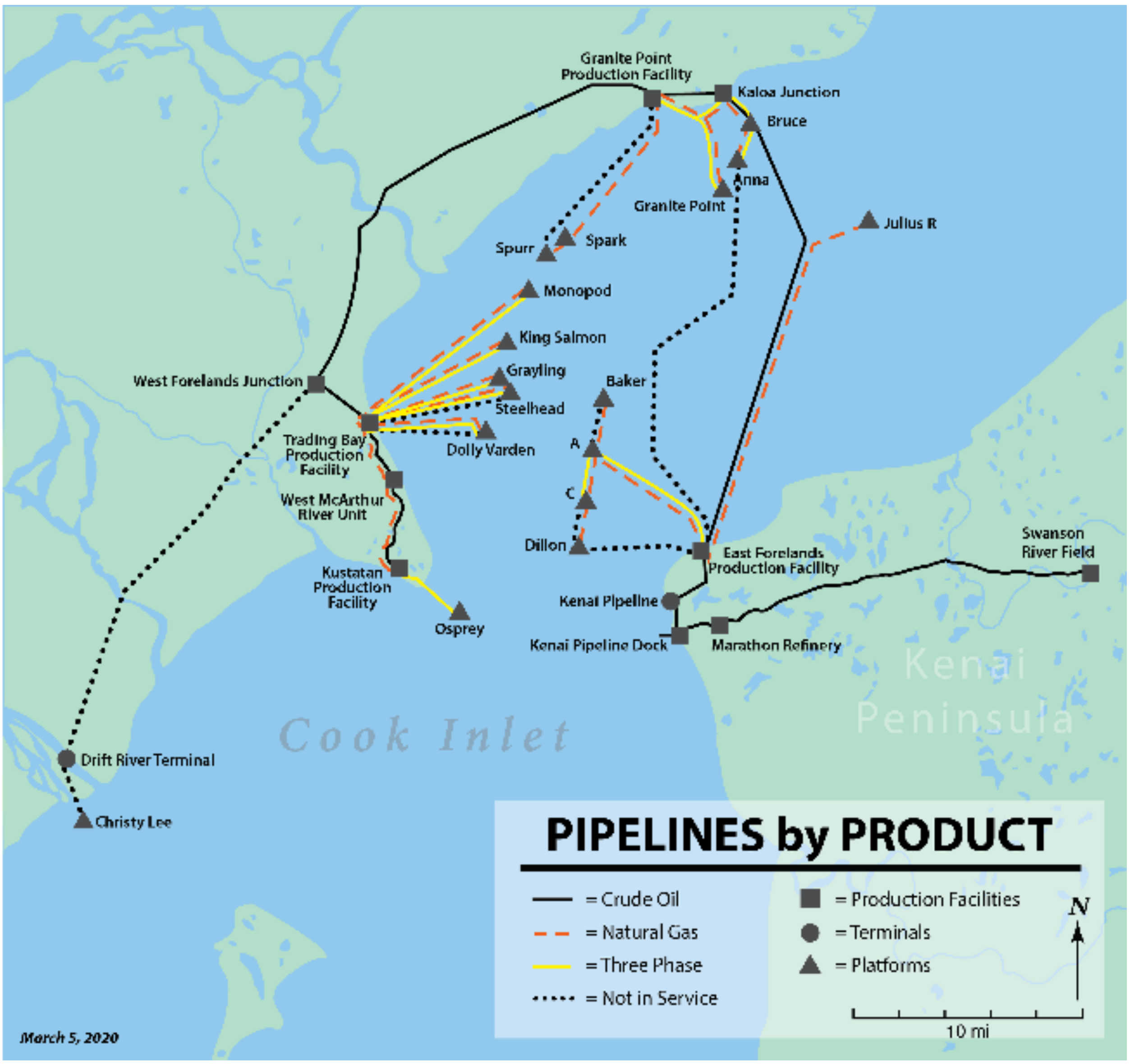

Figure 2.2-1 In-scope pipelines by commodity

Pipelines by Operator

Pipeline ownership is dominated by Hilcorp which produces both natural gas and crude oil using about 168 miles of pipelines within the Cook Inlet area. Hilcorp also owns the onshore and sub-sea pipelines that carry three phase liquid and natural gas from offshore platforms to production facilities on both the east and west sides of Cook Inlet.

Harvest, a subsidiary of Hilcorp, operates about 103 miles of crude oil pipelines in Cook Inlet, including the Cook Inlet pipeline system and the Swanson River pipeline. These pipelines transport sales quality crude oil from processing facilities to the Kenai Pipeline terminal and the Marathon refinery in Niskiski. Currently, Harvest's pipelines going to the Drift River Terminal and the Christy Lee platform are being decommissioned.

Cook Inlet Energy is a subsidiary of Glacier Oil and Gas Company. Cook Inlet Energy operates all of the pipelines extending from the Osprey Platform through the West McArthur River Unit to the Trading Bay Production Facility. They own and operate about 27 miles of pipelines and produce both crude oil and natural gas.

Marathon, Furie, and BP own the rest of the pipelines within the project scope. Marathon owns approximately 5 miles of pipeline connecting Hilcorp's East Forelands Production Facility to the Kenai Pipeline Terminal and the Marathon refinery. Furie owns a 16-mile long natural gas pipeline that ties the Julius R platform to the CIGGS. BP owns about 32 miles of sub-sea legacy pipelines that were abandoned in the 1970s.

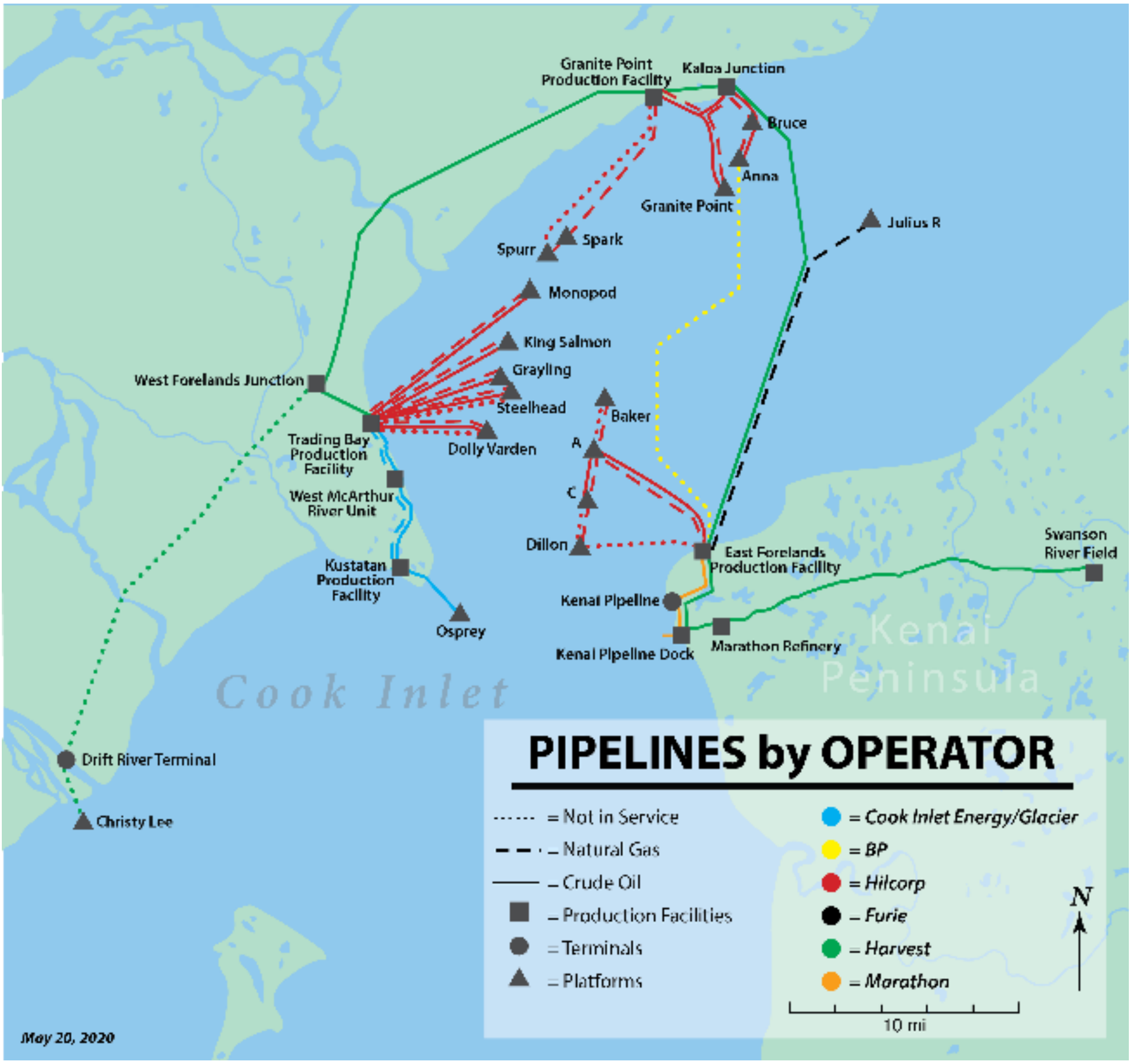

Figure 2.2-2 Pipelines by operator within the project scope

Pipelines by Year of Construction

Cook Inlet pipelines in this study were constructed between 1965 and 2018.[7] Table 2.2-2 shows the number and mileage of pipelines by the era of construction and the current commodity being shipped through the pipeline. Of the pipelines where construction date is known, 74% of the pipeline miles were constructed prior to 1970 and are now at least 50 years old.

Table 2.2-2 In-scope pipelines by commodity and decade of construction, where known

ERA OF CONSTRUCTION	CRUDE		THREE PHASE		NATURAL GAS		NOT IN SERVICE	
	number	miles	number	miles	number	miles	number	miles
1960-1969	4	47	9	48	13	65	11	73
1970-1979	2	27	1	5				
1980-1999								
2000-2019	4	16	2	3	2	4		
Unknown	1	1			4	33	2	32

2.3. Past Loss-of-Integrity Events

Spills are an indicator of the integrity of a pipeline system. Ideally a record would be kept for each line with the date, cause, and size of all leaks. Unfortunately, detailed records of spill by pipeline do not exist for Cook Inlet. Spill data has been kept by various agencies over the years, but reporting requirements and recording keeping practices have changed over time, so the data are not consistent.

A composite database of spills greater than one barrel from oil production facilities was assembled for the Bureau of Ocean and Energy Management and used to provide a general indication of spills from the Cook Inlet pipeline infrastructure.[8] The database was queried for spills from a source of "pipe or line", which includes pipelines in this study, but also includes spills from pipes or lines within oil production facilities and platforms. Figure 2.2-3 presents the number of spills from "pipes or lines" greater than one barrel by year. Figure 2.2-4 presents the total volume of those spills in barrels. Overall 104 spills were attributed to spills from pipes or lines between 1966 and 2019 with a combined volume of 9,654 barrels.

The first pipelines installed in the mid 1960s had numerous failures due to current-induced vibration (Belmar, 1993b). There were 15 failures between 1966 and 1976 which caused the operators to abandon two lines (B1 and B2 in Table 2.1-1) and develop a program of regular inspections and pinning unsupported spans in other pipelines. Belmar also reports that there have been a number of failures of pipeline risers into the platforms caused by external corrosion. These failures were also addressed with operator management programs. In 1987, a subsea pipeline failed due to rubbing on an exposed rock. In 2001, a series of sheens seen in the Inlet were attributed to leaks from the previously abandoned B1 and B2 pipelines, which were

[7] Date of construction for some pipelines could not be determined.

[8] There have also been gas leaks in recent years, as noted above (ADEC, 2017), but data on gas leaks is even more limited than for oil and so is not summarized here.

thought to still contain some crude oil. The sheens stopped when the lines were flushed out and sealed.

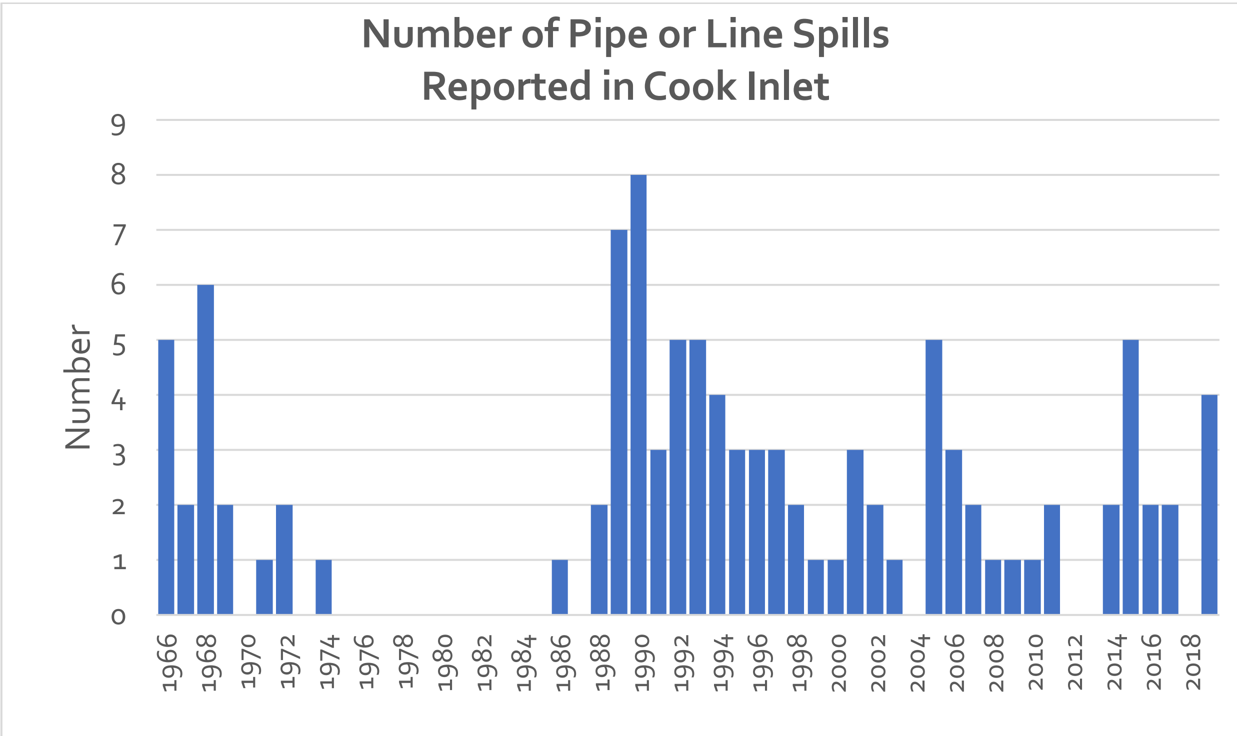

Figure 2.2-3 Number of pipe or line spills greater than one barrel reported in Cook Inlet, 1966-2018

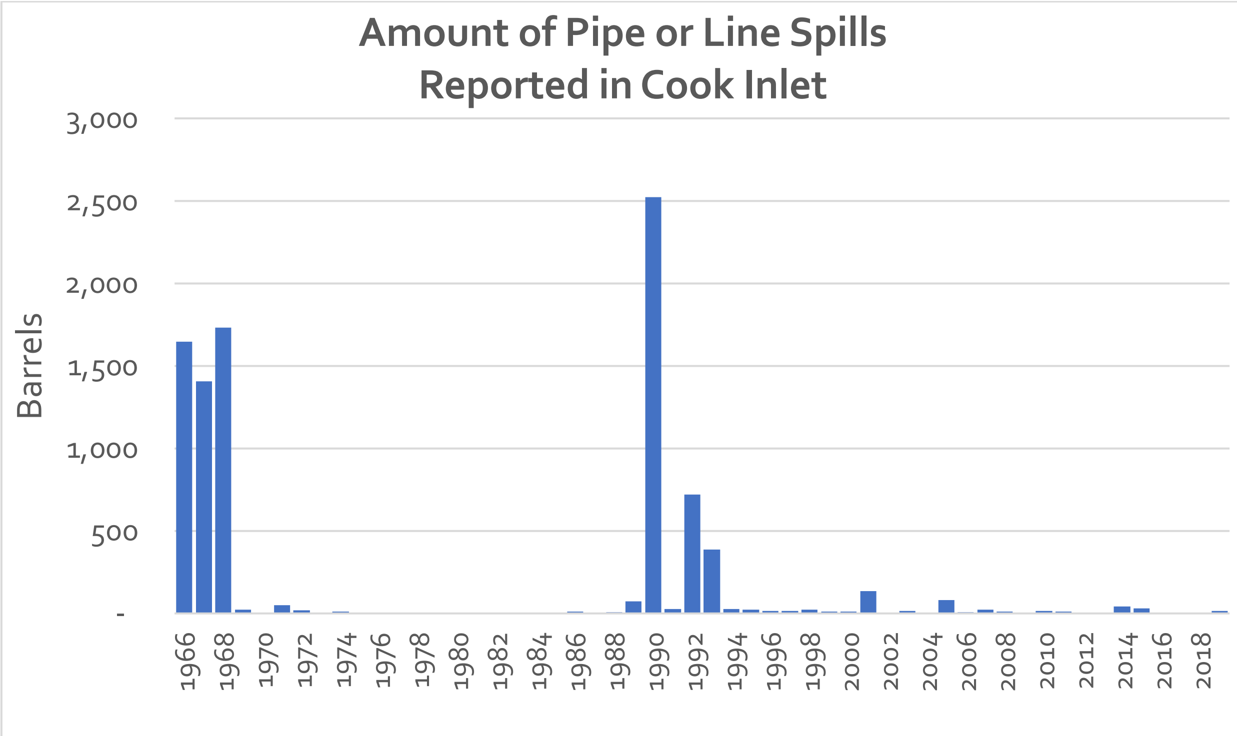

Figure 2.2-4 Total volume of pipe or line spills greater than one barrel reported in Cook Inlet, 1966-2018

As noted above, the pipeline-related spills in the mid-1960s were related to induced vibration due to the high tidal currents in Cook Inlet affecting unsupported spans in the subsea pipelines. Operators developed procedures to survey pipelines and pin unsupported spans with concrete. Since those procedures were implemented there have not been further spills due to this cause. The large spill (2,300 bbl) in 1990 was the result of third-party damage at the Drift River Terminal. There were three larger spills in the early 1990s (400 bbl and 220 bbl in 1992 and a 378 bbl spill in 1993). All three occurred on land at facilities and were attributed to freezing or ice falling from a tank. Otherwise there have not been any large oil spills from Cook Inlet area pipelines in the past 30 years.

2.4. Potential Spill Consequences

There may be safety, environmental, and/or socio-economic impacts if a pipeline fails. All three types of potential consequences are possible in Cook Inlet, and could occur simultaneously.

Safety refers to worker and public safety. Many of the pipelines in the project scope are in remote or uninhabited areas, but there are some in and around Nikiski that go near residential communities and commercial/municipal sites. (Pipelines that are *out* of this project's scope include gas distribution lines to and through Kenai Peninsula communities, product lines to Anchorage, and gas lines from onshore production areas south of Kenai.)

Environmental impacts are likely to be greater if the spill occurs in, or reaches, water than if it stays onshore. A consequence analysis conducted for potential spills associated with vessel traffic in Cook Inlet discusses both environmental and socioeconomic consequences of marine spills that may result from vessel incidents, including both crude oil and refined products. Potential impacts to habitat, fish, birds, mammals, subsistence uses, recreational and commercial fishing, commerce (including tourism), and oil industry and port operations were identified (Nuka Research, 2013).

Socio-economic consequences of a spill are closely tied to environmental impacts (e.g., loss of, or loss of access to, a species harvested for subsistence, commercial, or recreational purposes), with the addition of the potential impacts associated with decreased production if there is a halt or slowdown due to a pipeline leak.

The consequences of a pipeline spill will depend on the product spilled (gas, three phase, or crude oil), location and timing of the release, volume, and effectiveness of any response. In general, safety is the primary concern if there is a gas leak, while environmental impacts are more likely for crude oil releases.

2.5. Regulatory Framework

Several state and federal agencies regulate the pipelines studied, including permitting or otherwise regulating pipeline siting and construction, operations and maintenance, decommissioning, and/or spill response.

Two agencies have primary oversight responsibility for measures related to pipeline integrity and spill prevention: the ADEC Division of Spill Prevention and Response (SPAR) and the federal PHMSA within the U.S. Department of Transportation. In addition, the U.S. Coast Guard has requirements for piping and loading arms used to transfer oil between a vessel and shoreside facility.[9] The State Pipeline Coordinators' Section (SPCS), within the Alaska Department of Natural Resources' Division of Oil and Gas, oversees the lease associated with the converted sub-sea pipeline across Cook Inlet [Ha7]. This includes requirements for maintenance of the lease area and reporting on right-of-way management and environmental measures.[10] Other agencies have responsibilities related to pipeline siting and spill response. Agency mandates are summarized in Appendix B.

This section describes the regulatory context for pipelines within the project scope and some general regulatory requirements. More specific regulatory requirements related to the pipeline threats considered by the Expert Panel are discussed in Section 3 along with the Panel's recommended best practices.

Alaska Department of Environmental Conservation (ADEC)

While ADEC can intervene in any spill of oil or hazardous substances affecting Alaska lands or waters, the Department has regulations specific to the integrity of pipelines carrying liquid crude oil (crude or three phase) on land or in State waters. (Unless a gas release occurs, the State does not regulate natural gas lines.) Currently, all of the Cook Inlet oil and gas infrastructure is located in State waters.[11]

Under ADEC's regulatory definitions, the pipelines within the project scope are categorized as one of the following, if they are carrying oil (or three phase liquids):

- Flowlines that are part of the production facility and transmit the oil (or combination of oil, water, and gas that is produced from a well) from the well pad or marine structure where the oil is produced to a transmission line.[12] In Cook Inlet, these are subsea lines from platforms to shore (or, in some cases, to another platform).
- Crude oil transmission lines that transport the oil, usually from production facilities.[13] Most crude oil transmission lines are onshore, with the exception being the Harvest Cross-Inlet pipeline [Ha7] converted from gas to crude oil in 2018.

[9] 33 CFR 156.170
[10] AS 38.35.015 (see: http://dog.dnr.alaska.gov/Services/Pipelines)
[11] Submerged Lands Act [43 U.S.C. §§1301-1315]
[12] 18 AAC 75.990(173)
[13] 18 AAC 75.990(134)

- Facility oil piping that is within facilities all around Cook Inlet, but for the purpose of this study scope it applies only to the loading lines at the KPL dock [K1][14] in Nikiski and the no-longer used line at the Drift River Terminal/Christy Lee Platform [Ha1, Ha2].

ADEC regulations require operators of oil pipelines to have an approved Oil Discharge Prevention and Contingency Plan. These plans describe the spill prevention measures required for regulated oil pipelines.

Regulations related to the threat categories discussed by the Expert Panel are addressed in Section 3. In addition, ADEC requires varying types of preventive measures and leak detection systems:

- Flowlines must have a leak detection system or internal and external corrosion control and monitoring programs consistent with *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* (ASME B31.4-2002) if they are buried or submerged. Alignment with the American Petroleum Institute's (API) *Piping Inspection Code, Inspection, Repair, Alteration, and Re-rating of In-service Pipelines* (API 570) is also required for aboveground flowlines.[15]
- Crude oil transmission pipelines must have leak detection and monitoring programs in place and the ability to stop a leak within an hour of detection or one percent of throughput. This includes weekly aerial surveillance for remote pipelines.[16]
- Facility oil piping must have a corrosion control program in line with referenced industry standards, but only if placed in service after 2008. This limit is not the case for either of the two lines in the project scope. If the line at the Christy Lee Platform was put back into service, however, then the requirements would take effect for that line.[17]

ADEC regulations also specify that unless explicitly pre-empted by federal law, if state and federal requirements for a particular pipeline (or other facility) are different, the more stringent application applies.[18]

Pipeline and Hazardous Materials Safety Administration (PHMSA)

PHMSA's Office of Pipeline Safety implements federal pipeline safety regulations.[19] In contrast to the focus of ADEC regulations on oil lines, PHMSA has regulations for both oil and gas lines. Included in the scope of this study are gas lines (regulated gathering and transmission lines) and oil lines ("hazardous liquid" lines). These are regulated under different sections of the

[14] Numbers in brackets refer to individual pipelines as listed in Table 2.2-1. This numbering system is used for this project only, allowing the reader to connect references to individual pipelines in the text, Table 2.2-1, and Appendix B.
[15] 18 AAC 75.047(d)(2)
[16] 18 AAC 75.055
[17] 18 AAC 75.080(c)(1-4)
[18] 18 AAC 75.007(c)
[19] As a federal agency, PHMSA has primary authority over most *inter*state pipelines. States regulate *intra*state pipelines if they have a program certified by PHMSA. As Alaska does not have such a program, PHMSA regulates pipelines in Alaska, all of which are intrastate.

regulations but have similar requirements. Unless exempted within the regulations, PHMSA regulations apply to both subsea and onshore pipelines.

PHMSA regulations for gas pipelines (49 CFR 192) and oil pipelines (49 CFR 195) specify requirements related to pipeline construction and design, materials, components, leak detection, testing and inspection, operator training, maintenance, security, corrosion control, and integrity management.

PHMSA requirements vary depending on a pipeline's location, but because Cook Inlet is a "high consequence area" under PHMSA regulations, almost all oil pipelines in the Cook Inlet area must have approved integrity management plans unless they are officially abandoned. The exceptions are lines regulated by the U.S. Coast Guard rather than PHMSA. PHMSA-regulated gas pipelines in remote areas are not required to have integrity management plans. PHMSA's regulation of production gas pipelines also depends on where the first processing occurs (see Section 2.5.5).

The PHMSA-regulated Cook Inlet subsea liquid pipelines are subject to the most stringent of PHMSA's requirements since they are "offshore" and within an "unusually sensitive area."

U.S. Coast Guard

In Cook Inlet, the U.S. Coast Guard regulates two lines used to transfer crude oil at Drift River Terminal (off the Christy Lee Platform) – although now out of use – and one line at the KPL dock in Nikiski.

Coast Guard regulations at 33 CFR 156.170 do not require integrity management plans or corrosion mitigation measures, but they do require inspection and annual leak testing to demonstrate that all components (valves, gauges, alarms, piping, etc.) are properly functioning.

Pipelines No Longer in Service

ADEC regulations specifically address out-of-use flowlines and facility oil piping. The owner/operator must notify ADEC when flowlines are removed from service as described in 18 AAC 75. 047(i)(3. If flowlines are removed from service for more than a year, they must be free of accumulated oil and isolated from the system.[20] Alternatively, an operator can keep a line in service even if not being used, but must maintain it the same level required of a line that is actively in use. *A flowline that is removed from service under Alaska regulations will be subject to new flowline requirements if it is ever placed into service again.* Regulations are silent regarding crude oil transmission pipelines that are no longer being used.

By contrast, PHMSA requirements (which include both gas and oil lines) refer to the abandonment of a line, and do not require notification or purging and sealing of the line until they are planned to be permanently removed from service. The last owner or operator of abandoned offshore facilities and abandoned onshore facilities that cross over, under, or

[20] 18 AAC 75.047(f) and 18 AAC 75.080. Regulations specify different options for ensuring the line is sufficiently cleaned.

through commercially navigable waterways must file a report with PHMSA.[21] Thus, there are some lines in Cook Inlet that remain subject to PHMSA regulations even though they are out-of-service but not yet "abandoned."

At the time of the inventory developed for this project, 14 lines were not currently in use in Cook Inlet (see Table 2.2-1).

Unregulated Pipelines

While the application of regulations may vary depending on a pipeline's location or other characteristics, most pipelines in the project scope are regulated to at least some extent by ADEC, PHMSA, or both agencies. However, some pipelines within the project scope are not regulated by either agency (unless a spill occurs).

ADEC does not regulate any gas pipelines (unless responding to a leak). PHMSA regulates both oil and gas pipelines, but has other exceptions. Where these apply to gas lines, the line is not regulated by either ADEC or PHMSA. An oil or gas pipeline is exempted from PHMSA regulations if it is offshore in state waters, as is the case for all pipelines in Cook Inlet, *and* is upstream of the point at which oil or gas is produced or where produced oil and gas are first processed.[22] Because of this, pipelines in Cook Inlet that come from a platform where the produced gas or liquid (oil/water) is *not* processed at the platform are exempt from PHMSA requirements. There are also two gas gathering lines that onshore, unregulated gas gathering lines exempt from PHMSA regulations [Hi5, Hi6].

At the time of the inventory developed for this project, there were four pipelines in the project scope that were not directly regulated by ADEC, PHMSA, or the U.S. Coast Guard. Of these, three are not in service [B1, B2, Hi13]. A production gas line [F1] from the Julius R platform is currently in use but not regulated by any of the agencies (though spill response and mitigations would be).

[21] 40 CFR 192.727 for gas and 40 CFR 194.402(c)(10) for hazardous liquids; definition at 40 CFR 192.3

[22] PHMSA also does not regulate oil (hazardous liquid) gathering lines in rural areas and more than ¼ mile from Cook Inlet. These lines would be regulated by ADEC as flowlines.

3. THREATS, REQUIRED MITIGATIONS, AND RECOMMENDATIONS

This section describes potential threats to the integrity of Cook Inlet area pipelines generally, mitigation measures required in state or federal regulations, and the recommendations of the Expert Panel. The recommendations are organized around the threat types identified by ASME (2004), with a section at the end for general recommendations not directly related to a threat type.

3.1. External Corrosion

External corrosion refers to the deterioration – or rusting – of a metal pipeline from the outside due to interactions with the environment. This corrosion can weaken the pipeline to the point that a leak occurs, or weaken the pipeline or components so they are more susceptible to damage from other threats.

Because of the cold temperatures in Cook Inlet (which increase dissolved oxygen) along with strong tidal currents, external corrosion rates may be greater than onshore, requiring higher electrical currents in the cathodic protection systems used. Additionally, external coatings may be worn away by contact with ice, silt, or rocks.

Relevant Regulations

Identifying and mitigating external corrosion is a focus of both federal and state regulations as summarized in the table below.

Table 3.1-1 Federal and state requirements related to external corrosion

	PHMSA	ADEC
BURIED OR SUBMERGED PIPELINES	• Must have cathodic protection (CP) in place within a year after construction. • Must monitor CP system annually. • Must check CP rectifiers 6x/year (no less than every 2-1/2 months). • Excavated piping must be visually inspected. • IMP: Smart-pig or hydrotest every 5 years for liquids • IMP: Smart-pig or hydrotest every 7 years for gas for onshore gas lines in high-consequence areas only	**FLOWLINES:** • Establish procedures to implement corrosion control as outlined in Chapter VIII (and IX for offshore lines) of ASME B31.4 (Corrosion Control), and • The procedures, including CP, must be prepared and carried out or under the direction of individuals qualified, by training or experience, in corrosion controls. • Must have cathodic protection (CP) in place within a year. New lines must have CP in place when they are installed. • Must monitor CP system annually. • Excavated piping must be visually inspected. • Exposed facility piping to be visually inspected monthly. **COTP:** No specific standards for corrosion mitigation.

	PHMSA	ADEC
ABOVE GROUND	• Must have appropriate coating for above-ground pipes. • Onshore: must inspect coating every 3 years. • Offshore: must inspect coating annually. • Leakage surveys are required for gas transmission pipelines.	**FLOWLINES:** • Establish procedures to implement corrosion control as outlined in Chapter VIII (and IX for offshore lines) of ASME B31.4 (Corrosion Control), and • The procedures, including CP, must be prepared and carried out or under the direction of individuals qualified, by training or experience, in corrosion controls. • Must have appropriate coating for above-ground pipes. • Must inspect coating every 3 years.

Recommended Best Practices

The Expert Panel found external corrosion to be a primary potential threat to Cook Inlet pipelines. The recommended best practices for external corrosion focus on inspecting for external corrosion or damage to protective coatings in places where it is more likely to occur or if required testing indicates any indication of a problem. The recommendations emphasize the use of a combination of methods to identify and correct corrosion. NACE's Offshore Corrosion Assessment Training is a good introduction to methods for identifying corrosion on offshore facilities.

The Panel recommends the following best practices:

1. Conduct annual pipe-to-soil surveys at test stations to detect locations where the cathodic protection system does not meet requirements in NACE SP0169-2013, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems.*

2. Conduct close-interval surveys to identify degraded coating or mechanical damage, if either:
    a. Pressure testing is used to test integrity and there has been cathodic protection interference, or there has been down-time in the cathodic protection rectifier; or
    b. In-line inspection (ILI) – e.g., "smart-pigging" – results indicate need for additional testing.

    Also conduct close-interval surveys within the first few years after installation of a new line to evaluate coating integrity and ensure it wasn't damaged during installation.

    While some periodic internal inspections are required for most in-scope pipelines, close interval surveys are intended to determine if the cathodic protection system is controlling external corrosion and if repairs to the coating system are warranted.

3. Inventory and inspect places where steel pipelines are enclosed in a casing, such as at a road crossing. Cased crossings are a concern due to the potential for electrical shorting

between the casing and the carrier pipe that can result in ineffective cathodic protection for some length.

Cased crossings can be checked either by conducting a lower explosive limit (LEL) test to detect the presence of leaking hydrocarbons or using an electrical short test to determine if the carrier pipe is electrically shorted to the casing, which means the pipe is not fully protected.

For a confined space such as between the casing and carrier pipe, a test for volatile hydrocarbons can verify there is no buildup of combustible material from leakage for any hydrocarbon pipeline (liquid or gas). A commercially available combustible gas indicator (CGI) should be used to confirm that no further investigation is required.

To prevent pipeline degradation, it is important that the pipeline be electrically isolated from the casing. Monitoring is important to assure that isolation is functioning properly. NACE International SPO200-2014, *Standard Practices*, *Steel-Cased Pipeline Practices* contains recommendations on design, installation, maintenance, repair and monitoring of steel-cased pipelines such as at road crossing. The NACE standard covers applicable technical procedures for determining electrical isolation.

When possible, casings should be removed and the pipeline should be replaced with heavy-wall pipe.

4. Examine lines for crevice corrosion and atmospheric corrosion, including:
    a. Inspecting metal-to-metal and other contact points using an API 570 methodology and installing insulators at points of metal-to-metal contact, as appropriate.
    b. Conducting ultrasonic testing (UT) on risers if close metal contact is a threat or if warranted by visual inspection.
    c. Inspecting for corrosion under pipe supports and at penetrations.

    Crevice corrosion occurs at or adjacent to a gap between two adjacent materials and is particularly a concern where above-ground piping is supported. Atmospheric corrosion is a concern in the same types of locations when exposed to the air (not submerged).

    Both PHMSA and ADEC require atmospheric corrosion monitoring at pipe supports, but the use of API 570 methods is recommended for all pipelines. ILI cannot reach all areas where corrosion may occur, so a variety of inspection techniques should be used in combination.

5. Examine lines for corrosion under insulation and limit potential for corrosion by:
    a. Removing unnecessary insulation.
    b. Removing all insulation to conduct complete 3-year atmospheric corrosion inspections (rather than just spot-checking separate points along the line).
    c. Conducting radiographic testing (when insulation removal is not possible).
    d. Using modern insulation products that are designed for corrosion protection when installing new or replacing insulation.

e. Using cages rather than insulation if personnel protection is the intent.

Insulating material can trap moisture, causing corrosion, thus requiring inspection and remediation.

6. Alternate ultrasonic testing and magnetic flux leakage ILI technologies during scheduled integrity assessments to more completely capture anomalies. Examine all of the resulting images for problems, not just those at hot spots.

   These inspections are not always required but are important because they examine the entire line both externally and internally, providing the most complete inspection of a line. Magnetic flux leakage testing is easier to implement than ultrasonic testing, but only provides information about both internal and external corrosion if the pipe is thin enough. Ultrasonic testing, on the other hand, provides good data on the presence of both internal and external corrosion even for thicker pipelines, but it is harder to implement since the pipeline must be thoroughly cleaned in advance.

7. Ensure effective cathodic protection by:
   a. Determining if there is AC/DC interference and, if there is, mitigating it as appropriate.
   b. Inspecting rectifiers at least every 2-1/2 months and consider using remote monitoring technology in lieu of manual inspections.
   c. Assessing the impact of shielding coatings when integrating CP and ILI assessments.

8. Reduce potential corrosion at air-soil interfaces by regularly inspecting coatings and repairing them when needed.

3.2. Internal Corrosion

Internal corrosion is affected by the composition of the fluid in the pipeline, flow rates, temperature, and pressure. Cook Inlet pipelines in the project scope vary in the hydrocarbon and water content, as would be expected for oil field operations, with typical internal corrosion potential. Slower-flowing lines are more likely to see microbial-influenced corrosion. Hydrogen sulfide and carbon dioxide, which would accelerate internal corrosion, are not present in Cook Inlet lines.

Mitigating internal corrosion requires condition monitoring through adequate inspection and identification of any change in operation of the system (e.g., temperature, pressure composition) to anticipate corrosion rates and identify any change in those rates. Internal corrosion, while not as probable as external corrosion, was still determined to be of concern in Cook Inlet.

Relevant Regulations

PHMSA and ADEC both have requirements intended to prevent or mitigate internal corrosion, as shown in Table 3.2-1 below.

Table 3.2-1 Federal and state requirements related to internal corrosion

PHMSA	ADEC
• Must evaluate internal corrosion. • If corrosion is present, must institute mitigative measures. • If corrosion mitigation is used, must utilize corrosion monitoring (e.g. coupons at 2x/yr.) • Whenever possible, inspect internal surface of the pipe for evidence of corrosion. • Smart-pig or hydrotest every 5 years for liquids • Smart-pig or hydrotest every 7 years for gas	• Establish procedures to implement corrosion control as outlined in Chapter VIII (and IX for offshore lines) of ASME B31.4 (Corrosion Control), and • The procedures must be prepared and carried out or under the direction of individuals qualified, by training or experience, in corrosion controls. • Must have internal corrosion monitoring program. • If corrosion is present, must institute mitigative measures. • If corrosion mitigation is used, must utilize corrosion monitoring (e.g. coupons at 2x/yr.)

Recommended Best Practices

A sound internal corrosion monitoring program is strongly recommended and should include at least the following items.

1. Develop a written internal corrosion monitoring and mitigation program which makes use of available monitoring technologies, pigging, inhibitors/biocides, and lab testing. Have the program reviewed by a qualified internal corrosion engineer.
2. Evaluate pipe installed before the late 1970s for preferential seam corrosion and use of low-frequency electric resistance welds. These lines are susceptible to cracking at or near the weld seams. By the end of the 1970s the welding used had largely transitioned to being high frequency, but most Cook Inlet pipelines were installed prior to this time period). PHMSA's TTO #5 – Integrity Management Program Delivery Order DTRS56-02-D-70036 should be used for weld assessment and seam evaluation. Any identified issues should be managed accordingly.
3. Identify and inventory dead leg and low-flow segments and mitigate issues with any high-risk segments. Dead legs are susceptible to under-deposit corrosion (a type of crevice corrosion) and microbially-influenced corrosion.

3.3. Incorrect Operations

Incorrect or inadequate procedures or human error may lead to pipeline failures. The panel did not identify any reason to believe there are factors related to the Cook Inlet context which indicate this is more likely there than anywhere else.

Safe operating procedures should be documented, reviewed, controlled, and followed. Similar to other recommendations within this report, such as varying inspection techniques, for example, no single mitigative procedure or action is guaranteed to be reliable so a combination of measures is needed.

Relevant Regulations

PHMSA and ADEC both have requirements intended to prevent or mitigate incorrect operations, as shown in Table 3.3-1 below.

Table 3.3-1 Federal and state requirements related to incorrect operations

PHMSA	ADEC

• Must have an operations and maintenance (O&M) manual that addresses normal, abnormal, and emergency response operations.
• O&M Manual and all procedures must be reviewed annually.
• Control rooms must follow control room management regulations:
  ○ safety-related points tested
  ○ communication plan
  ○ backup SCADA[23] tested annually
  ○ shift-change logs maintained daily
  ○ fatigue training
  ○ SCADA alarm performance reviewed monthly
  ○ SCADA alarm plan reviewed annually
  ○ SCADA system review annually
  ○ Controller training program in place
  ○ Workload analysis performed annually
• Must have a drug and alcohol testing program in place.
• Must have an Operator Qualification program in place.
	• Substance abuse and medical monitoring program required

Recommended Best Practices

The following best practices will help to reduce human-caused problems.

1. Establish task-specific and equipment-specific operating and maintenance procedures. Written procedures that are specific to the equipment being used is important, rather than relying on an operator's general knowledge or experience.
2. Conduct a hazard analysis prior to conducting non-routine tasks. Performing tasks that are non-routine or particularly complicated can result in failures if the threats are not fully understood. An evaluation prior to executing the operation should be conducted to identify and address threats and risk drivers.
3. Ensure operator and contractors are qualified to implement assigned procedures. In addition to meeting qualification requirements for the purpose of compliance, it is important to invest the time and effort in technical, device-specific and/or procedure-specific training.

3.4. Manufacturing or Installation Defects

Pipeline failures may occur because of manufacturing defects in pipeline components that are not identified prior to installation, or problems with the installation itself. Failures can also

[23] Supervisory Control and Data Acquisition (SCADA) systems are automated systems allowing remote monitoring and control of equipment.

occur if the acquisition, installation, and use of equipment is not approached in an integrated way across a company (and contractors) through the various phases of a project. This can be addressed through a Process Safety Management (PSM) approach that includes a Management of Change (MOC) program which ensures that the necessary steps are taken to verify the adequacy of all aspects of design, engineering, material selection, purchasing, operations, and maintenance.

While many of the pipelines in Cook Inlet were installed decades ago, this same consideration applies to replacement components.

Relevant Regulations

PHMSA regulations establish standards for the fabrication and installation of pipe and components, considering the conditions, operating pressure, temperature, and other factors related to pipeline design life.

Recommended Best Practices

1. Confirm that design and engineering follow current regulations and industry standards, manufacturers have internal QA/QC programs, purchasing specifies the appropriate item, and on-site inspection verifies the item is received as intended.
2. Develop and implement a thorough MOC program that verifies adequacy of the various implementation steps, including design, engineering, material selection, purchasing, operations and maintenance. This is focused on stakeholder communication and QA/QC through the project lifecycle.
3. Ensure that defects caused by substandard welding or fabrication are identified before a pipeline is put into service by implementing the following during construction:
    a. Conduct non-destructive testing (radiographic testing, phased array, ultrasonic testing, mag particle, dye penetrant, etc.) on *all* piping welds during construction and repairs.

       Poor quality welds can result in delayed pipe failures so must be identified promptly.
    b. Provide qualified inspectors and testing procedures during manufacturing and construction to verify such items as fabrication quality, worker qualifications, construction in accordance with project specification, and QA/QC processes are followed as specified across the project lifecycle.
    c. Run a geometry pig during commissioning to identify defects and repair them before the line is put into service.

3.5. Equipment Failure

Pipeline failures may occur because of equipment failures that are not associated with manufacturing or installation. These may be related to use of equipment or a component beyond its design life, or, in Cook Inlet, due to wave- and current-induced vibration, ice, wind and earthquake loading, freezing/thawing, and the cumulative effects of these factors. Maintenance based on failure history particular to Cook Inlet facilities can help assure a fit-for-purpose program. For pipelines specifically, as opposed to equipment contained on a platform or other facility, this is primarily an issue if, for example, a valve failure leads to over- or under-pressure of the line.

Relevant Regulations

Not applicable.

Recommended Best Practices

Even when best practices are followed during construction and maintenance of pipelines, equipment can still fail and cause problems with pipelines. Best practices such as those listed below should be implemented to reduce the likelihood of equipment failures.

1. Implement a maintenance program to address the failure risk of wear components such as seals, O-rings, and gaskets. The program should use predictive and preventative techniques to identify component failure levels and intervals and assure that components whose failure can result in a loss of primary containment are repaired or replaced within their useful service life prior to consequential failure.
2. Prioritize maintenance for protective and high-consequence equipment (e.g., vibration shutdowns, seal failure detection, pig traps, overpressure equipment).
3. Ensure adequate support structures for all ancillary small-bore piping and components to prevent vibratory fatigue.

3.6. Third Party/Mechanical Damage

Mechanical damage to pipelines by third parties (individuals not associated with pipeline construction, operations, or maintenance) can be a source of damage to pipelines. Unintentional third-party damage could occur to subsea pipelines by a vessel anchor, or onshore by construction or other vehicles. (For the onshore pipelines in-scope, this is more likely on the east side of the Inlet).

Common Ground Alliance has established best practice guidelines for underground utilities. The CGA Best Practices Guide is available online[24] and includes recommendations for one-call centers, facility owners, excavators, locators, project owners, and designers.

The expert panel strongly recommended that CGA guidelines be followed by all Cook Inlet pipeline operators. Within the project scope, most land-based pipelines are above ground or underground only for short distances (e.g. intertidal areas, bluffs), but the CGA guidelines may still be appropriate.

Intentional damage by a third party is always possible as well, and many of the lines in scope are relatively inaccessible to the general public (either on the west side of the Inlet or under water).

[24] https://commongroundalliance.com/best-practices-guide

Relevant Regulations

PHMSA and ADEC both have requirements intended to prevent third party damage to onshore pipelines, as shown in Table 3.7-1 below.

Table 3.6-1 Federal and state requirements related to third party damage

PHMSA	ADEC

• Onshore lines must have pipeline marker signs.
• Right-of-way patrol 26 times per year.
• Must be in a one-call program.
• Must have a written Public Awareness program in place:
  ○ Plan to be reviewed annually
  ○ Liaise with emergency responders annually
  ○ Liaise with affected public every 2 years
  ○ Liaise with public officials every 3 years
  ○ Liaise with excavators annually
	• Flowlines on land are required to have line markers at each road crossing and at one-mile intervals [18 AAC 75.047(e)]
	• Exposed facility piping must be protected from vehicle damage.

Recommended Best Practices

The expert panel determined that mitigating third-party mechanical damage in Cook Inlet needs to focus on best practices specific to onshore, offshore, and intertidal zone environments.

Onshore

1. Implement Common Ground Alliance (CGA) Best Practices, emphasizing signage. This includes checking signs every spring and clearing vegetation in late summer to ensure signs can be seen. Signs should also have a phone number to call if a member of the public identifies a potential problem with the pipeline.
2. Directly contact private landowners annually to ensure they know where pipelines cross their property.
3. Maintain rights-of-way so that pipeline corridors are clearly visible for routine patrols and to avoid unintended disturbance by third parties.
4. Identify and mitigate potential for vehicular damage to above-ground facilities.
5. Evaluate and enhance security of pipelines, including locking valves at remote facilities.

Offshore

1. Install signs at beaches that are visible to vessels offshore, so they are aware of the presence of pipelines and to take care when deploying fishing gear or anchors.
2. Ensure pipeline corridors are included on nautical charts and in the U.S. Coast Pilot or other navigation publications so vessel operators avoid them if anchoring. At the time

of this project, many but not all pipeline areas were noted on NOAA charts and in the U.S. Coast Pilot. Missing information includes both active and abandoned lines.[25]

3. Update information about subsea pipelines and anchoring risks in the Cook Inlet Harbor Safety Plan[26] and distribute it to vessel operators. The Plan lists many, but not all, of the pipelines currently present in Cook Inlet, but this list could be updated with information from this project.
4. Consider using Automatic Identification System virtual navigational aids to mark pipeline corridors.

Transitions across intertidal zone

1. Communicate directly with set net fishermen, Alaska Department of Natural Resources tideland lease holders, and other beach users to ensure they know where pipelines are located and to ask them to report any potential problems with pipelines. These are particularly relevant "affected stakeholders" or "public" in the Cook Inlet context.

3.7. Weather/Outside Forces

Environmental conditions in Cook Inlet that are most likely to damage pipelines include strong tidal currents and sea ice.[27] Currents and shore ice are known to shift pipelines that pass through intertidal areas; while planned for in design and construction, such movement needs to be carefully monitored. Subsea pipelines may also be subject to "vortex induced vibrations" caused by strong currents. These occur where pipelines are not resting on the bottom of the Inlet and can cause the pipeline to rub or bump against rocks or otherwise lose stability resulting in a leak. (PHMSA, 2017) While warmer winters have reduced sea ice in Cook Inlet in recent years, even if the Inlet does not freeze for as long – or have as much ice coverage – as it used to, the presence of any sea ice in or moving through Central Cook Inlet may threaten pipelines.

Cold temperatures may also cause a pipeline to freeze (PHMSA, 2017; Barrett, 2019).

Pipelines may also be subject to earthquakes, landslides (or significant shoreside erosion of bluffs), or volcanic eruptions, all of which are known to occur in the Cook Inlet area.

Relevant Regulations

There are no regulations specific to environmental conditions that may affect pipelines (except external corrosion, as discussed above), but inspections generally (and construction or siting requirements) could identify (or prevent) problems caused by weather or external forces. Regulators may also require actions to mitigate actual or potential leaks.

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[25] See NOAA Coast Pilot 9, Chapter 4 Cape Spencer to Cook Inlet and associated NOAA charts. The Coast Pilot does warn mariners that there could be uncharted pipelines in the area along with other underwater obstructions.

[26] The Cook Inlet Harbor Safety Plan is available at: cookinletharborsafetycommittee.org

[27] Weather conditions may also impede the ability to respond to a leak, as occurred during a gas leak in the Inlet in 2017 (ADEC, 2017; PHMSA, 2017). However, this is outside the scope of the study.

Recommended Best Practices

Operators should have measures such as those listed below in place to mitigate potential damage caused by weather or other external forces.

1. Conduct comprehensive visual inspections where pipelines cross beaches upon ice melt in the spring (at low-low tide) and mitigate problems identified, such as if lines are shifting at or near the amount intended in their design.
2. Use an inertial mapping tool during ILI to establish the location of each pipe and critical anomalies. Maintain records of locations for future comparisons.
3. Annually evaluate and secure (pin) subsea lines as needed to:
    a. Prevent vortex induced vibration and inspect annually for displacement.

        A safety order issued by PHMSA following a leaking subsea gas line in 2017 specified high resolution side scan sonar inspection be used to identify pipeline sections that are not adequately supported or secured well enough to prevent vibrations. Unsupported stretches of 10 feet or more require inspection by divers to assess the pipeline surface condition (PHSMA, 2017).

    b. Prevent damage from erosion or rock rubbing.
4. Protect aboveground piping and components from snow/ice fall damage where located near structures or trees that may accumulate ice/snow.

3.8. General Recommendations

In addition to the preceding recommendations, the Expert Panel had several recommendations that were not specific to an identified threat category.

Maintain a detailed pipeline inventory including associated incidents and releases

Regardless of threat category or line type, the first, overarching recommendation was that pipeline operators maintain current inventories of the location and status of all lines, including cased crossings, metal-to-metal or other contact points, pipe-soil and air-soil interfaces, dead leg or low flow line segments, line insulation, and other critical inspection points. It should also include a spill history, including spill causes, and repairs or mitigations implemented. API 754 can be used as guidance for documenting losses of integrity, investigations, and reporting.

An accurate and detailed inventory is essential for operators to ensure that they inspect and maintain all vulnerable points on a regular basis. This information otherwise exists only as institutional knowledge held by the employees familiar with the infrastructure. Having a detailed inventory as recommended here will mitigate the impacts of normal personnel turnover or changes in infrastructure ownership (as have occurred many times in the past 15 years in Cook Inlet).

Apply Pipeline Safety Management Systems (PSMS) approach including a Management of Change (MOC) program

Although referenced above, the Expert Panel wanted to highlight the importance of ANSI/API 1173, *Pipeline Safety Management Systems*, and API-754, *Process Safety Performance Indicators for the Refining and Petrochemical Industries.* ANSI/API 1173 recommends best practices related to management, engaging stakeholders both internally and externally, risk management (including data collection and periodic review), operational controls (including Management of Change), incident investigation and analysis, safety audits and data analysis internally, and approaches to continuous improvement.

Baseline information for a given system should be assessed, and significant deviations defined. Changes in the system or significant deviations from the baseline would require further assessment to determine if mitigation or other action is required to address risk to the system. The program should investigate and address any facility failures, failures of mitigative measures such as cathodic protection or inhibition, and track failure near-misses as a leading indicator.

Change management should also assure managed risk of alteration and repair of facilities.

Ensure Appropriate Management of Pipelines No Longer in Service

One topic that was discussed repeatedly during the in-person meeting was that of out-of-service/inactive lines versus abandoned lines. The experts noted that operators often have lines that are not currently being used, but that have not been formally abandoned per regulatory requirements as they may be put back into use in the future. As a result, these lines may contain residual product, but are often not being monitored and maintained in the same manner as actively used lines. As was noted in Section 2.5 of this report, federal regulatory agencies only require notification of lines which have been abandoned, whereas state agencies require notification and draining of flowlines and facility oil piping when the lines will not be used or maintained for a year or more. The panel experts agreed that all lines not formally abandoned in a manner which meets applicable regulations for abandonment should be treated as active lines. Therefore, the recommendations described above are to be considered applicable to all lines that have not been cleaned, isolated from all processes, and formally abandoned.

4. CONCLUSION

The purpose of this project was to identify measures that could be implemented to sustain the safe operation of Cook Inlet's pipeline infrastructure. The safe operation of Cook Inlet pipelines is central to the production of oil and gas there and the protection of the environment and economy. A panel of experts with knowledge of pipeline operations, oversight, and integrity management reviewed a current, detailed inventory of Cook Inlet pipelines compiled for this project. Most Cook Inlet operators also shared information with the panel at some level: notably, Hilcorp Alaska, LLC, which owns most of the pipelines in the project scope either directly or via their subsidiary company, Harvest Alaska, LLC, made their pipeline records available to Nuka Research for the inventory and met directly with the Expert Panel as well.

The Expert Panel delivered a list of three general recommendations and 34 specific recommendations intended to minimize the chance of a release due to external or internal corrosion, incorrect operations, manufacturing or installation defects, equipment failure, third party/mechanical damage, or weather or outside forces. Many of these practices represent established industry best practice. Some are practices that are already required for some pipelines in Cook Inlet by either ADEC or PHMSA. However, the panel strongly encouraged that the recommended measures should be implemented for *all* pipelines considered in the project scope regardless of a pipeline's regulatory status or the commodity transported.

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APPENDIX A – EXPERT PANEL

Chris Dash – After receiving his Ph.D. in Metallurgical Engineering from The Ohio State University in 1988, Chris began working corrosion issues in a large oil company's research division. In late-1989, Chris came to Alaska and stayed through mid-1996, working various environmental, corrosion monitoring, corrosion chemical, and inspection-related jobs. In late-1997 after a stint in corrosion research, Chris returned to work on the Alaska North Slope, where he was responsible for corrosion monitoring, vessel and pipe inspections, and maintenance pigging. Beginning in 2000, Chris held an Anchorage-based job where he was responsible for smart pigging and corrosion group interactions with other organizations; he served as the Corrosion, Coatings, and Cathodic Protection Technical Authority. In late-2010, Chris transferred to Bartlesville, Oklahoma where he was responsible for inspection technology development. Returning to the North Slope in late-2015, Chris's duties focused on chemical injection and corrosion monitoring.

In addition to his Ph.D., Chris has a M.S. in Metallurgical Engineering from The Ohio State University and a B.S. in Chemical Engineering from The University of Tennessee. Chris is a certified Professional Engineer in Chemical Engineering in Alaska and Oklahoma. He holds API 510, API 570, and NACE Cathodic Protection Technologist.

James Joseph (Joe) Howell – Joe first came to Alaska while working summers during college, after growing up on a family farm in Alabama. Following his graduation from Auburn University with a degree in Chemical Engineering, he worked both onshore and offshore in oil field production engineering in Louisiana. He transferred to Alaska in 1984 and for the last 35 years, has worked in the Alaska oil industry in both upstream production activities and crude oil transportation.

Joe's experience includes field development and planning, project engineering, project management, extensive facility engineering and operations support. Risk assessment and identification, process safety and process risk mitigation are the main focus of his expertise. Currently, he is the process safety subject matter expert for his employer and serves as a representative on the American Petroleum Institute in the Process Safety Work Group and Facility Siting Recommended Practices Committee.

Andrew Kendrick – Andrew is a Senior Consultant and Managing Partner of Kendrick Consulting LLC (KCLLC), an engineering consulting firm with offices in Colorado, California, and Alaska. KCLLC provides specialized consulting services focused on risk analysis, regulatory compliance, and integrity management in the natural gas, petroleum and pipeline industry.

Andrew has a bachelor's degree in Geology from the University of Texas with advanced graduate work in Geotechnical Engineering from the University of Pittsburgh. He is a nationally certified professional geologist through the American Institute of Professional Geologists (AIPG) and a member of American Society of Mechanical Engineers (ASME), American Gas Association (AGA), National Association of Corrosion Engineers (NACE), and the Common Ground Alliance (CGA). Andrew served on the Board of Directors for the Pipeline Open Data Structure (PODS) group from 2005 to 2007, and recently supported the Pipeline and Hazardous Materials Safety Administration (PHMSA) Risk Management Work Group (RMWG) during their research into pipeline risk model effectiveness.

Chris Myers – Chris Myers started working in the petroleum industry in 1981 with a small construction company in North Kenai. By the time he retired in 2013 he had fulfilled a variety of industry duties including roustabout, assistant welder, all operator positions, Field Foreman, Field Superintendent, and Area Manager.

Over his 32-year career Chris has been responsible for all aspects of daily operations from maintenance and well head to sales and worked on all oil and gas properties in the Cook Inlet area. With the exception of the refined product lines, he has worked for most of the companies operating pipelines in the Cook Inlet area, including but not limited to DOT pipelines, the Kenai Gas Field, and the Swanson River Field.

Shirish Patil – Shirish Patil is a Saudi Aramco Chair Professor in the Petroleum Engineering Department in the College of Petroleum Engineering & Geosciences, King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia. Shirish has 33 years of global experience in oil and gas R&D and transportation projects. Prior to joining KFUPM in 2016, Shirish spent 30 years at the University of Alaska Fairbanks (UAF), where he rose through the ranks of Assistant Professor to Professor of Petroleum Engineering and also served the university in numerous capacities as Director of Petroleum Development Laboratory, Associate Director of the Institute of Northern Engineering, and Interim Director of the Office of Electronic Miniaturization.

Shirish's research experience spans various areas of oil and gas research and development of new technologies for improved oil and gas recovery and infrastructure integrity. He has managed/co-managed several U.S. Department of Energy grants and other projects with international oil companies. He has been Principal or Co-Principal Investigator of over 25 successfully completed projects. Shirish holds B.E. degree in Mechanical Engineering from the University of Pune, Pune, India; M.S. in Mechanical Engineering from the University of Pittsburgh; M.S. in Petroleum Engineering; M.S. in Engineering Management; and Ph.D. in Mineral Resources Engineering, all from the University of Alaska Fairbanks, Alaska.

APPENDIX B – AGENCY REGULATORY AUTHORITIES

Table B-1 Summary of state authorities related to Cook Inlet pipelines

<table>
<tr><th rowspan="2">AGENCY</th><th rowspan="2">PIPELINE JURISDICTION</th><th colspan="2">REGULATORY AUTHORITIES</th></tr>
<tr><th>Right-of-Way, Construction, Operations</th><th>Response Planning or Response</th></tr>
<tr><td>State Pipeline Coordinator's Section
Division of Oil and Gas (DOG)
Alaska Department of Natural Resources (ADNR)</td><td>Common carrier pipelines, including several out-of-scope lines in the Cook Inlet area and the Cross-Inlet pipeline that was converted to carry crude oil from the west to east side of Cook Inlet in 2018</td><td>Ensure compliance with ROW leases (AS 38.35.015):
• Review/approve operators' Quality Assurance Plans, Surveillance and Monitoring Programs, and construction & operations plans
• Review annual reports (including results of self-audits/assessments, incidents)
• Field inspections
• Engineering inspections to follow up on structural or integrity concerns[28]</td><td>Not applicable</td></tr>
<tr><td>Alaska Department of Environmental Conservation (ADEC)</td><td>Liquid crude oil and refined hydrocarbon pipelines (AS 46.03.020, AS 46.03.030, AS 46.03.060)
Spills to Alaska lands or waters</td><td>Requirements for leak detection and prevention, operator inspections, and leak shut-off (18 AAC 75.055)
Pipeline operations, inspections, and maintenance requirements (AS 46.03.020)</td><td>Review and approve operator contingency plans (18 AAC 75.400)
State On-Scene Coordinator (SOSC) for spill response</td></tr>
<tr><td>Alaska Department of Fish and Game</td><td>Specific type of pipeline not relevant</td><td>Manage activities that occur in legislatively designated special areas (AS 16.20) where a Special Area Permit is required to construct or place structures, explore energy opportunities, etc.
Oversee any activity below the ordinary high-water mark of an anadromous stream or any activity that could impede the efficient passage of resident or anadromous fish requires a Fish Habitat Permit. (AS 16.05.841-871).</td><td>Advise on oil spill response planning and response; wildlife-related response activities or those occurring in state special areas.</td></tr>
<tr><td>Alaska Oil and Gas Conservation Commission (AOGCC)</td><td colspan="3">Commission is not specific to pipelines. Authority includes overseeing and adopting regulations on construction, permitting, and waste reduction efforts of oil and gas related facilities in Alaska. (20 AAC 25).</td></tr>
</table>

[28] August 2, 2017 email from Jason Walsh, State Pipeline Coordinator

Table B-2 Summary of federal authorities related to Cook Inlet pipelines

AGENCY	PIPELINE JURISDICTION	REGULATORY AUTHORITIES	
		Right-of-Way, Construction, Operations	Response Planning or Response
Army Corps of Engineers	Jurisdiction not specific to pipelines, but any structures (33 CFR 322)	Permits construction of any structures including pipelines in navigable waters of the U.S.	N/A
Environmental Protection Agency	Only regulates platforms, not pipelines (40 CFR 112.11, 112.7)	N/A	Requires Spill Prevention, Control, and Countermeasure Plans (SPCC) from facilities (40 CFR 112)
National Marine Fisheries Service **National Oceanic and Atmospheric Administration**	N/A	Agency must consult on activities that may affect a listed species and will assess the effects of the action on the listed species (ESA 7(a)(2))	Implement endangered species consultants during emergencies such as oil spills. (ESA 7(a)(2) or 7(d).
Pipeline and Hazardous Materials Safety Administration—Office of Pipeline Safety (OPS) **Department of Transportation**	Interstate transportation pipelines and pipeline facilities. Regulates intrastate transportation pipelines and pipeline facilities in states without certified programs (Alaska included). Onshore and many offshore pipelines (49 CFR 190,191. 192, 194, 195).	Integrity management regulations for hazardous liquid (49 CFR 195.450 and 195.6) Integrity management of all pipelines considered "offshore" and "unusually sensitive" (49 CFR 195) Enforcement against violations (49 CFR 190).	- Requires response plans for onshore oil pipelines including on-scene spill mitigation procedures and response activities. These are updated every 5 years. (49 CFR 194, Appendix A)
U.S. Coast Guard	Piping (or any equipment) used to transfer oil or hazardous substances to or from a vessel > 250 bbl on navigable waters, unless regulated by the Department of Interior (33 CFR 156.100 - 105) Oversight ends at edge of "marine transfer area," defined as first valve within secondary containment area at the facility or the bulk storage tank valve or manifold (33 CFR 100.105)	May require advance notice of a transfer if in a remote area or there is a prior history of spills (33 CFR 156.118). Transfer must be stopped of a discharge occurs (33 CFR 156.125). Includes equipment requirements and inspections for transfer hoses (33 CFR 156.170). If Facility receives fuel by vessel to platform transfer, then it is regulated under 33 CFR 154.100 and required to have an operations manual under 33 CFR154.300, and a response plan under 33 CFR 154.1015.	Federal On-Scene Coordinator (FOSC) for marine/coastal zone spills (40 CFR §300.120) If the Facility conducts over the water transfers to or from a vessel, the COTP reviews facility oil spill response plan (33 CFR 154.1010). Requirements of the plan include: actions facility personnel will take in the event of a spill, a description of the facility, and capacities of all piping.

AGENCY	PIPELINE JURISDICTION	REGULATORY AUTHORITIES	
		Right-of-Way, Construction, Operations	Response Planning or Response
U.S. Fish and Wildlife Service	N/A	Review proposed projects and suggest potential mitigation options Participate in the NEPA process and provide consultation under the ESA as requested. - Formal consultation on project citing and approval (ESA)	- Provide for coordinated, immediate, and effective protection, rescue and rehabilitation of, and minimization of risk of injury to, fish and wildlife resources and habitat. (40 CFR 300.210) - Contribute to update of Sensitive Areas section of subarea Contingency Plan - Comment on wildlife protection aspects of operator contingency plans (OPA 300.210(C)(4)(i)) - Conduct Natural Resource Damage Assessment and Restoration in the event of a spill (40 CFR 300.615).

APPENDIX C – COOK INLET ENERGY REDOUBT/MCARTHUR RIVER SYSTEM

Redoubt/McArthur River Fuel Gas System

The Redoubt/McArthur River fuel gas system operated by Cook Inlet Energy (CIE) is composed of one on-land pipeline that move natural gas from the Trading Bay Production Facility to the Kustatan Production Facility to fuel operations. Figure C-1 shows the locations of the pipeline. Table C-1.1 contains the name and primary characteristics of the pipeline.

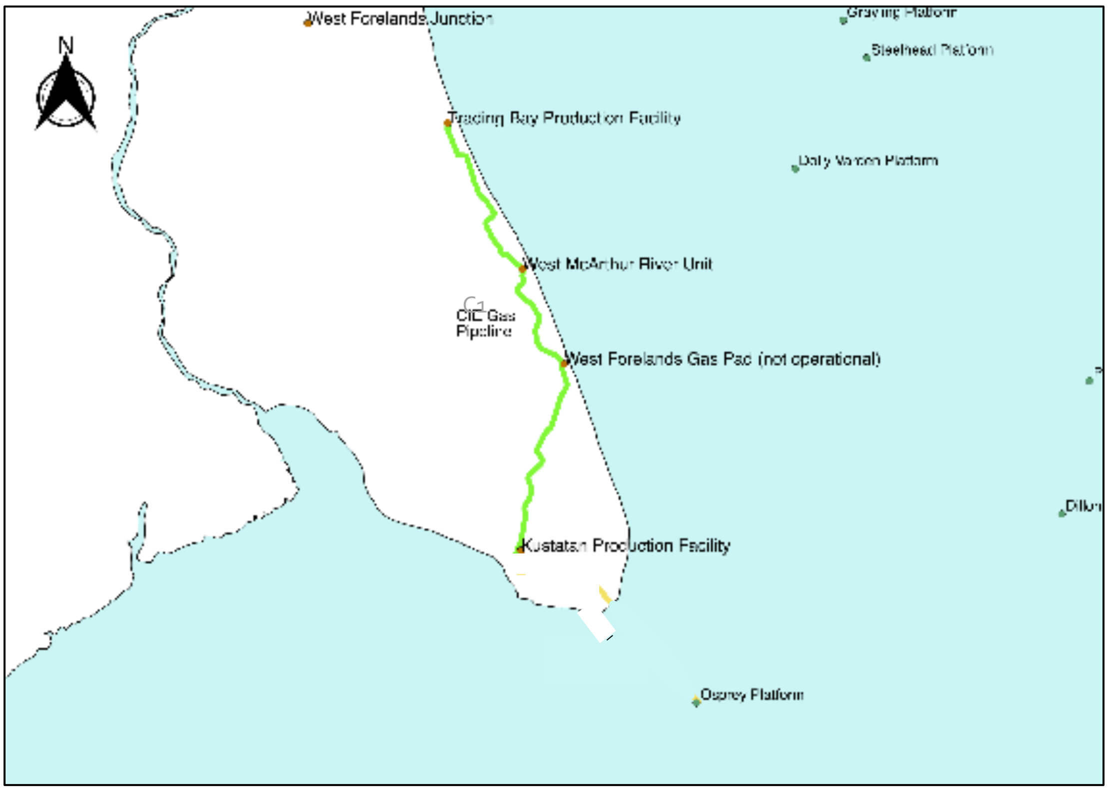

Figure C-1. Location of the pipelines that comprise the Redoubt/ McArthur fuel gas system.

Table C-1.1. Principal characteristics of the Redoubt/ McArthur fuel gas system.

Report Designation	Operator's Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
C1	**6-FG-1990-CIGGS-PL**	**6.625**	**7.82**	**1999 and 2002**

Regulatory

The CIE fuel gas pipeline does not fall under specific State or PHMSA regulatory categories. Table C-1.2 presents the regulatory designation of the Trading Bay Fuel Gas System.

Table C-1.2. State and Federal Regulatory Designations for Trading Bay fuel gas pipelines.

Operator's Designation	State Regulation	Federal Regulation
6-FG-1990-CIGGS-PL	**None**	**PHMSA**

Integrity Management

Leak Detection

There is no leak detection on this pipeline.

Cathodic Protection (CP)

The pipelines within this transmission system are protected by an impressed current system to protect these lines and operations in accordance with appropriate NACE standards (RP1069-2002).

Inspections

Pigging

The CIE gas pipeline is pigged frequently for maintenance and smart pig (in-line inspections) are performed on a schedule determined by the operator.

Physical

Information on physical inspections for these pipelines is not found in public records and was not provided by the operators.

Redoubt/McArthur River Oil Production System

The Redoubt/McArthur River oil production system, operated by Cook Inlet Energy (CIE), is composed of two subsea pipelines[29] and one on-land pipelines that move three phase oil production (gas, oil, water) from production wells to the production facilities at Kustatan and West McArthur River Unit. Figure C-2 shows the locations of the pipelines. Table C-2.1 contains the name and primary characteristics of each pipeline.

Figure C-2. Location of the pipelines that comprise the Redoubt/ McArthur oil production system.

Table C-2.1. Principal characteristics of the Redoubt/ McArthur oil production pipeline system

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
C3	**8-PC-1950-WMRU-PL**	**8.625**	**1.8**	**2002**
C4	**8-PC-1900-OSP-PL**	**8.625**	**2.0**	**2000**
C5	**6-UTL-1920-PL**	**6.625**	**1.9**	**2002**

Regulatory

These three-phase oil production pipelines are all designated as flowlines for purpose of ADEC regulations and are thus regulated under 18 AAC 75.047. None of the pipelines within this system fall under Federal

[29] One of these sub-seas pipelines in was not in use in 2018.

regulatory categories. Table C-2.2 presents the regulatory designation of the Redoubt/ McArthur oil production pipelines.

Table C-2.2. State and Federal Regulatory Designations for Redoubt/ McArthur oil production pipelines.

Operator Designation	State Regulation	Federal Regulation
8-PC-1950-WMRU-PL	**ADEC as flow line under 18 AAC 75.047**	**None**
8-PC-1900-OSP-PL	**ADEC as flow line under 18 AAC 75.047**	**None**
6-UTL-1920-PL (not in use in 2018)	**ADEC as flow line under 18 AAC 75.047**	**None**

Integrity Management

Leak Detection

There is no leak detection in this pipeline system

Cathodic Protection (CP)

All pipelines within this system are equipped with an impressed current cathodic protection system in place to protect these lines and operations in accordance with appropriate NACE standards (RP0169-2002).

Inspections

Pigging

The eight-inch Osprey produced crude pipeline is regularly maintenance pigged. The six-inch utility pipeline to the Osprey platform was not in use in 2018 and was not being maintenance pigged. These lines have been smart pigged (inline inspection) and the operator has an inspection program.

Physical

Information on physical inspections for these pipelines is not found in public records and was not provided by the operators.

Redoubt/McArthur Oil Transmission System

The Redoubt/McArthur oil transmission pipeline system, operated by Cook Inlet Energy (CIE), is composed of two on-land pipelines that move sales grade crude oil from Kustatan Production Facility and West McArthur River Unit to the Trading Bay Production Facility for transportation by the Harvest Alaska pipeline system. Figure C-3 shows the locations of the pipelines. Table C-3.1 contains the name and primary characteristics of each pipeline.

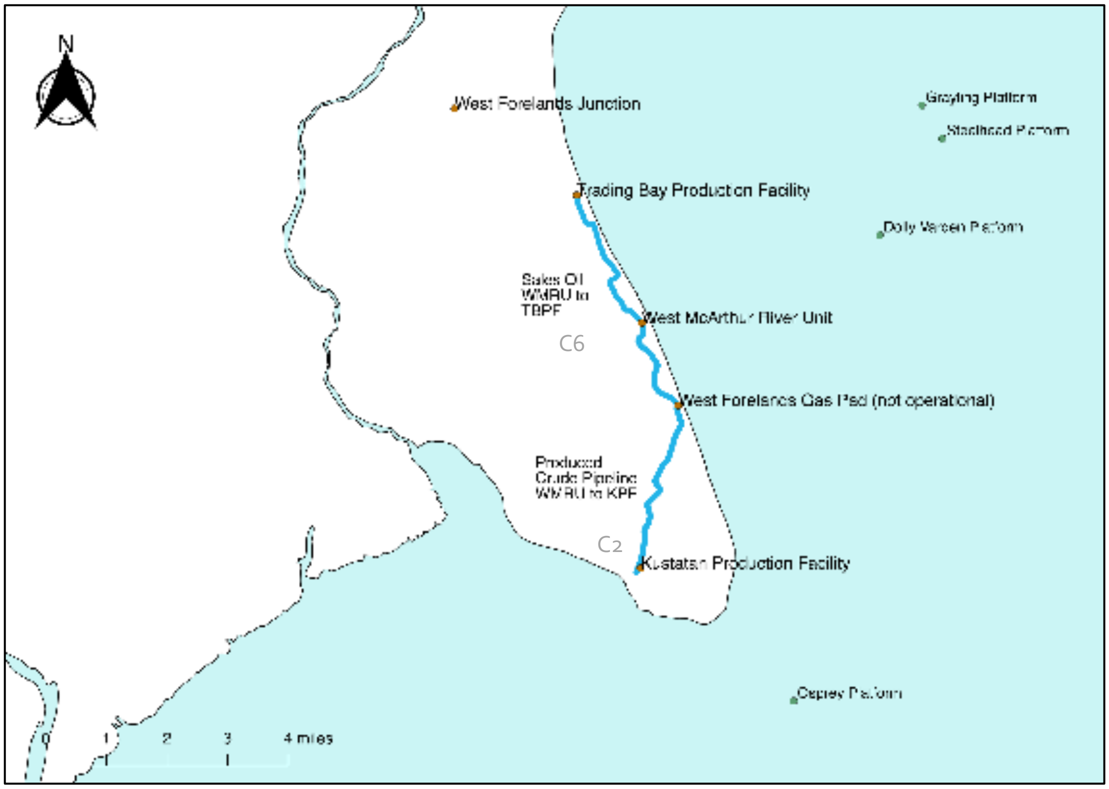

Figure C-3. Location of the pipelines that comprise the Redoubt/McArthur oil transmission pipeline system.

Table C-3.1. Principal characteristics of the Redoubt/McArthur oil transmission pipeline system.

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
C2	**4-OIL-1930-KPF-PL**	**4.5**	**4.8**	**2006**
C6	**8-OIL-1960-WMRU-PL**	**8.625**	**2.7**	**2002**

Regulatory

Two sales grade crude oil pipelines are designated as crude oil transmission pipes for purpose of ADEC regulations and are thus regulated under 18 AAC 75.055. None of these lines are regulated under a specific federal regulatory category. Table C-3.2 presents the regulatory designation of the Glacier Oil Production System.

Table C-3.2. State and Federal Regulatory Designations for the Glacier Oil Transmission pipelines.

Operator Designation	State Regulation	Federal Regulation
4-OIL-1930-KPF-PL	**Crude Oil Transmission Pipe (18 AAC 75.055; 75.425(e)(4) (A) (ii))**	**None**
8-OIL-1960-WMRU-PL	**Crude Oil Transmission Pipe (18 AAC 75.055; 75.425(e)(4) (A) (ii))**	**None**

Integrity Management

Leak Detection

None of the pipelines in this system have leak detection systems in place.

Cathodic Protection (CP)

The pipelines within this transmission system are protected by an impressed current system to protect these lines and operations in accordance with appropriate NACE standards (RP1069-2002).

Inspections

Pigging

The Sales oil flowline and Kustatan transmission pipeline are reported to be maintenance pigged and have been smart pigged (inline inspection). CIE has a program for future inline inspections.

Physical

Information on physical inspections for these pipelines is not found in public records and was not provided by the operator.

APPENDIX D – FURIE/KITCHEN LIGHTS SYSTEM

Kitchen Lights Gas Production System

The Kitchen Lights natural gas production system, operated by Furie, is composed of one subsea pipeline that moves produced "wet" gas from Julius R. platform to Furie's Production Facility at the East Forelands Production Facility for processing. Figure D-1 shows the locations of the pipeline. Table D-1.1 contains the name and primary characteristics of the pipeline.

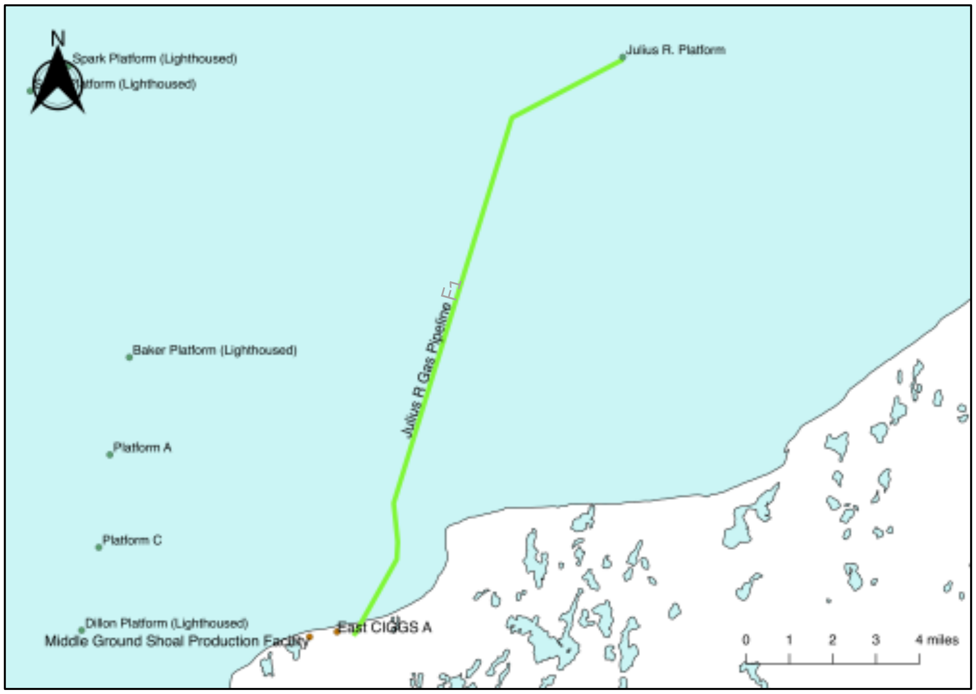

Figure D-1. Location of the pipelines that comprise the Kitchen Lights gas production system.

Table D-1.1. Principal characteristics of the Kitchen Lights gas production system.

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
F1	**Julius R Gas**	**20**	**16**	**2015**

Regulatory

This gas production pipeline does not fall under specific State regulatory categories. The pipeline is also not regulated under a specific PHMSA regulatory category. Table D-1.2 presents the regulatory designation of the Kitchen Lights gas production pipeline.

Table D-1.2. State and Federal Regulatory Designations for Kitchen Lights gas production pipeline.

Operator Designation	State Regulation	Federal Regulation
Julius R Gas	**None**	**None**

Integrity Management

Leak Detection

Information on leak detection for this pipeline is not found in public records and was not provided by the operators.

Cathodic Protection (CP)

Information on cathodic protection for this pipeline is not found in public records and was not provided by the operators.

Inspections

Pigging

Information on pigging for this pipeline is not found in public records and was not provided by the operators.

Physical

Information on physical inspections for this pipeline is not found in public records and was not provided by the operators.

APPENDIX E – HILCORP ALASKA/GRANITE POINT SYSTEM

Granite Point Fuel Gas System

The Granite Point fuel gas system, operated by Hilcorp Alaska, LLC (HAK), is composed of two subsea pipelines and two on-land pipelines that move natural gas from the Cook Inlet Gas Gathering System to offshore platforms. Figure E-1 shows the locations of the pipelines. Table E-1.1 contains the name and primary characteristics of each pipeline.

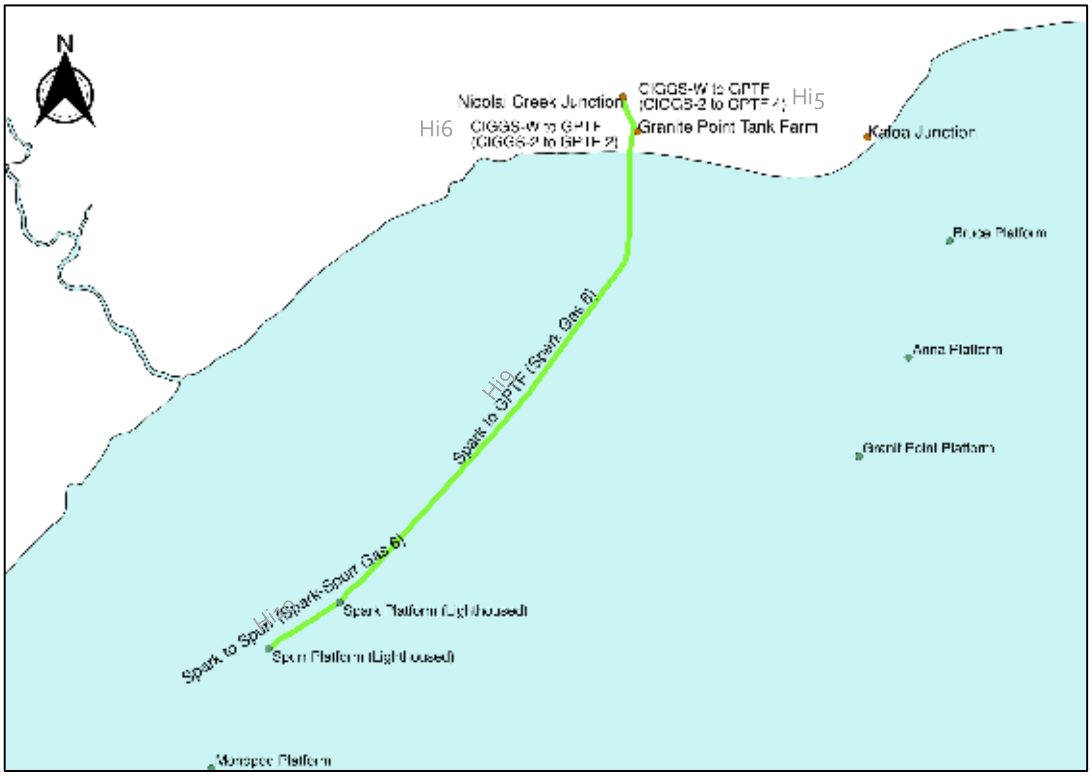

Figure E-1. Location of the pipelines that comprise the Granite Point fuel gas system.

Table E-1.1. Principal characteristics of the Granite Point fuel gas system.

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
Hi10	**Spark-Spurr Gas 6**	**6.625**	**1.2**	**1968**
Hi9	**Spark Gas 6**	**6.625**	**7.2**	**1969**
Hi5	**GIGGS-2 to GPTF 4**	**4**	**0.46**	**unknown**
Hi6	**GIGGS-2 to GPTF 4**	**2**	**0.48**	**unknown**

Regulatory

These fuel gas do not fall under specific State regulatory categories. All four lines are regulated by PHMSA as natural gas lines under 49 CFR Part 192. Table E-1.2 presents the regulatory designation of the Granite Point Fuel Gas System.

Table E-1.2. State and Federal Regulatory Designations for Granite Point fuel gas pipelines.

Operator Designation	State Regulation	Federal Regulation
Spark-Spurr Gas 6	**None**	**PHMSA 49 CFR Part 192**
Spark Gas 6	**None**	**PHMSA 49 CFR Part 192**
GIGGS-2 to GPTF 4	**None**	**Unregulated Class 1 onshore gathering line**
GIGGS-2 to GPTF 4	**None**	**Unregulated Class 1 onshore gathering line**

Integrity Management

Leak Detection

Information on leak detection for these pipelines is not found in public records and was not provided by the operators.

Cathodic Protection (CP)

Information on Cathodic Protection for these pipelines is not found in public records and was not provided by the operators.

Inspections

Pigging

Pigging is not conducted on the Spark/Spurr Platform Gas Pipeline. Information on pigging for the other pipelines is not found in public records and was not provided by the operators.

Physical

Information on physical inspections for these pipelines is not found in public records and was not provided by the operators.

Granite Point Gas Production System

The Granite Point gas production system, operated by Hilcorp Alaska, LLC (HAK), is composed of three subsea and on-shore pipelines that move produced "wet" natural gas from the offshore platforms to the Granite Point Production Facility where it is processed and fed into the Cook Inlet Gas Gathering System for distribution. Figure E-2 shows the locations of the pipelines. Table E-2.1 contains the name and primary characteristics of each pipeline.

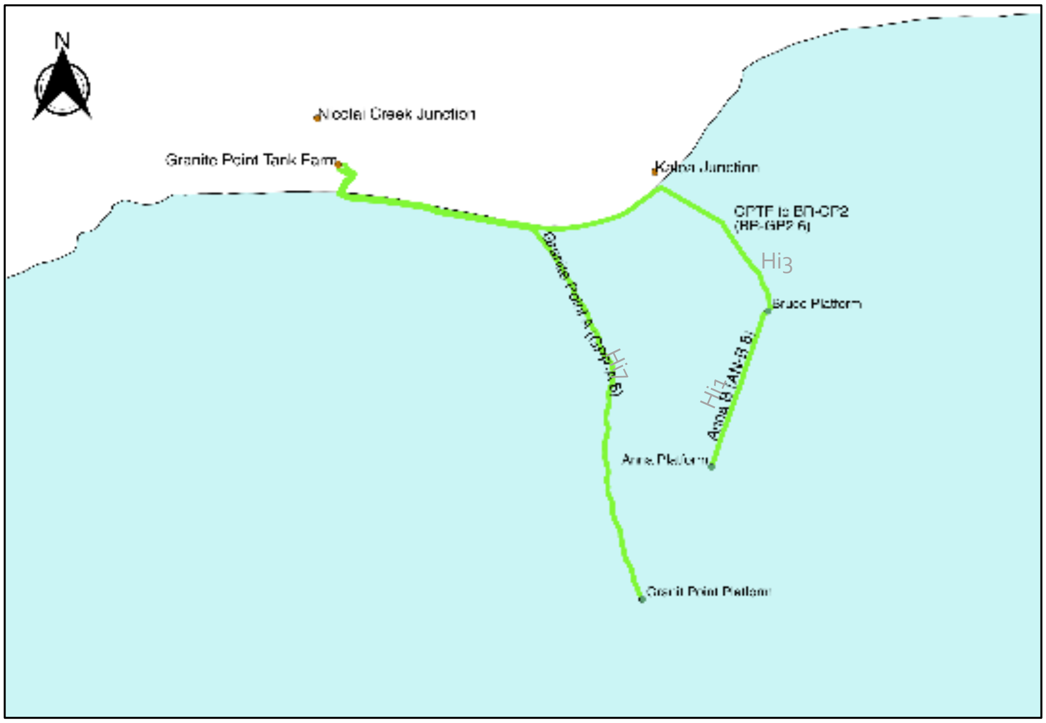

Figure E-2. Location of the pipelines that comprise the Granite Point Gas Production System.

Table E-2.1. Principal characteristics of the Granite Point Gas Production System

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
H7	**GPP-A 8**	**8.625**	**6.12**	**1966**
H3	**BR-GP2 6**	**6.625**	**5.3**	**1974**
H1	**AN-B 8**	**8.625**	**1.62**	**1966**

Regulatory

These gas production pipelines do not fall under specific State regulatory categories. All three lines are regulated by PHMSA as natural gas pipelines under 49 CFR Part 192. Table E-2.2 presents the regulatory designation of the Granite Point Gas Production System.

Table E-2.2. State and Federal Regulatory Designations for Granite Point Gas Production pipelines.

Operator Designation	State Regulation	Federal Regulation
GPP-A 8	**None**	**PHMSA 49 CFR Part 192**
BR-GP2 6	**None**	**PHMSA 49 CFR Part 192**
AN-B 8	**None**	**PHMSA 49 CFR Part 192**

Integrity Management

The Granite Point Platform gas line (Hi7) is bi-directional and can also be used to provide fuel gas to the platform if needed.

Leak Detection

All pipelines within this system are equipped with flow meters that will detect catastrophic failures.

Cathodic Protection (CP)

These pipelines have an impressed current cathodic protection system is in place.

Inspections

Pigging

Granite Point Platform A Pipeline (Hi7) and Bruce Platform GP2 (Hi3) are both not routinely pigged. Anna Platform B pipeline is piggable and can be pigged in both directions.

Physical

Annually each pipeline is inspected using sonar technology. The purpose of this survey is to identify unsupported pipeline spans of 50 feet or greater in length, identify the start, mid-span and stop of the spans with differential Global Positioning System (GPS) coordinates, height of the span and depth of water adjusted to mean lower low water (MLLW) and to identify noteworthy subsea topographic anomalies located within 10 feet of all pipelines. Divers place cement bags under the pipe to support any unsupported spans over fifty feet in length. Once the pipeline is supported from underneath, additional cement bags are placed over the pipeline to pin the pipeline at the support location.

Granite Point Oil Production System

The Granite Point oil production system, operated by Hilcorp Alaska, LLC HAK), is composed of three subsea pipelines that move three-phase production from offshore platforms to Granite Point Tank Farm for oil, gas, and produced water separation. Figure E-3 shows the locations of the pipelines. Table E-3.1 contains the name and primary characteristics of each pipeline.

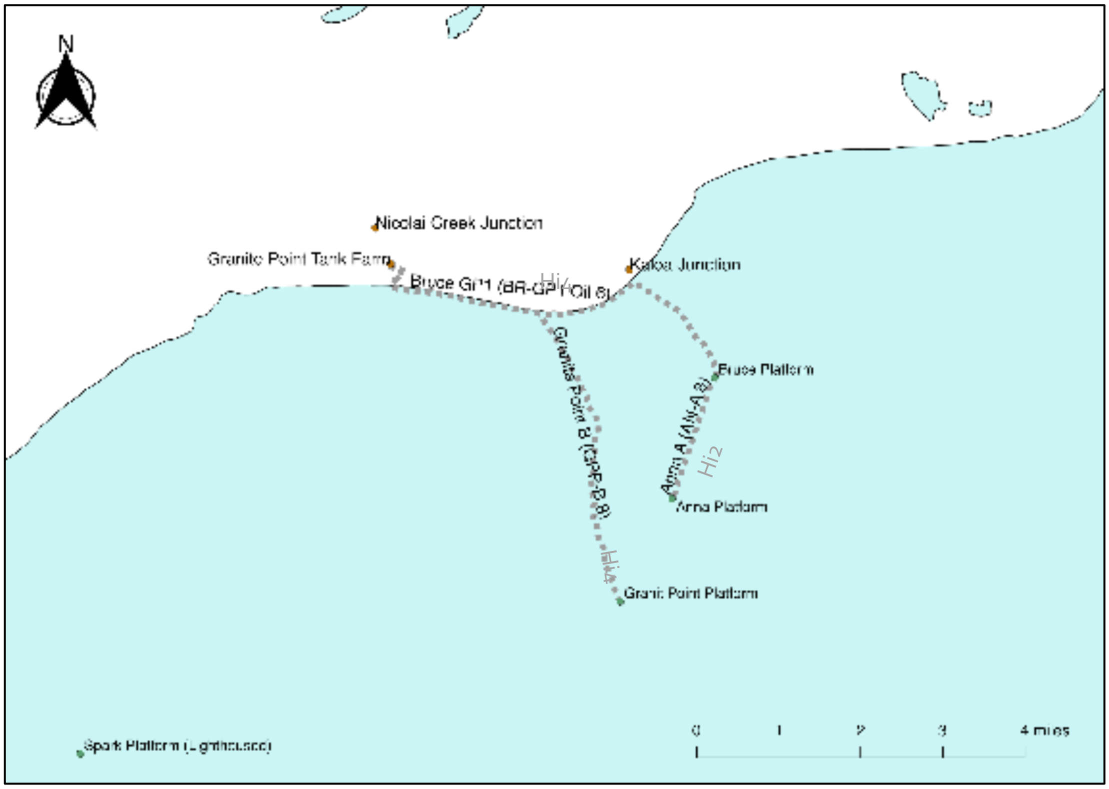

Figure E-3. Location of the pipelines that comprise the Granite Point oil production system.

Table E-3.1. Principal characteristics of the Granite Point oil production system pipelines.

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
Hi8	**GPP-B 8**	**8.625**	**6.1**	**1966**
Hi4	**BR-GP1 Oil 6**	**6.625**	**5.3**	**1974**
Hi2	**AN-A 8**	**8.65**	**1.62**	**1966**

Regulatory

These three-phase oil production pipelines are designated as flowlines for purpose of ADEC regulations and are thus regulated under 18 AAC 75.047. All three lines are regulated by PHMSA as hazardous liquid pipelines under 49 CFR Part 195. Table E-3.2 presents the regulatory designation of the Granite Point Oil Production System.

Table E-3.2. State and Federal Regulatory Designations for Granite Point Oil Production pipelines.

Operator Designation	State Regulation	Federal Regulation
GPP-B 8	**ADEC as flow line under 18 AAC 75.047**	**PHMSA 40 CFR Part 195**
BR-GP1 Oil 6	**ADEC as flow line under 18 AAC 75.047**	**PHMSA 40 CFR Part 195**
AN-A 8	**ADEC as flow line under 18 AAC 75.047**	**PHMSA 40 CFR Part 195**

Integrity Management

Leak Detection

Flow lines transfer production fluids (oil, gas, water and sediment) to onshore facilities for separation. These flow lines operate under pressure. A loss in pressure indicates that a leak may have occurred. A low-pressure alarm sounds and the operator starts to investigate the cause. If the operator decides and/or the next level alarm goes off, the operator initiates shut down procedures. In addition, automatic shut-in alarms engage valves to discontinue flow to the line. If the pressure drops or rises 10 percent, the automatic shut-in occurs. Each flow line has a 24-hour pressure recording device that monitors and documents the pressure in the flow line at the exit point from the platform. Pressure records are stored for a minimum of three years.

In addition to pressure indicators, flyover inspections of onshore flow lines with a ROW are conducted every two weeks. Onshore flow lines on HAK property are inspected during daily rounds.

Cathodic Protection (CP)

The flow lines are provided external corrosion protection by the use of external coating systems and impressed current cathodic protection. In addition, cathodic protection is measured from each platform and at onshore locations.

HAK ensures that measures for controlling corrosion in flow lines are undertaken per 18 AAC 75.047(c), which includes a corrosion monitoring and control program, external corrosion control of buried or submerged flow lines consistent with National Association of Corrosion Engineers (NACE) International's Standard Recommended Practice -- Control of External Corrosion on Underground or Submerged Metallic Piping Systems. A program designed to minimize internal corrosion, including, as appropriate, one or more of the following:

- removal of foreign material by scraping or pigging;
- treatment of residual water or dehydration;
- injection of inhibitors, biocides, or other chemical agents;
- removal of dissolved gases by chemical or mechanical means;
- gas blanketing; or
- continuous internal coating or lining;

Internal maintenance of offshore flow lines is accomplished by corrosion coupons, pigging and the use of corrosion inhibitor and biocides, if necessary. Pigging removes loose sediment and corrosion products that may have settled out of the fluid stream and that promote the formation of local corrosion cells. Pipelines are pigged frequently.

A non-hazardous corrosion inhibitor is added to the annulus between the J-tube and the pull tube to further prevent external corrosion of the platform riser pipes if the annulus is determined to be wet. A non-hazardous corrosion inhibitor is added to the platform leg internally where there is an ADEC regulated riser if the leg is determined to be wet.

Inspections

Flow lines are inspected per API 570.

Pigging

Flow lines attached to platform risers are inspected with a "smart pig," or equivalent technology, which records pipe wall thickness.

Physical

Per ASME B31.4-2002, Section A451.5, offshore flow lines are inspected at a minimum annually using side scan sonar. The purpose of this survey is to identify unsupported pipeline spans of 50 feet or greater in length, identify the start, mid-span and stop of the spans with differential Global Positioning System (GPS) coordinates, height of the span and depth of water adjusted to mean lower low water (MLLW) and to identify noteworthy subsea topographic anomalies located within 10 feet of all pipelines. Divers place cement bags under the pipe to support any unsupported spans over fifty feet in length. Once the pipeline is supported from underneath, additional cement bags are placed over the pipeline to pin the pipeline at the support location.

APPENDIX F – HILCORP ALASKA/MIDDLE GROUND SHOAL SYSTEM

Middle Ground Shoal Fuel Gas System

The Middle Ground Shoal fuel gas system, operated by Hilcorp Alaska, LLC (HAK), is composed of four subsea pipelines that move natural gas from the Middle Ground Shoal Production Facility to offshore platforms. Figure F-1 shows the locations of the pipelines. Table F-1.1 contains the name and primary characteristics of each pipeline.

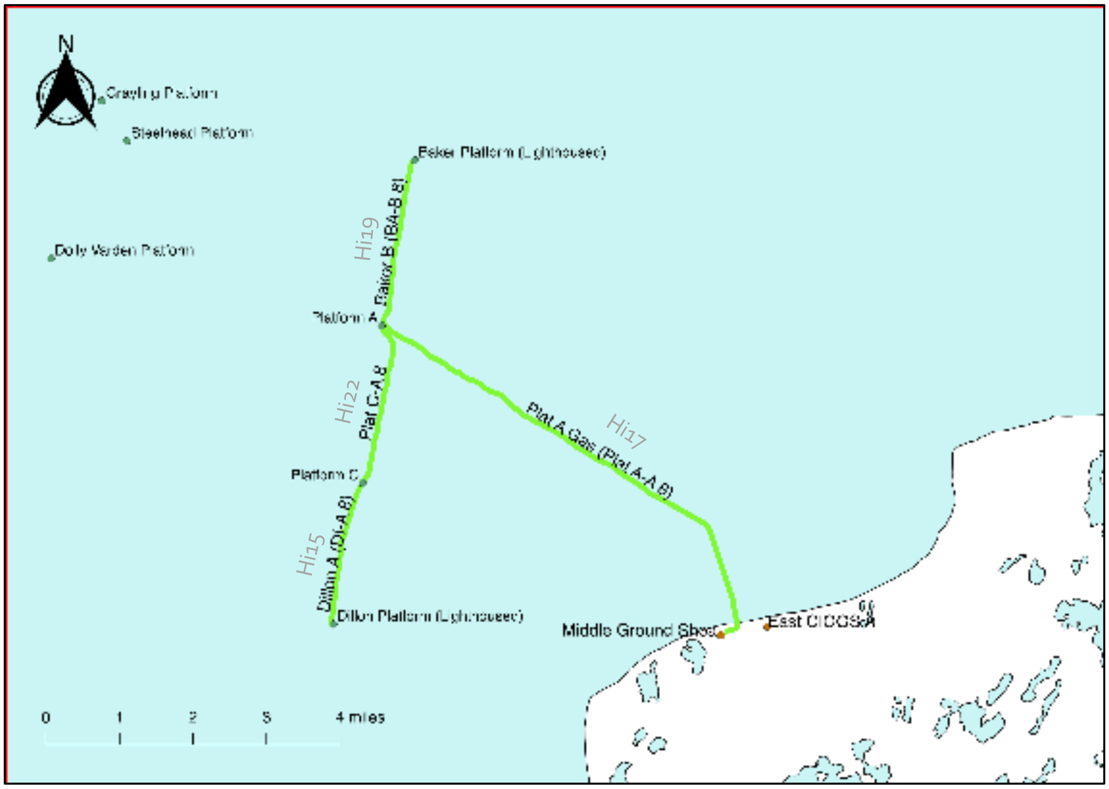

Figure F-1. Location of the pipelines that comprise the Middle Ground Shoal fuel gas system.

Table F-1.1. Principal characteristics of the Middle Ground Shoal fuel gas system.

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
Hi15	**DI-A 8**	**8.625**	**2.3**	**1966**
HI22	**Plat C-A 8**	**8.625**	**2.3**	**1967**
Hi19	**BA-B 8**	**8.625**	**2.3**	**1965**
Hi17	**Plat A-A 8**	**8.625**	**7**	**1965**

Regulatory

These fuel gas do not fall under specific State regulatory categories. All four lines are regulated by PHMSA as natural gas lines under 49 CFR Part 192. Table F-1.2 presents the regulatory designation of the Middle Ground Shoal Fuel Gas System.

Table 1.2. State and Federal Regulatory Designations for Middle Ground Shoal fuel gas pipelines.

Operator Designation	State Regulation	Federal Regulation
DI-A 8	**None**	**PHMSA 49 CFR Part 192**
Plat C-A 8	**None**	**PHMSA 49 CFR Part 192**
BA-B 8	**None**	**PHMSA 49 CFR Part 192**
Plat A-A 8	**None**	**PHMSA 49 CFR Part 192**

Integrity Management

Leak Detection

A Platform A Pipeline (Hi17) has a Shell designed leak detection system. Information on leak detection for the Baker Platform B, C Platform A, and Dillon Platform A pipelines is not found in public records and was not provided by the operators.

Cathodic Protection (CP)

There is an impressed current on each platform and MGS facility, which is electrically continuous.

Inspections

Pigging

Pigging is conducted on A Platform A pipeline (Hi17), but this pipeline cannot run smart pigs because of underwater manifolds and sharp bends. The other three pipelines are unable to be pigged.

Physical

A Platform A pipeline can be inspected by hydrotest. Annually each pipeline is inspected using sonar technology. The purpose of this survey is to identify unsupported pipeline spans of 50 feet or greater in length, identify the start, mid-span and stop of the spans with differential Global Positioning System (GPS) coordinates, height of the span and depth of water adjusted to mean lower low water (MLLW) and to identify noteworthy subsea topographic anomalies located within 10 feet of all pipelines. Divers place cement bags under the pipe to support any unsupported spans over fifty feet in length. Once the pipeline is supported from underneath, additional cement bags are placed over the pipeline to pin the pipeline at the support location.

Middle Ground Shoal Oil Production System

The Middle Ground Shoal oil production system, operated by Hilcorp Alaska, LLC (HAK), is composed of two subsea pipelines that move three-phase production from offshore platforms to the Middle Ground Shoal Oil Production Facility for oil, gas, and produced water separation. Figure F-2 shows the locations of the pipelines. Table F-2.1 contains the name and primary characteristics of each pipeline.

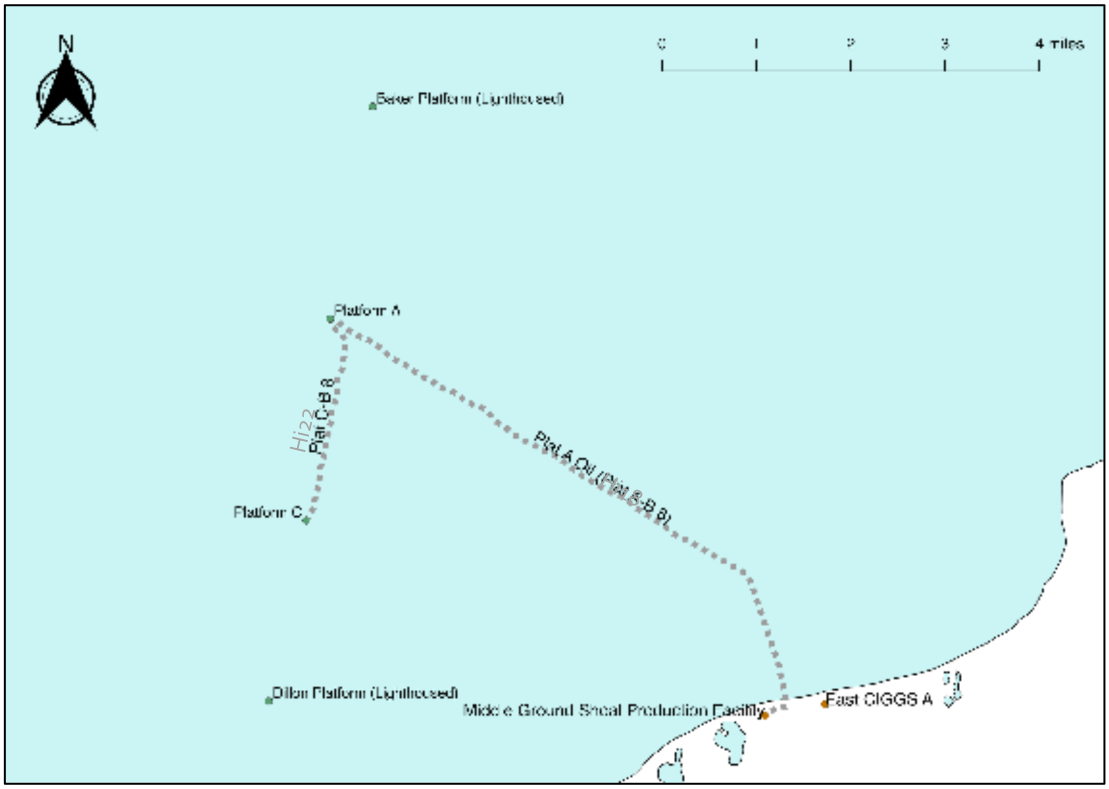

Figure F-2. Location of the pipelines that comprise the Middle Ground Shoal oil production system.

Table F-2.1. Principal characteristics of the Middle Ground Shoal oil production system.

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
Hi22	**Plat C-B 8**	**8.625**	**2.3**	**1967**
Hi18	**Plat A-B 8**	**8.625**	**7.16**	**1966**

Regulatory

These three-phase oil production pipelines are designated as flowlines for purpose of ADEC regulations and are thus regulated under 18 AAC 75.047. Neither of the two lines do not fall under a specific federal regulatory category. Table F-2.2 presents the regulatory designation of the Middle Ground Shoal oil production system.

Table F-2.2 State and Federal Regulatory Designations for Middle Ground Shoal Oil Production pipelines.

Operator Designation	State Regulation	Federal Regulation
Plat C-B 8	**ADEC as flow line under 18 AAC 75.047**	**None**
Plat A-B 8	**ADEC as flow line under 18 AAC 75.047**	**None**

Integrity Management

Leak Detection

Flow lines transfer production fluids (oil, gas, water and sediment) to onshore facilities for treatment. These flow lines operate under pressure. A loss in pressure indicates that a leak may have occurred. A low-pressure alarm sounds and the operator starts to investigate the cause. If the operator decides and/or the next level alarm goes off, the operator initiates shut down procedures. In addition, automatic shut-in alarms engage valves to discontinue flow to the line. If the pressure drops or rises 10 percent, the automatic shut-in occurs. Each flow line has a 24-hour pressure recording device that monitors and documents the pressure in the flow line at the exit point from the platform. Pressure records are stored for a minimum of three years.

In addition to pressure indicators, flyover inspections of onshore flow lines with a ROW are conducted every two weeks. Onshore flow lines on HAK property are inspected during daily rounds.

Cathodic Protection (CP)

The flow lines are provided external corrosion protection by the use of external coating systems and impressed current cathodic protection. In addition, cathodic protection is measured from each platform and at onshore locations.

HAK ensures that measures for controlling corrosion in flow lines are undertaken per 18 AAC 75.047(c), which includes a corrosion monitoring and control program, external corrosion control of buried or submerged flow lines consistent with National Association of Corrosion Engineers (NACE) International's Standard Recommended Practice -- Control of External Corrosion on Underground or Submerged Metallic Piping Systems. A program designed to minimize internal corrosion, including, as appropriate, one or more of the following:

- removal of foreign material by scraping or pigging;
- treatment of residual water or dehydration;
- injection of inhibitors, biocides, or other chemical agents;
- removal of dissolved gases by chemical or mechanical means;
- gas blanketing; or
- continuous internal coating or lining;

Internal maintenance of offshore flow lines is accomplished by corrosion coupons, pigging and the use of corrosion inhibitor and biocides, if necessary. Pigging removes loose sediment and corrosion products that may have settled out of the fluid stream and that promote the formation of local corrosion cells. Pipelines are pigged frequently.

A non-hazardous corrosion inhibitor is added to the annulus between the J-tube and the pull tube to further prevent external corrosion of the platform riser pipes if the annulus is determined to be wet. A non-hazardous corrosion inhibitor is added to the platform leg internally where there is an ADEC regulated riser if the leg is determined to be wet.

Inspections

Flow lines are inspected per API 570.

Pigging

C Platform B pipeline is inspected with a "smart pig," or equivalent technology, which records pipe wall thickness. A Platform B pipeline cannot be smart pigged, but instead pigged by scraper pigs.

Physical

Per ASME B31.4-2002, Section A451.5, offshore flow lines are inspected at a minimum annually using side scan sonar. The purpose of this survey is to identify unsupported pipeline spans of 50 feet or greater in length, identify the start, mid-span and stop of the spans with differential Global Positioning System (GPS) coordinates, height of the span and depth of water adjusted to mean lower low water (MLLW) and to identify noteworthy subsea topographic anomalies located within 10 feet of all pipelines. Divers place cement bags under the pipe to support any unsupported spans over fifty feet in length. Once the pipeline is supported from underneath, additional cement bags are placed over the pipeline to pin the pipeline at the support location.

APPENDIX G – HILCORP ALASKA/TRADING BAY FUEL SYSTEM

Trading Bay Fuel Gas System

The Trading Bay fuel gas system, operated by Hilcorp Alaska, LLC (HAK), is composed of four subsea pipelines and on-land pipelines that move natural gas from the Cook Inlet Gas Gathering System to offshore platforms. Figure G-1 shows the locations of the pipelines. Table G-1.1 contains the name and primary characteristics of each pipeline. The Monopod gas line (Hi30) is bi-directional and can be used for production or fuel gas as needed.

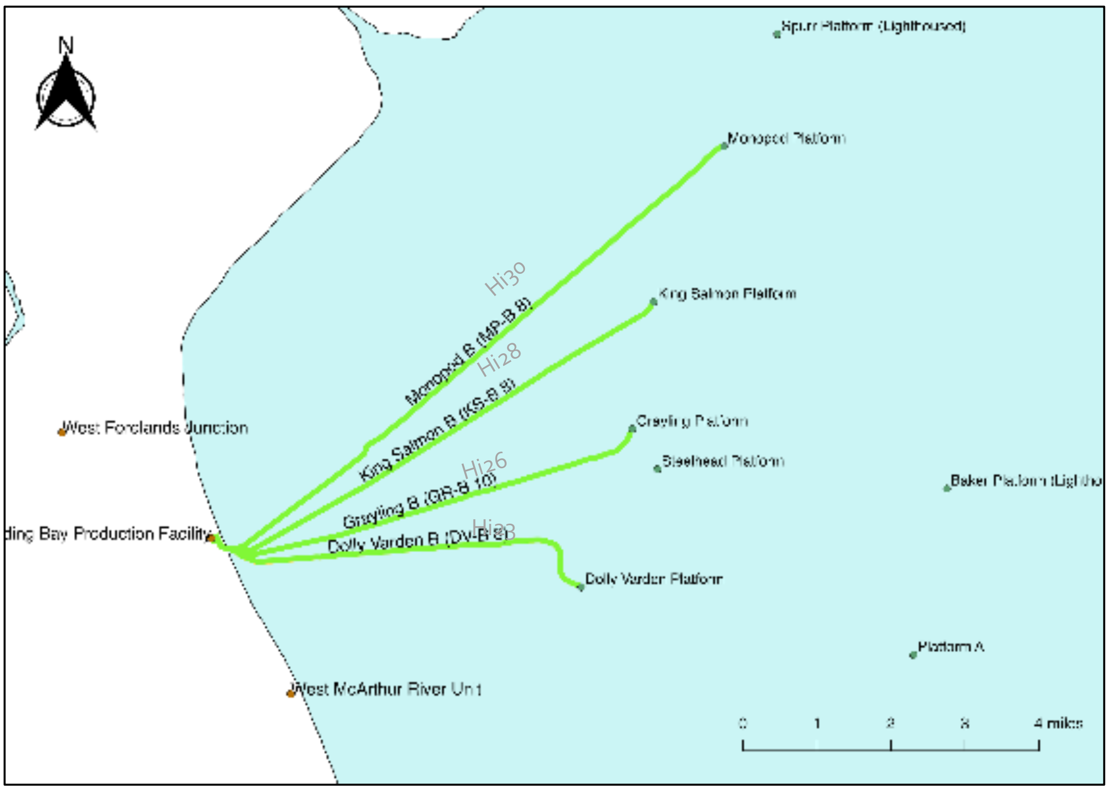

Figure G-1. Location of the pipelines that comprise the Trading Bay fuel gas system.

Table G-1.1. Principal characteristics of the Trading Bay fuel gas system.

Report Designation	Operator's Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
Hi30	**MP-B 8**	**8.625**	**8.98**	**1966**
Hi28	**KS-B 8**	**8.625**	**7.3**	**1966**
Hi26	**GR-B 10**	**10.75**	**6.42**	**1967**
Hi23	**DV-B 8**	**8.625**	**5.32**	**1967**

Regulatory

These fuel gas do not fall under specific State regulatory categories. All four lines are regulated by PHMSA as natural gas lines under 49 CFR Part 192. Table G-1.2 presents the regulatory designation of the Trading Bay Fuel Gas System.

Table G-1.2. State and Federal Regulatory Designations for Trading Bay fuel gas pipelines.

Operator Designation	State Regulation	Federal Regulation
MP-B 8	**None**	**PHMSA 49 CFR Part 192**
KS-B 8	**None**	**PHMSA 49 CFR Part 192**
GR-B 10	**None**	**PHMSA 49 CFR Part 192**
DV-B 8	**None**	**PHMSA 49 CFR Part 192**

Integrity Management

Leak Detection

Leak detection for these pipelines is indicated by a pressure loss. Pressure is monitored continuously by the operator.

Cathodic Protection (CP)

These pipelines are provided external corrosion protection by the use of external coating systems and impressed current cathodic protection. In addition, cathodic protection is measured from each platform and at onshore locations.

Inspections

Pigging

Pipelines attached to platform risers are inspected with a "smart pig," or equivalent technology, which records pipe wall thickness.

Physical

Annually each pipeline is inspected using sonar technology. The purpose of this survey is to identify unsupported pipeline spans of 50 feet or greater in length, identify the start, mid-span and stop of the spans with differential Global Positioning System (GPS) coordinates, height of the span and depth of water adjusted to mean lower low water (MLLW) and to identify noteworthy subsea topographic anomalies located within 10 feet of all pipelines. Divers place cement bags under the pipe to support any unsupported spans over fifty feet in length. Once the pipeline is supported from underneath, additional cement bags are placed over the pipeline to pin the pipeline at the support location.

Trading Bay Gas Production System

The Trading Bay gas production system, operated by Hilcorp Alaska, LLC, is composed of two subsea pipelines that move produced “wet” gas from the offshore platforms to Trading Bay Production Facility for gas production. Figure G-2 shows the locations of the pipelines. Table G-2.1 contains the name and primary characteristics of each pipeline. The Monopod gas line (Hi30) is bi-directional and can be used for production or fuel gas as needed.

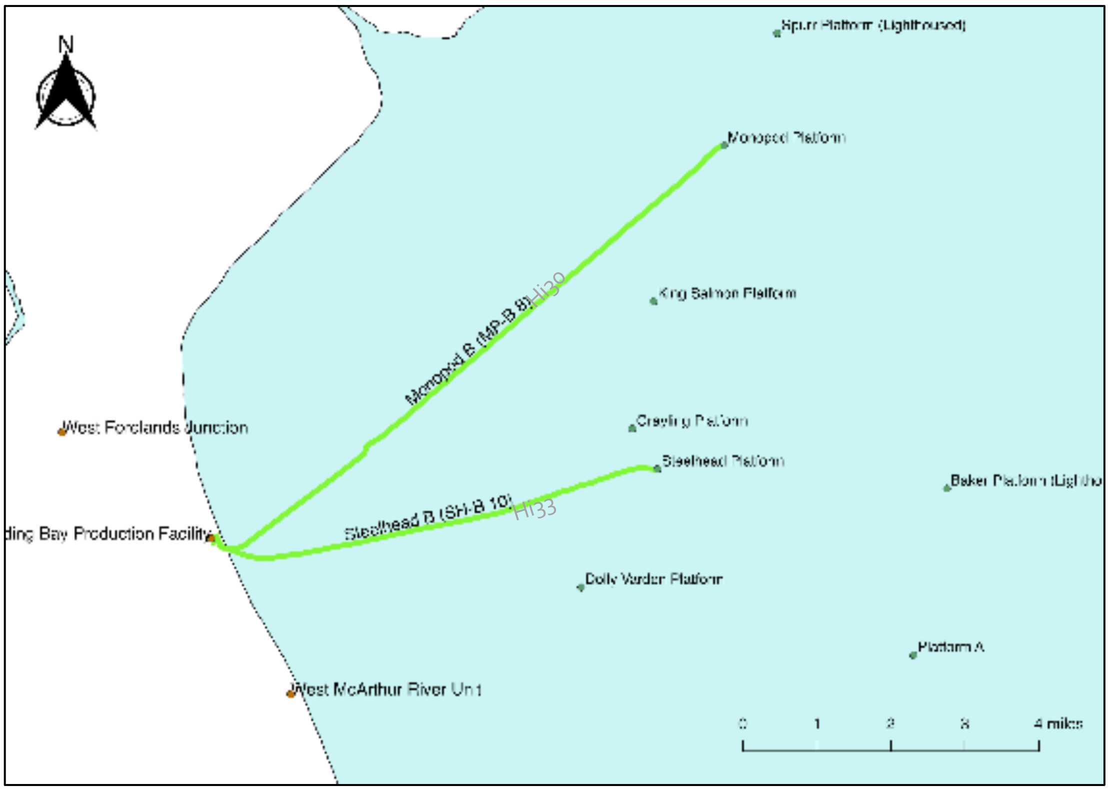

Figure G-2. Location of the pipelines that comprise the Trading Bay Gas Production System.

Table G-2.1. Principal characteristics of the Trading Bay Gas Production System

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
Hi30	**MP-B 8**	**8.625**	**8.98**	**1966**
Hi33	**SH-B 10**	**10.75**	**6.47**	**1986**

Regulatory

These gas production pipelines do not fall under specific State regulatory categories. Both lines are regulated by PHMSA as natural gas pipelines under 49 CFR Part 192. Table G-2.2 presents the regulatory designation of the Trading Bay Gas Production System.

Table G-2.2. State and Federal Regulatory Designations for Trading Bay Gas Production pipelines.

Operator Designation	State Regulation	Federal Regulation
MP-B 8	**None**	**PHMSA 49 CFR Part 192**
SH-B 10	**None**	**PHMSA 49 CFR Part 192**

Integrity Management

Leak Detection

Leak detection for these pipelines is indicated by a pressure loss. Pressure is monitored continuously by the operator.

Cathodic Protection (CP)

These pipelines are provided external corrosion protection by the use of external coating systems and impressed current cathodic protection. In addition, cathodic protection is measured from each platform and at onshore locations.

Inspections

Pigging

Pipelines attached to platform risers are inspected with a "smart pig," or equivalent technology, which records pipe wall thickness. Pigged once every 2-3 days for maintenance.

Physical

Annually each pipeline is inspected using sonar technology. The purpose of this survey is to identify unsupported pipeline spans of 50 feet or greater in length, identify the start, mid-span and stop of the spans with differential Global Positioning System (GPS) coordinates, height of the span and depth of water adjusted to mean lower low water (MLLW) and to identify noteworthy subsea topographic anomalies located within 10 feet of all pipelines. Divers place cement bags under the pipe to support any unsupported spans over fifty feet in length. Once the pipeline is supported from underneath, additional cement bags are placed over the pipeline to pin the pipeline at the support location.

Trading Bay Oil Production System

The Trading Bay oil production system, operated by Hilcorp Alaska, LLC (HAK), is composed of five subsea pipelines that move three-phase production from offshore platforms to the Trading Bay Production Facility for oil, gas, and produced water separation. Figure G-3 shows the locations of the pipelines. Table G-3.1 contains the name and primary characteristics of each pipeline.

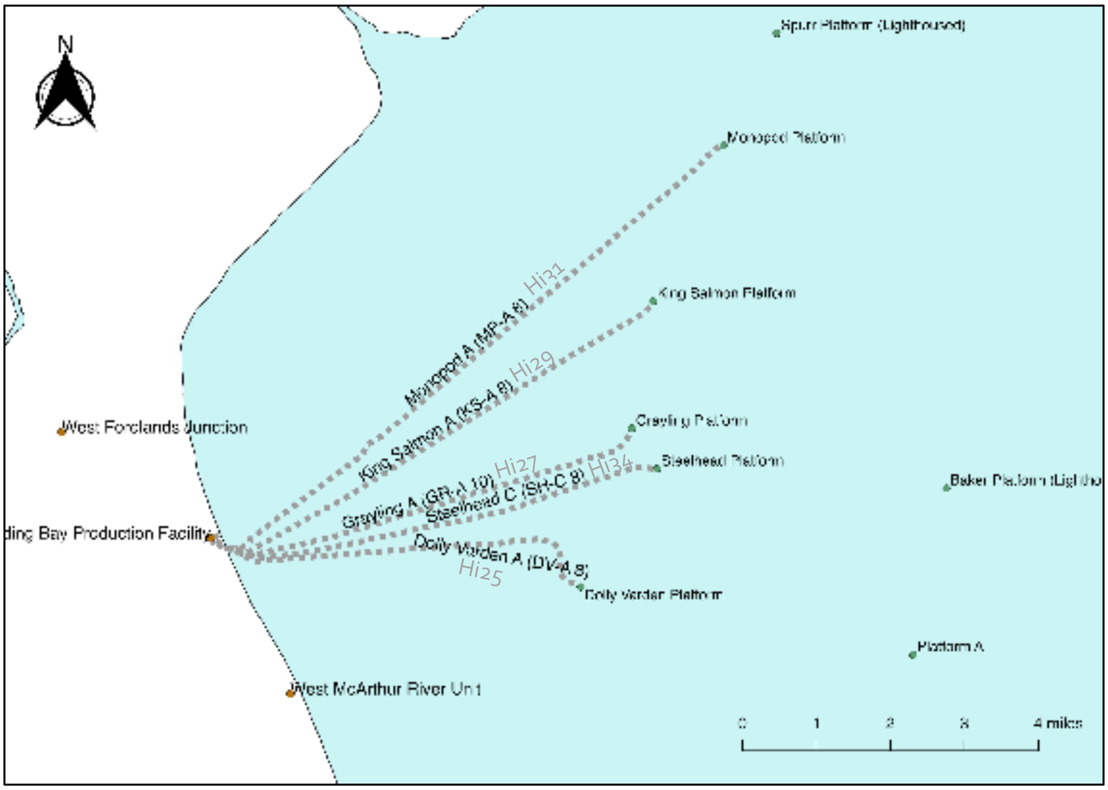

Figure G-3. Location of the pipelines that comprise the Trading Bay oil production system.

Table G-3.1. Principal characteristics of the Trading Bay oil production system

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
Hi31	**MP-A 10**	**8.625**	**8.98**	**1966**
Hi29	**KS-A 8**	**8.625**	**7.16**	**1966**
Hi27	**GR-A 10**	**10.75**	**6.42**	**1967**
Hi34	**SH-C 8**	**8.625**	**6.47**	**1986**
Hi25	**DV-A 8**	**8.625**	**5.32**	**1966**

Regulatory

These three-phase oil production pipelines are designated as flowlines for purpose of ADEC regulations and are thus regulated under 18 AAC 75.047. Two of the five lines are regulated by PHMSA as hazardous liquid pipelines under 49 CFR Part 195. Table G-3.2 presents the regulatory designation of the Trading Bay Oil Production System.

Table G-3.2. State and Federal Regulatory Designations for Trading Bay Oil Production pipelines.

Operator Designation	State Regulation	Federal Regulation
MP-A 10	**ADEC as flow line under 18 AAC 75.047**	**PHMSA 49 CFR Part 195**
KS-A 8	**ADEC as flow line under 18 AAC 75.047**	**None**
GR-A 10	**ADEC as flow line under 18 AAC 75.047**	**None**
SH-C 8	**ADEC as flow line under 18 AAC 75.047**	**None**
DV-A 8	**ADEC as flow line under 18 AAC 75.047**	**PHMSA 49 CFR Part 195**

Integrity Management

Leak Detection

Flow lines transfer production fluids (oil, gas, water and sediment) to onshore facilities for treatment. These flow lines operate under pressure. A loss in pressure indicates that a leak may have occurred. A low-pressure alarm sounds and the operator starts to investigate the cause. If the operator decides and/or the next level alarm goes off, the operator initiates shut down procedures. In addition, automatic shut-in alarms engage valves to discontinue flow to the line. If the pressure drops or rises 10 percent, the automatic shut-in occurs. Each flow line has a 24-hour pressure recording device that monitors and documents the pressure in the flow line at the exit point from the platform. Pressure records are stored for a minimum of three years.

In addition to pressure indicators, flyover inspections of onshore flow lines with a ROW are conducted every two weeks. Onshore flow lines on HAK property are inspected during daily rounds.

Cathodic Protection (CP)

The flow lines are provided external corrosion protection by the use of external coating systems and impressed current cathodic protection. In addition, cathodic protection is measured from each platform and at onshore locations.

HAK ensures that measures for controlling corrosion in flow lines are undertaken per 18 AAC 75.047(c), which includes a corrosion monitoring and control program, external corrosion control of buried or submerged flow lines consistent with National Association of Corrosion Engineers (NACE) International's Standard Recommended Practice -- Control of External Corrosion on Underground or Submerged Metallic Piping Systems. A program designed to minimize internal corrosion, including, as appropriate, one or more of the following:

- removal of foreign material by scraping or pigging;
- treatment of residual water or dehydration;
- injection of inhibitors, biocides, or other chemical agents;

- removal of dissolved gases by chemical or mechanical means;
- gas blanketing; or
- continuous internal coating or lining;

Internal maintenance of offshore flow lines is accomplished by corrosion coupons, pigging and the use of corrosion inhibitor and biocides, if necessary. Pigging removes loose sediment and corrosion products that may have settled out of the fluid stream and that promote the formation of local corrosion cells. Pipelines are pigged frequently.

A non-hazardous corrosion inhibitor is added to the annulus between the J-tube and the pull tube to further prevent external corrosion of the platform riser pipes if the annulus is determined to be wet. A non-hazardous corrosion inhibitor is added to the platform leg internally where there is an ADEC regulated riser if the leg is determined to be wet.

Inspections

Flow lines are inspected per API 570.

Pigging

Flow lines attached to platform risers are inspected with a "smart pig," or equivalent technology, which records pipe wall thickness.

Physical

Per ASME B31.4-2002, Section A451.5, offshore flow lines are inspected at a minimum annually using side scan sonar. The purpose of this survey is to identify unsupported pipeline spans of 50 feet or greater in length, identify the start, mid-span and stop of the spans with differential Global Positioning System (GPS) coordinates, height of the span and depth of water adjusted to mean lower low water (MLLW) and to identify noteworthy subsea topographic anomalies located within 10 feet of all pipelines. Divers place cement bags under the pipe to support any unsupported spans over fifty feet in length. Once the pipeline is supported from underneath, additional cement bags are placed over the pipeline to pin the pipeline at the support location.

APPENDIX H – HARVEST ALASKA SYSTEM

Harvest Alaska Oil Transmission Pipeline System

The oil transmission system, operated by Harvest Alaska, is composed of one subsea pipeline and five on-land pipelines that move sales grade crude oil from production facilities to the Marathon Refinery. Figure H-1 shows the locations of the pipelines. Table H-1.1 contains the name and primary characteristics of each pipeline.

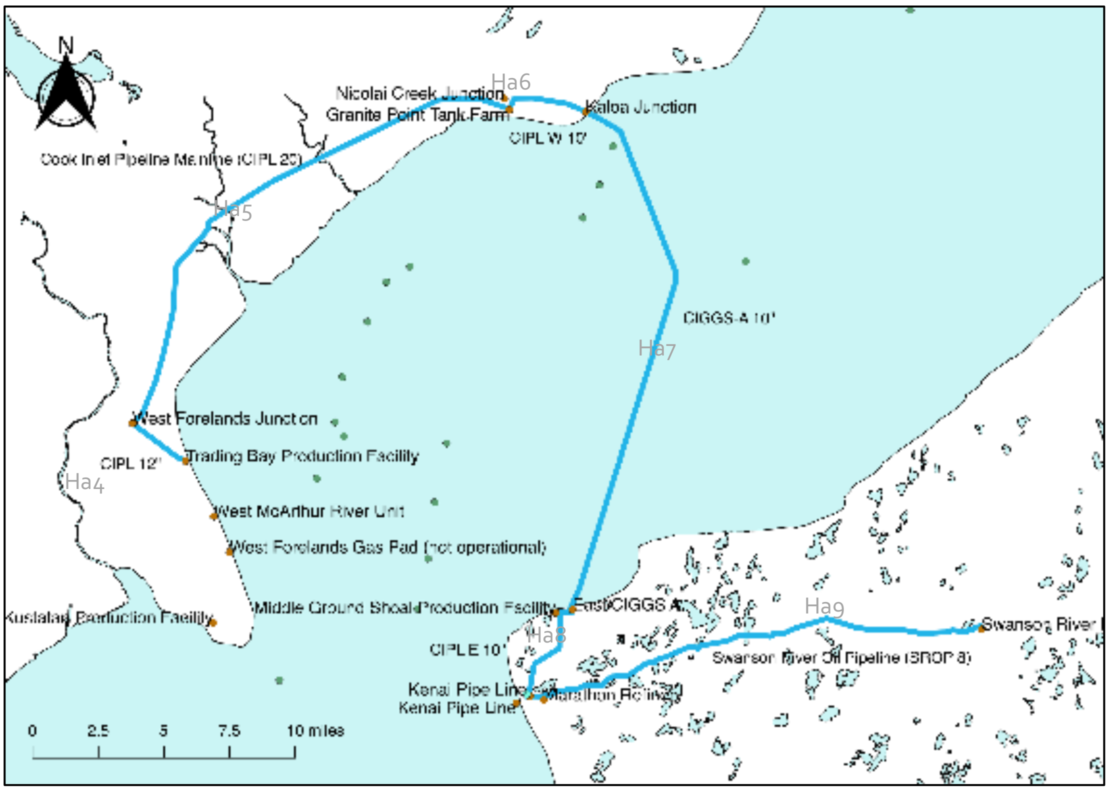

Figure H-1. Location of the pipelines that comprise the Harvest Alaska oil transmission system.

Table H-1.1. Principal characteristics of the Harvest Alaska oil transmission system

Report Designation	Operator Designation	Outside Diameter (inches)	Length (miles)	Year of Construction
Ha4	**CIPL 12**	**12.75**	**2.56**	**1967**
Ha5	**CIPL 20**	**20**	**21.7**	**1966-67**
Ha6	**CIPL W 10"**	**10**	**3.5**	**2018**
Ha7	**CIGGS-A 10"**	**10**	**21.7**	**1971**
Ha8	**CIPL E 10"**	**10**	**5.2**	**1972, 2018**
Ha9	**SROP 8**	**8.625**	**18.83**	**1960**

Regulatory

These sales grade crude oil pipelines are designated as crude oil transmission pipes for purpose of ADEC regulations and are thus regulated under 18 AAC 75.055. Two of the six lines are regulated by PHMSA as hazardous liquid pipelines under 49 CFR Part 195. Table H-1.2 presents the regulatory designation of the Trading Bay Oil Production System.

Table H-1.2. State and Federal Regulatory Designations for the Cook Inlet Oil Transmission pipelines.

Operator Designation	State Regulation	Federal Regulation
CIPL 20	**Crude Oil Transmission Pipe (18 AAC 75.055; 75.425(e)(4) (A) (ii))**	**PHMSA**
CIPL 12	**Crude Oil Transmission Pipe (18 AAC 75.055; 75.425(e)(4) (A) (ii))**	**PHMSA**
CIPL W 10"	**Crude Oil Transmission Pipe (18 AAC 75.055; 75.425(e)(4) (A) (ii))**	**PHMSA**
CIGGS-A 10"	**Crude Oil Transmission Pipe (18 AAC 75.055; 75.425(e)(4) (A) (ii))**	**PHMSA**
CIPL E 10"	**Crude Oil Transmission Pipe (18 AAC 75.055; 75.425(e)(4) (A) (ii))**	**PHMSA**
SROP 8	**Crude Oil Transmission Pipe (18 AAC 75.055; 75.425(e)(4) (A) (ii))**	**PHMSA**

Integrity Management

Leak Detection

The following leak detection information is applicable to four of the six pipelines within this system. Leaks detection uses two methods 1) volume balance and 2) rarefaction wave detection. The system uses Atmos Pipe and Atmos Wave Systems. Atmos Pipe compares volumes in to segments TBPF to GPTF and GPTF to KPL Junction. Atmos Wave detects negative wave pressure of a leak and can pinpoint a leak. There are 15 sensors in the Atmos Wave leak detection system.

The SCADA system on the pipeline has a reporting accuracy of 1 percent under normal operating conditions. The pipeline is equipped with a leak detection software package which uses a mass balance approach for leak detection. The system takes into account changes in flow, pressure, temperature, and density. Additionally, the controller monitors the pipeline pressure during transient and steady state conditions and has full authority to shut the pipeline down if a leak or leak-like condition is observed. In order to verify if the system is operating correctly, regular checks on equipment and software are conducted in accordance with preventive maintenance procedures.

Metered volume balancing is performed at least once every 24 hours, as required by 18 AAC 75.055(a)(2). The controller receives continual meter readings from wFPS and GPTF. These values are compared to the DRT meter to provide real-time over/short variance monitoring through the control system for both long-and short-term operator defined limits. A variance of +/-1 percent alerts facility personnel of a possible loss of product, and procedures are then taken to ensure that the oil volume in question is accounted for.

The following information is also applicable to SROP 8: Harvest implemented the Atmos pipe leak detection system in 2016. Atmos Pipe is a statistical pipeline volume balanced leak detection system. Flow verification is also implemented through the daily accounting system and is displayed continuously on the SCADA display in the control room, to meet the current regulation.

During "no flow" conditions pressure is held on the CIPL. The leak detection system monitors the pressure and operational parameters when the pumps are not operating. There is a leak detection alarm for both the static and transient condition that is tied into the SCADA system at the Harvest Kenai Control Room, which is staffed 24-hours per day.

Information on leak detection for the CIPL W 10" pipeline is not found in public records and was not provided by the operators.

Cathodic Protection (CP)

The pipelines within this transmission system are protected by an impressed current system.

Inspections

Pigging

Transmission pipelines are regularly maintenance pigged and smart pigged based on need according to the operator.

Physical

Stream crossing surveys at navigable rivers are conducted at least once every 5 years in accordance with 49 CFR Part 195.412 and more frequently dependent upon riverbed conditions. GPTF and WFPS are checked a minimum of one time per week by operator personnel and recorded in the Station Check logbook. Pressures and meter readings from these stations are monitored continuously via microwave telemetering at DRT Operations console. These readings are logged every hour by the Terminal Operator and recorded on the Daily Operations Log Sheet.

In accordance with 18 AAC 75.055(a)(3), the entire length of the pipeline is patrolled by aerial surveillance once a week, except during inclement weather. The goal of these aerial surveys is visual detection of a discharge or abnormal operating condition. Although the pipeline is buried 4 feet deep, any lost product would surface readily due to the line pressure, relatively high-water table in the area, and lower specific gravity of crude oil.

- Right of Way (ROW) patrol onshore, 26 x/yr, NTE 3 weeks
- ROW remote, weekly, NTE 3 weeks
- Inspect and test pressure limiting device, relief valve, pressure regulator, pressure control equipment 2 x/yr, NTE 15 months
- Conduct CP test 1 x/yr, NTE 15 months
- CP rectifier test, inspect reverse current switch, inspect diode, inspect critical bonds 6 x/yr, NTE @.5 months
- Examine coupons and other internal corrosion monitoring 2 x/yr, NTE 7.5 months
- Inspect for atmospheric corrosion onshore every 3 years, NTE 39 months

For the SROP 8 pipeline, additional inspection information includes:

In accordance with 18 AAC 75.055(a)(3), the entire length of the pipeline is patrolled by aerial surveillance once a week, except during inclement weather. The goal of these aerial surveys is visual detection of a discharge. Ground based surveillance may be substituted for aerial surveillance when operators are on ADEC regulated sections of the ROW.

Aerial or ground-based surveillance may be requested to verify a spill. Aircraft and helicopters for use are available 24 hours per day from Nikiski, Kenai, Anchorage, and Homer.

- ROW inspection NTE 3 weeks
- Same inspection schedule as CIPL.
- Each rectifier, reverse current switch, diode, and interface bond must be inspected 6x/yr, NTE 2.5 months