2013 ANNUAL REPORT

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STATE PIPELINE COORDINATOR'S OFFICE

STATE OF ALASKA
Sean Parnell, Governor

DEPARTMENT OF NATURAL RESOURCES
Joseph Balash, Acting Commissioner

STATE PIPELINE COORDINATOR'S OFFICE
Allison Iversen, Acting State Pipeline Coordinator

The State Pipeline Coordinator's Office Annual Report is available online at http://dnr.alaska.gov/commis/pco.

Copies may be requested from:

State Pipeline Coordinator's Office
411 West Fourth Avenue, Suite 2C
Anchorage, Alaska 99501

Front Cover: SPCO lease compliance staff accompanied the Northstar pipeline operator during the annual walking-speed surveillance. Photo credit: Ben Hagedorn
Back Cover: Trans-Alaska Pipeline System. Photo credit: Ben Hagedorn

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INTRODUCTION TO THE SPCO

The SPCO provides oversight of Alaska Statute 38.35 pipelines in Alaska. SPCO lease compliance specialists spend hundreds of hours each year monitoring pipelines and rights-of-way.

State of Alaska policy, as referenced in Alaska Statute (AS) 38.35.010, mandates that development, use and control of a pipeline transportation system make the maximum contribution to Alaska human resources development, increase the standard of living for all Alaska residents, advance existing and potential sectors of Alaska's economy, strengthen free competition in Alaska's private enterprise system and carefully protect its incomparable natural environment.

The Commissioner of the Department of Natural Resources (DNR) has the authority to issue leases on state land for pipeline rights-of-way to transport products under conditions prescribed by AS 38.35.015 and the associated administrative regulations. The Commissioner delegates the authority and responsibility to administer pipeline right-of-way leases, as allowed by AS 38.35.210, to the State Pipeline Coordinator.

An administrative order, signed by Gov. Walter Hickel in 1987, established the State Pipeline Coordinator's Office (SPCO) within the DNR. Subsequent administrative orders designated the SPCO as the State's lead agency for issuing right-of-way leases under AS 38.35, the Right-of-Way Leasing Act, and coordinating the State's efforts related to the federal right-of-way grant process. The SPCO also coordinates the State's oversight of pre-construction, construction, operation and termination of all common-carrier pipelines.

Organization
In addition to right-of-way and lease compliance specialists, engineers and administrative staff, the SPCO includes a representative from the Department of Fish & Game, Habitat Division; safety and electrical inspectors from the Department of Labor & Workforce Development; three representatives from the Department of Environmental Conservation, Spill Prevention & Response and Industry Preparedness programs; and inspectors/building permit reviewers representing the Department of Public Safety, State Fire Marshal's Office. A complete SPCO organizational chart is available in Appendix B.

Right-of-Way Leases
A right-of-way lease includes a wide range of commitments and governs the conduct of both the State and the lessee. A lease remains in effect for the lifetime of the corresponding pipeline and addresses construction, operation, maintenance and termination. The intent of every lease is to preserve human health and environmental stewardship through safe and responsible pipeline operations.

To ensure that all pipeline activities are conducted safely and in compliance with all applicable laws and regulations, each lease incorporates a comprehensive set of stipulations that require conformance to multiple technical, environmental and other important conditions. The stipulations require lessees to establish specific processes, programs and systems to be implemented in all aspects of pipeline operations. When properly administered by the lessee and monitored by the SPCO, the stipulation requirements can effectively ensure the reliable and safe operation of pipeline systems.

The SPCO, in issuing and providing continued oversight of right-of-way leases, strives to limit duplication of efforts while utilizing the expertise of cooperating regulatory agencies. When other state or federal regulatory agencies have jurisdictional authority over certain aspects of pipeline operations, the SPCO will work with the agencies and their respective subject matter experts and regulatory enforcement staff to ensure safe and reliable operations.

Sections Overview
In addition to the liaisons mentioned above, the SPCO is composed of five main sections: administration, lease compliance and monitoring, right-of-way and permitting, special projects and engineering.

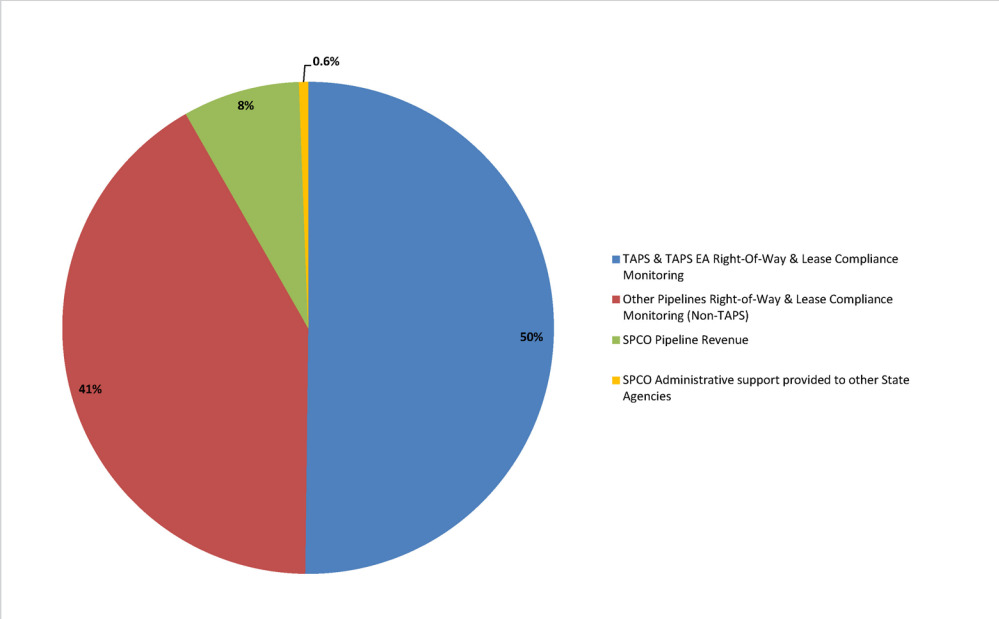
ADMINISTRATIVE SECTION

The administrative section performs multiple functions critical to daily office operations. Administrative staff manages incoming and outgoing correspondence; right-of-way case files; and financial, procurement and other administrative records. Administrative staff assists with public records requests and performs all administrative functions relating to personnel, payroll, recruitment, budgeting, grants and contracts, accounting, computer and network maintenance, facility management, property control, procurement and travel. In fiscal year 2013 (FY13), administrative staff coordinated and finalized more than 247 travel arrangements for SPCO compliance and right-of-way specialists to conduct pipeline compliance, assessment and inspection activities.

Reimbursable Service Agreements

Reimbursable service agreements (RSAs) are contractual agreements between two parties to reimburse for costs undertaken for specified activities. The administrative section begins the RSA process with a pipeline proponent by requesting an annual work plan. Based on the plan the pipeline proponent provides, the administrative section works with project staff and management to identify the state agency resources needed to fulfill the proponent's objectives. Administrative staff members coordinate with jurisdictional state agencies, assist with the development of budget estimates for annual costs associated with the application and provide the applicant with a consolidated state agency oversight budget estimate.

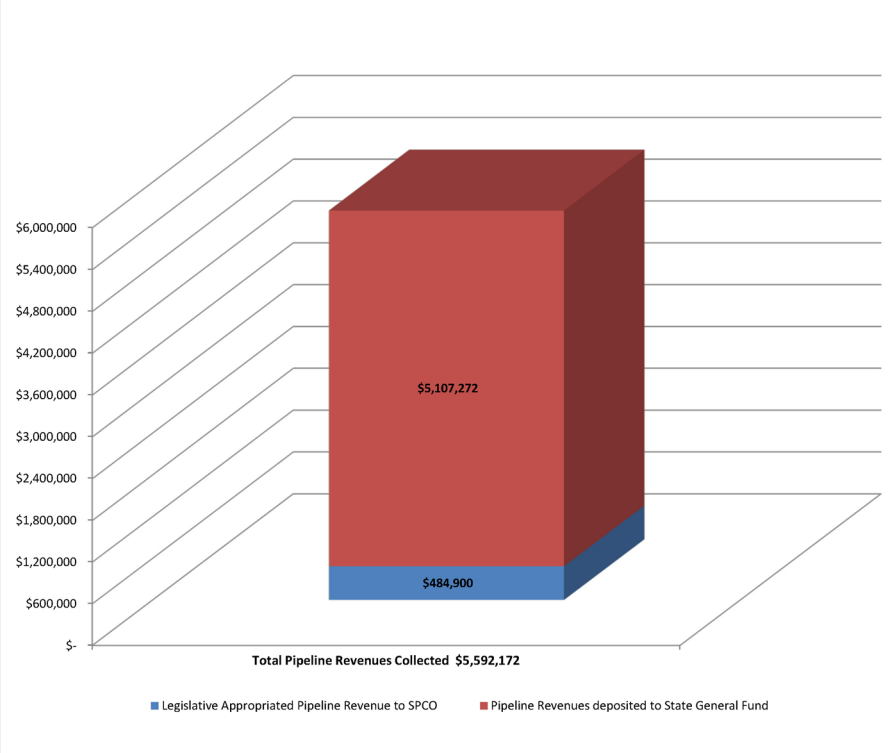
SPCO FY13 Budget Expenditures



Budget Overview

The SPCO budget is revenue-based and largely funded with reimbursements from industry. State agency representatives are supported through reimbursable service agreements administered by the SPCO; this integrates the expertise and authority of multiple departments into one coordinated office. SPCO FY13 program costs totaled $5,355,153.

Pipeline Revenues

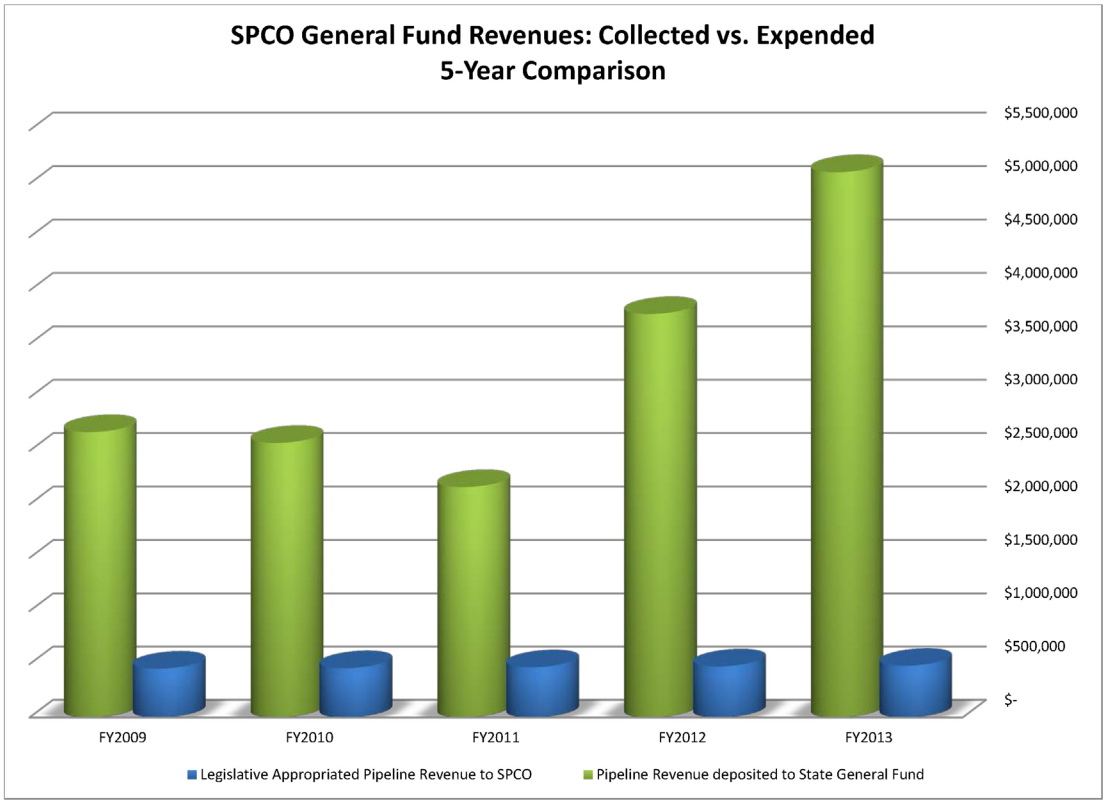


On behalf of the State, the SPCO collects program receipts, also known as pipeline revenues, from lease payments, material sales and application fees.

Pipeline revenues are deposited in the State's general fund. SPCO FY13 pipeline revenue collections grossed $5.59 million. Actual lessee contributions to pipeline revenues are itemized in Appendix E.

Each year, the Alaska Legislature appropriates some general fund monies to the SPCO, which are used to support operations unrelated to any specific pipeline lease. The FY13 net deposit (revenue collected minus legislative appropriation) to the general fund was $5.11 million.

SPCO General Fund Revenues - Collected vs. Expended - Five Year Comparison



LEASE COMPLIANCE SECTION

Lease compliance specialist Justin Selvik confers with an APSC contractor during a surveillance of a TAPS project site.

The role of the lease compliance section is to monitor common-carrier pipeline operations for compliance with AS 38.35 right-of-way lease requirements. The lease compliance team evaluates compliance by conducting field inspections, researching lessee operating processes and reporting findings. The lease compliance team continually works with lessees to verify that the processes and documentation required for lease compliance are available for review and properly utilized by lessees and contractors.

Each fiscal year, lease compliance specialists work to evaluate compliance for every lease requirement in one particular section of each lease - either the general section, environmental section or technical section. For example, if compliance specialists are evaluating general lease stipulations in the current fiscal year, then next year they will focus on environmental stipulations. Because many lease provisions are administrative and do not require compliance efforts, lease compliance specialists determine the functional status of each lease requirement to plan annual surveillance efforts. Other lease provisions apply to specific activity phases, such as construction or termination, and may not be applicable to surveillance and monitoring programs during normal pipeline operations. Some provisions, referred to as "conditional" provisions, are invoked only after an action is initiated by the lessee or State Pipeline Coordinator.

The lease compliance team conducts surveillances on SPCO-jurisdictional pipelines throughout the year and records observations in surveillance and lease compliance reports. Surveillance reports serve as independent compliance evaluations, the factual basis for assessments or technical reports, or as supporting documentation for an agency permit issuance determination or verification. Lease compliance reports provide descriptions of the SPCO field activities and observations in support of the surveillance reports. Surveillance reports and lease compliance reports are then provided to the lessee to convey lease compliance findings.

Because lease requirements cover a broad range of subjects, the lease compliance team frequently utilizes the expertise of the SPCO engineers, right-of-way specialists, and other state and federal agencies to maintain a comprehensive monitoring program. Many lease stipulations impose requirements that are overlapped by state or federal laws or regulations administered and enforced by other regulatory agencies. To avoid duplication of efforts, lease compliance specialists defer to other regulatory enforcement agencies to ensure compliance with those lease requirements. The lease compliance team monitors and reports on the enforcement activities as they relate to specific lease requirements.

The lease compliance team periodically performs in-depth assessments that focus primarily on processes or systems or are derived from a compilation of field observations. Compliance specialists first identify the scope of an assessment, then apply the appropriate level of sampling and resources required to compile the report. The lease compliance team integrates available information from research, interviews, surveillances, and other documentation to evaluate pipeline operations for compliance with lease requirements.

Each year the lease compliance team receives and evaluates the annual reports required of the lessee by every state pipeline right-of-way lease. Lessee annual reports provide information from the past year regarding right-of-way maintenance and engineering activities, internal compliance monitoring, and ongoing studies of specific areas of interest, such as areas of land that are highly susceptible to erosion. The lease compliance team then summarizes lessee annual reports for inclusion in the SPCO annual report.

The compliance monitoring program is dynamic and responds to changing conditions. An annual internal review provides an opportunity for SPCO staff to incorporate program improvements or other necessary modifications to the monitoring program.

ENGINEERING SECTION

SPCO engineers provide technical oversight of facilities, equipment, infrastructure and activities on pipeline leases. The section also provides, upon request, engineering assistance and recommendations to liaison agencies, the DNR Commissioner and the State Pipeline Coordinator.

The engineering section evaluates technical submittals against applicable codes and regulations and AS 38.35, which requires that "the applicant has the technical and financial capability to protect state and private property interests," the lessees "maintain the leasehold and pipeline in good repair," and "promptly repair or remedy any damage to the leasehold."

The engineering section also coordinates with other agencies to provide technical assistance. The principal efforts of engineering fall into one of four categories:

Lease Pre-Application
Pre-application activities involve gathering information on the technical portion of a proposed project and analyzing the issues involved in the project. Engineering provides guidance and help for technical and regulatory issues. Typically, an applicant prepares a design basis. The purpose of the design basis is to ensure that the proposed pipeline and facilities adhere to industry standards, meet regulatory and legal requirements, and protect the environment while ensuring safety.

Lease Processing
Engineering's role in the leasing process primarily is to evaluate and prepare a recommendation to the State Pipeline Coordinator on the technical capabilities of the lease applicant. In addition, the engineering section provides technical conditions or requirements for inclusion in the lease.

Lease Monitoring
The engineering section provides technical evaluations of the construction and operation of pipelines and facilities. This work includes reviewing major maintenance, repairs and construction. This often involves providing independent engineering opinions on leasehold activities.

Special Projects
Engineering may work on items that do not have a direct relationship to the leases. This type of work includes:

- Providing technical assistance to other state organizations
- Preparing technical opinions
- Analyzing the impact of new regulations or other government activities
- Evaluating new technologies and their applicability to resource development

RIGHT-OF-WAY AND PERMITS SECTION

The SPCO right-of-way and permits section (ROW section) is responsible for a multitude of tasks related to pipeline lease administration. The ROW section processes lease amendments, implements public processes (as required by state statute), prepares legal land contracts, writes decision documents, issues project-specific authorizations, administers rental and other payments, reviews letters of non-objection and performs myriad other functions as necessary or requested by the State Pipeline Coordinator.

A SPCO ROW specialist conducts a surveillance inspection of a Trans-Alaska Pipeline System operations material site.

Lease Administration
The ROW section is responsible for permitting or coordinating any activity associated with a lease. The ROW section is the point of contact within the SPCO for land use and pipeline rights-of-way.

Permitting
The ROW section issues lease authorizations for all AS 38.35 pipelines, along with land use permits, temporary water use permits, material sales contracts, and rights-of-way for roads and boat launches required for operations and maintenance activities and special projects. The permit review process can involve a substantial amount of coordination; each project has unique lease or permit requirements, often depending on these factors:

- Type of work activity
- Project details (schedule, location, special circumstances)
- Land ownership
- Public notice requirements
- Public comments
- Navigable waters proximity
- Water use needs
- Coordination with state, federal and local agencies
- Enforcement and jurisdictional implications
- Effect on habitats and wetlands
- Impact on fish and wildlife
- Engineering and surveying standards
- Land appraisals
- Potential to disturb historic, prehistoric and archaeological resources

Amendments
The ROW section evaluates and adjudicates amendments to SPCO jurisdictional leases. The lease amendment process is used to revise lease language or add lands to existing rights-of-way for maintenance and operation purposes, or both. The amendment process includes a Commissioner's Decision and public notice.

Other Administrative Duties
The ROW section manages rental schedules, directs and processes payments, documents pipeline activities, assists staff to maintain the SPCO case files, updates the State of Alaska Land Administration System and performs any additional tasks associated with lease administration. The ROW section also issues and manages material sales contracts with lessees and conducts annual surveillance inspections of TAPS operations material sites.

A summary of these authorizations is provided in Appendix H: Authorizations, Rights-of-Way and Permits issued by SPCO; more details can be found under individual pipeline sections.

Land Administration System Case File Audit
SPCO right-of-way staff completed the third and final part of a three-part audit of the land administration system (LAS) case file records for each active pipeline right-of-way lease and grant case file administered by the SPCO. The LAS system is the statewide land records system, available to the public at: http://dnr.alaska.gov/projects/las/lasmenu.cfm.

The LAS system is used to locate, research and verify land ownership and land use on State lands. Keeping the LAS case file records accurate and up-to-date is important for DNR adjudicators and the public when researching the status of State lands. The LAS audit was divided into three parts for each case file audited.

Part one of the audit involved review and update of each of the four basic record types in LAS: summary record, land record, transaction record and legal description record. Part two of the audit involved a quality control check of the part one updates and reviewing and updating LAS revenue and billing subsystem records for each case file. Part three included a final quality control check of updates made during parts one and two for each case file along with any final edits, corrections and updates to the LAS case file records. As a result of the audit, the SPCO improved the consistency of information by adding and updating data for all the leases.

Alaska Mapper is a mapping system that serves as a visual interface into LAS. The system provides access to casefile data, from status plats and links to land case file summaries, details and abstracts. The way that DNR authorizations are displayed in Alaska Mapper is dependent upon the completeness and accuracy of LAS. The SPCO provided the current surveys of several pipeline leases; the information was incorporated into Alaska Mapper by Information Resource Management (IRM) section.

Also as a result of the audit, industry and the public include have better access to more accurate and up-to-date information, more accurate locations on Alaska Mapper, and several additional hyperlinks to view recorded documents on the Recorder's Office website. The accuracy of the locations on Alaska Mapper will allow land managers to better adjudicate other compatible uses being issued in the vicinity of pipelines.

SPCO and DNR Survey

Surveys on state land need to be approved by the Statewide Platting Supervisor prior to releasing land interests in construction rights-of-way, and are necessary for calculating acreages for leases. The SPCO entered into a Reimbursable Service Agreement (RSA) with the DNR Survey Office to expedite the reviews of surveys related to the AS 38.35 Leases. In FY12, survey and SPCO staff conducted research of approved pipeline right-of-way surveys to determine and evaluate the survey criteria and type of recording completed. In FY13, survey staff provided recommendations and drafted survey instructions in order to request more consistent criteria for pipeline rights-of-way surveys. SPCO staff provided input to the survey instructions.

Process Mapping

During FY13, SPCO staff undertook an extensive process mapping project, focusing on linked dependencies among processes and improving the effectiveness of SPCO activities. The new process maps help SPCO staff consistently execute activities and ensure that SPCO authorizations are consistent with statute and state policy.

Several of the process maps have been shared with industry representatives and other agencies through the pre-lease and permitting stages of projects. The maps assist outside entities understand what contributions and involvement are required and assist in planning the expected timeframes associated with SPCO authorizations and reviews. This project is closely linked with an effort at the SPCO to develop appropriate templates for SPCO authorizations.

The table below contains basic information about SPCO-monitored pipelines; including the location by region, lessee and status.

Issued Leases	ADL #	Location	Length (miles)*	Lessee(s)	Status
Alpine Diesel	415932	North Slope	34	ConocoPhillips	Operating
Alpine Oil	415701	North Slope	34	ConocoPhillips	Operating
Alpine Utility	415857	North Slope	34	ConocoPhillips	Operating
Badami Sales Oil	415472	North Slope	25	BPTA**	Operating
Badami Utility	415965	North Slope	31	BPTA**	Operating
Endicott	410562	North Slope	26	Endicott Pipeline Co.	Operating
Kenai Kachemak	228162	Cook Inlet	50	Kenai Kachemak Pipeline, LLC	Operating
Kuparuk	402294	North Slope	28	KTC***	Operating
Kuparuk Extension	409027	North Slope	9	KTC***	Operating
Milne Point	410221	North Slope	10	Milne Point Pipeline, LLC	Operating
Milne Point Products	416172	North Slope	10	Milne Point Pipeline, LLC	Operations Suspended
Nikiski Alaska	69354	Cook Inlet	70	Tesoro Alaska Pipeline Co.	Operating
North Fork	230928	Cook Inlet	7.4	Anchor Point Energy	Operating
Northstar Gas	415975	North Slope	17	Northstar Pipeline Co., LLC	Operating
Northstar Oil	415700	North Slope	16	Northstar Pipeline Co., LLC	Operating
Nuiqsut Natural Gas Pipeline	416202	North Slope	14	North Slope Borough	Operating
Oliktok	411731	North Slope	28	Oliktok Pipeline Co.	Operating
Trans-Alaska Pipeline	63574	Prudhoe Bay to Valdez	800	****	Operating

* *The lengths in the table are the approximate total length of the pipeline centerline.*
*** BP Transportation (Alaska)* *** *Kuparuk Transportation Co.*
**** *BP Pipelines (Alaska) Inc., ConocoPhillips Alaska Transportation Inc., ExxonMobil Transportation Company, Koch Alaska Pipeline Co. and Unocal Pipeline Company. Koch Alaska Pipeline Co. and Unocal Pipeline Co. both indicated that they would release their respective interest in TAPS during FY13.*

SPECIAL PROJECTS SECTION

Members of the SPCO Special Projects Section lead a public hearing in Nuiqsut.

The SPCO Special Projects section is the office's first point of contact for all new and potential pipeline right-of-way applicants. Since 2009, the SPCO has seen a significant increase in the number of applications and interest in building common carrier pipelines. The Special Projects section was created to provide new applicants more focused attention and assistance, in order to maintain proposed schedules and streamline state, federal and local permitting requirements.

The Special Projects section conducts pre-application meetings with potential applicants. These meetings are essential to coordinating realistic timelines and provide an invaluable opportunity to discuss potential obstacles or challenges in preparing and processing the lease application. At the pre-application meetings, the SPCO typically outlines the right-of-way leasing process, including public processes and other state permits necessary for the project. Additionally, key aspects of the usual right-of-way lease and stipulations, such as designs, work plans and schedules are thoroughly discussed.

Once the SPCO officially receives the right-of-way application, the Special Projects section initiates a formal process of adjudication and analysis. This process includes issuing a 60-day public notice of the application, researching and drafting the Commissioner's Analysis and Proposed Decision, and drafting the right-of-way lease and stipulations. During this time, the Special Projects section also coordinates negotiations of the draft lease with the applicant. Once the proposed analysis and a draft lease have been finalized, a second 30-day public notice is issued soliciting comments on those documents. Comments received during the public review period are considered in the Commissioner's Final Decision. If the applicant has met all the requirements and the DNR Commissioner determines that the potential lessee is "fit, willing and able" to construct, operate, maintain and eventually terminate the pipeline, then the Commissioner may issue a lease.

Agency Coordination

Coordination with other agencies is a key responsibility of the SPCO and is handled by the Special Projects team for all new projects. Most large pipeline projects require additional permits from other state agencies; accordingly, it is important that the permitting process for a project be as efficient as possible. The SPCO ensures that agencies with permitting authority for the project are brought in early to meet with the applicant and are given ample information and time to review each project. Requests for additional information from agencies are coordinated through the SPCO in order to reduce redundancy and keep pace with project timelines. The SPCO is primarily a land management office; however, its statutory authorities cover a variety of public interests, such as technical designs and aquatic and biotic resources. The SPCO relies on its coordinate agencies, as the experts in their respective fields, to review project documents and to contribute to the SPCO's analysis, lease and stipulation drafting processes. This coordination and consistent communication have proven instrumental in fulfilling both the state permitting requirements and the applicant's project needs.

Lease Negotiation

The SPCO drafts the Commissioner's Analysis and Proposed Decision, the lease and stipulations. An initial draft is given to the applicant for its review and response. In general, the body of the lease has proven to be a tried-and-true instrument of the state in granting specific rights for the purposes of constructing, operating, maintaining and terminating common carrier pipelines. The stipulations, which are an appendix of the lease, contain project specific mitigations that are often the subject of detailed negotiations.

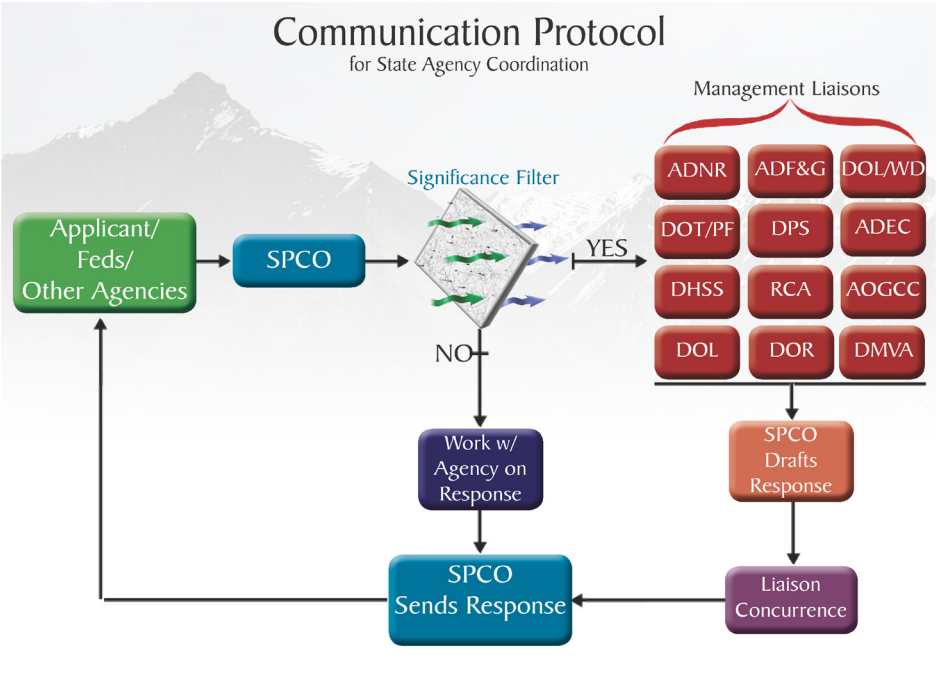
Issuing Leases

Once a final lease has been agreed upon and all reviews and comment periods have been completed, the applicant and DNR Commissioner both sign the lease. The Special Projects team continues to work with the project proponent – now as a lessee – until all of the required documentation for initiating construction is submitted and approved by the SPCO. Once construction begins, the Special Projects section turns the lease over to SPCO Compliance section representatives, who work closely with the lessee during construction and maintain the SPCO field relationship with the lessee, and to the SPCO ROW group, that manages additional permitting requirements, required contacts and payments under the lease.

SPCO COMMUNICATION PROTOCOL

State agencies and their subject matter experts play major roles in pipeline project review. The SPCO coordinates the participation of state agencies in the review process. This review process developed informally over several years, since there were long periods with no new lease activity, but in FY11 the SPCO formalized the communication protocol for state agencies.

The lack of a well-defined process prior to FY11 resulted in some project proponents and federal agencies independently soliciting information and input directly from various levels within a department. The new protocol ensures that management is well informed, agency input is timely and can be tracked, and all parties receive regular and relevant project status updates.



The above diagram represents the SPCO-managed flow of information between pipeline right-of-way applicants and State of Alaska agencies.

Today, with multiple gas pipeline proposals, a proposal for a new pipeline route for existing Cook Inlet production and several new pipelines under review on the North Slope, there are numerous pipelines in various stages of the lease pre-application and application processes.

The SPCO requested that the commissioner for each agency with a role in pipeline permitting and oversight designate a "management liaison" to represent the commissioner's office. These positions have become the focal point to help disseminate important documents, review key positions and policy decisions and ensure that the right people get the information they need to make informed decisions.

The SPCO will continue to allocate the necessary resources to ensure that coordination efforts are successful. With multiple potential pipelines under discussion or review at the SPCO, it is more important than ever that the State of Alaska maintain a clear protocol for pipeline project management to make certain that affected departments and agencies are kept current on significant issues.

SPCO LIAISONS

Alaska Department of Environmental Conservation

The mission of the Alaska Department of Environmental Conservation (ADEC) is to conserve, improve and protect Alaska's natural resources and environment and to enhance the health, safety, economic and social well-being of Alaskans. As a SPCO liaison agency and a participating member of the Joint Pipeline Office, the ADEC strives to accomplish its mission through implementing state statutes and regulations governing jurisdictional pipelines and facilities throughout Alaska.

ADEC representatives conduct an inspection of oil spill response equipment at the Trans-Alaska Pipeline Yukon Response Base.

Three full-time ADEC employees are located in the SPCO. The designated liaison provides technical and policy advice and overall coordination of ADEC efforts within the SPCO; the other two are environmental specialists and focus primarily on oil spill prevention and response readiness.

The ADEC liaison provides coordination and policy guidance for implementing the requirements of ADEC's air quality, water, environmental health and contaminated sites divisions. The ADEC divisions oversee wastewater and solid waste operations and permits, air and water quality permits and management of contaminated sites. The ADEC liaison is a member of the Joint Pipeline Office management team and works with JPO and SPCO staff to ensure that authorizations and permits are consistent with ADEC statutes and regulations.

The ADEC environmental program specialists focus exclusively on oil discharge prevention and contingency plan (C-plan) requirements for the Trans-Alaska Pipeline System (TAPS) and Valdez Marine Terminal (VMT). The ADEC Spill Prevention and Response Division's industry preparedness program requires comprehensive review and approval of TAPS and VMT C-plans every five years.

C-plan activity oversight involves inspecting facility and response equipment, auditing records and conducting and evaluating oil spill response exercises. ADEC's prevention regulations provide for direct oversight of facility piping, crude oil storage tanks, secondary containment and the TAPS mainline. The SPCO engineers, along with licensed professional engineers in ADEC's industry preparedness program, provide continuous support to the environmental program specialists for technical analysis of compliance with prevention regulations.

Alaska Department of Fish & Game

The Alaska Department of Fish & Game (ADF&G) liaison acts primarily as a staff assistant to the director of the Habitat Division. The liaison's duties were expanded in 2010; in addition to managing ADF&G issues related to TAPS, the redefined position also serves as the ADF&G lead on a proposed gas line to the Donlin Gold mine site and the ADF&G liaison to the Petroleum Systems Integrity Office (PSIO). ADF&G administers the fish habitat permit program under Alaska Statutes 16.05.841 and 16.05.871, which includes issuing fish habitat and special area permits, commenting on other agency permits, conducting compliance inspections (using SPCO surveillance procedures) and, when necessary, taking enforcement actions.

The ADF&G liaison's mission is to ensure that pipeline activities avoid or mitigate foreseeable impacts to fish and wildlife resources, habitats and public use of fish and wildlife.

The liaison works with state and federal agencies, Donlin Gold, LLC, and Alyeska Pipeline Service Co. to review and provide input on design criteria, project plans, schedules, procedures, manuals, technical specifications, drawings, facility site selection, alignments and restoration or mitigation proposals pertaining to pipeline-related work, including:

- Pipeline pre-construction
- Construction
- Operation
- Maintenance
- Termination activities

The ADF&G liaison serves on the JPO management team, provides environmental comments for authorization requests under the state TAPS lease and federal grant, reviews TAPS and VMT oil spill contingency plans, participates in oil spill response events and drills and prepares surveillance reports and assessments that document the lessee's compliance with environmental and other lease and federal grant stipulations.

Lee McKinley, the ADF&G liaison to the SPCO (second from left), confers with work crew members and other agency staff at a TAPS project site.

Alaska Department of Labor and Workforce Development

The Alaska Department of Labor and Workforce Development (DOLWD) is represented within the SPCO by a safety liaison and electrical inspector; both positions focus primarily on TAPS.

Ray Elleven conducts a worksite safety inspection at TAPS Pump Station 7.

The DOLWD safety liaison serves as the SPCO program manager for worker safety and DOLWD technical and policy objectives. He conducts annual safety inspections of TAPS work sites and facilities, reviews project safety plans, monitors APSC accident statistics and represents DOLWD on the JPO management team. He also serves as the SPCO safety manager and facilitates staff safety training.

The DOLWD electrical inspector liaison and licensed Alaska electrical administrator serves as the SPCO electrical safety program manager. He spends most of his time conducting routine and random inspections of TAPS facilities to ensure compliance with Alaska's electrical codes and licensing requirements. The DOLWD electrical inspector has the legal authority, established by Alaska statutes and administrative codes (see SPCO website for detailed information), to enforce the National Electrical Code (NEC), State electrical codes and licensing requirements on behalf of the SPCO and the JPO.

The liaison is a member of the International Association of Electrical Inspectors (IAEI). He attends meetings and training sessions hosted by IAEI and other continuing education training on NEC requirements, and he maintains a journeyman electrician license.

Alaska Department of Public Safety, Division of Fire and Life Safety, State Fire Marshal's Office

The duties of the State Fire Marshal's Office (SFMO) liaison to the SPCO include (but are not limited to) annual fire inspections, constructions and building inspections, building and fire system plan reviews, code interpretations, assisting in fire investigations and incident reports, investigation of incident reports and fire system failures.

The liaison conducts inspections of all oil and gas process and production facilities on a state-wide basis; this includes 18 common carrier lines, offshore platforms, gas process facilities, refineries, all Cook Inlet producers, all North Slope producers and TAPS. The liaison coordinates his activities with the Division of Fire and Life Safety directors office and the Plan Review Bureau.

SPCO Fire Marshal liaison John Cawthon conducts a fire and life safety inspection at the Valdez Marine Terminal.

After conducting an inspection, the liaison prepares reports detailing any code violations found and corrective action required. He establishes correction compliance dates and conducts follow up inspections until all deficiencies have been corrected or address as required by current codes.

The SFMO liaison represents the Division of Fire and Life Safety at JPO and SPCO meetings, conferences and working groups at the direction of the State Fire Marshal. He assists the JPO in the development of fire prevention programs for TAPS facilities and operations. He also provides training and technical assistance to SPCO and JPO staff and TAPS owners and operators regarding state fire and safety laws regulations and requirements.

JOINT PIPELINE OFFICE

Mission Statement: To work proactively with Alaska's oil and gas industry to safely operate, protect the environment and continue transporting oil and gas in compliance with legal requirements.

The State/Federal Joint Pipeline Office (JPO) was created in 1990 to facilitate coordination between state and federal agencies in monitoring TAPS and a proposed pipeline project to commercialize North Slope gas.

Since its inception, the scope of the JPO has increased to include petroleum and natural gas pipelines within the State of Alaska and the adjoining Outer Continental Shelf under the respective authorities or jurisdiction of one or more participating agencies.

The JPO is composed of representatives from the following agencies:

State Agencies

Department of Environmental Conservation

Department of Fish and Game

Department of Labor and Workforce Development

Department of Natural Resources: State Pipeline Coordinator's Office

Department of Public Safety: Division of Fire and Life Safety

Department of Transportation and Public Facilities

Federal Agencies

Department of Defense: Army Corps of Engineers

Department of the Interior
- Bureau of Land Management, Office of Pipeline Monitoring
- Bureau of Ocean Energy Management, Regulation and Enforcement

Department of Homeland Security
- Transportation Security Administration
- U.S. Coast Guard

Department of Transportation: Pipeline and Hazardous Materials Safety Administration

Environmental Protection Agency

JPO cooperating agencies share the desire to maintain a system-wide approach to pipeline oversight. The JPO Executive Council Agreement is available online at www.dnr.alaska.gov/commis/pco. Each agency has a unique mission; however, the participating agencies collectively focus their resources on oversight activities that facilitate the safe and reliable transportation of oil and gas to market. Administratively, the lead federal agency of the JPO is the Bureau of Land Management

(BLM), represented by the Office of Pipeline Monitoring. The lead state agency of the JPO is the Department of Natural Resources, represented by the State Pipeline Coordinator's Office.

The JPO was formed to provide better service to the public and industry by eliminating duplication of efforts; coordinating activities; improving communication between agencies, industry and the public; sharing expenses and streamlining the permitting process. While all agencies retain their individual authorities, through the JPO they collaborate on administrative, technical and regulatory issues regarding jurisdictional oil and gas infrastructure. The terms of these collaborative efforts are described in the Operating Agreement for the Joint Pipeline Office, available online at www.dnr.alaska.gov/commis/pco.

TRANS-ALASKA PIPELINE SYSTEM (TAPS)

Atlantic Richfield Co. and Exxon discovered the Prudhoe Bay oil field in March of 1968. The owner companies operating at Prudhoe Bay established Alyeska Pipeline Service Co. (APSC) in 1970 to build and operate TAPS. The State of Alaska and APSC entered into a right-of-way agreement on May 3, 1974; the lease was renewed in November of 2002. See Appendix D for more acreage, survey and lease information.

In 1977, construction of TAPS was completed and major oil production began on the North Slope. TAPS is composed of an 800-mile, 48-inch diameter pipeline, the Valdez Marine Terminal (VMT), 11 pump stations (original plans specified 12 pump stations, but only 11 were constructed) and various support facilities.

The State right-of-way lease applies to the 344 miles of state-owned land in the TAPS right-of-way. Information about the TAPS right-of-way lease appraisal can be found in Appendix E: Pipeline Right-of-Way Lease Appraisal Information.

Approximately 376 miles of federal lands and 80 miles of private lands (including Native corporation and Native allotment lands) account for the remainder of the 800-mile pipeline. APSC owns 8.2 miles of the TAPS right-of-way, primarily consisting of lands associated with the VMT and pump station (PS) 1, PS8 and PS9.

North Slope crude oil enters TAPS at PS1 in Prudhoe Bay. TAPS crosses three major mountain ranges before reaching its terminus in Valdez. Three of the four active pump stations (PS1, PS3 and PS4) maintain the necessary pressure to pump crude oil over Atigun Pass, the highest elevation point along TAPS at an altitude of 4,739 feet (the elevation at PS1 is 22 feet above sea level). PS5 provides pressure relief as crude oil descends south of Atigun Pass.

APSC placed PS7 in warm standby mode in 2007. The fourth active pump station, PS9, provides pressure to push the crude oil over the Alaska Range and Thompson Pass and complete its passage to the VMT.

TAPS was built with 177 valves to isolate sections of the pipeline and minimize the size of a spill in the event of a pipeline rupture. The valves are placed to limit the amount of a spill, at any point along the pipeline, to a maximum of 50,000 barrels from static drain down. Valves are placed at major river crossings and other locations where a quick response would be critical in a spill event.

The VMT is the TAPS terminus. The VMT spans approximately 1,000 acres along Prince William Sound near the Port of Valdez. Oil is loaded on tankers at the VMT for shipment. The VMT has a vapor recovery system for the crude-oil storage and relief tanks, a powerhouse, support facilities, crude storage, tanker berths, crude-oil handling systems and metering facilities.

Throughput in TAPS peaked at more than two million barrels of oil per day (bopd) in 1988. The subsequent decline in flow rate triggered a re-evaluation of operating conditions by APSC and the TAPS owners. APSC provided conceptual modifications in the Final Environmental Impact Statement for the TAPS right-of-way lease renewal in 2002; a conceptual engineering review was developed in 2003. The lessees approved changes to the pump station configurations, referred to as *strategic reconfiguration*.

TAPS STRATEGIC RECONFIGURATION/ELECTRIFICATION AND AUTOMATION

Alyeska Pipeline Service Co. completed strategic reconfiguration (SR) facilities at PS3, PS4 and PS9 during 2005-2008. Past strategic reconfiguration projects involved installing new pumps, variable frequency drives, electrical motors and either turbine generators (PS3 and PS4) or connections to a commercial electrical grid (PS9).

During FY13, APSC continued work on the final phase of SR at PS1. This phase of SR is now referred to as the electrification and automation project (EA).

APSC originally started work at PS1 in the 2000s, but shut down efforts for several years. It restarted work during FY11. APSC installed most of the equipment and new modules during the initial work efforts; the primary project work in FY11, FY12 and FY13 has involved cable pulling, which needs to be completed prior to initiating other work. The EA project appears to be proceeding according to plan and the targets for cable pulls have been met or exceeded.

The major elements of the EA/SR project include:

1. Three new mainline pumps
2. Three new variable-frequency drives, used for controlling pump speed
3. Three new electrical motors, to drive the new mainline pumps
4. One new Siemens 12mW turbine generator for electrical power
5. One new 5mW turbine generator for electrical power
6. One backup 19.2 mV power line and substation connecting PS1 to the Prudhoe Bay power grid
7. Modification of two of three existing booster pumps for electrical service

APSC forecasts completion of the PS1 EA project to occur in the summer of 2014.

AUFEIS

Aufeis, also known as icings, is a sheet-like mass of layered ice that freezes and accumulates along stream banks or floodplains. The formation results from increased hydrostatic pressure of flowing water behind ice dams, anchor ice or ground water. As confined water pressure builds, icing mounds may form and crack, forcing the release of pressurized water to the surface. Thermal contraction cracking can also facilitate the release of sub-ice water to the surface, which freezes and consequently forms a new layer of ice. This continued process forms ice laminations that increase the thickness of the ice with each successive flow of water creating accumulations that can range from centimeters to several meters thick. Aufeis accumulations generally melt during the summer months and typically reoccur in the same locations every year; however, the timing and the extent of ice accumulation can change with changes in seasonal weather and water. There are several factors that can contribute to an increase or decrease in the accumulation of ice, such as air temperature, river or stream water levels and the amount of groundwater in permafrost confined aquifers.

Left: Aufeis remediation at PLMP 197.
Right: Aufeis buildup around a vertical support member prior to remediation

Along the Trans-Alaska Pipeline System, aufeis occurs in numerous locations every year. During high-ice accumulation years there are several locations along TAPS that can be at risk. Damage due to the encapsulation and jacking of the pipe or lateral stresses on vertical support members and bents imposed by large ice accumulations is a concern. Aufeis is an arctic region hazard that has to be monitored and controlled with a remediation program.

APSC monitors all aufeis accumulations along TAPS throughout the winter and has procedures in place to remediate aufeis to ensure the integrity of the pipeline system is not compromised.

TAPS LOW FLOW/COLD WEATHER OPERATIONS/COLD RESTART

Approximately half of TAPS is above ground and exposed to arctic weather conditions. The cool-down rate of this segment is higher than the buried sections. Oil is found naturally with water and gas in North Slope reservoirs. Processing plants remove the majority of produced water; a small but significant fraction remains. Under normal operating modes, water and sediment can comprise up to 0.35 percent of the oil delivered to PS1; however, in recent years the North Slope oil fields have averaged water contents below this limit. Water segregation within TAPS or upsets in oil processing plants on the North Slope can create pulses of oil with higher water contents.

The original TAPS specifications allowed for up to 0.25 percent water and 0.25 percent sediment. The TAPS owners later changed this limit to 0.35 percent basic (or bottoms) sediment and water (BS&W), which are the non-hydrocarbons produced with oil and gas. Sediments make up a very small proportion of the BS&W. Since the 2006 low-flow event (see page 25) North Slope operators have worked to reduce water in TAPS. Reports indicate that the average BS&W in TAPS is typically in the range of 0.10 to 0.21 percent. In addition, operators reduced the magnitude and number of excursion events. These events do not result in the production of pure water, but typically oil/water mix with 0.35 to 2.5 percent water. Although field operators have made modifications to their processing facilities, these improvements appear mainly to be the result of tighter process tolerances and improved operational discipline.

During winter, with lower flow rates in TAPS, fluids might cool to a point where water can form into ice within the mainline, pump station piping, equipment, instrumentation, connections and other areas. Bulk paraffin can create similar issues. Low production rates could also occur if one or more plant, shipping or tanker loading upsets disrupts flow during a period equal to the TAPS transit time. Ice can damage pump impellers, plug screens, bind equipment surfaces, plug instrumentation, coat sensors and stop flow in other ways.

Within the past decade, TAPS has experienced three low-flow events caused by mechanical problems or tanker loading delays:

The lowest internal temperatures dipped to 37°F

Temperatures bottomed below 40°F

The lowest internal temperatures were reduced to 26°F

None of these incidents was serious enough to prevent restart of TAPS; however, longer shutdowns or lower flows might result in severe operational difficulties. Concern about cold weather operations, cold restart and ice formation has grown over the past two decades.

Primary Low Flow Issues

The heat-transfer analysis submitted for the original TAPS design basis reveals that TAPS has always been susceptible to cold temperature problems from TAPS or North Slope upsets; however, throughput decline during the past two decades has resulted in increased operational risks. Typical flow rates during the last winter ranged from 500,000-550,000 bopd. Reduced throughput has removed contingency thermal reserves and increased the probability that winter upsets could produce an extended shutdown.

Principal winter operational risks that TAPS will face with lower throughput include:

Ice Formation
Free or fixed ice has the potential to create problems, such as disabled instrumentation, plugged pump screens, frozen valves and damaged pump impellers.

Wax
Deposition of paraffins and asphaltenes is predicted to increase as fluid temperatures in the pipeline drop.

Pigging
The reduced velocity of maintenance pigs may decrease the efficacy of cleaning the pipe walls. A larger number of pigs in the pipeline at any time add operational concerns.

Water Dropout
Oil and water will start separating more readily as flow decreases.

Geotechnical
Segregation of water and a transition in flow regime from turbulent to laminar flow may increase internal corrosion, especially at the bottom of the pipe.

Cold Restart and Cold-Weather Operations Procedures
Based upon wintertime conditions, APSC is now capable of implementing operating procedures for one of three operating modes:

1. **Normal Operations.**

1. **Cold-Weather Operations.** When internal temperatures drop below 40°F, APSC can optionally implement contingency operational procedures that will increase the temperature of the oil. This operating regime is for flowing conditions with temporary low-temperature excursions with or without short-duration shutdowns or slowdowns. APSC does not have to implement these operating procedures for all of TAPS. It can do so for one or more segments of the pipeline and have the rest remain in normal operating mode.

2. **Cold Restart.** APSC will implement these procedures under more severe conditions, after internal temperatures have dropped well below normal operating range and if flow in the mainline has been stopped for extended durations. This operating regime is for a static flow situation or for an extended shutdown in winter. Measures may involve additional heating, contingencies such as pumping fluid both north and south in the mainline to reduce oil gel strength, removing ice and wax accumulations and restarting the pipeline with ice and thick crude oil.

Recycling Fluid to Add Heat

After the January 2011 incident, APSC started additional recycling of oil around pump stations. APSC now recycles oil at PS3, PS4, PS7 and PS9. APSC monitors mainline temperatures and adjusts the amount of recycling at each pump station according to mainline fluid temperatures and weather.

TAPS recycling involves pumping some or all of the TAPS flow through station piping and one or more pressure-reducing valves. Pumps add energy to the fluid, and the pressure drop converts some of the flow energy to heat. The oil, after recirculating through the pump stations, flows down the mainline. This is an effective method to raise oil temperature.

Cold-Weather Operations Projects

None of the four stations listed above had originally been designed to operate in the recirculation mode. At PS4, a strategic reconfiguration facility, APSC replaced the standard valve, meant mostly for fully open/fully closed operation, with a drag valve. Drag valves are a type of control valve, sometimes called cage valve. They are intended to operate continuously in a partially-open mode.

APSC made more extensive modifications at PS7, a legacy pump station. APSC operates this station only during the winter for recirculation purposes. Its original purpose was to push oil south in the mainline. In its current mode, PS7 circulates a slipstream of oil from the mainline and pushes it through two partially closed valves to increase its temperature. Improvements made at PS7 address the following issues:

1. MLU-1 suction and discharge block valves had to be used as throttling valves, causing vibration and wear.

2. Certain system components required manual control and increased staffing.

3. APSC disconnected some ancillary systems (such as the oil sump) when PS7 had been converted to warm stand-by status and these had to be operated manually.

APSC had originally attempted to replace the block valve with a flow diffuser. The main part of a diffuser is an inner basket with multiple small holes. This modification was intended to increase recycle rates and consequently add more heat. The installation, however, experienced flow-induced vibrations.

Currently, all four recycle stations (PS3, PS4, PS7 and PS9) are fully operational.

At the beginning of the fiscal year, APSC canceled a proposed turbine heat recovery project at PS4. APSC had previously canceled a similar project at PS3. These projects would have used the waste heat in the turbine exhaust to heat crude in the mainline. In place of these, APSC is pursuing a project to add an indirect line heater at PS5. APSC is also investigating more heaters, emulsifiers, freeze-depressants, water-removal, insulation projects and other technical changes to TAPS.

COLD RESTART PROJECTS

APSC in FY13 replaced the engine that powers the cold-restart pump at PS12. The original pump did not meet air quality permitting requirements. During this year, APSC continued to work on site support, automation and communications. These changes should improve reliability and availability.

Refinery Heat
The energy increases from three refineries is a combination of residuum volume and temperature. Two of the refineries have had either stable contributions or increased outputs. By far the largest contributor is Flint Hills, and its rates and the residuum temperature have dropped in recent years, resulting in less heat added at North Pole. The Flint Hills refinery implemented an energy savings project and closed two of three process trains. During the past year, APSC successfully negotiated an agreement for the refinery to contribute more heat to TAPS.

Risk Mitigation
The four fundamental approaches for reducing risks of wintertime operations are:

1. Change the effects or characteristics of the ice by injecting additives such as freeze-depressants or emulsifiers

2. Reduce the amount of ice by reducing the amount of water in the fluid

3. Increase the temperature of the fluid

4. Increase production rates from old fields and introduce oil from new fields

APSC appears to be concentrating on the option of water removal. This could involve something as simple as a large tank at PS1 that allows water to settle to the bottom, where it can be drained. Reduction of water and sediment content below the current standard might reduce problems caused by ice formation.

The company has moved its ice studies from Sarnia, Ontario, to the University of Oklahoma. Very few facilities have the capability of performing flowing ice studies of hydrocarbon mixtures. The studies are set to resume during 2013/2014. The primary focus of this set of investigations is to characterize the rate and volume of ice formation at various water concentrations and the conditions under which ice forms.

Low Flow Study
In June 2011, APSC issued an updated TAPS Low-Flow Impact Study (LoFIS) study. APSC initiated the work after a low-flow/low-temperature event in November of 2006. Among other conclusions, the study identified problems at throughput volumes between 300,000 and 550,000 bopd. Although other studies were released into the public domain, APSC appears to be working toward solutions utilizing the LoFIS study as a guide.

In addition to the major issues described elsewhere, these studies, as a group, identified a number of detailed issues. Among the long-range operational challenges are:

- Internal water accumulations and "debris clouds" at pipeline low points and in front of pipeline pigs
- Transition of the primary flow regime from turbulent to laminar
- Additional corrosion caused by segregation of water
- Increased ILI risks with lower flow velocities, increased wax accumulations and longer transit times
- Reduced efficacy or dispersion of internal corrosion chemical treatments at lower flows
- Cold restart issues and increased oil shear values created by the increased percentage of heavier residuum in the southern pipeline segment and consequent increased gel strengths
- Crude heaters and their effects, especially on the generation of wax
- Ability to reliably operate and manage large numbers of crude heaters
- Performance of the leak detection system at low flow rates
- Locations of water accumulate during pipeline shutdowns or slowdowns

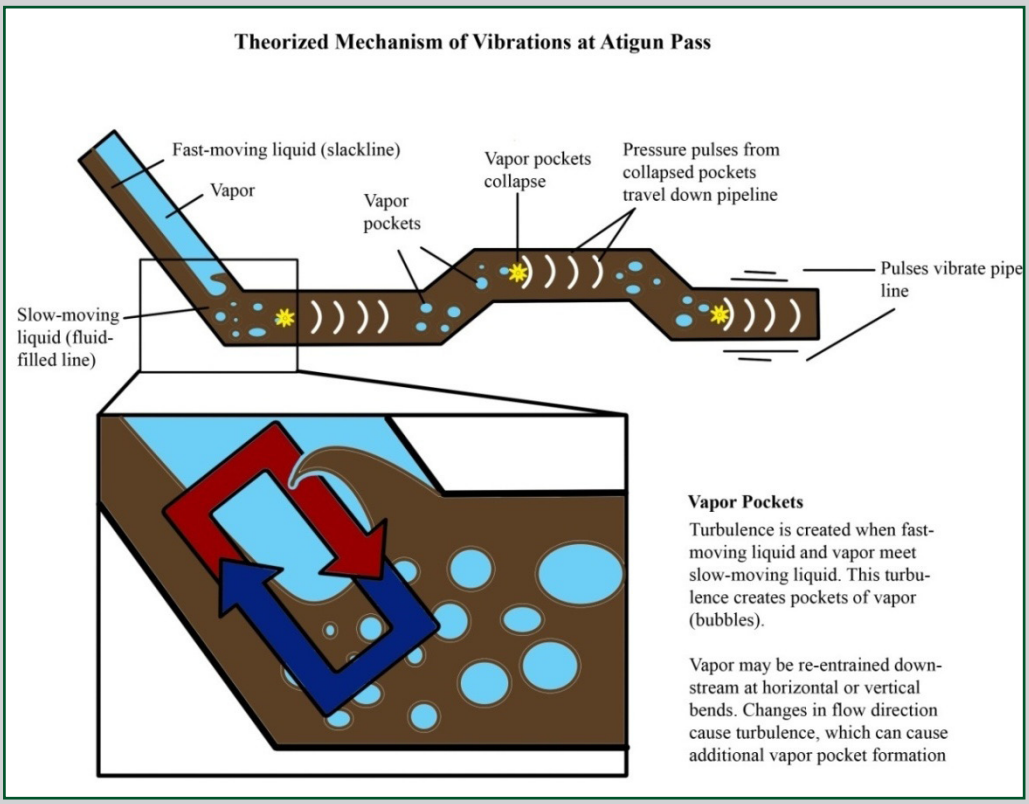
Cold restart project with new diesel engine and pump staged at TAPS Pump Station 12.

- The potential of accumulations of ice during winter shutdowns, including resultant pigging problems
- The ability to run maintenance pigs at low velocities
- Operation of instrumentation and equipment under conditions of increased wax deposition
- Operationally managing increased numbers of pipeline pigs
- Accuracy of ILI in slackline areas
- Operational unknowns caused by low throughput excursions, pipeline slowdowns and shutdowns when the throughput is already low
- Operational unknowns resulting from multiple smaller shutdowns or slowdowns
- The composition of future crude oil, including heavy and viscous oil

TAPS VIBRATIONS IN THOMPSON, ATIGUN AND ISABEL PASSES

TAPS reaches its highest point in Atigun Pass, where the elevation of the pipeline is 4,739 feet. The second highest is at Isabel Pass, in the Alaska Range, at 3,420 feet. The third is at Thompson Pass, north of Valdez, at 2,812 feet. Observers have reported vibrations on the south side of each mountain pass.

Oil in TAPS gains energy as it drops in elevation, trading the potential energy of higher elevations for kinetic energy and pressure at lower elevations. As it speeds up on the downhill slope, oil flow creates a slackline condition, where both liquid and gas fill the pipe cross-section. Where the fast-moving liquid hits the fully filled section below, some of the fluid momentum dissipates, potentially causing vibrations. The following illustrates the presumed cause:



Thompson Pass started to experience vibrations large enough to require mitigation during the 1990s. APSC raised fluid level in the mainline at the bottom of the pass, reducing free-fall elevation and fluid impact energy. Vibrations at Atigun are smaller than those at Thompson Pass, and vibrations at Isabel are smaller than at Atigun. Observers reported vibrations south of all three passes during the low-flow event in 1995, and following a temporary shutdown of half of the Prudhoe field in 2006.

APSC installed a backpressure control system south of Thompson Pass approximately 15 years ago. It appears to be successfully mitigating the problem. Reports of vibrations south of Isabel Pass have been growing, but vibrations there are still intermittent and less severe than at the other sites. Consequently, for the past several years, the focus of vibration mitigation on the mainline has been at Atigun Pass.

APSC contracted with a vibration engineering company to evaluate the mainline pipe at Atigun. The consultant instrumented a section of pipe and concluded that there was still a significant factor of safety in the combined stresses (tri-axial plus cumulative fatigue). Therefore, the focus on vibrations has been on the pipeline supports.

During the past five years, APSC discovered cracks in a number of pipeline supports, called "shoes," in the Chandalar Shelf area of Atigun Pass. The cracks have appeared to be mostly in welds, sometimes propagating from welds to the base metal. The following photographs show a typical shoe and a typical metal-fatigue crack:

Shoe (left) and a fatigue crack (right) in the Atigun Pass area.

APSC now has a monitoring program in place that includes visually inspecting shoes in suspect areas on a regular basis. The monitoring program, when it discovers cracks, assesses the damage and responds with one of three actions:

1. Repair by grinding out the crack and filling with new weld metal
2. Replace the shoe with one of the new, stronger design
3. Monitor more minor cracks for signs of change

The contribution of pipe vibrations to these cracks is still being debated. APSC lists contributing factors as the geometry of the welds and the type of fillet welds. Fillet welds are inherently less strong than full or partial penetration welds; however, recently replaced shoes developed cracks. Consequently, APSC has developed a stronger design, modified with the addition of a stiffener plate and more welding. A consultant performed a finite-element analysis on the redesign, which is a detailed mathematical analysis that divides a shape into numerous elements for calculation, allowing an analyst to prepare a highly-detailed stress map.

The SPCO will continue monitoring the situation at the three mountain passes as throughput changes. During the past year, engineering and compliance groups visited the sites. The original TAPS design has built-in redundancies, such as safety factors and the allowance for limited support failure. APSC has concluded that the vibrations in these areas do not appear to constitute an integrity threat in the near future.

YUKON RIVER LANDSLIDE

A landslide is the downward sliding of a mass of material down a slope as a consequence of a soil failure. These failures can occur as a result of a number of causes. Examples are undercutting by streams or rivers, reduced shearing resistance brought on by a loss of soil cohesion (generally due to oversaturation, loading, weathering and freeze thaw cycles), or a combination of these conditions. This process usually occurs over time, eventually leading to generally rapid downslope movement of material. Seismic shocks can cause landslides to occur in short periods of time or immediate failure events, depending on the stability of soils or bedrock and degree of shaking.

A landslide occurred during the winter of 2012 on the southwest side of the Yukon River Bridge crossing at mile 56 of the Dalton highway. The total landslide area is approximately 230 feet wide and 450 feet long. Blocks in the slide were up to 20 feet thick, 30 feet wide and 100 feet long. The initial scarp created varied between 40 and 50 feet high.

The cause for this slope failure is being assessed by Alaska Department of Transportation & Public Facilities along with Alyeska Pipeline Service Company. The preliminary investigation involved drilling a pair of 151-foot test holes on the south end of the Yukon River Bridge to determine the sediment and rock lithology. The initial stages of this investigation have included installation of instrumentation to continuously measure ground temperature and an inclinometer to monitor any changes in slope angle. A future drill hole study is planned to determine what measures, if any, need to be taken to ensure long term slope stabilization.

TAPS THROUGHPUT AND RELIABILITY

APSC issues reports on reliability for each month and for each calendar year. Availability is the percentage of time that an item is available when it is needed for service. Reliability is the probability that an item or system will function correctly when needed, as measured over a reporting period.

During FY13, the SPCO counted 34 unplanned shutdowns or slowdowns. This compares to 41 the previous fiscal year. The cumulative time outage for FY13 increased to 34 hours and 12 minutes. The prior year's total was 26 hours, 8 minutes.

The average duration of each event was 51 minutes. The longest unplanned shutdown, 8 hours and 1 minute, was created by a commercial power outage at PS9.
TAPS average availability was 99.6 percent for the fiscal year. This nominally was the same as the previous year. During FY2012, the availability was 99.7 percent. For comparison, the historical average for the legacy pump stations (operating in the decade prior to Strategic Reconfiguration) was 99.97 percent.

The Strategic Reconfiguration design basis specifies a minimum 99 percent system availability. TAPS achieved this requirement over the fiscal year and in 10 of the 12 months. The shortfalls during those months were not significant.

APSC reports total throughput by calendar year, not fiscal year. In 2012, throughput averaged 547,866 bopd. This represents a 6.3 percent reduction from the 2011 average.

The 2011 reporting period included the January 2011 PS1 leak and low-temperature incident, which resulted in two unplanned, long-duration shutdowns of TAPS, the longest being 84 hours.

ROCK GLACIERS

Rock glaciers are large, tongue-shaped masses of angular debris and soil with ice filling pore spaces below the surface, fed by rock and erosional debris, commonly found at the bottom of glacially abandoned bowl shaped valleys. The rate of downslope movement of rock glaciers can vary from centimeters to meters per year, depending on the composition of material, water and ice content and seasonal temperature. Recent research indicates that permafrost degradation might act as an accelerant. Stephen Capps, in a 1910 article in the Journal of Geology, "Rock Glaciers in Alaska," originally described them and defined them as a new landform. During the past century, the USGS, DGGS and international geological agencies have researched these types of landforms.

There are multiple rock glaciers with varying states of activity along the TAPS corridor in the Brooks Range. The rates of travel of some have them have increased. Most notable are ones in the area around Dalton Highway milepost 229. The Alaska Department of Transportation & Public Facilities has provided financial and technical support to monitor and inventory these slope features. The consensus is that, in the short term, these rock glaciers pose no threat to TAPS. The highway in this area is between the rock glaciers and the pipeline, so a remedy for the road will have to be found and implemented prior to one being needed for TAPS.
Rock glaciers have caused maintenance issues for culverts along the Dalton Highway. ADOT&PF is investigating several alternative solutions. One possible short-term remedy, now in the conceptual/planning phase, is a project to realign the Dalton Highway to the west at milepost 229.

TAPS PIGGING

Most operators of long distance, crude oil transmission pipelines utilize maintenance pigs to clean the inside surface of the pipe. Without cleaning pigs, deposits accumulate on the inner wall, constricting the flow until hydraulic losses between pumps exceeds the maximum allowable operating pressure, forcing the operator to either reduce flow or shut down.

APSC uses different types of pigs for various purposes; it runs cleaning pigs regularly and every three years runs an In-Line Inspection (ILI) device, also known as a smart pig. During the last fiscal year, APSC used a Vectra Magnetic Flux (MFL) ILI tool. This is combination tool, with both a smart pig to measure remaining wall thickness and an inertial guidance pig (similar to a Geopig®) to assess the centerline pipe position. Both are important integrity indicators. One finds corrosion defects and some other potential problems; the other finds movements such as heave or subsidence.

A previous Joint Pipeline Office agreement specified that the ILI be completed no later than 2012. Under Gov. Letter No. 26367, APSC applied to USDOT/PHMSA to defer the ILI because a more advanced tool would not be available until 2013. The manufacturer claimed that it could read remaining metal in locations with extra thickness, such as sleeves or supports. Under Gov. Letter No. 26699, USDOT/PHMSA approved the schedule change. At the time of this report, the SPCO knows that the ILI run did not find any conditions requiring immediate remediation, but a more detailed analysis will be available in FY14 (data analysis from a major ILI run can take several months).

Lowered throughput has made maintenance pigging both more important to the operations of TAPS and more problematic. The optimal velocity range for pigs traveling in oil pipelines is generally considered to be two to seven miles per hour. Flow in TAPS has reached the point where pigs travel at speeds near the bottom of this range or below. Slow travel speeds mean that three pigs are often in the pipeline at the same time. In June 2013, for the first time, four pigs were simultaneously running in TAPS.

In response to these changes, APSC is making changes to its maintenance pigging program. It has made changes to pigs and the frequency of pigging and is planning to build a pig launcher and receiver at PS9 in 2014 (PHMSA's Notice of Proposed Safety Order CPF No. 5-2011-5001S listed the need for an additional launcher and receiver between PS5 and PS10).

SPCO FY13 TAPS ACTIVITIES - LEASE COMPLIANCE

Throughout FY13, the SPCO conducted surveillances and reported on the condition of the TAPS right-of-way, facilities, maintenance activities and administrative protocols. The lease compliance section's FY13 TAPS activities yielded 44 surveillance reports, 16 lease compliance reports and three assessments (see Appendix G for a complete list of reports). Below are brief summaries of a few SPCO lease compliance activities along TAPS in FY13.

First Quarter FY13:
Right of Way Surveillance
The SPCO conducted an annual surveillance of the TAPS right-of-way in intervals between June and September 2012. During the surveillance, SPCO staff made visual observations of the workpad, the pipeline, the above-ground pipeline support structure and appurtenances (such as gates and signs). Lease compliance staff recorded observations made during the 2012 right-of-way surveillance and summarized its findings in five lease compliance reports; 13-SPCO-R-001, 13-SPCO-R-002, 13-SPCO-R-007, 13-SPCO-R-008 and 13-SPCO-R-010.

During the FY13 right-of-way surveillance, SPCO staff recorded conditions that appeared abnormal to SPCO staff. Some of the observations included isolated areas of ground cracking, sinking and erosion along the workpad; damaged insulation modules; Teflon pads that had become detached from the pipeline support shoe; floating support shoes and support shoes with excessive longitudinal shoe offset; abnormalities in the pipeline jacketing system; and damaged or missing appurtenances such as gates, signs and fencing. None of the conditions observed during the surveillance presented an immediate threat to human health and safety, the environment or pipeline integrity.

Following the FY13 right-of-way surveillance, lease compliance staff met with APSC to review the results. The SPCO determined that many of the observations did not meet APSC's reporting criteria, or were already recorded in APSC's maintenance work database. Based on the minor severity of the conditions observed, the SPCO found the right-of-way in a condition acceptable to the State Pipeline Coordinator.

The SPCO later utilized the information gathered during the FY13 surveillance in support of an assessment evaluating maintenance and the overall condition of the right-of-way. A complete description of the assessment may be found on page 41 of this report under the heading "Assessment of the TAPS Right-of-way and Work Pad." During the right-of-way surveillance and assessment, SPCO followed a methodology established in 2011. Applying a consistent methodology ensures that the surveillance can be repeated in the future, both to assess APSC's performance in correcting conditions previously observed and to perform a right-of-way maintenance trending analysis.

Second Quarter FY13:
Fuel Gas Line Valve Replacement

On October 14, 2012, SPCO staff traveled to the TAPS fuel gas line (FGL) to monitor project work to replace three manual valves; #5, #7 and #9. APSC executed project F802 to replace FGL valves that have aged beyond their useful life and to move the valve enclosures further from the Dalton Highway. The project entailed excavating the old valves, installing stopples and new piping to bypass the old valves, constructing new access workpads for the new valves and cleaning and abandoning-in-place the old upstream and downstream piping.

APSC replaced three of the eight FGL valves in 2012 and plans to replace the remaining valves in 2014. Construction of access pads to the new valve locations required amending the TAPS right-of-way lease, ADL 63574. The SPCO amended the right-of-way lease to include an additional 0.78 acres for the new valve locations, and will provide future amendments when appropriate.

While at valve #5, SPCO staff observed APSC applying a coating primer to flanges, welds and areas of new piping with damaged coating. Applying pipe coatings requires very specific atmospheric and pipe temperatures, so APSC performed the work under

temporary hooches. At the time of the visit, APSC was experiencing difficulty achieving the proper pipe temperature due to unseasonably cold weather and FGL operating temperatures that fall below the coating specifications.

The FGL at manual valve #9 before the bypass piping is installed (left), and the FGL at manual valve #5 with a coating primer applied to recent modifications (right).

SPCO requested and was provided with documentation to verify that pipeline coatings were properly applied and inspected. SPCO staff found all the documentation to be complete, indicating that inspectors had found the application of the coating acceptable.

During the site visit, SPCO observed APSC conducting project work in a manner compliant with the TAPS right-of-way lease. APSC staff demonstrated patience and ingenuity in confronting complications encountered while attempting to apply pipeline coating to the new and old FGL piping. SPCO staff completed four surveillance checklists with satisfactory findings and lease compliance report 13-SPCO-R-013 from the field visit.

Third Quarter FY13
Pump Station 7 Crude Heating

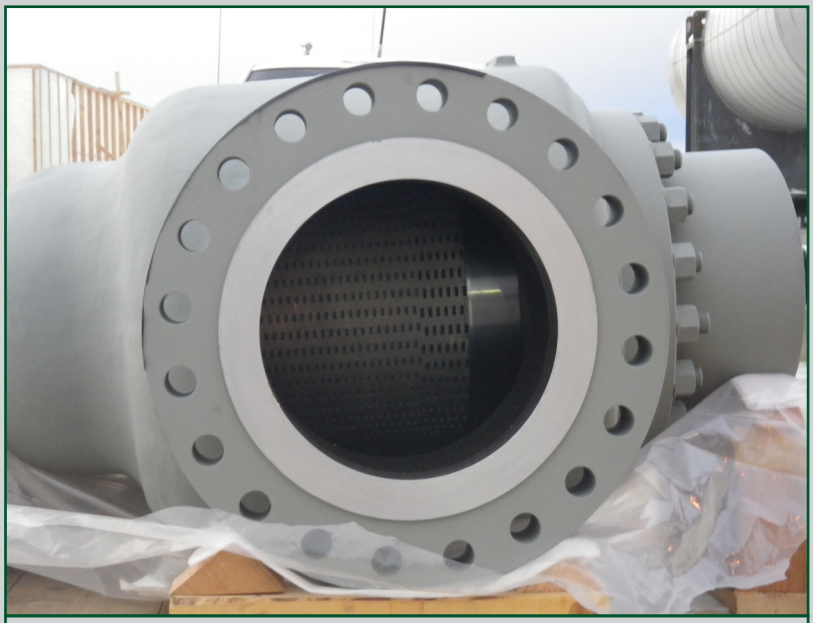
On January 17, 2013, SPCO issued lease compliance report 13-SPCO-R-018, documenting a SPCO site visit to PS7. The purpose of the trip was to monitor crude heating operations, also known as crude oil recycling. SPCO staff met with an operations and maintenance manager to discuss crude heating, review procedures for recycle operations and monitor the progress of recent project work.

Under project F807, APSC performed piping, electrical and instrumentation modifications at PS7 to upgrade crude heating operations. The project entailed installing two new drag valves that use a drop in pressure to increase the crude oil heating potential. The drag valves can be operated while partially closed, which allows the mainline unit pump (MLU) to operate at near maximum horsepower (and heating capacity) in a full head configuration.

At the time of the SPCO visit, APSC was operating one MLU driven by the a remaining Rolls-Royce Industrial Avon turbo-jet engine at PS7. APSC staff indicated that, due to vibration issues, APSC was operating the jet engine at about 90 percent of its optimal operating speed. The reduced operating speed was recommended by the APSC rotating equipment engineer. At the time of the site visit, PS7 was adding 8° F of heat to the TAPS mainline crude stream. According to APSC staff, operating the jet engine at 90 percent consumes about 20,000 gallons of fuel per day.

During the winter of 2012/2013 APSC recycled crude through two drag valves, situated on the MLU suction piping and discharge piping. To avoid complications caused by vibrations, APSC operated the crude heating system with the suction drag valve at 55 percent open and the discharge drag valve at 70 percent open, in accordance with the APSC rotating equipment engineer's recommendation. APSC staff indicated that upon the installation of additional bracing on the recycle piping, the drag valves may be operated down to 5 percent open.

APSC staff showed SPCO staff some additional bracing that had already been installed. SPCO staff observed the suction drag valve making a rattling sound with no indication of substantial vibrations around the valve. APSC staff stated that APSC engineering has acknowledged the sound.



Drag valve installed at PS7.

APSC is continuing project work to make PS7 a Safety Integrity Pressure Protection System (SIPPS) node, provide for control of the pump station from OCC in Anchorage, upgrade a rupture disc to provide pressure relief in the crude heating system and complete electrical connections for sump reinjection.

APSC staff provided temporary operating procedures to SPCO staff for review at PS7. SPCO noted that APSC procedures PS 07 Normal Operations Activities (7.2.04-07) and PS 07 Recycle Operations (4.1.12-07) address shutting valves for scraper pigs, manually operating the sump and pressure differentials across the relief rupture disc. SPCO staff observed that recycle operations at PS7 require APSC to continally staff the control room with a technician. An additional roaming technician is always on-site while APSC is recycling crude through drag valves to add heat at PS7.

Fourth Quarter FY13
RGV 69 Stem Seal Replacement

On June 8, 2013, SPCO monitored maintenance work APSC performed on remote gate valve (RGV) 69, located at pipeline milepost 435.9. The work entailed replacing primary valve stem seals. APSC replaced the seals due to stem weep discovered during regular valve inspection and maintenance. SPCO staff observed APSC technicians successfully replace the stem seals and secondary seal grease injection pipe.

Stem weep is crude oil pushed by pipeline pressure up the stem, past seals that are packed against the valve stem. Stem weep in small quantities is not an immediate threat to human health and safety, pipeline integrity or the environment. Small accumulations of stem weep are contained in the bottom valve stuffing box, which is bolted shut. Stem weep in large quantities may fill the stuffing box to the point that crude oil is released to the environment.

An APSC technician uses a torque wrench to tighten packing gland flange nuts.

APSC conducted the valve maintenance work on RGV 69 during a scheduled shutdown to help reduce potential complications. Upon arrival to the work site, SPCO staff placed a lock on the valve stem electrical breaker as part of the energy isolation safety protocol used for the maintenance work. SPCO staff noted that APSC staff had established a master copy of the procedures that were being completed step-by-step. APSC used Safe Maintenance Procedure SMP-M33-032 for the stem seal replacement. This procedure is specific to valves where the valve body can be blown down to zero pressure with low crude flow through the body drain, or a body seal with low "leak-

by." APSC technicians on-site mentioned that they found very little evidence of leak-by in RGV 69, based on the presence of anti-freeze in the valve body left over from winterization.

SPCO staff entered the valve enclosure where APSC technicians were removing packing gland nuts and restraining the packing gland above the primary stem seal with wire. SPCO noted a small accumulation of crude at the bottom of the primary seal assembly that had been caused by stem weep through the old primary stem seal. APSC technicians cleaned and greased the valve stem, then pointed out some minor pitting on the valve stem to SPCO staff. The pitting on the stem did not warrant any action.

SPCO observed APSC staff replace the old stem packing rings with new packing rings. The packing rings are stacked around the valve stem and are then compressed against the stem by tightening nuts on the packing gland flange. APSC technicians used a pneumatic torque wrench to tighten the packing gland nuts to create a good seal (see image on previous page).

SPCO staff returned the following day to find the RGV 69 valve enclosure in a clean condition. Insulation was still removed from the around the valve stuffing box, likely to facilitate a second inspection by APSC staff after the pipeline was restarted and the newly replaced seals had experienced operating pressures. SPCO requested, and was provided with, completed and signed copies of the procedures used for the RGV-69 stem seal replacement. SPCO lease compliance staff generated lease compliance report 13-SPCO-R-035 and four satisfactory surveillance checklists from the site visit.

Assessment of APSC Improvement to Maintenance Work Prioritization Process
In FY13 the SPCO conducted a follow-up to a SPCO assessment conducted in FY12. SPCO conducted assessment 11-SPCO-A-001 in FY12 to evaluate the APSC Maintenance Work Prioritization Process. The FY12 assessment found that the APSC system for initiating major maintenance work did not directly correlate the risk of not completing a project with the time required to implement the project. The assessment recommended that APSC include an examination of how maintenance work is prioritized in its root cause analysis of the January 2011 incident at PS1.

APSC responded to the assessment by identifying specific modifications made to the Project Management Process, AMS-003. SPCO conducted research to determine how the administrative process modifications addressed SPCO's findings from the FY12 assessment and evaluated APSC's response to the recommendations provided.

The FY13 follow-up assessment found that APSC has demonstrated an effort to improve the project work request (PWR) process by clarifying the use of prioritization scores and stage/gate requirements. The process of prioritization scoring resembles a form of risk assessment; however, with regard to risk, it has no direct influence on project implementation timelines. The SPCO will continue to address this matter in future analyses.

The FY13 follow-up assessment also provided additional information on the status of the 2011 PS1 booster pump piping failure incident. Based on lessons learned from the 2011 incident, APSC has established contingencies for a failure of PS1 booster pump suction piping. These contingencies are intended to facilitate a prompt response to a pipe failure and abate the risk of extended operational upset.

Assessment of the TAPS Right-of-Way and Work Pad

Between June and September of 2012, SPCO staff conducted surveillances of the TAPS right-of-way. As part of the surveillances, SPCO staff recorded visual observations of the pipeline, its support structure and appurtenances. The surveillances were documented in multiple SPCO reports issued during 2012.

This assessment utilized information gathered during the 2012 SPCO surveillances to verify that APSC is conducting maintenance in a manner consistent with TAPS right-of-way lease requirements. The assessment analyzed APSC records and procedures and geographic information developed by the SPCO to evaluate TAPS right-of-way maintenance.

The assessment found that APSC right-of-way maintenance work management systems and surveillance and monitoring programs continue to effectively identify major maintenance needs along the TAPS right-of-way. The assessment found that APSC maintenance processes are acceptable in regard to the lease covenants and recommended that APSC consider reinforcing the process by which right-of-way conditions are communicated to bolster consistency in reporting.

Assessment of APSC's Tank 190 Overfill Incident Management Action Plan

In response to a 2010 overfill of crude storage tank 190, APSC conducted a root cause analysis and created the Tank-190 Overfill Incident Management Action Plan (MAP). The MAP describes the actions needed to address the root and contributing causes of the overfill incident. APSC used the MAC process to track actions taken to address the causes of the tank overfill.

In FY13 SPCO assessed the APSC response to the Tank-190 overfill incident. Using the MAC process, the report evaluates APSC's methods to address the root causes of the incident.

The assessment found that APSC utilized the overfill incident as a catalyst to implement numerous improvements to process, procedure and design. One such improvement includes APSC's "High Learning Value Event" process, which is designed to increase employee awareness during pipeline operations. In the follow-up to the Tank-190 overfill incident, APSC demonstrated compliance with the TAPS right-of-way lease by improving the methods used to learn from incidents, providing situational awareness training, making design changes to prevent complications during shutdowns and updating the APSC procedure-writing and safe operating committee processes. The assessment recommended that APSC consider incorporating newly developed processes in its Quality Assurance Manual, QA-36.

SPCO FY13 TAPS ACTIVITIES - RIGHT-OF-WAY SECTION

The SPCO ROW section in FY13 conducted inspections and completed surveillance reports for the 26 operating material sites on state land along TAPS between Deadhorse and Fairbanks.

The State Pipeline Coordinator's Office right-of-way (ROW) section in FY13 completed 27 authorizations and 31 material site designations in support of pipeline pre-lease activities and lease maintenance and repair activities, comprising:

- Eight temporary water use permits and three amended temporary water use permits
- Six land use permits
- Two material sale contracts
- Five right-of-way lease amendments
- Thirty-one material site designations

Authorizations are listed in more detail in Appendix H: Authorizations, Rights-of-Way, and Permits Issued by SPCO.

Mineral Material Site Surveillance

During FY13, the SPCO ROW section conducted inspections and completed surveillance reports for the 26 operating material sites on state land along TAPS between Deadhorse and Fairbanks (surveillance report numbers 13-TAPS–S-021, 13-TAPS–S-024 to 13-TAPS–S-028, 13-TAPS–S-030 and 13-TAPS-S-032 to 13-TAPS–S-050). The sites were inspected to determine compliance with the material sale contracts, mining and reclamation plans and TAPS lease stipulation 2.6. The material sites were found to be clean and well-maintained. SPCO staff notified APSC of two unsatisfactory observations made during the field visits; APSC provided information to allow the SPCO to satisfactorily close out the two items. All the sites met the requirements for high-quality mineral material sites.

Land Use Permits
The SPCO issues land use permits to APSC for maintenance and construction activities, including low-water crossings and pipeline work pad maintenance, below-ground pipe excavation, soil investigations, mineral material storage and oil spill contingency sites and Conex storage. APSC tracks projects that require permitting and applies for permits in advance of project work. Other permit applications may result from observations or surveillances by either APSC or SPCO staff, or from unexpected events such as floods and wind storms. In FY13, the SPCO issued six land use permits for TAPS activities.

Temporary Water Use Permits
The ROW section authorizes temporary water use permits for the use of water resources on state land related to the TAPS right-of-way. If the water source is from a fish stream, then special requirements may be added to the permit to protect fish and other wildlife. The special provisions typically include intake placement guidelines, special screening requirements and water intake velocity. Temporary water use permitting efforts are coordinated with the SPCO ADF&G liaison. In FY13, the SPCO issued eight temporary water use permits and three amended temporary water use permits for TAPS activities.

TAPS Right-of-Way Amendment:
Fuel Gas Line, Manual Gate Valve Replacements
On August 9, 2012, the Commissioner signed the amendment to add approximately 0.78 acres of land adjacent to the Dalton Highway near mileposts 311.7 and 342.1, to replace two existing below ground valve sets on the TAPS Fuel Gas Line (FGL) and make modifications to the Pump Station 3 lateral piping. FGL Manual Gate Valves (MGV) No. 5 and No. 7 were replaced with above ground valve sets that were set farther from the highway on new gravel pads to prevent vehicular damage. The project will increase the long term integrity of the new pipe and valve sets. Access workpads were constructed from the Dalton Highway to the new valve sites and vehicle gates were installed to control access.

TAPS Right-of-Way Amendment:
Channel Plug Extension at Sagavanirktok River, PLMP 24.7
On June 6, 2013, the DNR Commissioner signed the "Amendment of the Right-of-Way Lease for the Trans-Alaska Pipeline, ADL 63574, Sagavanirktok River Channel Plug Extension, PLMP 24.7" to add approximately 41.5 acres of state land in the floodplain of the Sagavanirktok River.

The purpose of adding this land is to extend the existing channel plug at PLMP 24.7 approximately 400 feet to the north to protect the integrity of TAPS by preventing a side channel of the Sagavanirktok River from encroaching toward the shallow buried pipe. During construction, the lands will be used for material extraction and equipment staging areas. The SPCO issued a material sale contract, ADL 419923, for the 5,000 cubic yards of gravel that will be extracted from a gravel bar south of the existing channel plug. The material sale contract was issued based on AS

38.05.565, which allows the department to sell material from a source other than those designated under AS 38.05.550(b). AS 38.05.565(a)(3) allows the department to issue a material sale contract to a holder of a land lease issued by the department if the materials to be extracted are necessary and incidental to the primary purpose of the lease and the materials are put to beneficial use in a way that alters the character, usefulness or availability of the materials in their native forms.

The gravel extraction and all the work on the structure is expected to be conducted outside active flowing water. The new structure will be built using the footprint of the existing channel plug. The SPCO consulted with ADF&G concerning APSC's access to the project site and gravel extraction area. ADF&G determined that this project will require a Fish Habitat Permit. Final site access will be determined by ADF&G and will be dependent upon existing field conditions.

The lands needed to accommodate the channel plug extension project after construction will be less than those during construction. After construction and for the Commissioner's approval, APSC will submit an as-built survey with the acreage to be retained to the TAPS right-of-way lease.

The SPCO will examine the project area upon completion of the construction activities to ensure all lands are in a condition acceptable to the Commissioner.

TAPS Right-of-Way Amendment:
Buried Rock Grade Control Structures, PLMP 777.7
On June 20, 2013, the DNR Commissioner signed the "Amendment of the Right-of-Way Lease for the Trans-Alaska Pipeline, ADL 63574, Scour Protection at Sheep Creek, Pipeline Milepost 777.7" to add approximately 6.2 acres to construct and maintain two buried rock grade-control structures at the pipeline crossing of Sheep Creek at PLMP 777.7 in order to prevent exposure of the buried pipe due to streambed erosion. In the project area, the buried pipeline follows the north side of Lowe River Valley and lies between the Richardson Highway and the Lowe River. ADF&G will conduct a fish stream survey of Sheep Creek in the summer of 2013 to determine whether it is utilized by anadromous fish.

TAPS Right-of-Way Amendment:
Cathodic Protection Upgrades, PLMP 579.2
On June 26, 2013, the DNR Commissioner signed the "Amendment of the Right-of-Way Lease for the Trans-Alaska Pipeline, ADL 63574, Cathodic Protection Upgrades, Pipeline Milepost 579.2" to add approximately 0.25 acres of state land east of the Delta River, north of Suzy Q Creek. The site is approximately 39 miles south of Delta Junction, east of the Richardson Highway. The purpose of adding this land was to allow for the installation of new Anodeflex, drilled magnesium rods, Thermal Electric Generator (TEG), fuel tank, and power module at PLMP 579.2 as part of cathodic protection upgrades to protect the buried pipeline from corrosion.

Designation of Material Sites

An act relating to the Alaska Land Act and Material Disposals, House Bill 361 was signed into law on May 22 and became effective July 1, 2012. This act substantially changed the process DNR must follow when selling materials from state land; pertinent to the SPCO, AS 38.05 was amended by adding new sections under "Article 14. Material Sales."

Under AS 38.05.550(b), DNR is required to designate sources or sites for the sale and extraction of materials by issuing a decision under AS 38.05.035(e) and providing notice in accordance with AS 38.05.945. Once designated, these sites can remain open for material sales indefinitely or until closed by the DNR. No additional public notice is required for sales from designated sites; however, a State Historic Preservation Office review is required for the expansion of working limits and public notice is required for the expansion of legal limits. Materials sales from these sites can be negotiated or competitive sales conducted to meet the requirements of AS 38.05.555-565.

The SPCO issued a Final Finding and Decision on September 20, 2012, that designated the 31 material sites from which the SPCO has issued material sales contracts to AS 38.35 lessees. This designation allows the SPCO to sell materials from these sites to support AS 38.35 pipeline related activities. All the designated sites had been used in the past as materials sites to support AS 38.35 pipeline related activity and the majority of these sites had been used since TAPS construction.

Of the 31 sites designated, 12 are also used by the Alaska Department of Transportation & Public Facilities (ADOT&PF). Four of the shared sites are located in the Southcentral Region and the remaining eight are in the Northern Region. Material sale contracts for ADOT&PF are issued by the respective regional offices of DNR's Division of Mining Land & Water (DMLW). The regional offices addressed the designation of these shared sites for purposes other than pipeline-related actions in separate decisions.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION LIAISON FY13 TAPS ACTIVITIES

An ADEC environmental program specialist conducts a site visit in FY13. ADEC representatives at the SPCO review and enforce compliance with C-plans for TAPS and the VMT.

The ADEC representatives at the SPCO review and enforce compliance with state environmental requirements for TAPS and common carrier pipeline activities in Alaska. In so doing, they support the SPCO in oversight of the sections and stipulations of the Alaska Right of Way Lease relating to public safety and environmental protection. The ADEC liaison officer coordinates with the various divisions of ADEC for matters pertaining to TAPS and is the ADEC representative to the JPO management team. The liaison officer facilitates coordination and consistency with other JPO agencies concerning ADEC authorizations for TAPS and common carrier pipeline activities in Alaska.

DIVISION OF ENVIRONMENTAL HEALTH

ADEC's Division of Environmental Health (EH) regulates drinking water, food safety and sanitary practices. The environmental health programs involved with TAPS include solid waste disposal, pesticides, drinking water, and food service.

APSC project # W-Y-017, PS-10 Straight Pipe Project, required the reopening of the drinking water, domestic wastewater and personnel living quarters (PLQ) at PS10 during the 2013 construction season. These systems were last used in the late 1990s; reactivation required the inspection and program approval of both the legacy drinking

water and wastewater disposal systems at the station. The ADEC liaison coordinated with EH and APSC to ensure plans for returning the systems to service would meet state criteria. The kitchen at the PS10 PLQ was damaged beyond repair for the short duration of the project during the 2002 Denali Fault quake and APSC decided to bring in a temporary kitchen to support project staff. The catering facility moved to the site was inspected by the food safety program to ensure compliance with department regulations. A sanitary survey of the drinking water system was a requirement of approval from the drinking water program and was conducted in July 2013. The ADEC liaison made several visits to the site to monitor the project and coordinated with APSC and ADEC program staff to ensure department requirements were met.

Solid Waste Disposal: Stipulation 2.2.6.2 is the primary lease requirement for TAPS solid waste disposal sites. There are three ADEC permitted solid waste disposal sites (SWDS) on TAPS. APSC manages these permits and is responsible for the proper collection, storage and disposal of solid waste at these facilities. During FY13, there were no compliance issues identified by ADEC for these facilities. Assistance of the liaison was requested by BLM for the current permits and oversight reports relating to the SWDS operated by APSC for BLM records and staff review. The liaison provided the requested permits and monitoring reports to both BLM and SPCO for inclusion in their respective document systems.

Pesticides: Stipulation 2.2.5.1 requires that APSC receive approval from the State Pipeline Coordinator and the BLM Authorized Officer prior to using pesticides on the TAPS right-of-way. ADEC's pesticide control regulations, 18 AAC 90, require APSC to obtain permits for pesticide use within the TAPS right-of-way. APSC continues to seek alternative measures to avoid or minimize the use of pesticides on TAPS. In FY13, there were no pesticide use requests from APSC.

The ADEC liaison assisted the Pesticides Program with questions regarding routine and historic pesticide use on TAPS. Program staff was interested in how the stipulations of TAPS right-of-way were administered at the JPO and how the required SPCO and AO approvals were managed. The liaison briefed the program on the requirements of the state and federal stipulations and how the approval process is administered at the JPO. The liaison also advised program staff of internal APSC requirements and procedures concerning pesticide use. These discussions included a description of the typical pesticide uses on TAPS. In addition, the liaison provided insight into the anticipated future use of pesticides on TAPS by industry and land managers.

Drinking Water: The drinking water program ensures that systems supplying water for drinking meet the minimum health standards required by ADEC's drinking water regulations. The program oversees the operation and specific monitoring plans for each permitted systems on TAPS. APSC maintained 14 ADEC-approved drinking water systems along TAPS during FY13. All of the systems were operated in compliance with ADEC requirements.

Food Service: Every food service facility associated with TAPS is required to maintain a food service permit. The food safety and sanitation program focuses on risk factors that are directly linked with the causes of food-borne illnesses. There were seven food service permits associated with TAPS operations during FY13 and no significant compliance issues for these facilities.

DIVISION OF WATER

The Division of Water (WQ) oversees compliance with the water quality and wastewater discharge standards outlined in 18 AAC 70, 18 AAC 72 and 18 AAC 83. The requirements of ADEC's water regulations apply to all TAPS operations. During FY13, ADEC reviewed project activities that involved wastewater discharge, visiting those sites frequently to ensure compliance with department regulations and right-of-way stipulations. ADEC also reviewed solid waste disposal sites and active material sites for compliance with ADEC storm water requirements. There were no compliance issues identified in FY13.

In 2008, the Environmental Protection Agency (EPA) approved the State of Alaska's application to administer and enforce the Alaska Pollutant Discharge Elimination System (APDES) program in lieu of EPA's National Pollutant Discharge Elimination System (NPDES) program in Alaska. The approved state program included an implementation plan that transferred administration of program components in phases over a multi-year period. The final phase of the transfer was successfully conveyed to ADEC on October 31, 2012. With primacy, the department now maintains direct oversight of TAPS wastewater discharge permits, including discharges associated with oil and gas and other facilities where primacy was not previously transferred to ADEC. The existing EPA NPDES permits are being assimilated into the APDES Program. These permits will be administered by DEC under state regulation 18 AAC 83.

DIVISION OF AIR QUALITY

APSC holds nine Title V Operating and 20 Title I Construction permits for TAPS pump stations 1, 3, 4, 5, 6, 7, 9, 10 and the VMT. These permits are issued and overseen by the air permits program. There are seven minor, source specific permits issued to APSC for emission sources at various pump stations and the VMT. ADEC monitors compliance throughout the year, conducting compliance inspections and review of operator monitoring reports. The ADEC liaison coordinates with the air permit program, SPCO and JPO agencies to support compliance with air quality stipulations.

The potential need and ability to restart TAPS following a shutdown in cold weather conditions continued to be a significant concern for JPO agencies during FY13. APSC's installation of the additional cold restart engines at PS12 and PS7 were instrumental in moving the plan forward. The ADEC liaison worked with JPO and SPCO agencies, ADEC's Air Permit Program and APSC throughout FY13 to ensure that all ADEC requirements were identified and addressed in order for APSC to install the units and implement the plan. APSC installed the final auxiliary engine at PS12 in the fall of

2012 and conducted a test start in December. The successful installation of the engine culminated a joint effort of the department and JPO stretching back several years. During this time the ADEC liaison continued to provide relevant information and assistance to the SPCO, JPO and APSC.

TAPS and VMT Air Permit Compliance Status: The ADEC liaison routinely coordinates with program staff concerning compliance inspections and to ensure permitting issues or status changes are communicated to the SPCO and APSC is operating in accordance with applicable ADEC requirements. Three compliance evaluations were conducted on TAPS during FY13. The program inspected and evaluated the VMT, PS3 and PS4. The ADEC liaison gave a briefing of the reports and findings to the JPO. Copies of the ADEC evaluation reports have been provided to the SPCO and other JPO agencies for their records.

ADEC Compliance Reviews

Facility	Review Date
PS3	9/18/2012
PS4	9/19/2012
VMT	9/26/2012

Early in 2012, the air permits program was petitioned by APSC for a determination of permit compliance regarding a planned test at PS1. The test was to involve the release of a volume of petroleum vapor in November 2012. The test was intended to characterize a vapor "cloud" that could be released in an event overpressure of the PS1 receiving tanks. This test was postponed several times and finally occurred on March 25, 2013. The ADEC liaison continually tracked the project and kept the JPO agencies informed of department activities associated with the test. There were no issues or concerns identified by the department concerning the test and the test did not result in a violation of the PS1 permit.

SPILL PREVENTION & RESPONSE DIVISION

Contaminated Sites Program: In FY13 there were 32 contaminated sites along TAPS. Throughout the year the liaison coordinates with the ADEC contaminated sites staff to provide SPCO and JPO with assistance in the resolution of contaminated sites issues along the TAPS right-of-way corridor and to ensure these sites are returned to the land managers in an acceptable condition. The primary focus of the liaison's efforts during FY13 was to assess and identify closure options along TAPS and the VMT; however, this effort was interrupted by changes in program staff, which required the postponement of field inspections. The field evaluation of contaminated sites will remain an effort of the liaison in FY14.

The Prince William Sound Regional Citizens Advisory Council (PWSRCAC) has a significant stake in the safe operation of the southern end of TAPS and the VMT. PWSRCAC is a member of the VMT C-plan coordination group and is active and involved in providing additional review of most of the operations at the VMT, whether

they involve air emissions, water quality, facility integrity or oil discharge prevention and response planning. As a result, the ADEC liaison and environmental program specialists at the SPCO attend many committee and board of directors meetings. During FY13, ADEC staff attended all three board of directors meetings and numerous oil spill prevention and response committee meetings.

Oil Discharge Prevention and Contingency Planning (C-plan): C-plans are required by State of Alaska pollution prevention statutes and regulations, the TAPS right-of-way lease and the federal grant of right-of-way. Variations of spill prevention and response plans are also required by JPO member federal agencies, including PHMSA, USCG and the EPA. ADEC staff at the SPCO review and enforce compliance with C-plans for TAPS and the VMT. In so doing, they support the SPCO in fulfilling lease stipulation 2.14, contingency plans. Each C-plan is reviewed for compliance with State of Alaska statutes and regulations in 18 AAC 75, Article 1 and Article 4. Once approved, C-plans must be renewed every five years. The operator may submit proposed plan amendments during the effective period for ADEC's review and approval. ADEC conducts the review of the TAPS Pipeline and VMT C-Plans in coordination with BLM and other JPO agencies. Oversight of C-plan compliance includes reviewing the plan application, conducting and evaluating spill response exercises, and conducting audits and inspections of facilities, equipment and documentation.

TAPS Pipeline C-plan: The response planning group (RPG) composed of APSC, ADEC and JPO personnel, meets monthly to facilitate ongoing oversight of the C-plan and compliance with State of Alaska statutes and regulations and federal grant stipulations for oil spill response planning. The RPG meetings provide for interagency and APSC coordination for C-plan amendments, drills and exercises, inspections, audits and emerging issues among the various JPO agencies and APSC.

On November 30, 2011, ADEC approved the renewal application with six conditions of approval. On December 26, 2012, ADEC issued APSC a Notice of Violation (NOV) for failure to notify the department of and complete an Annual Commodity Release Leak Detection Test as required by the plan renewal conditions of approval. On May 16, 2013, department staff attended the required test as observers. Efforts are ongoing to resolve the NOV.

With two new Environmental Program Specialists joining the SPCO in FY13, a great deal of time was spent in TAPS training, exercises, facility familiarization, and inspections to develop relationships and improve operational understanding for regulatory oversight.

Valdez Marine Terminal C-plan: The VMT C-plan coordination group meets quarterly to discuss ongoing oversight and coordination of activities, compliance, emerging issues, exercises, inspections and scheduling of response drills. ADEC and BLM staff participate in these meetings. The PWSRCAC is also a member of the VMT C-plan coordination group and participates regularly in meetings and review of the VMT C-plan.

On October 15, 2012, ADEC received APSC's application for renewal for the VMT C-plan. After providing recommendations for improvement ADEC found the plan sufficient for public review on February 14, 2013. On March 6, 2013, ADEC initiated a 30-day public comment period for the VMT C-plan. Plan renewal efforts are ongoing with an extension granted for the current plan until December 9, 2013, in order to complete the reviews and renewal. APSC's initiative to rewrite the response planning standards (RPS) oil spill scenario in the VMT C-plan grew into an effort to reorganize the entire C-plan, as a result this renewal has required a great deal of review to ensure continued compliance with state regulations while maintaining the level of detail in the plan required by previous conditions of approval, inspections and exercises. The renewal process has included a great deal of interagency coordination, communication with the public and ongoing meetings with APSC.

During FY13, ADEC entered into negotiations for corrective actions for the VMT secondary containment system that stemmed from a notice-of-violation issued in 2008. The deadline for secondary containment repairs of October 31, 2012, was missed due to various failures in timing, planning and material procurement. ADEC staff continue to work with APSC to complete permanent repairs and achieve sufficiently impermeable secondary containment.

Drills and Inspections: ADEC has regulatory authority to require C-plan holders to conduct oil spill response exercises. Specific requirements for exercises are incorporated into both TAPS and VMT C-plans. In FY13, ADEC staff participated in three major spill response exercises at TAPS and the VMT. APSC conducts at least one incident management team (IMT) exercise per year. At these exercises, the ADEC response team is led by a state on-scene coordinators (SOSC). The SOSC, federal on-scene coordinator (FOSC) and incident commander, together with their support staff, form the unified command. The unified command is responsible for executing an effective response.

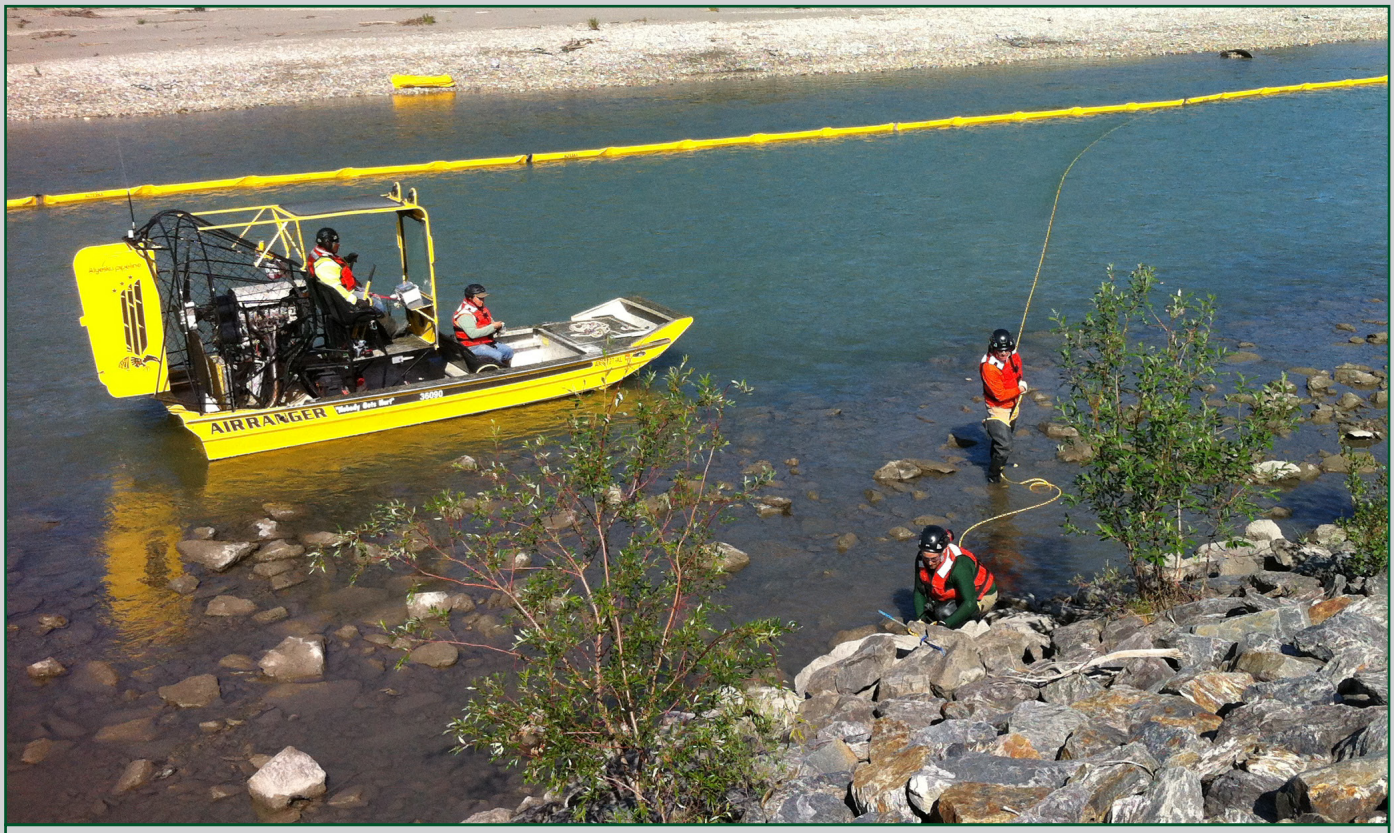
Major Oil Discharge Response Exercises, FY13

Date	Facility	Exercise Type	Location	Agencies
11/7/12	VMT	Scenario 4 IMT Tabletop	Valdez	ADEC, BLM, USCG
4/18/13	TAPS	Source Control, IMT	Fairbanks	ADEC,BLM, EPA
6/12/13	VMT	Scenario 4 IMT Tabletop (Day 1) Equipment Deployment (Day 2)	Valdez	ADEC, BLM, USCG

ADEC conducts compliance inspections of the prevention requirements and C-plan commitments to determine the response readiness of the plan holder. A key component of ADEC oversight involves assessment of readiness and response training. ADEC's inspections for FY13 were based on priorities established in cooperation with the JPO oil spill team and inspections are coordinated with other JPO agency staff to avoid duplication and enhance efficiency. During FY13, ADEC staff conducted four field inspections:

ADEC Field Inspections, FY13

Date	Facility	Inspection Focus	Location
12/28/12	VMT	Mitigation Measures and Readiness	Valdez
6/6/13	TAPS	Secondary Containment, Tanks, Records Review	PS4
7/9/13	TAPS	Secondary Containment, Tanks, Records Review	PS7
7/12/13	TAPS	Secondary Containment, Tanks, Records Review	PS6



ADEC has regulatory authority to require C-plan holders to conduct oil spill response exercises. In FY13, ADEC staff participated in three major spill response exercises on TAPS and the VMT.

DEPARTMENT OF FISH & GAME LIAISON FY13 TAPS ACTIVITIES

The SPCO Fish and Game liaison reported in FY13 that APSC baseline crews have been actively maintaining low-water crossings and culvert structures along the TAPS right-of-way.

The ADF&G liaison conducted field inspections of the TAPS right-of-way with APSC representatives at various locations along the 800-mile pipeline, from the North Slope to Valdez. The ADF&G liaison visited pre and post-project sites and prepared surveillance reports at a representative sample of the locations. The liaison discussed with APSC solutions for construction, maintenance and project timing to avoid or minimize impacts to fish resources and habitats.

The ADF&G liaison's surveillance activities revealed that, in an effort to ensure efficient fish passage, APSC baseline crews have been actively maintaining low-water crossings and culvert structures along the right-of-way in compliance with the conditions and stipulations of Fish Habitat Permit FH 11-SPO-0007. The liaison completed 96 individual written surveillance reports on drainage structures along TAPS. In addition, the ADF&G liaison wrote a trip report that provided surveillances on 70 drainage structures in FY13 (see Appendix G for a full list of reports).

APSC Environmental Surveillances and Repairs

APSC conducted fish stream surveillances at 705 sites along TAPS. The APSC right-of-way and civil maintenance group worked on 98 drainage structures in FY13.

Eight sites required extensive repair to provide long-term fish passage. This necessitated the issuance of Fish Habitat Permits by ADF&G at the SPCO. There were 133 sites that required routine maintenance. Some of that work was completed in 2012 and the remainder scheduled for 2013; the remaining 564 sites required no work.

Clarke's Lake

Clarke's Lake is located at pipeline milepost (PLMP) 92.36, approximately 12 miles north of PS3. During original construction, a causeway was built bisecting the lake into two parts connected hydraulically through two small 24-inch culverts. One of the culverts was subsequently crushed at an unknown date leaving just one culvert to provide fish passage between the two lakes. This lake is suspected to hold Lake Trout, Dolly Varden char and Arctic Grayling.

In FY13, APSC removed the crushed culvert and installed a low water crossing (LWC) to improve fish passage. This should be a great improvement from the previous two culvert system and will improve both fish passage and the hydraulic connection between the two lakes while still providing equipment access along the drivelane. ADF&G will continue to monitor and work with APSC in the future to ensure both fish passage and safe vehicle access at this site.

Beaver Dam Removal

In the past, APSC would submit multiple requests under the TAPS lease and grant for removal of nuisance beaver dams that threatened pipeline and right-of-way integrity and, in some cases, blocked fish passage. Authorizations issued by the JPO would include similar stipulations.

In FY11, the JPO issued on a one-year trial basis a line-wide authorization for beaver dam removal within the TAPS right-of-way. The authorization included several specific conditions, notifications and reporting requirements. The intent of the authorization was to allow for a faster response time to minimize potential damage and to discourage beavers from investing significant time and energy in areas adjacent to the work pad.

Under this authorization, APSC was able to remove six beaver dams in FY12. After a review of the 2012 beaver dam removal activities, it was decided to renew the line-wide authorization until 2013. In 2013 APSC removed only four beaver dams. Two were removed under the line-wide authorization and the remaining two were removed under separate authorization.

DEPARTMENT OF LABOR & WORKFORCE DEVELOPMENT FY13 TAPS ACTIVITIES

Safety Inspections

The SPCO safety liaison conducted 34 annual safety inspections of TAPS facilities for compliance with the health and safety requirements in Stipulation 1.20: Health and Safety. TAPS facilities include the pump stations, response bases, the Fairbanks-area shops and storage facilities and the VMT. The safety liaison uses Federal Occupational Safety and Health Administration (OSHA) standards (29 CFR 1910 and 29 CFR 1926) to develop and update inspection criteria.

In addition to annual inspections, the safety liaison conducted 23 work site safety inspections. The standard for a work site inspection is the same as annual safety inspections, but with more emphasis on safety programming and procedures.

ADOL&WD Inspections

Project	Number of Inspections
Berth 4 Overhaul	1
Fuel Gas Line Valve Replacement	2
PLMP 490 Oil Spill Exercise	1
PLMP 652 Mainline Integrity Investigation	1
PLMP 653 Mainline Integrity Investigation	1
PLMP 776 Mainline Integrity Investigation	2
PS1 Below-ground Piping	2
PS1 Electrification & Automation project	4
PS1 Tank 110	3
PS4 Heat Recovery	1
PS6 Straight Pipe	2
PS7 Below Grade Corrosion Investigation	2
PS9 Below Grade Corrosion Investigation	1
PS10 Straight Pipe	2
PS12 Cold Restart	1
VMT Tanks 13 & 14	1

Injuries

APSC injury rates are below the Bureau of Labor Statistics (BLS) national average for North American Industry Classification System code 486, Pipeline Transportation. BLS maintains injury rates by calendar year and the most recent statistics available at the time of reporting are from December 31, 2011.

The National Total Recordable Cases rate for 2011 was 2.5 injuries per 200,000 man-hours worked. APSC and its contractors had six recordable injuries in 2012. APSC and its contractors had no lost-time injuries in 2012.

Electrical Inspections

Dan O'Barr, the SPCO electrical inspector, conducts inspections of the PS1 electrification and automation project.

The SPCO electrical inspector tracks code violations, issues notices of violation and verifies corrections with follow-up inspections. The electrical inspector confirms that electricians and contractors are licensed and inspects electrical work during random on-site inspections to verify that the code requirements are met. The electrical inspector focuses on timely verification of code violation abatements.

In FY13, the SPCO electrical inspector performed 78 inspections, issued one notice of violation involving mislabeled electrical equipment at PS1 (which was cleared after the operator replaced some of the equipment and obtained the proper labeling for the rest), and reviewed 65 certificates of fitness. The electrical inspector also provides code interpretations and is the JPO engineering staff's code compliance consultant. A list of all FY13 inspection reports can be found in Appendix G.

DEPARTMENT OF PUBLIC SAFETY FIRE MARSHAL FY13 TAPS ACTIVITIES

The State Fire Marshal liaison inspects control panels at the Valdez Marine Terminal. The SFMO liaison to the SPCO performs inspections on an annual basis under the authority of AS 18.70 and AS 42.06.630.

The State Fire Marshal's Office (SFMO) in FY13 conducted multiple fire and life safety inspections on TAPS and associated facilities. Inspection sites included TAPS pump stations, the Glennallen Response Base and the Valdez Marine Terminal. The SFMO liaison also performed several plan reviews associated with TAPS facilities and provided code advice and interpretations for proposed projects at the VMT and PS1. The SFMO liaison to the SPCO performs inspections on an annual basis under the authority of AS 18.70 and AS 42.06.630.

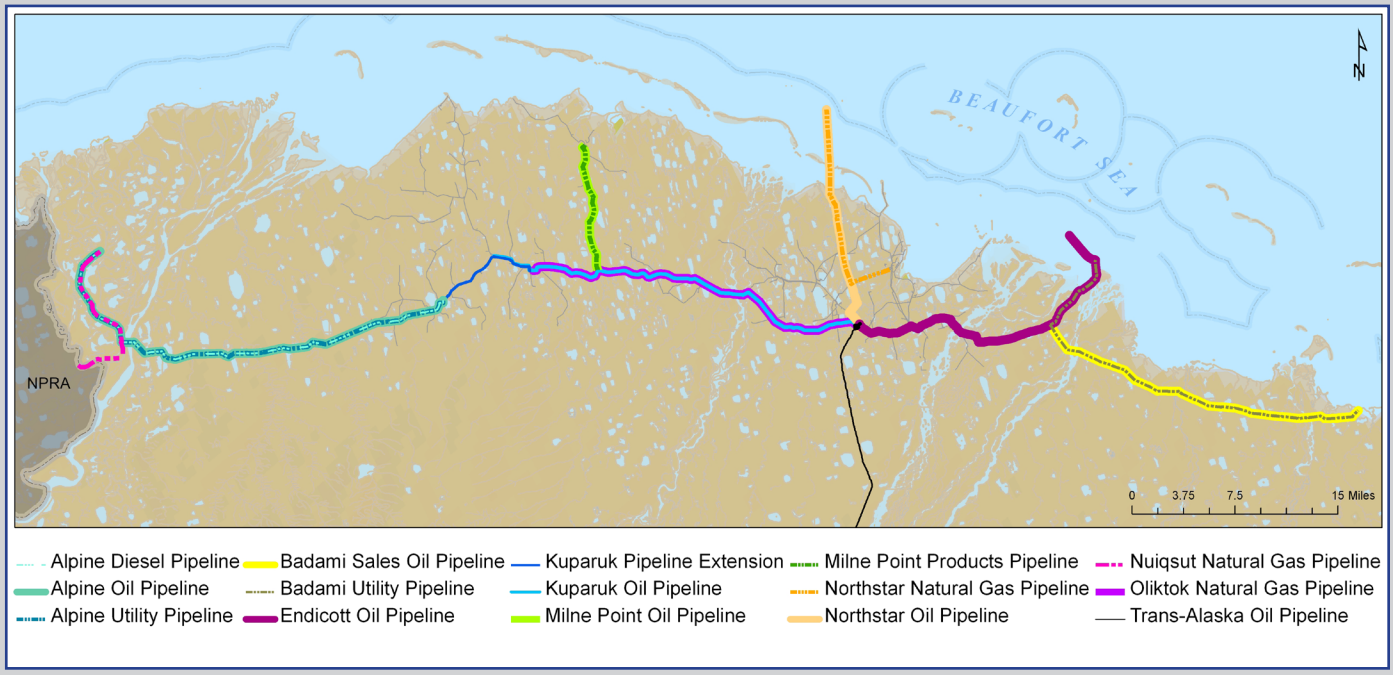
March 2013

The SFMO liaison in March of 2013 conducted fire and life safety inspections of PS1-PS4, including Galbriath Airport near PS4. There were 33 code violations noted during the inspections. The violations ranged from electrical violations, such as overloaded power cords, to improperly secured flammable gas containers. Several smoke and heat detectors were not functioning correctly and some minor issues involving the fire panels were noted. APSC representatives corrected many of the violations on-the-spot and confirmed that the remainder have been addressed in an official letter to the SFMO liaison. The increase in violations from the previous years' inspections may be attributed to more contractor work being performed at the northern pump stations.

April 2013
The SFMO liaison identified five corrective actions items for PS8, PS8, PS10 and the North Pole metering facility. Most of these items were minor in nature, involving replacement of ceiling tiles, exit doors and exit signage. A walk-through was conducted of the personnel living quarters at PS10; several smoke detectors were identified not functioning and the fire panel was not yet operational for the planned temporary occupancy. ASPC was allowed to open the camp with a fire watch in effect until the fire panel was back in operation. ASPC responded to the corrections on May 5th; all items were corrected.

June 2013
The SFMO liaison observed 42 fire and life safety violations between the Valdez Marine Terminal and the Glennallen Response Base. Violations included missing ceiling tiles, numerous electrical violations (as noted in section 605 of the 2009 International Fire Code) , sprinkler system violations and violations concerning proper exiting and exit doors. Many of the violations were noted in Area 19 of the Valdez Marine Terminal, PS12 and the Scada building at the VMT. Both the number and severity of the violations increased over last year. This may have to do with the work at PS12 and the number of contractors working in Area 19 of the VMT. APSC responded to the violations on August 19, 2013, identifying each violation and noting corrective action that was taken.

NORTH SLOPE PIPELINES



This section of the SPCO annual report focuses on SPCO-juridictional pipelines on the North Slope of Alaska. The North Slope has seven existing common carrier pipelines and several proposed* (see the Proposed Pipelines section of this report).

BP Exploration (Alaska) Inc. (BPXA) operates the Badami, Endicott, Milne Point and Northstar pipeline systems on the North Slope. The Badami system includes Badami oil and utility pipelines, the Milne Point system includes Milne Point oil and product pipelines, and the Northstar system includes Northstar oil and gas pipelines.

ConocoPhillips Alaska, Inc. (CPAI), operates the Alpine, Kuparuk and Oliktok pipeline systems on the North Slope. The Alpine system is composed of the Alpine diesel, oil and utility pipelines. The Kuparuk system includes the original Kuparuk pipeline and Kuparuk extension.

North Slope Borough (NSB) operates Nuiqsut Natural Gas Pipeline (NNGP), which transports natural gas from the CPAI Alpine production pad to the village of Nuiqsut.

Each pipeline subsection includes an overview of the pipeline system and highlights from SPCO compliance, right-of-way and engineering activities during 2013.

**Information on Point Thomson Export Pipeline, which was under construction in FY13, can be found in the Proposed Pipelines section.*

BP TRANSPORTATION (ALASKA) INC. PIPELINES

BADAMI PIPELINES

DNR issued the Badami Sales Oil Pipeline Right-of-Way Lease (ADL 415472) and the Badami Utility Pipeline Right-of-Way Lease (ADL 415965) on December 15, 1997. See Appendix D for acreage, survey and lease information.

The Badami Sales Oil Pipeline and the Badami Utility Pipeline run parallel on vertical and horizontal support members from Endicott to Badami, the eastern-most producing oilfield on the North Slope. The only buried segments of these pipelines are below-grade crossings at the Shaviovik, Kadleroshilik and Sagavanirktok Rivers. Flow in Badami Sales Oil Pipeline is east-to-west and flow in Badami Utility Pipeline is the reverse, west-to-east.

Badami Sales Oil Pipeline is insulated and 12 inches in diameter. It originates at the Badami Central Production Facility (CPF). Badami CPF houses the pigging facilities, mainline pumps and metering equipment for the pipelines. The pipeline terminates at a tie-in on Endicott Pipeline. From the termination, Badami and Endicott oils commingle and flow through the Endicott pipeline to PS1, and then through TAPS.

Badami Utility Pipeline originates at an intersection on the Endicott causeway. It connects to the fuel gas line that feeds the satellite island from the Endicott main production facility. It transports fuel gas from the Endicott tie-in to Badami CPF, a distance of 31 miles. When Badami is producing, the oilfield does not typically need the utility pipeline. It generates fuel gas in sufficient volumes to support all field facilities. BPTA has operated the utility pipeline only for short-duration or transient conditions, such as a "cold startup" of the Badami facilities. It also has operated the utility pipeline briefly to supply gas needed to propel ILI devices through Badami Sales Oil Pipeline.

Declining production prompted BP to suspend Badami pipeline operations three times; in 1999, from 2003 to 2005 and a third time from 2007 to 2010. Savant Alaska and ASRC Exploration joined the project during 2008. Savant became the facility operator in late 2011.

The Badami pipeline continues to flow at low rates. Oil reaches ambient temperatures during the 22-mile transit to the Endicott pipeline. BP has had to clear a partial ice plug by flushing with methanol. The pipeline should have increased flow at rates up to 10,000 bopd when the Point Thomson development begins production.

Changes in the next few years should mitigate the low-flow issues in this pipeline. The Point Thomson Export Pipeline will connect to the pipeline near the Badami production facility. Changes to the Badami Pipeline to accommodate Point Thomson production will be minimal. Plans call for the installation of a piggable wye near the Badami facility. With this special wye, a pig launched to clean or inspect the Point Thomson Export Pipeline can travel to the Endicott pig receiver.

BP constructed the Badami weir on the west bank of the eastern Sagavanirktok River channel to control erosion at the location of the trench used during construction of the Badami pipeline. It intersected an unnamed oxbow lake and changed the surface drainage in the area.

An SPCO engineer and BP consultant made separate trips to the installation in 2012. Their reports indicated that the weir is functioning as designed. Overall, revegetation of the area has been successful.

Badami Oil and Utility Pipelines Release of Interests
During FY13, the SPCO conducted final field inspections and completed the analyses and recommendation for releasing the construction rights-of-way acreage to the operation and maintenance rights-of-way for both Badami Oil and Utility pipelines. On August 14, 2012, the release of interests for Badami Sales Oil Pipeline Right-of-Way Lease was signed by the Lessee and the DNR Commissioner. The release of interests for the Badami Utility Pipeline Right-of-Way Lease was signed on January 17, 2013.

Badami Transfer of Interest
On April 25, 2013, the Commissioner received a request to transfer lease ownership for the Badami Sales Oil Pipeline (ADL 415472) and the Badami Utility Pipeline (ADL 415965) from BP Transportation (Alaska) Inc. (BPTA) to Nutaaq Pipeline, LLC (Nutaaq). Nutaaq is owned by Savant Alaska, LLC, and Badami Pipeline Holding, LLC, which is 100 percent owned by Arctic Slope Regional Corporation Exploration, LLC.

BPTA is currently the owner and operator of the Badami pipelines, but since January 2012 personnel from Savant or one of its affiliates have been providing operator services to the Badami pipelines. Savant and ASRC Exploration were involved in the effort to restart production from the Badami Unit in November 2010 and officially took over unit operations in January 2012. The transfer to Nutaaq would result in some management changes, but no changes in the use of the Badami Pipeline rights-of-way are proposed. The SPCO is currently processing the transfer request.

July 2012:
Badami Oil Terminus Inspection
On July 12, 2012, SPCO staff traveled to the Badami Oil Pipeline tie-in to Endicott Oil Pipeline. In the 2010 Annual ADNR Surveillance and Monitoring Report submitted to the SPCO, BP reported that a natural gas liquids spill of 0.5 gallons occurred at remote terminal unit (RTU) no. 3 on August 10, 2010. SPCO staff verified that the site appeared clean; there was no indication of any contamination on the site from the 2010 spill.

The pig receiver for Badami Oil Pipeline was enclosed within a temporary tent and had secondary containment surrounding it. BPXA staff stated that a pig was anticipated to arrive within the next day. The pig receiver and tent enclosure appeared clean. SPCO staff was informed that on July 15 the pig arrived 14 days after being launched.
A lease compliance report and three surveillances were completed for the trip; all reflected satisfactory conditions (SPCO letter 12-356-AS).

March 2013:
Walking-speed Survey
On March 10, 2013, SPCO staff traveled to the North Slope to observe contractors perform a walking-speed survey (WSS) of Badami Oil and Badami Utility pipelines. SPCO staff traveled 1.5 miles of Badami Utility Pipeline with the contractor, beginning at the "T" adjacent to Endicott Satellite Drilling Island and walking south along the Endicott road causeway.
SPCO staff walked approximately 1.4 miles of the Badami Utility Pipeline right-of-way with the WSS crew. Anomalies identified during the WSS are addressed through work order systems for each pipeline facility. Each anomaly is given one of four priority conditions:

Priority 1• Immediate Condition
Priority 2• 180-day Condition
Priority 3• 18-month Condition
Priority 4• Reevaluate during the next scheduled inspection

Coating damage was observed on the pipeline, with most coating damage observed on the side of the pipeline facing the road. According to BPXA personnel, the damage is likely due to the snowblowing that clears the road adjacent to the pipeline. The snow is blown to the downwind side of the road, which is sometimes to the west and sometimes to the east. Rocks from the roadway occasionally get blown out with the snow and is possible that these could make contact with the pipeline, causing damage to the coating. The snow is blown over the pipeline rack, but it is likely that not all the snow and road debris make it all the way over pipeline rack. External corrosion was also observed where welds were made during pipeline construction.

None of the anomalies recorded were considered Priority 1 condition. All anomalies noted were recorded by the data entry technician for inclusion in the WSS report and the BPXA maintenance system. SPCO staff did not observe any issues with the condition of the right-of-way. The right-of-way appeared to be in an acceptable condition. A lease compliance report and ten surveillances were completed for the trip; all reflected satisfactory conditions (SPCO letter 13-127-AS).

March 2013:
State Fire Marshal Annual Inspection
On March 19, 2013, the SFMO liaison conducted fire and life safety inspections for Savant Alaska at the Badami facilities. There were six minor hazards identified and Savant was quick to repair/correct the issues.

ENDICOTT PIPELINE

Endicott Pipeline transports crude oil to TAPS PS1 from Endicott oil field, which was the first continously producing offshore oil field in the Arctic.

Endicott oil field development is located on offshore state land approximately 10 miles northeast of Prudhoe Bay. BPXA, the Endicott Pipeline operator, describes Endicott as the first continuously producing offshore oil field in the Arctic.

Endicott facilities are situated on man-made gravel islands, called the main production island (MPI), the satellite drilling island (SDI) and Endeavor Island, a small island that abuts the MPI. Endicott lies north of Sagavanirktok River Delta about 15 miles east of Prudhoe Bay and inside the barrier islands in the Beaufort Sea. The Endicott islands are linked to shore by a 1.5-mile causeway, with a road and above-ground pipeline support from the inter-island causeway that links MPI and SDI to the Sagavanirktok River Delta uplands. An eight-mile gravel road extends from the end of the causeway to the Prudhoe Bay road system. The causeway system provides year-round access to a portion of the Endicott pipeline and facilities.

Endicott Pipeline transports processed crude oil from the Endicott oil field development and the Badami oilfield to Trans-Alaska Pipeline System PS1. The 16-inch diameter Endicott pipeline originates at Module 303 on MPI, is mounted on vertical support members along the main causeway and parallels the onshore road system until it terminates at PS1 where there is a pig receiver and metering equipment. The Badami sales oil pipeline connects to the Endicott pipeline at the approximate mid-point of Endicott Pipeline. Badami oil is comingled with Endicott oil for delivery to PS1. See Appendix F of this report for more information on the physical characteristics of Endicott Pipeline.

The operational right-of-way for Endicott Pipeline is 150 feet wide, except along the causeway, where the right-of-way width is 500 feet (see Appendix D for acreage, survey and lease information).

Endicott Heater Installation

Crude oil transported by Endicott Pipeline at times does not meet the target oil temperature for delivery to PS1. To remedy this situation, BP is modifying the Northstar heater located at PS1. It will heat oil in both the Northstar and Endicott pipelines. At PS1, the Endicott pipeline also carries oil from the Badami pipeline and will transport Point Thomson natural gas liquids in the future.

BP will maintain bifurcated flows within the shell of the heater, raising oil temperatures independently on both pipelines. The flows will not be comingled because metering is located downstream of the heater. BP is able to modify the Northstar heater to perform dual duty because oil flow rates in both pipelines are now well below their original levels.

Material deliveries delayed the schedule for this work from fall 2012 to summer 2013. As of the end of this reporting period, work is proceeding according to the revised timeline. BP is reporting good progress on the installation of VSMs, piping and valves. The new heater configuration is scheduled be finished, hydrotested, started up and operational soon after the start of the next fiscal year.

July 2012:
Right-of-way Surveillance

On July 12, 2012, SPCO staff traveled the Endicott Oil Pipeline right-of-way from the satellite production island to PLMP 18. SPCO staff went to the Northstar Oil Pipeline heater module where the Endicott Oil Pipeline heater will be installed. The right-of-way was in an acceptable condition, free of debris or signs of erosion. Animal crossings, and pipeline transitions and casings were all in an acceptable condition at the time of the surveillance.

Endicott with new VSM installed on upper lines.
Photo courtesy of BP Transportation, Alaska.

SPCO staff traveled to PLMP 18 to observe the site where the 32-inch diameter seawater treatment plant pipeline to Flow Station 2 and the 24-inch diameter gas pipeline to Flow Station 2 were in contact with Endicott Pipeline in 2010. Vertical support members were installed in the spring of 2012. The temporary cribbing used to lift the seawater treatment plant pipeline off of Endicott Pipeline was still at the

site. SPCO staff observed a dent in the jacket of the Endicott pipeline, but it did not appear to pierce through the jacket and into the insulation. The seawater treatment plant pipeline had been elevated approximately 12 inches above Endicott Pipeline. A lease compliance report and four surveillances were completed for the trip; all reflected satisfactory conditions (SPCO letter 12-356-AS).

September 2012: Right-of-way Surveillance

On September 17 and 18, 2012, SPCO staff performed a surveillance of the Endicott Oil Pipeline right-of-way from the satellite production island to PS1. The right-of-way was free of debris or signs of erosion and was in an acceptable condition at the time of the surveillance.

SPCO staff found a casing at PLMP 18, near Flow Station 2, where soil and rocks had collected around the pipeline jacket. Material in the casing could allow water to collect, which can lead to external corrosion. BP personnel noted the observation and drafted a work order to remove the debris from the casing. SPCO staff requested and received a copy of the work order, which indicated that the casing was cleared of all material on September 19, 2012.

While conducting the right-of-way surveillance SPCO staff encountered a work crew performing a forward-looking infrared inspection of Endicott Pipeline. FLIR crews use a specialized camera that uses infrared to detect heat emanating from the pipeline that could indicate a pipeline rupture. There are three FLIR crews that perform daily monitoring of the pipelines by driving on the adjacent roads along the pipeline right-of-way.

SPCO staff encountered a road crossing integrity inspection at PLMP 21 during the right-of-way surveillance. The inspection was part of a field-wide mitigation project where all road crossings that had the potential for ground water were put on a list to be excavated and investigated for external corrosion. At these sites the pipe was excavated, inspected for corrosion, coated with fusion bonded epoxy, reinsulated, placed inside a road casing and then re-buried. The work crew was on site while SPCO staff was at the dig. The entire pipeline had been exposed, cleaned and enclosed within a hooch tent. SPCO staff observed some external corrosion on the pipeline. These areas of corrosion were to be coated with fusion-bonded epoxy to protect from further corrosion. SPCO staff observed the work site to be clean free of debris. A lease compliance report and eight surveillances were completed for the trip; all reflected satisfactory conditions (SPCO letter 13-003-AS).

May 2013: State Fire Marshal Annual Inspection

In early May 2013 the SFMO liaison conducted annual fire and life safety inspections of Endicott facilities, including the personnel living quarters. BP and contractor personnel are being housed at Liberty Camp until ongoing blast radius studies are completed. There were 11 items noted that required correction, including missing ceiling tiles and non-functioning smoke and heat detectors. Notice was received by June 3 that all items have been corrected.

MILNE POINT PIPELINES

Milne Point pipelines with Milne Point production facilities in the background.

Milne Point oil pipeline construction began in 1984 and was completed the following year. The 14-inch diameter pipeline was designed to transport processed crude oil from Milne Point Unit, operated by BPXA, to Kuparuk Pipeline, operated by CPAI. Milne Point Pipeline originates at Milne Point Central Facilities Pad (CFP) Module 58, passes below Spine Road east of Central Processing Facility One (CPF-1) and terminates at the Kuparuk Pipeline connection near Module 68. Module 68 houses metering instruments, leak detection equipment and a pig receiver. In 2007, BPXA removed a section of Milne Point Pipeline inaccessible to pigging tools and replaced it with corrosion-resistant duplex stainless steel.

The Milne Point products pipeline was built in 2000 and placed on Milne Point Pipeline supports. The eight-inch pipeline transported natural gas liquids from Oliktok Pipeline to the Milne Point CFP for use in enhanced oil recovery processes. BPXA shut down the Milne Point products pipeline in 2002 and, in December of 2006, purged and physically disconnected it from Oliktok Pipeline, in compliance with SPCO and USDOT/PHMSA regulations.

July 2012:
Right-of-way Surveillance
On July 12, 2012, SPCO staff traveled to the Milne Point Oil and Milne Point Products pipeline rights-of-way, beginning at the production pad and ending at the Kuparuk Pipeline tie-in. The right-of-way was free of debris and in an acceptable condition at the time of the surveillance.

Milne Point production pad after BP regraded the edge of the pad.

SPCO staff stopped at several pipeline transitions where the Milne Point pipelines transition below ground. These below-ground sections function as wildlife crossings and areas where vehicles can cross the pipeline via ice roads. SPCO observed slight erosion occurring on the west side of the gravel pad over the pipeline. The erosion did not appear to be affecting pipeline casing depth of cover or the functionality of the road pullout and ice road access. SPCO staff will monitor the area in the future to determine if erosion rates are increasing.

A lease compliance report and four surveillances were completed; all reflected satisfactory conditions (SPCO letter 12-356-AS).

September 2012:
Right-of-way Surveillance
On September 17 and 18, 2012, SPCO staff performed a surveillance of the Milne Point Oil and Milne Point Products pipeline rights-of-way, beginning at the production pad and ending at the Kuparuk Pipeline tie-in.

During a July 2012 surveillance SPCO staff observed slight erosion occurring in the area where the Milne Point Oil and Milne Point Products pipelines leave the production pad. The edge of the pad appeared as though it had been scoured from water runoff. BP personnel had recently regraded the edge of the pad and SPCO staff observed during the September surveillance that the erosion appeared to have been remediated.

SPCO staff stopped at all pipeline transitions where the Milne Point pipelines transition below ground. The majority of casings appeared to be in good condition. SPCO staff found a casing at PLMP 22 where the centralizer had been crushed. The pipeline jacket was approximately 0.25 inches from making contact with the casing. Centralizers help to reduce jacket corrosion by elevating the pipeline out of water and preventing

moisture saturation of the insulation, which can lead to external pipe corrosion. BP personnel agreed that it was a reportable condition and stated that a work order would be completed to repair the centralizer. On September 28, 2012, BP personnel emailed SPCO staff a copy of the work order.

SPCO staff observed during a July 2012 surveillance that there was slight erosion occurring on the west side of the gravel pad over the pipeline. The erosion did not appear to be affecting pipeline casing depth of cover or the functionality of the road pullout and ice road access. SPCO staff has not observed any additional erosion since the July 2012 surveillance.

Crushed centralizer on Milne Point Oil Pipeline. A work order was drafted to replace the centralizer. SPCO staff confirmed that the centralizer was replaced.

During the September surveillance SPCO observed jersey barriers hanging slightly over the edge of a pullout. The jersey barriers were still functional and would prevent a vehicle from driving off the pullout and making contact with the pipelines. SPCO staff and BP personnel discussed the issue and agreed it was reasonable to relocate the jersey barriers so that they were not hanging over the edge. BP personnel stated that it was not a priority before winter but would be addressed during summer 2013.

SPCO staff observed the Milne Point pipeline rights-of-way to be in an acceptable condition. The rights-of-way were clean and SPCO staff did not observe any damage to the surface. SPCO staff confirmed that the centralizer that was discovered to have been crushed was replaced. A lease compliance report and eleven surveillances were completed for the trip and all reflected satisfactory conditions (SPCO Letter 13-003-AS).

May 2013:
State Fire Marshal Annual Inspection

In May 2013 the SFMO liaison conducted annual fire and life safety inspections of both Milnie Point CPU and A Pad. There were four hazards noted on the pads and in the camp. BP was very fast to correct the issues with the help of the fire chief. A small electrical fire occurred during the liaison's visit; it was very informative to see the fire brigade respond quickly and effectively to the fire under the direction of the fire chief.

NORTHSTAR PIPELINES

Northstar Gas Pipeline (foreground) and Northstar Oil Pipeline (background) looking north at a road crossing.

Northstar oil field is located about six miles off the Alaska coast in the Beaufort Sea. Royal Dutch Shell discovered the reservoir in 1983 with exploration wells drilled from Seal Island (also known as Northstar Island), where the Northstar production facilities are positioned today.

BPXA acquired most of the Northstar leases and began efforts to develop the field in 1995. DNR issued a pipeline right-of-way lease in October of 1999; BPXA began producing oil from Northstar in late 2001.

The Northstar oil pipeline transports processed crude oil from the Northstar facilities to TAPS PS1. A second pipeline transports natural gas, used to maintain reservoir pressure, from the Prudhoe Bay central compressor plant to Northstar Island. The two pipelines share vertical support members for their above-ground sections and a subsea trench for the offshore portion.

The trenched pipes were designed and constructed to withstand seabed ice gouge and settlement loading conditions of thawed soils. In addition to standard leak detection systems that monitor pressure, volume and temperature in the pipeline, the operator employs a leak detection system called LEOS (Leak Detection and Location System), which is designed to sense hydrocarbon vapors surrounding the pipelines. In FY12 BPXA tested the LEOS secondary leak detection system on the Northstar subsea pipeline segment and concluded that the enhancements have greatly reduced the threshold detection level. USDOT/PHMSA regulates the Northstar pipelines' corrosion inspection programs. See Appendix F for more information on the physical characteristics of the Northstar pipelines.

September 2012:
Right-of-way Surveillance

On September 17 and 18, 2012, SPCO staff performed a surveillance of portions of the Northstar Oil and Gas pipeline rights-of-way. SPCO staff stopped at seven road crossings where the pipelines were in casings underneath the road. All of the casings appeared to be in good condition.

SPCO staff stopped at the Caribou Crossing Area Module where Northstar Gas Pipeline begins. All portions of the Northstar pipelines rights-of-way appeared to be in good condition. A lease compliance report and eight surveillances were completed for the trip; all reflected satisfactory conditions (SPCO letter 13-003-AS).

March 2013:
Walking-speed Survey

On March 26, 2013, SPCO staff observed contractors perform a walking-speed survey (WSS) of the Northstar Oil and Gas pipelines. Prior to meeting with the WSS crew, SPCO staff and BP personnel traveled to Skid 50, north of where Northstar Oil Pipeline terminates at PS1. The group traveled by truck on the pipeline access road to the Putuligayuk River crossing. SPCO staff and BP personnel walked underneath the pipeline crossing and to the north side of the river. The pipeline crossing was in an acceptable condition; no damage or anomalies were documented.

SPCO staff and BP personnel traveled on Spine Road to cross the Putuligayuk River and then returned to the Northstar Oil Pipeline access road. The Northstar Oil Pipeline between Skid 50 and 0.5 miles upstream of the Putuligayuk River was obscured by a snow drift, making it difficult to assess the condition of the pipeline. As it pertains to the WSS, this portion of the pipeline will be examined during Phase II, which will occur in the summer months.

Northstar Oil Pipeline crossing the Putuligayuk River.

SPCO staff met the WSS crew at the Caribou Crossing module and then traveled by Tucker SnoCat 1.5 miles west to Northstar Oil Pipeline. SPCO staff walked approximately 1.5 miles of the Northstar Oil Pipeline right-of-way with the WSS crew.

Two anomalies were noted in the 1.5 miles that the SPCO traveled. Both anomalies were dents in the jacketing that did not appear to puncture the jacket. Both anomalies were noted by the WSS technician and recorded by the data entry technician. The WSS stated that many of the anomalies noted during the 2012 WSS had been repaired. SPCO staff observed the pipeline and appurtenances to be in an acceptable condition.

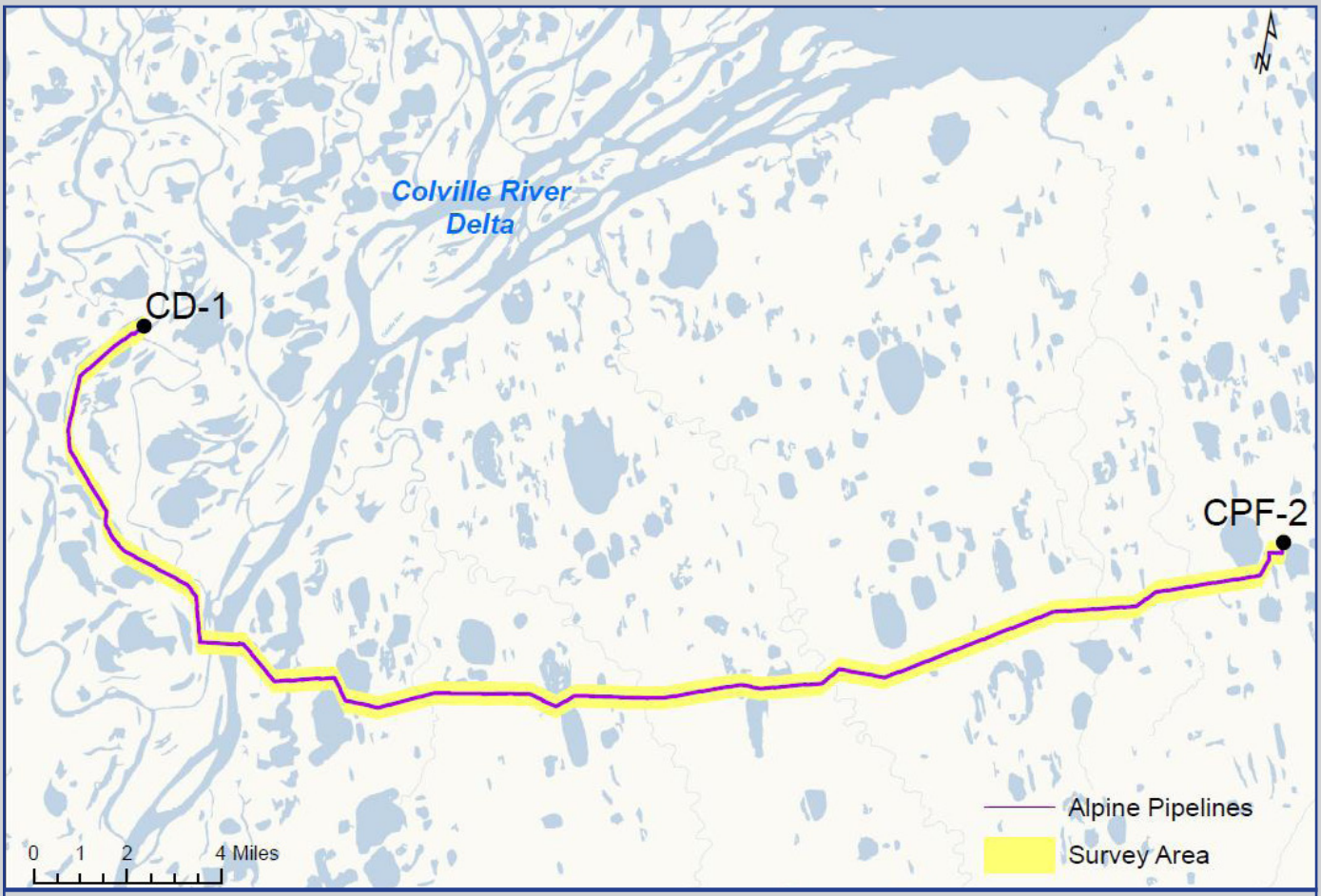
SPCO staff observed a survey monument adjacent to the pipeline on a horizontal support member. The monument appeared to be undisturbed. An orange marker connected to the vertical support member clearly marked the presence of the survey monument.

A lease compliance report and nine surveillances were completed for the trip; all reflected satisfactory conditions (SPCO letter 13-126-AS).

May 2013:
State Fire Marshal Annual Inspection
In May 2013 the SFMO liaison conducted annual fire and life safety inspections of Northstar facilities. The new blast-resistant network operations center was in place and in operation. There were six minor violations noted that required correction. Notice was received from BP on June 3 that all items had been corrected.

CONOCOPHILLIPS ALASKA, INC. PIPELINES

ALPINE PIPELINES



Alpine pipelines rights-of-way and survey area

Alpine pipelines, each approximately 34 miles long and operated by CPAI, connect the western-most development on the North Slope to infrastructure in the Kuparuk River Unit (KRU).

The 14-inch Alpine oil pipeline transports processed crude oil from the Alpine Central Facility (ACF) to CPAI's Central Processing Facility Two (CPF-2). The Alpine diesel pipeline transports heating fuel and other petroleum products from CPF-2 to ACF. The Alpine utility pipeline transports treated seawater, used in enhanced oil recovery operations, from CPF-2 to ACF. All three pipelines are mostly above-ground; see Appendix F for detailed physical characteristics of the Alpine pipelines.

Although the Alpine utility pipeline does not transport petroleum products and therefore is not subject to the provisions of the Right-of-Way Leasing Act, the SPCO was delegated jurisdiction by the DNR Division of Mining, Land and Water and subsequently issued the Alpine Utility Pipeline Right-of-Way Grant (ADL 415857) according to the provisions of AS 38.05, the Alaska Land Act. See Appendix D for Alpine pipelines lease information.

June 2012:
Avian Monitoring Project

SPCO compliance staff in June 2012 traveled to the Alpine Development to observe the annual avian monitoring project. Areas of the North Slope are designated as Unusually Sensitive Areas for Spectacled Eiders, which are considered a threatened species under the Endangered Species Act. The lessee's objective during the field visit was to identify and gather distribution and abundance data for Spectacled Eiders within a 0.5-mile corridor surrounding the pipeline rights-of-way.

SPCO determined that the program satisfied the surveillance and monitoring program commitments for monitoring avian species. The SPCO evaluation included conduct of operations and elements from the lessee's quality assurance program. All observations yielded satisfactory results (SPCO letter 12- 358-AS).

July 2012:
Below-grade Casing Surveillance

The Alpine below-grade casing inspection program is designed to ensure the mechanical integrity of the Alpine pipelines through external and internal corrosion monitoring and corrosion control mitigation. Inspection results communicate the external condition of each pipeline to management for the dual purpose of scheduling immediate corrective action items and planning annual maintenance activities.

SPCO discovered a damaged culvert and potential safety hazard at the DS-2F access road cased pipeline crossing.

SPCO compliance staff observed the lessee's contractor inspect each pipeline cased crossing for debris, water traps, damage to the casing, pipeline or pipeline centralizers and insulation. Centralizers are important for preventing pipeline-to-casing contact.

During the inspection, SPCO staff identified a damaged culvert that had the potential to be a safety hazard. On September 21, 2012, the lessee's contractor removed the damaged culvert and installed a new culvert near the site.

April 2013:
Right-of-way Surveillance
In April 2013 SPCO staff conducted surveillances of the Alpine Diesel, Oil and Utility pipeline rights-of-way. The surveillances of the shared right-of-way began at the Kuparuk Central Processing Facility 2 and ended at the Alpine Central Processing Facility.

SPCO observations included surveying work pads associated with operations and maintenance, the physical pipeline, the aboveground pipeline support structure and appurtenances. SPCO staff did not identify any reportable conditions along the shared right-of-way. Twelve satisfactory surveillance reports and a lease compliance report were produced by the SPCO; detailed observations can be found in SPCO letter 13-319-AS.

May 2013:
State Fire Marshal Annual Inspection
In late May 2013 the SFMO liaison conducted annual fire and life safety inspections of the Alpine facilities. Seven minor violations were documented, including missing ceiling tiles and welding safeguards that did not meet fire code requirements.
The lessee confirmed in an August 16 correspondence that all the items had been addressed.

KUPARUK PIPELINES

A survey crew takes measurements of Kuparuk Pipeline. Data from the surveying activities are used to track changes in elevation.

The Kuparuk oil field, discovered by Sinclair Oil in 1969, is the second-largest oil field on the North Slope. Representatives of the DNR and Kuparuk Pipeline Co. signed a right-of-way lease agreement for Kuparuk Pipeline (KPL) in September of 1980.

The original 16-inch KPL, constructed in 1981, carried processed crude oil to PS1. Kuparuk Pipeline Extension (KPE) was later constructed to connect CPF-2 to CPF-1, and comprised both 12-inch and 18-inch segments.

When the new 24-inch KPL was constructed in 1984, the original 16-inch KPL pipeline was converted to Oliktok Pipeline, which carries natural gas liquids from PS1 to CPF-1. In 2009 a 12-inch segment of KPE was replaced with 18-inch pipe, which made that portion of the pipeline accessible to pigging tools. Physical characteristics of the pipeline, including diameter and product transported, are provided in Appendix F.

September 2012:
Right-of-way Surveillance

SPCO compliance staff accompanied the Kuparuk roads and pads maintenance foreman during one of multiple roads and pads inspections performed during the 2013 summer months. SPCO observed the foreman inspecting Kuparuk roads, pads and bridges for significant damage to road markers, culvert reflectors and any structural damage.

SPCO staff observed the foreman inspecting bridge abutments and crossings for erosion and sloughing. During a separate inspection that takes place every four years, bridges are thoroughly inspected by an approved engineering contractor.

SPCO staff verified the lessee commitment to prevent or abate situations that could endanger the health and safety of people, that adequate communications were in place to ensure safe pipeline operations and maintenance and that roads and pads were accessible.

During the September surveillance SPCO also accompanied a survey crew contracted by the lessee to carry out the erosion survey. The survey crew took elevation measurements from the top of steel and then took measurements from the ground. These measurements are used to calculate pipeline structure subsidence and jacking or movement that could affect pipeline integrity.

SPCO staff verified that the lessee satistfied its commitments to carry out erosion mitigation surveys on an annual basis and as communicated in surveillance and monitoring program. In addition, SPCO staff verified the lessee's commitment to prevent or abate situations that could endanger human health and safety and that communication protocols ensured the safety of the survey crew and SPCO compliance staff. SPCO staff issued nine satisfactory surveillance reports and a lease compliance report containing details of the inspection (SPCO letter 13-331-AS).

April 2013:
Right-of-way Surveillance
SPCO compliance staff traveled to Kuparuk, Kuparuk Extension and Oliktok pipelines in April 2013 to evaluate the physical conditions of the shared rights-of-way from PS1 to CPF-2 and to observe the surveillance methods used by the lessee to track maintenance tasks.

Excessive snow cover prevented SPCO compliance staff from inspecting the Kuparuk Extension pipeline and right-of-way. SPCO compliance staff will perform a follow-up surveillance of the right-of-way during FY14.

SPCO compliance staff determined the lessee's surveillance and monitoring program was functioning as intended. Ten surveillance reports and a lease compliance report were generated from the field visit and follow-up activities (SPCO letter 13-XX-AS).

June 2013:
State Fire Marshal Annual Inspection
In early June 2013 the SFMO liaison completed annual inspections of Kuparuk Pipeline. These inspections include CPF-1, CPF-2 , KIC Pad and the KCC. There were 24 code violations noted, ranging from non-fucntioning exit lights to inoperative smoke detectors. A written response was received from ConocoPhillips on July 15 indicating that all corrections had been addressed.

OLIKTOK PIPELINE

ConocoPhillips plans to convert Oliktok Pipeline to transport natural gas. The conversion is scheduled to be completed in late 2014.

The 16-inch Oliktok Pipeline runs 28 miles from Module 100 at CPF1 at Kuparuk to Module 501 at PS1. It was the original production pipeline from the Kuparuk field, but it proved too small for the needed rates. A larger parallel pipeline, the present Kuparuk Pipeline, soon replaced it. Since that time, Oliktok Pipeline has transported natural gas and natural gas liquids. It has also been in shutdown status during times of non-use.

ConocoPhillips plans to convert the service of the Oliktok pipeline from natural gas liquids (NGLs) to natural gas. Current plans call for the conversion to be complete by late 2014. The work primarily consists of making physical changes, such as adding small amounts of piping and valves, changing instrumentation and controls, performing integrity assessments and satisfying regulatory requirements. To prove the integrity of the pipeline, ConocoPhillips is planning to run an ILI device while it is still in NGL service, tentatively in 2013. The operator also plans to conduct a hydrotest in 2014.

In addition to the conversion project, ConocoPhillips is installing a fiber cable in the right-of-way. This cable will provide higher speed data transfers and better communications.

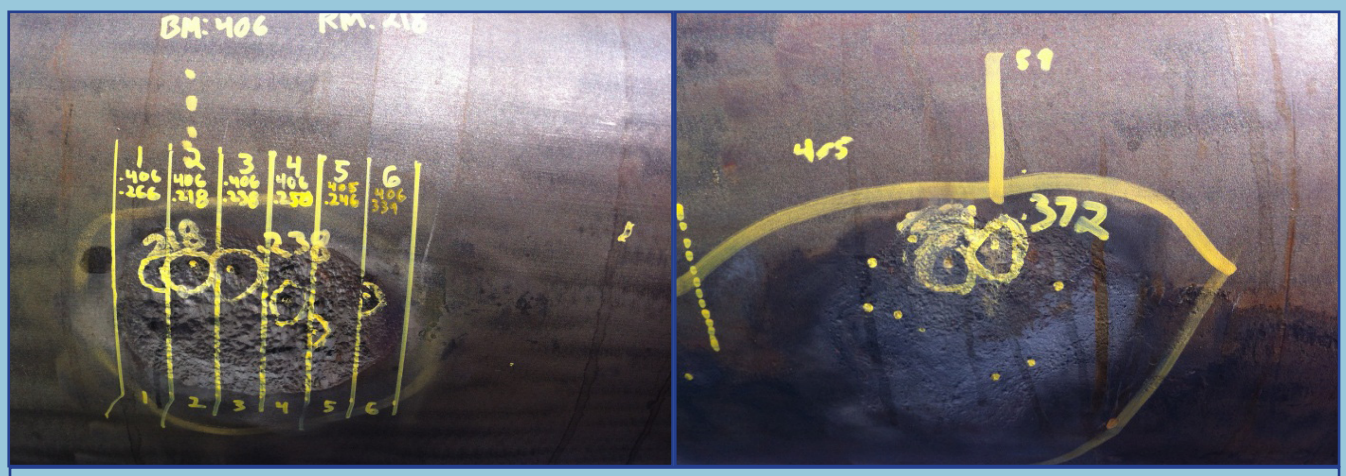
April 2013:
Right-of-way Surveillance
SPCO compliance staff traveled to Kuparuk, Kuparuk Extension and Oliktok pipelines in April 2013 to evaluate the physical conditions of the shared rights-of-way from PS1 to CPF-2 and to observe the surveillance methods used by the lessee to track maintenance tasks.

SPCO staff determined that the lessee's surveillance and monitoring program was functioning as intended. Six surveillance reports were issued for Oliktok Pipeline along with a lease compliance report (SPCO letter 13-331-AS).

May 2013:
State Fire Marshal Annual Inspection
In late May 2013 the SFMO liaison inspected the facilities associated with the Kuparuk Extension and Oliktok pipelines. There were 28 violations noted during the inspection; the majority of these were noted in the West Wing of the Kuparuk Operations Center. Violations ranged from painted sprinkler heads to open penetration into rated corridors and fire doors not operating correctly. ConocoPhillips was diligent in responding to each violation; the liaison was provided with the proper assurance that all had been addressed by August 16.

CONOCOPHILLIPS ALASKA, INC. SLEEVING PROCESS

ConocoPhillips Alaska Inc. (CPAI) has a wide-ranging corrosion inspection program for its pipelines on the North Slope. This includes corrosion under insulation (CUI) as well as an in-line inspection (ILI) pigging program. Both are used to determine the location and magnitude of corrosion. If the corrosion is deemed extensive enough for further inspection, then the steel jacketing and foam insulation is removed so up-close inspections can be completed. In a typical year, CPAI completes approximately 20 sleeves per year on the Kuparuk Pipeline (KPL) alone and dozens more on other pipelines across the North Slope.



Surface corrosion on the KPL, typically caused by water intrusion.

After the ILI and CUI inspections are complete and the data has been analyzed, corrosion specialists conduct a visual inspection and utilize specialized tools to determine the wall thickness at the corrosion areas. The wall loss is marked on the pipeline and cataloged. After the extent of the corrosion

has been documented, the process of determining the sleeve length begins. The coupling location is determined by both visual and ultrasonic testing inspections. Pits and localized corrosion can making welding difficult and are typically avoided.

The CPAI fabrication shop uses sections of pipe that match the pipelines in the field to help fabricate the couplings that will be the same size as the pipeline and the sleeve itself which has a diameter of two inches greater than the pipeline. For example, a section of 24-inch pipe, matching the KPL pipe in size and thickness is used to fabricate the 24-inch diameter couplings (0.375 inches thick) that are welded directly to the KPL and the 26-inch diameter sleeve (0.5 inches thick).

The couplings are welded to the fabrication pipe and then the sleeve is welded to the couplings as if they were being welded to the pipeline. This ensures a proper fit in the field. Once the fabrication sleeve is completed the parts are dismantled and taken to the field to be installed.

The couplings are installed at the specific areas as stated above. Once all the weld passes are complete the CPAI technicians inspect the welds using both visual and magnetic particle testing inspections, which can find flaws in the welds that a visual inspection cannot, to ensure the welds are adequate.

Once the couplings are installed and testing confirms the welds do not have any flaws, the sleeves are welded to the couplings, leaving an annular space of the thickness of the couplings between pipeline and the sleeve. This space will be filled with a grout material to fill all the void space between the existing pipe and the new sleeve. The grout is poured into the annular space through three spouts located on the top of the sleeved section. After the grouting process is completed the three spouts are capped and welded shut.

The sleeve is then wrapped in a corrosion resistant tape, and after new insulation and metal sheeting are installed over the sleeve the process is complete.

Sleeve welded to the couplings and spouts being capped and prepared for welding.

Functionally, the process creates a full pressure containment sleeve that can independently take full line pressure if the underlying pipe is penetrated by corrosion. While there are several types of installations CPAI uses full pressure containment sleeves exclusively to minimize the risk to the pipelines on the North Slope.

NORTH SLOPE BOROUGH PIPELINES

NUIQSUT NATURAL GAS PIPELINE

Nuiqsut Natural Gas Pipeline shares horizontal and vertical supports with the Alpine pipelines from the production pad to the west bank of the Colville River, where it transitions below ground until it reaches the village of Nuiqsut.

The North Slope Borough (NSB) constructed the Nuiqsut Natural Gas Pipeline (NNGP) to transport natural gas from the Alpine production pad to the village of Nuiqsut, located within the Colville River Delta. The 14.4-mile pipeline shares horizontal and vertical supports with the Alpine pipelines from the production pad to the west bank of the Colville River, where it transitions below ground until it reaches Nuiqsut.

DNR issued the NNGP Right-of-Way Lease, ADL 416202, to the NSB in the spring of 1999. Construction began shortly thereafter and completed the same year; however, due to delays in finalizing gas supply contract negotiations, acquiring the necessary regulatory approvals and building the distribution facilities, NNGP did not become operational until September of 2008. By 2009, service was available to the 122 homes and 30 commercial buildings that submitted service requests to NSB. Nuiqsut is the third North Slope community (after Barrow and Deadhorse) to provide heat and electricity from natural gas.

The flow in NNGP increased in FY11, as more natural gas was consumed in Nuiqsut. NSB introduced a program to convert heating-oil appliances to natural gas in the village. Problems with new natural-gas engines were resolved, which resulted in more

electrical energy being produced from natural gas and less from diesel generators. In August of 2010, NSB performed a corrosion assessment, coating investigation, an inspection of the cathodic protection system and ultrasonic testing of pipeline wall thickness. The cathodic protection system is on the buried portion of the pipeline. The 14.4-mile line has two segments; an 8.8-mile above-ground segment that runs from the Alpine pad to the Nechelik channel crossing of the Colville River and a 5.6-mile below-ground segment that runs under the channel to the distribution point at Nuiqsut. A number of issues involving cathodic protection and coating were recorded.

Prior to NNGP start-up, the SPCO had required a professional engineering report and a field investigation of the coating deterioration on the pipeline. The coating has visibly deteriorated in the three years since the report. USDOT/PHMSA, the agency with specific authority over pipeline integrity, is responsible for monitoring pipeline coating problems. USDOT/PHMSA has been aware of the NNGP coating deterioration since prior to start-up. The SPCO continues to share information from site inspections with USDOT/PHMSA - both agencies plan to look more closely at the situation during future inspections.

August 2012:
Right-of-way Surveillance
SPCO compliance staff accompanied the NNGP Operator from the village of Nuiqsut, traveling to the Alpine Development situated 14 miles north of the village.

The operator anticipated completing the coating damage repair, which included verifying damage from prior years and documenting any new damage. The operator began assessing the extent of coating damage at the first flange off the Alpine Development pad (pictured on page 80). Due to the extent of damage identified and recorded, the operator was unable to complete the coating damage evaluation that day. The operator intended on finishing the inspection later that month.

Coating damage and evidence of atmospheric corrosion on the Nuiqsut natural gas pipeline.

January 2013:
Change of Operator
In late 2012/early 2013 SPCO was notified that NNGP did not have a qualified operator operating and maintaining the transmission pipeline. SPCO management and staff began working closely with the North Slope Borough management team to ensure the lessee obtained a fully qualified operator to perform daily operations, maintenance duties and emergency response to ensure the integrity of the pipeline system.

SPCO contacted USDOT/PHMSA to notify the agency of the NNGP operator situation. NSB made strides to monitor the pipeline system from its offices in Barrow and used the distribution pipeline operator for monitoring the pressure-reducing valve station managing communications with Alpine Pipeline operations.

In mid-January, NSB assured SPCO management that in February 2013 a qualified operator would be contracted to perform operations and maintenance duties. In mid-February NSB management notified SPCO that the borough assembly had approved a contract for WHPacific to operate NNGP.

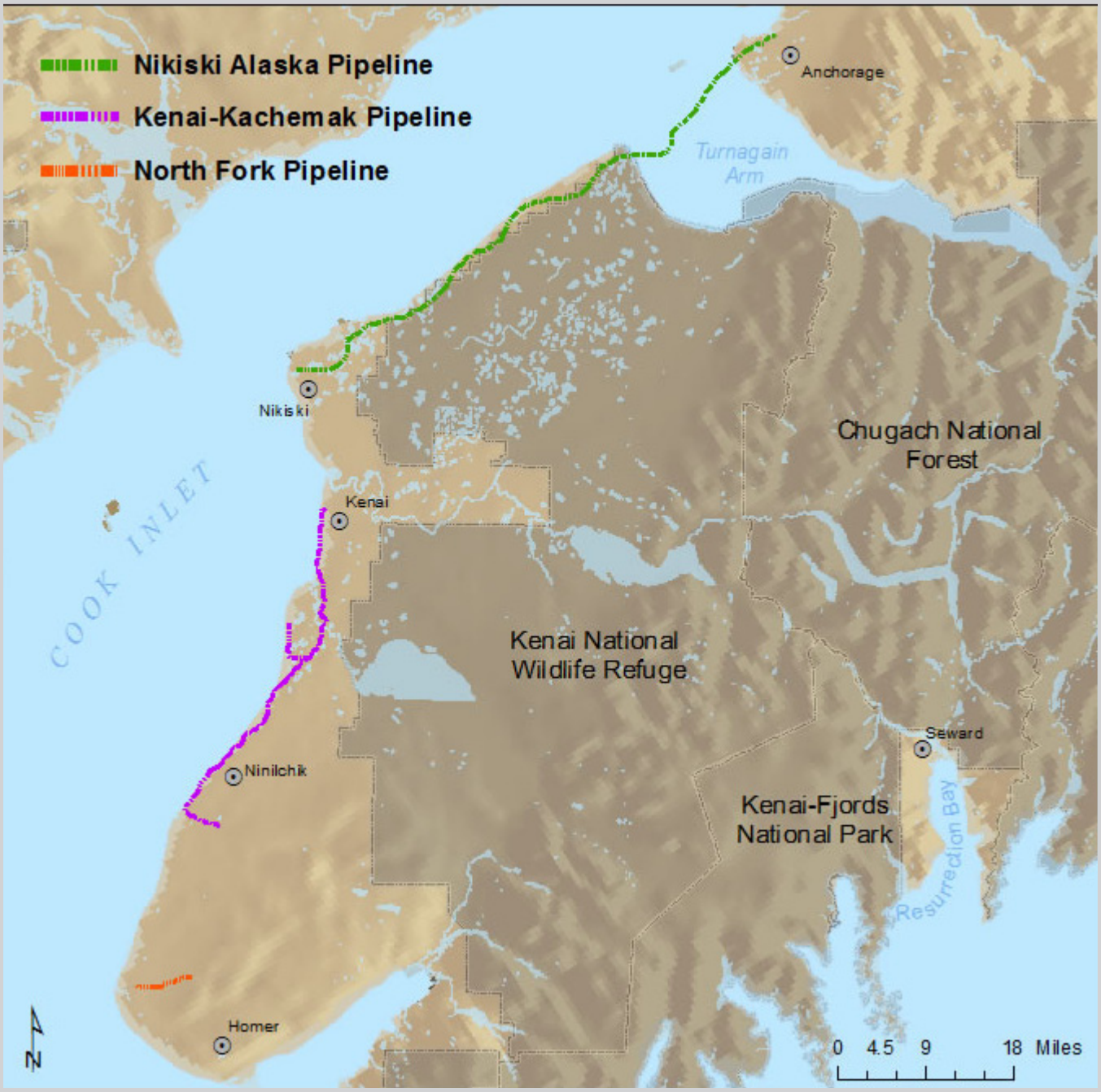
April 2013:
Right-of-way Surveillance and USDOT/PHMSA Notice of Probable Violation
SPCO compliance staff and USDOT/PHMSA staff traveled to Nuiqsut to meet with NSB and WHPacific representatives and conduct a pipeline right-of-way surveillance. The group observed and documented the condition of pipeline system and leasehold from the pressure-reducing valve station to the above-grade transition and a short distance of the right-of-way.

The USDOT/PHMSA inspector identified multiple locations along the pipeline with apparent damage to the pipeline coating and possible atmospheric corrosion. The inspection resulted in a warning letter issued by USDOT/PHMSA (CPF 5-2012-0008W) concerning cathodic protection and the condition of the external coating on the Nuiqsut pipeline. Cathodic protection is a technique for mitigating external corrosion in buried pipelines by inducing a voltage in the metal. Coatings are films or coverings that provide surface protection (similar to paint). In the letter, USDOT/PHMSA advised the NSB that no enforcement action would be initiated or civil penalties assessed unless the operator failed to address the violations.

In response to the USDOT/PHMSA letter, the NSB produced a 2013 Work Plan with detailed plans to address the items identified during recent inspections, including cathodic protection system improvements and pipeline coating removal and repair. SPCO compliance and USDOT/PHMSA staff will continue to monitor the operator's progress in improving and maintain the pipeline system during FY2014. Detailed information from the SPCO surveillance are included in letter 13-185-AS.

June 2013:
State Fire Marshal Annual Inspection
In early June 2013 the SFMO liaison completed the annual inspections for the Nuiqsut Pipeline. These inspections included the gas injection building and associated storage skid. There were three minor code violations noted during the visit. The NSB was quick to address the concerns and correct them to the satisfaction of the State Fire Marshal.

SOUTHCENTRAL PIPELINES



This section of the report focuses on southcentral Alaska pipeline systems under the jurisdiction of the SPCO. Before 2010, southcentral Alaska SPCO-jurisdictional pipelines included Kenai Kachemak Pipeline (KKPL), operated by Marathon Pipe Line, LLC (MPL), and Nikiski Alaska Pipeline (NAP), operated by Tesoro Alaska Pipeline Company (Tesoro). In 2010, the SPCO issued a right-of-way lease to Anchor Point Energy, LLC, for a 7.4-mile long natural gas pipeline from the North Fork production pad to the Anchor Point area. North Fork Pipeline began transporting gas on April 7, 2011.

KENAI KACHEMAK PIPELINE

Valve station for a lateral production pad tie-in at pipeline milepost 23.8

The Kenai Kachemak Pipeline (KKPL) is a high-pressure, primarily buried, natural-gas transmission pipeline on Alaska's Kenai Peninsula. Throughout its route, the pipeline parallels Kalifornsky Beach Road, the Sterling Highway, Cohoe Loop Road, and Oilwell Road. It was built in three phases during 2003, 2004, and 2006. The KKPL mainline was built with 12-inch pipe of 0.330 and 0.5-inch wall thickness, and is rated for a maximum allowable operating pressure of 1,480 pounds per square inch (psig). Specific physical characteristics of the pipeline and extensions are provided in Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines.

KKPL begins at the Happy Valley production pad and ends at the Marathon Oil Company 500 Master Meter Building, running generally south to north. Seven Cook Inlet wells currently transport natural gas through KKPL. Some natural gas is distributed from KKPL for local use.

The original right-of-way lease was issued to KKPL, LLC, on November 26, 2002. The lease was amended twice and is set to expire November 25, 2032. The first amendment, executed on June 16, 2004, added 48 acres to the right-of-way to accommodate Phase 2 of construction, referred to as the Happy Valley Extension (HVE). The second amendment, executed on April 24, 2006, added 35.6 acres of State land for construction of Phase 3, referred to as the Kasilof Extension (KE).

The Right-of-Way Release of Interest was finalized in FY09, reducing the right-of-way from the construction width of 60 feet to the operational width of 20 feet.

January 2013:
Right-of-Way Surveillance

The Alaska Department of Transportation and Public Facilities (ADOT&PF) is expanding portions of the Sterling Highway to accommodate a passing lane for segments of the highway between Kasilof and Ninilchik. SPCO staff observed preliminary brushing occurring at several locations along the pipeline right-of-way. Marathon had given approval for all the work within the pipeline right-of-way, as long as no excavation is occurring.

SPCO staff spent time at a site where flooding occurred in September 2012. SPCO staff observed no residual issues from the flooding. A new culvert had been installed and the road was restored and regraded. Additional rip-rap rocks had been installed adjacent to the culvert to prevent bank erosion as the stream changes direction into the culvert.

SPCO staff was provided with a work order associated with cleaning pigs on KKPL. No cleaning pig was run on KKPL in 2012 due to the potential of having a pig stuck in the pipeline prior to the winter months (high gas demands) and the pending transfer to Hilcorp. Cleaning pigs are not required to be run each year. The MPL Integrity and Corrosion groups approved the delay of the cleaning pig run on September 18, 2012. The lack of pig run was given a MPL incident number and entered into the ALIRTS tracking database. SPCO staff was provided a copy of the MPL incident form along with workorders for the most recent cleaning run performed on July 22, 2011.

Restored and regraded washout of Kalifornsky Beach Road and KKPL right-of-way.

A lease compliance report and six surveillances were completed for the trip; all reflected satisfactory conditions (SPCO letter 13-045-AS).

September 2013:
State Fire Marshal Annual Inspection

The week of September 12, 2012, the SFMO Liaison completed the annual inspections for KKPL Pipeline. The facilities were inspected under the Authority of AS 18.20 and AS 24.06.630. The facilities were inspected to the 2009 International Fire, Building and Mechanical Codes and adopted NFPA Standards. There were five code violations that were minor in nature. The operator was very fast to respond and indicate that corrections had been completed.

NIKISKI ALASKA PIPELINE

Nikiski Alaska Pipeline right-of-way near PLMP 10.

Nikiski Alaska Pipeline is a buried pipeline that begins at Tesoro Alaska Pipeline Company's (Tesoro) Kenai Refinery in Nikiski. The pipeline route runs along the Kenai Spur Highway through the Captain Cook State Recreation Area, and then parallels the coast to Point Possession before crossing the Turnagain Arm. The pipeline route continues along the Tony Knowles Coastal Trail, through the Ted Stevens Anchorage International Airport, and then along Northern Lights Boulevard. The pipeline runs near the Alaska Railroad right-of-way for the remainder of the route, terminating at the Port of Anchorage.

The Nikiski Alaska Pipeline Right-of-Way Lease, ADL 69354, was executed on January 30, 1976, and is scheduled to expire January 29, 2031 (see Appendix D: Acreage, Survey, and Lease Information). The lease has been amended four times. The pipeline right-of-way is typically 10 feet wide for operations and maintenance (see Appendix E). The total system length is 52.8 miles; 20 miles located on State land, occupying 64.2 total acres (see Appendix F).

The Nikiski Alaska Pipeline was constructed in 1976. The pipeline has a 10.75-inch outside diameter and transports refined petroleum products (jet fuel, gasoline and diesel) from Tesoro's Kenai Refinery to the Port of Anchorage. The pipeline operates under USDOT/PHMSA pipeline safety regulations and transports refined products suitable for industrial, government, commercial and consumer use. The Nikiski Alaska Pipeline's maximum operating pressure (MOP) is 1,440 psig. Mainline pumps, meters, and the pig launcher are located at Tesoro's Kenai Refinery.

August 2012:
Right-of-Way Surveillance

SPCO compliance staff traveled to Nikiski to conduct an aerial surveillance of the Nikiski Alaska Pipeline right-of-way from the Tesoro refinery to the terminus at the Port of Anchorage. The flight path followed the pipeline in a northeast direction at approximately 150 feet elevation. The flight followed the pipeline right-of-way for approximately 45 miles to Point Possession where the pipeline reaches Cook Inlet. Using a GPS mounted inside the aircraft the pilot followed the pipeline alignment across Cook Inlet until reaching Point Campbell near Kincaid Park in Anchorage. The alignment was then followed across Ted Stevens International Airport, down Northern Lights Boulevard, then north along the railroad right-of-way until reaching the coastal trail and the port of Anchorage.

SPCO staff observed where a new cathodic protection anode bed was installed in March of 2011. The anode bed is located at pipeline mile post (PLMP) 13. The aboveground infrastructure included a rectifier, anode junction box, CP bond junction box, and the CP coupon test station. The fencing around the site appeared to be in good working condition.

Nikiski Alaska Pipeline right-of-way crossing at Miller Creek with evident erosion occurring at both creek banks.

SPCO staff observed multiple sheens on standing water along the right-of-way between Captain Cook State Park and MLV 4. All sheens observed were in wetland areas. SPCO staff did not observe any discoloration around the sheens that would indicate a hydrocarbon leak.

The fencing around MLV 4 appeared to be damaged but in working order. The fencing appeared to be in the same condition observed by SPCO staff in April and had not deteriorated over the course of four months. SPCO staff observed no pipeline-related equipment outside the fencing at MLV 5, as noted from a ground surveillance conducted in April, 2012.

Between Captain Cook State Park and Point Possession there are six Alaska Department of Fish and Game (ADF&G) designated anadramous fish streams. Tesoro has a fish habitat permit from ADF&G to cross Seven Egg, Otter, Scaup, Bishop and Miller Creeks. The permit was issued on October 21, 2010, and expires on December 31, 2015. Leaf Creek has a bridge over it and therefore does not necessitate a fish habitat permit to cross the creek.

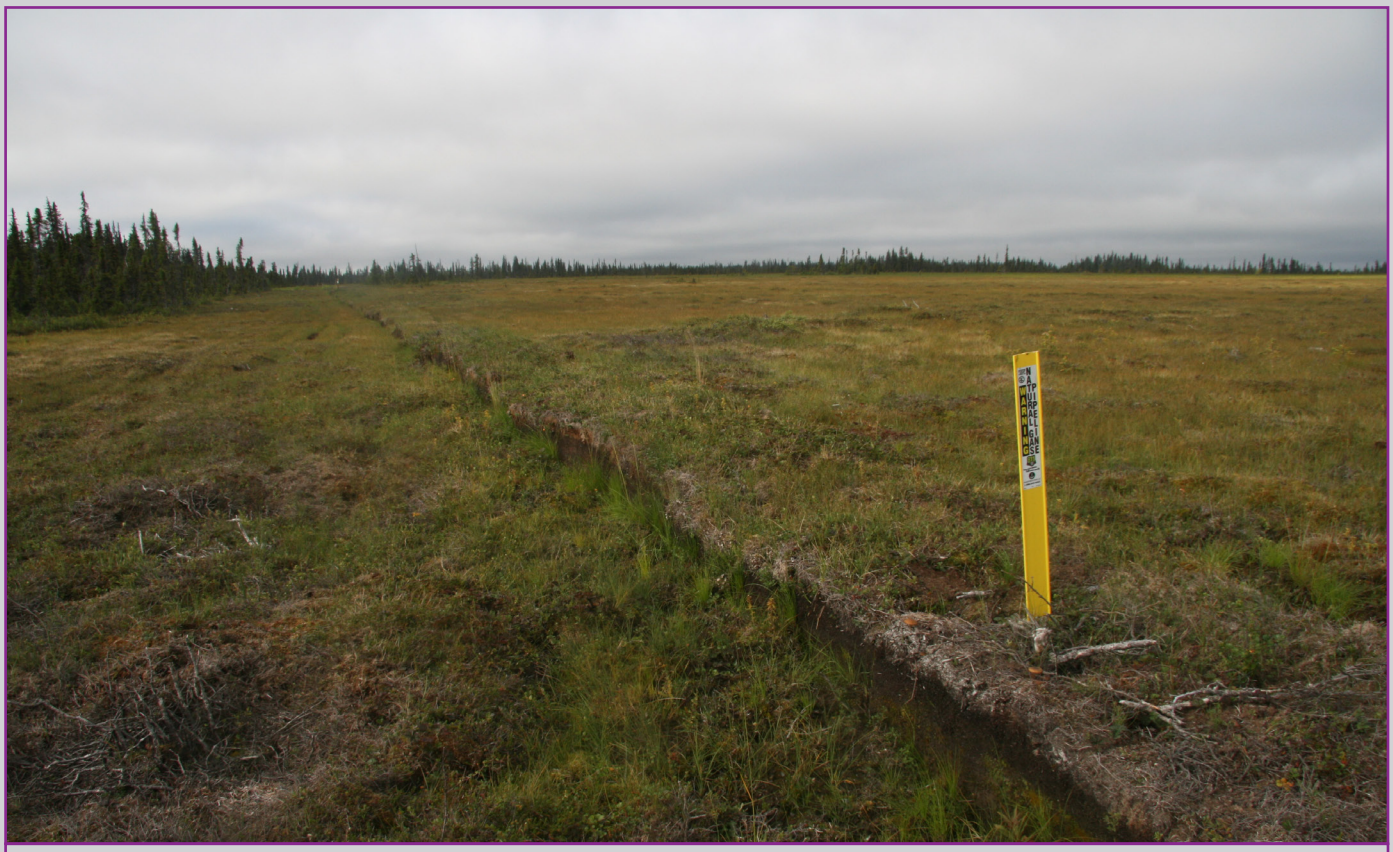
Stream crossings at Seven Egg, Otter, Scaup, and Bishop Creek all appeared to be in good condition. No erosion was witnessed at any of these stream crossings. Miller Creek has erosion occurring at both sides of the creek with an extended drive lane going past the banks of the stream and into the floodplain. It appears that the bank erosion is occurring because of the right-of-way traffic.

Nikiski Alaska Pipeline right-of-way near PLMP 30.

The right-of-way appeared to be in a variable condition. Portions appeared to be in good repair, while others were muddy wetlands. There was evidence that the right-of-way is well traveled due to the amount of vehicle tracks observed. All aboveground pipeline valves observed were located within fence enclosures, which were in good repair.

A lease compliance report and seven surveillances were completed, one of which had unsatisfactory findings for the Miller Creek crossing (SPCO letter 12-436-AS). SPCO staff contacted ADF&G and provided notification of the stream crossing erosion.

NORTH FORK PIPELINE



SPCO staff inspect the North Fork right-of-way one year after construction.

The SPCO granted Anchor Point Energy, LLC, an AS 38.35 Right-of-Way Lease for the purpose of constructing dual four-inch natural gas pipelines, called the North Fork Pipeline. The entire pipeline length is 7.4 miles with 6.6 miles of the length on State land. The North Fork Pipeline begins at the North Fork Production Pad, located 8.6 miles east of Anchor Point, and terminates in Anchor Point. The pipeline ties into Anchor Point Pipeline, operated by Alaska Pipeline Company.

The North Fork Pipeline comprises two segments, 6.25 miles of Fiberspar Linepipe and 1.25 miles standard steel construction. The Fiberspar Linepipe is a composite pipe consisting of an inner thermoplastic pressure barrier reinforced by high-strength glass fibers embedded in an epoxy matrix. This was the first time that a common carrier line, regulated by USDOT/PHMSA, was constructed out of a composite pipe material. USDOT/PHMSA required that a special permit, with project-specific stipulations, be issued for the pipeline construction.

Pipeline construction began in October 2010 and completed at the end of February 2011. The right-of-way width was 50 feet during construction and decreased to a 20-foot operating width post-construction.

First delivery of gas occurred on March 31, 2011.

August 2012:
Right-of-way Surveillance

SPCO compliance staff traveled to Anchor Point to conduct surveillances of the North Fork Pipeline right-of-way and observe the operator's surveillance and monitoring activities. SPCO staff, along with the EH&S manager for All American Oilfield, drove the right-of-way from the pad for 1.2 miles. SPCO staff and the EH&S manager then walked the remaining 5.35 miles of the right-of-way to the blowdown station where the Fiberspar LinePipe connects to the steel pipelines.

Overall the right-of-way was in an acceptable condition at the time of the surveillance. Surface vegetation appeared to be in good condition. No erosion was evident at stream crossings and there was no blockage of fish passage. The vegetation blocks placed over the pipeline after burying the pipeline does not appear to have settled much since the 2011 right-of-way surveillance by the SPCO. One section of blocks appeared to have dead vegetation on them near PLMP 3. All other vegetative blocks appeared to be covered in healthy vegetation.

Slight erosion appeared to be occurring on a slope at PLMP 1. SPCO staff observed a small trough over the buried pipe where it appeared water had flowed at one time. A depth of cover survey conducted in April indicates that there is adequate cover in this area. SPCO staff will continue to monitor the erosion at this site.

All stream crossings observed on the right-of-way appeared to have clear passage for fish. SPCO staff observed no erosion occurring at any creek crossings.

SPCO staff drove the right-of-way from the blowdown station to the transfer of custody pad. All fencing around the blowdown station appeared to be in good condition no erosion was observed at the North Fork Anchor River crossing.

SPCO staff near the North Fork Anchor River crossing.

SPCO staff requested from the operator the three most-recent right-of-way surveillance forms, including the surveillance that was conducted with the SPCO on August 14, 2012. SPCO also requested the most recent leak detection and cathodic protection surveys. On September 27 the SPCO received all requested documents. All documents received by the SPCO indicated compliance with the SPCO right-of-way lease.

A lease compliance report and ten surveillance reports were completed from the trip; all resulted in satisfactory findings (SPCO letter 12-433-AS).

September 2013:
State Fire Marshal Annual Inspection
The week of September 12, 2012, the SFMO Liaison completed the annual inspections for the North Fork Pipeline. There were four minor code violations that were field-corrected by the facility operator.

June 2013:
Right-of-way Surveillance
SPCO compliance staff traveled to Anchor Point to conduct surveillances of the North Fork Pipeline right-of-way. Information was gathered in preparation of a release of interest to reduce the right-of-way from the construction width of 50 feet to an operations width of 20 feet.

SPCO staff, along with a Five Star Oilfield Services representative, drove along the pipeline right-of-way for 1.5 miles. They then walked the remaining five miles of the pipeline right-of-way to the blowdown station where the Fiberspar LinePipe connects into the steel pipelines. From the blowdown station to the Enstar pad tie-in SPCO staff drove along the pipeline right-of-way and observed the North Fork Anchor River crossing.

Overall the right-of-way was in an acceptable condition at the time of the surveillance. Surface vegetation appeared to be in good condition. No erosion was observed at stream crossings. No blockage of fish passage was observed in any of the stream crossings. The vegetation blocks placed over the pipeline after burying the pipe appear to be settling to various degrees. In some areas the blocks have settled very little, while others have settled to the point of which they have subsided below the surrounding ground level. The minimum depth of cover for the pipeline is five feet. A depth of cover survey, conducted from April 2-6, 2012, found that the entire pipeline had the minimum depth of cover of five feet. The next scheduled depth of cover survey is scheduled for July, 2013.

Below is a summary of notable conditions observed on the ROW surveillance:

- PLMP 0.25 – Damaged cathodic protection test station at the south side of the North Fork Anchor River crossing

- PLMP 1.4 – Three trees fallen on the right-of-way; one damaged a pipeline marker.

- PLMP 1.4 to 1.5 – Subsidence occurring over the pipeline.

- PLMP 1.6 – Vegetative blocks not settling over the pipeline.

- PLMP 2 – Subsidence occurring over the pipeline (most significant on the line).

- PLMP 2.2 and 4.1 – Fallen tree on the right-of-way.

- PLMP 2.25 – Evidence of 3rd-party travel. This included rutted tracks running along the right-of-way for several hundred feet.

None of the observed conditions necessitate immediate mitigation measures. The subsidence occurring over the pipeline will continue to be monitored. The depth of cover survey scheduled for July will indicate if any of these areas of subsidence are not meeting minimum depth requirements.

The Five Star Oilfield Services representative stated that these observations would be included in a right-of-way surveillance form. It was indicated that the removal of the fallen trees into the right-of-way would be put onto a maintenance list.

All stream crossings observed on the right-of-way appeared to have clear passage for fish. SPCO staff observed no erosion occurring at any creek crossings. SPCO staff drove the right-of-way from the blowdown station to the transfer of custody pad. The right-of-way appeared to be in good condition. All fencing around the blowdown station appeared to be in good condition. SPCO staff observed no erosion at the North Fork Anchor River crossing.

SPCO staff found the right-of-way to be in an acceptable condition. No conditions observed were significant enough to prevent the SPCO from issuing a release of interest for lands associated with the construction right-of-way. A lease compliance report and six surveillance reports were completed from the trip; all reflected satisfactory findings (SPCO letter 13-245-AS).

PROPOSED PIPELINES

Before a pipeline right-of-way lease is issued by DNR, the SPCO conducts a review and decision process as required by AS 38.35, the Right-of-Way Leasing Act. Each potential pipeline lessee is evaluated to ensure that they meet the "fit, willing, and able" requirements outlined in AS 38.35.100. In FY13, the SPCO was in various stages of the leasing process with several potential and current applicants. See below for a brief description of theses pipeline projects.

ALASKA PIPELINE/SOUTHCENTRAL LNG PROJECTS

In May 2012, TransCanada and ExxonMobil, as proponents for the Alaska Pipeline Project, announced they would put on hold the work toward a natural gas pipeline from Alaska's North Slope to Alberta in order to focus on an option of building a pipeline and liquefied natural gas (LNG) facility to load LNG tankers to Asian or other world markets.

In May 2013, South Central LNG (SCLNG) began a summer field season exploring a proposed route for a pipeline and LNG facility to ship Alaska's North Slope gas to Asian and other world markets. SCLNG is an integrated team of BP, ConocoPhillips, ExxonMobil and TransCanada. The project remains in the conceptual stages; please see the ROW summary for a list of permits issued for the 2013 summer field season in support of this effort.

ALASKA STAND ALONE PIPELINE PROJECT

The State Pipeline Coordinator's Office issued a Right-of-Way lease to the Alaska Gasline Development Corporation (AGDC), a subsidiary of Alaska Housing Finance Corporation, on July 25, 2011. The Lease conveyed a right-of-way interest in State land for the development of an in-state 24-inch diameter natural gas liquids pipeline travelling from the North Slope to the Cook Inlet area where it would connect into the existing Cook Inlet natural gas delivery system. The lease included a right-of-way corridor, called the spur line, to travel approximately 35 miles from the mainline route to bring gas to Fairbanks.

Gov. Sean Parnell signed House Bill 4 in FY13, which changed a number of aspects of the ASAP project.

The SPCO, in addition to developing the Lease, worked as the lead state representative in the U.S. Army Corps of Engineers (USACE) Environmental Impact Statement process. The USACE was designated the lead federal agency and the

Bureau of Land Management, National Park Service, Environmental Protection Agency, United States Coast Guard, Pipeline and Hazardous Materials Safety Administration also participated as cooperating agencies in the EIS development process. The SPCO coordinated the state's comments, project review and participation on behalf of the Department of Fish and Game, the Alaska Department of Transportation and Public Facilities, Department of Labor and Workforce Development, Department of Environmental Conservation, State Historic Preservation Office, State Parks and Outdoor Recreation, Division of Mining, Land and Water, and the Health and Social Services Office. The USACE published the Final EIS (FEIS) on October 26, 2012.

In early 2013, plans for the ASAP project changed. The project now proposes to no longer ship natural gas liquids. This change allows the pipeline to operate at a lower pressure, with easier access for offtakes along the pipeline route. In addition, the project has increased to a 36-inch diameter pipe.

The 2013 legislative session held several hearings on – and ultimately passed – House Bill 4 (HB4), which changed a number of aspects about the original in-state gasline project known as ASAP. In addition to the changes made to the project, changes were also enacted to the existing Alaska Statute 38.35, including the option for certain pipelines to have "contract carrier" status. As this is new territory for the SPCO and the State of Alaska a team has been dedicated by AGDC to work with the SPCO in determining how the lease can be amended to reflect the changes that the legislature has enacted as law. The SPCO will be working diligently on this project during the upcoming year.

ASAP PERMITTING

AGDC has been issued two land use permits and two temporary water use permits for their 2013/2014 geotechnical program. AGDC currently has six active DNR permit authorizations and has one other permit satisfactorily closed. Other permits associated with the geotechnical program include authorizations from the Alaska Departments of Transportation and Public Facilities and Fish and Game, Natural Resources Office of History and Archaeology.

POINT THOMSON

The Pt. Thomson Lease was signed on October 31, 2012, by PTE Pipeline LLC (PTEP), a wholly owned subsidiary of ExxonMobil, and the Commissioner of the Department of Natural Resources. The signing of this lease was the culmination of three years of collaborative work, which began when PTEP submitted an AS 38.35 application to the SPCO in March of 2010. In the fall of 2012, the Commissioner's Analysis and Proposed Decision and Draft PTEP Lease were publicly noticed and the SPCO conducted public hearings on the analysis and draft lease in Kaktovik, Barrow, Nuiqsut and Fairbanks. Upon completion of the public notice and hearing processes, the DNR Commissioner issued a Final Finding and Decision and the PTEP Lease was signed by both parties.

The 22-mile Pt. Thomson Pipeline project is now under construction. The pipeline route is roughly parallel to the North Slope coast, varying 0.25 mile to 2.5 miles inland.

The nearest community to the pipeline is Kaktovik, which is approximately 60 miles to the east. The pipeline will transport liquid hydrocarbons from the Pt. Thomson Central Production Facility (also currently under construction) to the existing Badami Sales Oil Pipeline at the Badami Central Facilities Pad. With this lease and construction of this pipeline, ExxonMobil will be able to transport the Thomson Sand Reservoir reserves that are being developed simultaneously. The Point Thomson field, located approximately eight miles west of the Arctic National Wildlife Refuge and now the furthest most eastern developed oil field in Alaska, holds an estimated eight trillion cubic feet of natural gas and 20 million barrels of condensates.

Upon the finalization of the lease, PTEP submitted the required work plans, programs and engineering documents necessary to initiate construction activities. These documents included construction, operations, and maintenance plans for Erosion and Sedimentation Control, Cultural Resource Preservation, Groundwater Control, Disposal of Hazardous Waste, Wildlife Interaction, as well as a complete Quality Management Program and Emergency Preparedness Plan (the complete list of required submissions can be found in the Stipulations (Exhibit A) of the PTEP Lease). These plans and programs were circulated to the SPCO coordinate and liaison agencies for review and comments. Upon completion of review and either acceptance or approval of the required documents, the SPCO issued the Notice to Proceed in November of 2012. Soon after the PTEP team was mobilizing and in the field initiating pre-construction and construction activities.

With the signed lease and the Notice to Proceed issued, the project shifted internally at the SPCO. The compliance and engineering staff has taken responsibility of monitoring construction activities in accordance with the PTEP lease.

POINT THOMSON 2012-2013 WINTER CONSTRUCTION SEASON

Construction of PTEP between the project's central pad 22 miles west to Badami Oil Pipeline began in January 2013. Once the overland and right-of-way ice roads were completed, work crews began installing the pipeline support structures and some support and camp facilities. The following is a list of some of the accomplishments achieved by the project during the 2012/2013 ice road season:

- Construction of an approximately 22-mile overland ice road to ship goods and materials between Badami and Central Pad

- Construction of an approximately 22-mile ice road to aid in the installation of support structures

- Installation of approximately 2,200 vertical support members and horizontal support members that will support the oil sales and some in-field pipelines

- Installation of several temporary man camps to house personnel during the winter construction season
- Fabrication of the permanent 200-man camp (this camp was moved to the Central Pad during the ice road season and will be brought online during the summer of 2013)

• Development of a gravel mine site near the Central Pad (the mine will provide gravel to construct in-field roads, pads, and airport facilities)

More than 600 people worked on the project during the 2012/2013 season. There have been no loss-time accidents to date. SPCO surveillances found that mitigation measures initiated during the first phase of construction were successful and ensured minimal risk of damage to the tundra, wildlife, aquatic resources and subsistence activities.

In FY13 work crews installed approximately 2,200 vertical and horizontal support members for the Point Thomson Export Pipeline.

The second phase of the construction activities during the 2013/2014 ice road season will include the installation of a 12-inch sales-quality oil pipeline, the crude oil processing facility, well pads, access roads and other minor facilities related to oil production at Central Pad.

PTEP is scheduled to be online and transporting sales-quality oil to TAPS Pump Station 1 between October 2015 and April 2016. An estimated 10,000 barrels of oil per day is anticipated to be processed and shipped from Central Pad with a maximum design capacity of 70,000 barrels per day.

POINT THOMSON LEASE COMPLIANCE ACTIVITIES SUMMARY

March 19, 2013: SPCO compliance staff conducted a field visit of the PTEP project to observe PTEP construction progress and the implementation of the quality and spills and drips programs. SPCO prodcued a field report along with six satisfactory surveillance reports. The surveillance reports contained evaluations of quality management program elements performed in field by the construction crew, right-of-way accessibility, health and safety principles utilized by the contractor and PTEP personnel, and an update on PTEP right-of-way construction progress. Details of the inspection are in report 13-186-AS.

April 11, 2013: SPCO staff traveled to the PTEP project site to discuss the project schedule, monitor the project site and review quality assurance records. While on site, SPCO staff requested to review several inspection forms described by the quality assurance plan approved by the SPCO. The documentation SPCO staff reviewed indicated that, in regard to VSM installation records, PTEP demonstrated compliance with the approved Quality Management Program. PTEP appeared to be making and

recording the field modifications needed to prevent any adverse conditions to the pipeline. The site visit resulted in a trip report and one satisfactory surveillance report (SPCO letter 13-168-AS).

May 1, 2013: SPCO staff traveled to the PTEP right-of-way to observe the demobilization of the construction right-of-way. The right-of-way was clear of all construction equipment, and SPCO staff did not observe any debris or construction related items. No work was occurring within the construction right-of-way, as the ice road had been closed since April 24, 2013. All the VSMs for the entire PTEP right-of-way had been completely installed.

SPCO staff observed 10 staging areas used to store equipment and construction materials. Eight of the 10 staging areas were located on lakes with the other two on an ice pad on tundra. All the staging areas observed by the SPCO were clear of all equipment and construction materials.

The PTEP right-of-way crosses 17 rivers and streams on the route. SPCO staff did not observe any disturbances at any of the river and stream crossings. A lease compliance report and three surveillances were completed for the trip; all reflected satisfactory conditions (SPCO letter 13-193-AS).

POLAR LNG

Since receiving and public noticing the amended application in April of 2012, the SPCO has been drafting the Commissioner's Fit, Willing and Able Analysis and Preliminary Decision and negotiating the right-of-way lease and financial assurance requirements with Polar LNG, LLC (Polar). The applicant proposes to construct a pipeline and liquefied natural gas (LNG) facility on the North Slope in order to truck natural gas from Prudhoe to Fairbanks.

The proposed route begins west of Flow Station 1 and heads south across undeveloped state lands, then through existing North Slope lease tracts, across an unnamed lake (locally known as Lake McDermott) and terminates at the Polar LNG Pad within the Prudhoe Bay Unit in Deadhorse. The lease tract for the Polar LNG Pad is approved under a separate DNR authorization issued by the Division of Mining, Land and Water, Northern Region Office. The proposed pipeline right-of-way will contain one eight-inch diameter pipe. The pipeline design maximum throughput is approximately 50 million standard cubic feet per day. Planned construction timeframe is for the winter and summer 2013/2014.

GVEA

On December 7, 2012, the SPCO received an application from Golden Valley Electric Association (GVEA) for a right-of-way lease to construct and operate a natural gas pipeline and LNG facility on the North Slope. The proposed pipeline and facility were to be located just south of Flow Station 3 within the Prudhoe Bay Unit, entirely on State land. The pipeline was proposed to be approximately 2,640 feet long and 10 inches in diameter, with a proposed use of 29.5 million standard cubic feet (MMscf) of gas per

day. LNG from the facility was proposed to be trucked from the North Slope to Interior gas utilities and a vaporization and storage facility in North Pole. Upon receiving the application, the SPCO issued a public notice of the application and began review of the project; however, due to changes in project funding options, the application was withdrawn by the applicants on June 5, 2013.

TRANS-FORELAND PIPELINE

On November 26, 2012, Cook Inlet Energy submitted an application for an AS 38.35 Pipeline Right-of-Way across the seafloor of Cook Inlet. The application was public noticed on December 5th, 2012. The project proposes to construct a 29-mile pipeline to transport oil across Cook Inlet. The pipeline will be buried in uplands and tidelands, and anchored onto the seafloor across the inlet. The 26 offshore miles of the pipeline are located on State lands; the uplands on both sides of Cook Inlet, at the origination and termination points, are privately owned. The pipeline will extend from the Cook Inlet Energy-owned Kustatan Production Facility, located on the West Forelands of Cook Inlet to the Nikiski – Kenai Pipeline Company, located on the East Forelands of Cook Inlet. The proposed pipeline right-of-way will contain an 8.625-inch diameter pipe with a wall thickness of 0.5 inches. The applicant anticipates transporting up to 90,000 barrels of oil per day.

As the crow flies, the distance between the origin and termination points of the pipeline is only 10 miles; however, due to the nature of bathymetry and Cook Inlet tides, the applicant has proposed a horseshoe shaped right-of-way longer than the direct route. For a full explanation of this design, please review the application documents located on the SPCO's website. This pipeline, if built, will be utilized by Cook Inlet Energy and its affiliates to replace the current use of the Cook Inlet Pipeline, which transports oil to the Drift River Tank Farm where it is then loaded on tankers and transported across the inlet. Once built, Cook Inlet Energy and its affiliates will no longer need tankers to transport oil across Cook Inlet.

The SPCO has been working closely with Cook Inlet Energy to complete the Commissioner's Fit, Willing and Able Analysis and Proposed Decision, which will detail the project and its possible impacts on local resources and uses of those resources. Cook Inlet Energy has expressed the desire to have a right-of-way lease secured by fall of 2013.

DONLIN GOLD

As of the publication of this annual report, Donlin Gold LLC (Donlin) has not submitted an AS 38.35 application for its proposed pipeline originating near Cook Inlet and travelling to the Donlin mine site on the upper Kuskowim River. Donlin has been in close communication with the SPCO for over two years as it moves toward solidifying a route for the proposed 313 mile natural gas pipeline. The SPCO anticipates an AS 38.35 application from Donlin within the next twelve months. As part of the AS 38.35 application and analysis process, third parties will be notified of the application and the public will be afforded an opportunity to comment on an analysis and proposed decision.

The Donlin project is much larger than the pipeline. The entire purpose of the pipeline is to provide fuel for mining operations at the proposed Donlin Gold mine, which is proposed to be located near Crooked Creek. The mine and pipeline require a permit authorization under Section 10 of the Rivers and Harbors Act of 1899 and Section 404 of the Clean Water Act from the United States Army Corp of Engineers (USACE). The SPCO has been participating in the public scoping meetings and review of documents being prepared for the Environmental Impact Statement (EIS) that is being drafted by the USACE for the entire Donlin Gold project (pipeline and mine). This EIS will include a thorough discussion of the pipeline and pipeline route. The SPCO will not consider alternative routes to the pipeline; rather the SPCO will only analyze the route that Donlin applies for.

SPCO participated in public scoping meetings for the Donlin Environmental Impact Statement.

Due to the size of the Donlin project and the multiple components, including the mine, infrastructure in support of the mine and the pipeline, the DNR Office of Project Management and Permitting (OPMP) has taken on the lead state role as the coordinating state representative in the EIS process. The SPCO and OPMP have a cooperative relationship, under which the SPCO will provide analysis, review, engineering and land management support for all aspects of the EIS pertaining to the pipeline and the pipeline route. Thus far, as part of the EIS process, the SPCO participated in the Aniak and Bethel public scoping meetings, as well as regular project team meetings.

DONLIN GOLD PERMITTING

The SPCO has also been working closely with Donlin as the company seeks land use permits in order to conduct surveys and studies on the proposed pipeline corridor. Donlin has been issued two permits for their 2013 summer geotechnical program, including receiving authorizations from the Alaska Department of Fish and Game and the Department of Natural Resources Office of History and Archaeology. Donlin has had one other permit for a fuel cache site satisfactorily closed.

DONLIN GOLD FLYOVER

SPCO staff participated in a helicopter flyover of the proposed Donlin pipeline right-of-way route on June 11, 2013. The helicopter trip followed the proposed route of the pipeline from the Susitna Flats State Game Refuge, north and west through the Alaska Range, then west over to the Donlin temporary camp. Donlin staff pointed out the proposed horizontal directional drilling (HDD) locations as well as the two

Representatives from SPCO and ADF&G joined Donlin Gold Mine staff in summer 2013 for a helicopter flyover of the proposed right-of-way.

proposed above-ground locations of the pipeline (the pipeline will be buried except at these locations). The return trip included an alternate route through Dalzell gorge, to illustrate why it is not a preferred route for the pipeline. Weather was mostly clear and the entire pipeline route was observed by SPCO staff.

SPECTRUM LNG

On October 9, 2012, Spectrum Alaska, LLC, applied for an Alaska Statute (AS) 38.35 Right-of-Way Lease for the purpose of constructing and operating a natural gas pipeline and liquefied natural gas (LNG) facility on the North Slope. The proposed pipeline will transport natural gas from a connection just south of Flow Station 3 to a new pad adjacent to Spine Road where a LNG plant will be constructed. The entire proposed right-of-way, which includes the pad and LNG facility, is on State land. The pipeline will be eight inches in diameter, for a length of 1,100-feet, with a design maximum throughput of approximately 50 million standard cubic feet (MMscf) per day. The plant, which has an initial production capacity of approximately 100,000 gallons per day, will process the natural gas to LNG so it can be trucked to supply points. The initial planned construction timeframe was summer 2013 and winter 2014, subject to the completion of a Commissioner's Decision and issuance of a pipeline right-of-way lease. Since receiving and public noticing the application, the SPCO has been drafting the Commissioner's Fit, Willing and Able Analysis and Preliminary Decision, as well as negotiating the right-of-way lease and financial assurances with Spectrum Alaska, LLC.

FLINT HILLS/KOCH/CARIBOU

On November 2, 2012, Caribou North Slope, LLC and Koch Alaska Pipeline Company, LLC, both subsidiaries of Flint Hills Resources, LLC, jointly applied for a right-of-way lease to construct and operate a natural gas pipeline and LNG facility on the North Slope. The proposed pipeline and facility were to be located just south of Flow Station 3 within the Prudhoe Bay Unit, entirely on state land. The pipeline was proposed to be approximately 2,640 feet long and 10 inches in diameter, with a proposed use of 29.5 million standard cubic feet (MMscf) of gas per day. LNG from the facility was proposed to be trucked from the North Slope to a vaporization and storage facility in North Pole. Upon receiving the application, the SPCO issued a public notice of the application and began review of the project. The application was withdrawn by the applicants on January 24, 2013.

2013 ANNUAL REPORT

LESSEE ANNUAL REPORT SUMMARIES

LESSEE ANNUAL REPORTS

The lessee annual reports play an important role in SPCO lease compliance oversight. The SPCO compliance section carefully reviews each report to ensure the lessee met all applicable lease requirements and the expectations of the State Pipeline Coordinator. A lessee is required, per lease stipulation, to provide the following information in its annual report:

- Surveillance and monitoring program results, including annual and cumulative changes in facilities and operations

- The effects of changes on the pipeline system and the proposed actions to be taken as a result of the changes

- A list, by quarter, of all surveillances, audits, self-assessments or other internal evaluations

- A summary of findings, actions items and other observations identified in the listed evaluations

- Descriptions of corrective and preventative actions planned or implemented

- The state of, changes to and results from the risk management, quality assurance and internal and external safety programs

- Specific efforts made to comply with the right-of-way lease and stipulations

- Information on construction, operations, maintenance and termination activities necessary to provide a complete and accurate representation of the lessee's activities and the state of the pipeline system

- A summary of all events, incidents and issues which had the potential to, or actually did, adversely affect pipeline system integrity, the environment or the safety of workers or the public

- A summary of the lessee's response to the items mentioned in the previous bullet

- A summary of all oil and hazardous substance discharges, including the incident date; a description of the substance; the cause, volume and location of the discharge and subsequent clean-up actions.

The State Pipeline Coordinator may request additional information of the lessee, if necessary. After the SPCO reviews the lessee annual reports, the compliance section summarizes the information for inclusion in the SPCO annual report and compliance section field activities are reassessed to account for planned activities and events. As a result of the inconsistent reporting outlines employed by the different lessees, the summary format may vary between sections.

ALASKA STAND-ALONE GAS PIPELINE ANNUAL REPORT

Annual Report Review and Summary

The Alaska Gasline Development Authority (AGDC) was established to pursue an in-state gasline project, the Alaska Stand Alone Pipeline (ASAP), to deliver gas from the North Slope to Fairbanks, the Southcentral region and other communities wherever practicable. AGDC received an SPCO right-of-way lease for the ASAP project in July 2011. AGDC issued the ASAP Project Plan Update Year-End 2012. It is on file with the SPCO and available for public review.

Legislative Actions

During the 2012 Legislative session, House Bill (HB) 9 addressed issues ranging from ownership of the ASAP project, the ability of AGDC to enter into confidentiality agreements, common carrier vs. contract carrier operating structure, ratemaking authority and funding for design and engineering work. The legislation passed the Alaska House of Representatives but was not acted upon by the Alaska Senate. This has delayed much of the technical work and ability to move forward on preparations for an open season. During the 2013 legislative session a similar bill (HB 4) passed (although not covered in the 2012 AGDC annual report) and has provided AGDC with sufficient funding to ramp up the organization and advance the design and engineering work as well as facilitate commercial negotiations and prepare for open season. The newly passed legislation gives AGDC some autonomy and allows it to operate commercially as a contract carrier.

Design Update

Limited funding kept AGDC from proceeding with many of the activities originally planned for 2012, but it did update its project plan. Review of the original Base Case (option 8 in the 2011 Project Plan) that would have shipped conditioned natural gas and an enriched stream of natural gas solids, revealed a number of constraints including the number of required processing facilities. By shifting to a Base Case that will transport only lean gas with no natural gas liquids added (option 7 in the 2011 Project Plan), the planned 737-mile pipeline will utilize an industry-standard 36-inch diameter pipe, rather than the originally-proposed 24-inch diameter pipe. The change also eliminates most of the processing facilities. Combined, the changes lower the cost of the estimated tariff.

2012 Project Work

During 2012, AGDC made a significant effort to move the federal environmental impact statement (EIS) towards completion. The EIS is required before the issuance of a federal BLM right-of-way grant for the proposed pipeline. The final EIS was published by the US Army Corps of Engineers (COE) in October 2012. A record of decision and BLM grant of right-of-way are still pending.

All wetland work for the Section 404 permit application was completed in 2012. When the ASAP design basis and engineering are available for the new lean gas plan, AGDC will submit a completed application for the wetlands permit under the Clean Water Act. At that time the COE will determine if any additional NEPA analysis is required. AGDC made a significant effort during 2012 to increase stakeholder engagement and meet with members of all of the communities that have been identified along the proposed ASAP route. Members of the ASAP project team attended more than 80 public meetings during 2012 to provide project updates. The growing outreach effort is aimed at expanding public awareness of the project, keeping the public well-informed as the project changes and progresses, and increasing public support for the project.

2013 Planned Activities

Work will continue on the commercial and engineering aspects of the project. A comprehensive geotechnical field program is being planned for 2013 to obtain data necessary to refine the design of the pipeline and associated facilities. Cultural work will be conducted prior to implementing the borehole program. A major stream survey work plan is also scheduled for 2013. The field effort should begin in June or July. The air quality data collection will resume in 2013.

BPTA ANNUAL REPORT REVIEW AND SUMMARY

Introduction to the Lease and Reporting Requirements

The 2012 Annual Report from BP Transportation (Alaska) Inc. (BPTA - owner and leaseholder) covers a broad range of risk management programs aimed at managing safety, pipeline integrity and environmental risks. The report emphasizes preventive and corrective maintenance programs, environmentally sound operations, and providing consistent direction to all employees and contractors working at every level in support of BPTA pipelines.

Programs are aimed primarily at pipeline integrity, corrosion management, quality assurance, contractor oversight, lease and permit compliance monitoring, and numerous other programs to increase public and worker awareness. These programs apply to all BPTA pipeline operations on the North Slope.

The State of Alaska, through the pipeline right-of-way leases, requires each lessee to submit a comprehensive annual report annually summarizing the results of its surveillance and monitoring programs; changes to the pipeline system; results from the various quality assurance programs; information on any new construction, operations, or maintenance activities; all incidents and issues that had the potential to affect the pipeline system; and a summary of any hazardous discharges and subsequent clean-up. The BPTA annual report is available for public review.

The following sections summarize key information submitted by BPTA:

Pipeline Integrity and Risk Management
Personal Safety
Maintenance
Surveillance and Monitoring
Right-of-Way Events/Incidents/Issues
Special Projects

PIPELINE INTEGRITY AND RISK MANAGEMENT PROGRAMS

Quality Assurance Program (QAP)
The BPTA quality assurance program provides a structure based on the BP Exploration (Alaska) Inc. (BPXA, the pipeline operator under contract with BPTA) operating management system to ensure that all commitments to comply with lease stipulations and other BP or regulatory requirements are met and documented systematically. The QAP provides continuity of processes, training and standards (operating, safety and environmental) across all seven BPTA AS 38.35 pipeline leases. Also falling under the QAP is BPXA's environmental management program, certified to ISO 14001 with annual audits by DetNorske Veritas , an IS0 14001 registered firm.

USDOT/PHMSA Integrity Management Programs
BP has numerous risk management programs in place to meet the comprehensive USDOT/PHMSA pipeline integrity monitoring requirements. Some of these are summarized below:

Formal Risk Assessments (FRA) are conducted periodically for each BPTA pipeline under SPCO jurisdiction as well as other field lines not under SPCO authority (approximately 111 miles of pipeline on the North Slope annually). BPXA's FRA process includes operations management, corrosion specialists, and North Slope team members who collectively examine data from all available sources and assess potential threats to pipeline integrity, the likelihood of any given mode of failure, the consequences of such a failure and the effectiveness of the numerous preventative measures in place. This process is also used to develop mitigation measures and action items and to evaluate any preventative measures taken the previous year. The status of the 2011 preventative measures and action items were reviewed during the 2012 FRA to assure they were suitably addressed. USDOT/PHMSA audits these risk assessments regularly. USDOT/PHMSA has had no "findings" in their last several audits of BPXA's FRA.

The Operator Qualification (OQ) Program aims to reduce the probability of incidents/accidents and their consequences by ensuring that all workers, whether they are BP employees or contractors are properly trained, and that required skill certificates are current. The OQ utilizes a secure internet-based management database to retain and manage all training records. In 2012 new study guides were issued. BPXA consistently exceeds the OQ requirements set by USDOT/PHMSA regulations.
The goal of the **Public Awareness/Damage Prevention Program** is to increase aware-

ness of pipeline operations among people who live and work near pipelines in an effort to increase their awareness of potential for accidents and how to prevent them. In 2012, BPXA distributed approximately 125 surveys that will be used to evaluate and update the program.

BPXA has a **Drug and Alcohol Program** that includes employee and contractor testing. Efforts are aimed at eliminating substance abuse and providing a healthy, productive and safe working environment. Random testing at all facilities related to BPXA pipelines was performed on 25-37 percent of the employees depending on the facility. No positive results were reported at any facility.

The **USDOT/PHMSA Control Room Management Rule** went into full effect on August 1, 2012, and is aimed at preventing human error on the part of controllers responsible for remote operations of pipelines. BPXA reaffirmed its compliance with the USDOT/PHMSA rule through policy. Elements of the program include "Fatigue Risk Management," "Alarm Rationalization" and Control Room Management". In October 2012 USDOT/PHMSA conducted a four-day audit of the BPXA implementation of Control Room Management Rule. No compliance deficiencies were identified during this audit.

BPXA CORROSION MANAGEMENT PROGRAMS

BPXA's comprehensive corrosion management program is composed of many subprograms put in place so that corrosion can be identified early and mitigated effectively. The multi-faceted approach is part of a strategy to look for and manage problems from many different angles in order not to miss a hard-to-detect problem. The following is a summary of the key corrosion programs implemented by BPXA.

The **Internal Corrosion Monitoring Program** relies on electrical resistance (ER) measurements, and weight loss coupons (WLC) are removed and analyzed for any evidence of corrosion. ER coupons are monitored remotely and WLC coupons are removed and analyzed for any evidence of corrosion at regular intervals.

2012 Results• In 2012 no coupons on any of the BPTA pipelines exceeded the limits of general 2 mpy (milli-inches /year), or pitting of 20 mpy. Laboratory analyses showed no corrosion or pitting of note for any of the BPTA AS 38.35 sales oil lines.

The **Comprehensive Integrity Program (CIP)** is an annual program that focuses on identifying new corrosion mechanisms as well as assessing the extent of degradation at locations previously noted.

2012 Results• Eighty-seven inspections were performed in 2012. Only one inspection found any increase in wall loss. All other inspections showed no change or no new corrosion site. One location on the Milne pipeline showed an increase in wall loss and is scheduled for reexamination during the annual survey.

The **Corrosion Rate Monitoring (CRM) Program** focuses on identifying new corrosion mechanisms and assessing the extent of degradation at locations previously noted. Areas particularly susceptible to corrosion such as long seams welds, bottom of lines, elbows and girth welds are inspected at regular intervals. This is an inspection program intended to supplement other corrosion monitoring data. USDOT/PHMSA does not require pipelines carrying sales quality oil to follow this program; however, BPTA has chosen to monitor them under this program as a proactive measure.

2012 Results: 279 inspections at 178 locations were made in 2012. One new location was identified and will be followed. No other inspections showed any new or increased corrosion.

The **Frequent Inspection Program (FIP)** is aimed at managing areas already identified with significant corrosion with frequent inspections scheduled until an area is repaired, derated, taken out of service or corrosion rates are reduced to an acceptable level. None of the BPTA 38.35 pipelines (Badami, Northstar, Milne and Endicott) have levels of corrosion that would qualify them for this program.

The **In-Line Inspection (ILI) Program** utilizes pigs built with sophisticated instrumentation that can assess and record minute anomalies in a pipe wall as it travels the length of a pipe. The data assists corrosion engineers in their assessment of the condition of the equipment, the effectiveness mitigative efforts, and, when evaluated against historic ILI data, can show them when corrosiveness of the environment is changing.

ILI Schedule• An in-line inspection will be run on the Badami Sales Oil pipeline in 2013. Endicott and Milne sales lines are scheduled for ILI analysis in 2014. North Star Sales Oil pipeline and gas pipeline are scheduled for ILI inspection in 2015.

Badami ILI Results• A final report was issued on the 2010 ILI run confirming no immediate integrity concerns. Field verification activities were completed in 2011.

Endicott ILI Results• The final ILI report from the 2011 run found no integrity concerns. All necessary follow-up inspections were made during 2012. The field verification efforts showed that the tool performed within specifications. One anomaly identified during 2012 will have a field inspection in 2013.

Milne ILI Results• The final report from the 2011 inspection showed no integrity threats. After internal evaluation, BP identified 140 anomalies for field follow up. The 2012 field verification program was completed and the results showed that the ILI too performed within specifications. Fourteen anomalies are scheduled for field inspection in 2013.

Northstar ILI Results• An ILI tool inspection was made of both the North Star sales oil line and the gas line in July 2012. Neither inspection showed any immediate integrity concerns, no anomalies were reported by the vendor and no field follow-up is scheduled. A geopig mapping inspection was made of both lines during September 2012. No

immediate integrity concerns were identified. A third party strain analysis was made by a third party utilizing the geopig mapping data and provided to BPXA in December 2012. This effort too showed no immediate integrity concerns and no need for any field inspections. All inspection tools performed within their specifications.

At the sea-air interface on the Northstar Island two external anomalies that have been field inspected and mitigated since 2008 were reevaluated. Correlation with historic results show that the ILI tool performed within specifications.

The **Below Grade Piping Program** focuses primarily on the threat of external corrosion to below grade pipe. Excavation is performed where ILI data indicates a potential corrosion in areas where the ILI tool cannot inspect. This allows direct inspection and assures that the pipe is fit for service.

2012 Results· No significant corrosion was identified in any of the below grade BPTA pipelines with ILI. A Guided Wave Ultrasonic inspection was conducted at four locations on the Badami pipeline that are not piggable during 2012. No integrity or corrosion concerns were identified. Similarly, two non-piggable portions of the Northstar line were inspected in 2012. No corrosion was identified and the next Guided Wave inspections are scheduled for 2015.

The **Corrosion Under Insulation Program (CUI)** facilitates regular inspections of insulated pipe susceptible to corrosion from moisture.

2012 Results: No external inspections of the Badami pipeline or the Milne Point product line were scheduled for 2012. External inspections were made of the Endicott and Milne pipelines. The ILI tool used on the Northstar pipelines included an external inspection and no external concerns were noted. There were 529 external inspections mad on the Endicott pipeline. One grade D condition was identified and will be mitigated and monitored. Three grade F conditions were identified, all a result of mechanical damage. A pipeline maintenance package was generated for all three. There were 85 inspections of the Milne sales oil pipeline. Twenty-five grade D and six grade E conditions were found. The grade D sites will be mitigated and the grade E sites will be proactively sleeved even though they do not meet the failure criteria.

Pipe Condition Grade	**Wall Loss**
A	No Damage
B	1% to 20%
C	21% - 40%
D	41% to 60%
E	61% to 80%
F	>80% or not fit for service

The **Cathodic Protection Program** focuses on buried or submerged sections of the Badami and Northstar pipelines. These pipe segments are protected by cathodic protection systems and are inspected annually. Additionally, the Milne Point pipeline has isolation flanges installed to ensure electrical isolation between the stainless steel and carbon steel section. They are also checked regularly and do not affect the cathodic protection system.

2012 Results: The annual cathodic inspections for Northstar and Badami met industry acceptance criteria. In addition to the annual monitoring conducted for Northstar, a contractor completed a pipe-to-soil potential survey through the ice at 50-foot intervals for the entire length of both subsea pipelines during April 2012. This testing found that both pipelines have adequate cathodic protection. The surveyors were able to estimate the life of the anodes to be another 15 to 20 years. Damage to the monitoring system at Point Storkerson was evaluated and shown to have no impact on the cathodic protection system and will not cause any interference with the annual cathodic protection surveys.

BPXA conducts **Atmospheric Corrosion Monitoring** on bare pipe located onshore a minimum of once every three years (not to exceed 39 months), while offshore it is inspected once a year (not to exceed 15 months).

2011 Results: The visual inspection for atmospheric corrosion on the Milne Point Module 58 launcher/receiver and related piping was conducted in March 2012. They were found free of corrosion. Comprehensive visual inspections of the Endicott pipeline and the above ground Northstar oil pipeline, including pig launchers, access vaults, etc., were conducted in June 2012. The overall condition of the launcher at Endicott was very good. On the causeway, however, 14 areas of corrosion on the insulation jacketing were noted and the areas were repaired with new jacketing. The offshore portion of the Northstar pipeline had varying degrees of corrosion and these are scheduled for recoating. The Badami atmospheric corrosion inspection took place in July 2012. Some corrosion, of varying degrees, was noted and is also scheduled for recoating.

PERSONAL SAFETY PROGRAM

The BP personal safety program applies to all work activities on BPXA premises. Formally referred to as **Control of Work (CoW)**, it emphasizes accountability, training, competence, planning and scheduling, task-based risk assessments, and a Permit to Work process that is standard across all operating areas. Implementation of the personal safety program involves the permit-to-work system, crew toolbox meetings and worksite inspections. It also involves program implementation audits, lesson learned exercises, and most importantly an emphasis on stop work efforts at every staff level to prevent potential problems.

At every BP facility, employees assume ownership of a program and actively monitor each other's safety. The internal safety program is behavior based. The focus is to increase both employee awareness of safety processes and operating risks and involve-

ment in accident prevention. Statistics show that the program has been very effective. This past year, and for the last three years, there were no recordable accidents at any BP North Slope field or pipeline – Badami, Endicott, Milne or North Star.

Contractor safety is integrally tied to BPXA's CoW and internal safety program. Contractors must comply with all aspects of both programs; BP supervisors observe and actively engage with contractors through these programs. Prior to issuing a permit-to-work, BPXA meets with the contractor to assess job risks and mitigations. For non-routine work BPXA requires contractors to use the Authority to Proceed (ATP) process and the Task Hazard Analysis process. Work is analyzed for ways to protect employees and the environment.

MAINTENANCE

USDOT/PHMSA has extensive jurisdiction over pipeline integrity, including equipment requirement, design standards, preventive maintenance requirements, monitoring and inspections. To track compliance with USDOT/PHMSA requirements, BPTA has a computerized system for every facility. The system is used to track regularly scheduled preventive maintenance, including USDOT/PHMSA-required inspections and non-routine maintenance to prevent or correct problems as they are identified. The system is used to generate work orders and status reports.

PIPELINE SURVEILLANCE AND MONITORING

Surveillance and monitoring activities are performed routinely by the lessee. Both are self directed by the lessee to meet state or federal regulation as well as company concerns and goals. Surveillances can be accomplished by flying, driving or walking. USDOT/PHMSA requires surface conditions on or adjacent to each pipeline be inspected for indication of leaks or other problems at intervals not exceeding three weeks and at least 26 times a year.

In addition to USDOT/PHMSA required inspections, BPXA conducts visual inspections on all above-ground pipelines with walking speed surveys (WSS). Given the restrictions associated with each season, different components are sometimes inspected in both winter and snow-free conditions. WSSs provide an opportunity for visual inspection of many components of the pipeline system. In addition to inspecting pipe insulation and structural components, inspectors examine electrical equipment, communication equipment, chemical injection tubing, pipe casings, animal crossings and other site specific equipment.

USDOT/PHMSA Inspections· Endicott and Milne Point pipelines are road accessible and have drive-by surveys. Northstar and Badami have aerial inspections. Some of the aerial surveys include FLIR (forward-looking infrared) assessments that will delineate between warmer and colder temperatures, thus making it easier to detect small leaks. There were 74 aerial USDOT/PHMSA inspections of Badami, of which 36 included FLIR assessments; and 52 aerial inspections of Northstar, three of which included FLIR assessments. Endicott had 50 drive-by inspections and Milne Point had

26 drive-by inspections. No pipeline issues were identified during these surveys with the exception of a few minor issues on Endicott, which were repaired. In addition to the USDOT/PHMSA required drive-by surveys of Milne pipelines, facility operators requested additional drive-by surveys to check the pipe when there were unexplained alarms that did not clear within 10 minutes. The alarms remain unexplained, no leaks or other problems found that would have triggered the alarms.

The primary Badami WSSs were conducted in March and April 2012. Snow-covered areas were revisited in August 2012. Minor issues identified on the sales oil line included one jacked VSM, one settled VSM, 40 coating failures, two broken banding straps, one bent flange, three sheet metal perforations and one occurrence of graffiti. The issues reported on the Badami utility line were similar. There was no evidence of actionable erosion, no evidence of unauthorized entry, no sloping crossbeams, no tilted saddles, no failed anchors, no gaps between the pipe and saddles, no indication of pipeline vibration, no missing or broken vibration dampeners, no damaged pipeline insulation at the risers, no pressure ridges or ground cracking parallel to the pipe axis, no ground cracking warranting action, no flooding that threatened pipeline integrity, no areas of fish blockage, revegetated areas appeared well established, and no active brown bear or polar bear dens noted in the right-of-way.

The Endicott WSSs were conducted in April and July 2012. No problems requiring immediate action were identified. The minor issues that were noted included one occurrence of graffiti, four jacked VSMs, one VSM that had subsided, 12 anchors needing seals, one location with coating failure on a valve, 79 spots of minor sheet metal separation, seven sheet metal perforations, and one pressure indicator with no validation date. There was no bank or pad erosion, no visible sloping or tilting of any crossbeams, no saddles were tilted or suspended above a crossbeam, no gaps between any saddles and the pipe, no indication of pipe vibration, no humps, swales or ground cracking forming along the ROW, no damage to any communication sites or support structures, no evident of fish blockage, and no brown bear or polar bear dens found along the ROW.

The Milne WSSs were conducted at the end of August and beginning of September. No problems requiring immediate attention were observed. The issues noted on the sales oil line included 18 broken or missing vibration dampeners, 57 saddle or insulation banding straps that were broken or missing, 11 sheet metal perforations and numerous locations where the insulation jacketing has been crushed. There was no evidence of erosion that required action, no evidence or reports of wildlife blockage, no vandalism or sabotage, no out of place VSMs, crossbeams, saddles, or anchors. No indication of pipeline vibration, no pressure ridges or swales parallel to the pipeline, no ground cracking within 10 feet of the centerline, no fish blockage, and no evidence of brown bear or polar bear dens in the ROW.

The Northstar WSS of the above ground pipe were conducted in September 2012. No issues requiring immediate attention were identified. Some of the minor issues included 2 inadequate grades above road crossing casings, one jacked VSM, three missing

snubbers on TVAs, one vibration absorber tilting 40°, 16 coating failures, one insulation separation, one missing insulation jacketing, 22 spots where the insulation jacket was crushed or dented, two pressure indicator devices with expired calibration, one minor pipeline sag and four broken spacers/centralizers. Erosion was not an issue. There were no reports of wildlife blockage, no evidence of vandalism or sabotage, and no VSM crossbeam, saddle, vibration, or anchor issues. There were no scour issues associated with the Putuligyyuk River piles, no pressure ridges parallel to the pipe, no ground cracking within 10 feet of the pipe, no exposed pipe, no flooding or erosion that reduced the pipeline setback, no river channel obstruction, no settlement or ponding over the pipe, no changes preventing fish passage, and no brown bear or polar dens reported in the right-of-way.

Additional BPXA Internal Reviews: USDOT/PHMSA inspected BPXA North Slope pipelines during July and August 2012. The audit was extensive including 78 pages of detailed questions. No BPTA pipeline received a DOT/PHMSA Notice of Probable Violation, Warning Letter, or Notice of Amendment (related to plans and procedures) from the USDOT/PHMSA auditors.

BPXA conducted several internal reviews of their USDOT/PHMSA compliance efforts. In March 2012 they reviewed Northstar Gas pipeline's records and reported no findings. In March the In late May the BPXA Safety and Operational Risk team conducted an audit of USDOT/PHMSA records for which the only findings were minor procedural updates, which were completed by October 2012. In March, three BPXA USDOT/PHMSA experts conducted a review of Savant's Operator Qualification records. No compliance deficiencies were found.

ROW EVENTS/INCIDENTS/ISSUES

During 2012, BPXA had one USDOT/PHMSA Reportable Accident when approximately five gallons leaked from the Badami pig launcher valve, HV-1301. The oil and snow were recovered and taken to the Endicott snowmelt tank for treatment.

In April 2012, USDOT/PHMSA issued a Final Order closing the NOPV issued in 2008 for internal corrosion mitigation issues. The letter confirms the director's recognition that BPXA had taken all actions contained in the 2008 order.

Badami reported nine AOCs. Several were temporary loss of communication with different causes ranging from solenoid failures, blown fuse, extreme cold (-50°F), or a microwave communication upset. No loss of production was reported.

Endicott reported three AOCs. There were two brief power failures associated with PS1 and a brief plant upset that was quickly resolved.
Milne had several minor AOCs. There was a brief unintended shutdown in April due to testing on a new fire and gas activation system. There was a momentary pressure spike in August 2012 due to large fluctuation in flow and an unintended valve closure in September that was quickly corrected.

The Northstar sales oil pipeline experienced several brief shutdowns in June related to PS1 power failures. There was also a brief loss of communications to the Northstar sales oil line in July. Telephone communications were used until the server was restored.

The Northstar gas pipeline experienced one unintended valve closure in December caused by low pressure in the instrument airline due to ice. The line was cleaned with methanol and a heat trace was placed on it to prevent similar issues in the future.

There were four vehicle accidents within BPTA ROWs during 2012. No injuries were reported in association with these accidents. Two of them had no release or spill. Two of them had small spills noted below.

Oil and Hazardous Discharges
There were three reportable spills in BPTA rights-of-way during 2012. In April, five gallons of oil was found in the Badami oil pipeline's pig launcher. Oil and snow were removed and put in the Endicott snowmelt tank for hydrocarbon recycle. In February a spill of hydraulic fluid occurred when a vehicle ran into the Endicott causeway bridge and became wedged between the guard rails. The accident caused a hose on a loader to fail. The contaminated material was removed and taken to the grind and inject site for disposal. In the Milne ROW in October there was a spill of diesel and hydraulic fluid due to a vehicle accident. Initial clean-up was performed in accordance with Alaska Clean Seas guidelines. In accordance with the ADEC-approved plan there will be further site cleanup in March 2013.

There were six non-reportable leaks within the BPTA ROWs during 2012. All were cleaned up and contaminated material was disposed of according to approved guidelines.

SPECIAL PROJECTS

Badami Weir
The Badami Weir was constructed on the west bank of the eastern Sagavanirktok River channel to manage periodic high water flows and control erosion where a trench used during construction of the Badami pipeline intersected an abandoned oxbow. The Weir is inspected three times each summer in accordance with USACE and ADF&G requirements. These inspections took place June 11, July 19 and August 118, 2012. The weir is functioning as designed with water flowing through the established channel. Although there are some silt and sand deposits in the area, seeded grasses appear well established and some indigenous sedge have begun to colonize along the edges of the matting.

Annual Northstar LEOS Leak Detection System Test
The Northstar subsea pipelines are monitored with a special leak detection system, LEOS, based on sensing hydrocarbon vapors in the space surrounding the pipeline. The annual preventive maintenance and test of the LEOS system was completed August 23, 2012 and performed well. This system is in addition to a standard leak moni-

toring system that is constantly measuring pressure, volume and temperature.

Coastal Stability and Vegetative Rehabilitation at Northstar Shore Crossing
Historical data show the rate of coastal erosion in the vicinity of the Northstar pipeline above ground transition has averaged about 1.7 ft/yr. Since 1996, BP has conducted a coastal monitoring program annually in accordance with a USACE approved plan. This effort documents any shoreline changes near the Northstar makes landfall, especially where backfill has been placed over the buried pipe. Ten swaths perpendicular to the shoreline are profiled annually at intervals of 250 feet as well as the area on top of the pipeline from the backshore to wading depth. Only minor erosion has occurred in the past four years (including 2012) averaging 0.3-0.5 ft/yr. As a comparison, in 2003 and 2008 when there were large westerly storms, bluff erosion was greater than 5 feet. The toe of the pipeline pad is currently about 70 feet landward of the bank where the pipeline is buried, and the gravel berm that protects the pipeline riser is more than 125 feet from the shoreline. Given the excellent vegetative growth in the rehabilitated area of backfill and the pad, current pipeline setbacks, and the slow rate of coastal erosion, it was determined that no new mitigation measures were necessary at this time.

Northstar Subsea Pipeline Route Monitoring
The subsea pipeline monitoring program evaluates bathymetric data, documents ice gouges on the sea floor, and looks for strudel drainage features to determine locations of strudel scour in the vicinity of the pipeline. The 2012 work was conducted in two phases with a helicopter reconnaissance in early June, and a vessel based open-water survey, using several kinds of sonar technology, in late July. With minor localized exceptions and the notation of subsidence in an area where it had also been observed on four previous occasions, the bathymetric profile along the pipeline route was very similar to the one made in 2011. Of note, the section between Stump Island and the shore crossing is not only similar to 2011 but also to the pre-construction profile from 1996.

The only active subsidence noted was about 540' long and up to 1.5 feet deep. Subsidence has occurred annually since oil began flowing. It has been noted along half the pipeline route between Northstar Production Island and Stump Island. The amount of subsidence has decreased significantly in the last two years. The area of subsidence detected in 2012 was less than in 2011 and the smallest since 2003 when record keeping began.

Only 55 ice gouges were located on the sea floor in 2012, but only 19 were newly discovered and the rest were relic features. Eleven of the gouges crossed the pipeline alignment but none took the backfill below six foot minimum that is required. Ice wallows differ from gouges and are formed when the keel of an ice flow is grounded and the movement of water around the keel (from currents, waves or other action) creates a larger depression. Ice wallows are not common and have only been detected in the area of the pipeline four times since pipeline construction. No new ice wallows were detected this year.

Oversight of the subsea pipeline also includes monitoring of the Kuparuk river overflood which can extend well past the barrier islands. This year flood waters were substantial, but to the east of the Northstar pipeline alignment they were contained by Stump Island. To the west, they extended past the barrier islands. Over the actual alignment the flood waters extended to a point 7,700 feet north of Stump Island and 14,000 feet south of Northstar Island. A record high number of drainage features, 83, were located in the area north of Stump Island. The past average is 35.
A sonar search for strudel scours in the sea floor, which can result from overflooding, found 82 new depressions, both circular and linear. Only two of the scours found were in the area of backfill over the pipeline but did not cause the backfill thickness to violate the six foot minimum required.

Proposed 2013 Plans
All pipelines will continue to follow the USDOT/PHMSA schedule for aerial or drive-by inspections approximately every two weeks. All pipelines have scheduled USDOT/PHMSA preventive maintenance programs. Corrosion monitoring programs are scheduled for the 2nd quarter for all BPTA pipelines. The 2013 USDOT/PHMSA Integrity Management Program Formal Risk Assessment will be conducted the 4th quarter for all BPTA pipelines.

The primary Badami walking speed survey will be conducted during the 2nd quarter, as well the repairs recommended after review of the 2012 WSS. The Sagavanirktok River Weir (commonly referred to as Badami Weir) monitoring and the associated rehabilitation inspection is scheduled for the 3rd quarter along with the Cathodic Protection Survey.

During the 2nd quarter, Endicott has plans to recoat hand valves HV-5006 and HV-1391 in accordance with the atmospheric corrosion monitoring procedure. They will also make the repairs recommended after their 2012 WSS. The Endicott walking speed survey is scheduled for the 4th quarter.

Verification that the stainless steel pipe is isolated from the carbon steel pipe will be made on the Milne pipelines during the 2nd quarter. Repairs recommended after their 2012 WSS will also be made during the2nd quarter. The WSS will be conducted during the 4th quarter.

Northstar has scheduled phase one of the walking speed survey for the 2nd quarter and phase 2 for the 3rd quarter. During the 2nd quarter BPXA will also make repairs noted in the 2012 walking speed survey and conduct the cathodic protection survey. During the 3rd quarter, there will be ILI runs and the annual LEOS leak detection system will be tested. The pipeline route monitoring for subsea changes due to ice and currents will be conducted the 3rd quarter along with the coastal stability monitoring and the examination of the rehabilitation effort at the Northstar pipelined landfall.

CONOCOPHILLIPS ANNUAL REPORT REVIEW AND SUMMARY

Introduction to the Lease and Reporting Requirements

The 2012 Annual Reports from ConocoPhillips Alaska Pipelines (CPAP) cover a broad range of quality assurance and risk management programs. To maintain public confidence and ensure operations are compatible with both the economic and environmental needs of communities where it operates, CPAI has a quality program in place that represents a commitment to meet all design and engineering standards and to complying with all applicable laws and regulations.

Specific programs range from those required by USDOT/PHMSA, aimed primarily at pipeline integrity and corrosion management, to others, including a comprehensive quality assurance program, contractor oversight, lease and permit compliance monitoring and numerous programs to increase public and worker awareness. These programs apply to all CPAI pipeline operations on the North Slope. The State of Alaska, through the pipeline right-of-way leases, requires each lessee to submit a comprehensive report annually on the results of surveillance and monitoring programs; changes to the pipeline system; results from the various quality assurance programs; information on any new construction, operations, or maintenance activities; a summary of all incidents and issues that had the potential to affect the pipeline system; and a summary of any hazardous discharges and subsequent clean-up.

The following sections summarize key information submitted by CPAI:

- **Pipeline Integrity and Risk Management**
- **Personal Safety**
- **Maintenance**
- **Surveillance and Monitoring**
- **Right-of-Way Events/Incidents/Issues**
- **Oil and Hazardous Discharges**
- **Special Projects**

PIPELINE INTEGRITY AND RISK MANAGEMENT

Quality Assurance Program (QAP)
CPAI implements a Health Safety and Environmental Management System Standard (HSEMSS) to ensure all parameters of the QAP are met. Programs that fall under the QAP cover a broad spectrum, including personnel training, operations and maintenance, information documentation, management of change and emergency response. CPAI implemented the Operations Compliance Management System to ensure that operations are in compliance with all applicable laws, regulations and lease requirements. CPAI utilizes database software called IMPACT to track all findings and follow-up.

USDOT/PHMSA Risk Management Programs
USDOT/PHMSA conducted its annual inspection of the Alpine pipelines in October 2012. CPAI demonstrated full compliance with USDOT/PHMSA requirements.

With its **Integrity Management Program (IM)**, CPAI takes a comprehensive approach to risk management in an effort to identify potential hazards, minimize any operational problems, and decrease the potential for any health, safety or environmental problems. CPAI risk management programs meet federal pipeline integrity monitoring requirements. In February and April 2011 USDOT/PHMSA representatives performed an Integrity Management inspection following established integrity management protocols and did not report any significant issues.

The program requirements fall under the following general headings: high consequence area identification, risk assessment, inspection plan, inspection remediation, preventative and mitigative measures, personnel qualifications, quality assurance, management of change, documentation and communication, and overall program review.

CPAI conducts **Process Hazard Analyses (PHA)** using established protocols and technical standards performing project work on new or existing facilities. Workflow and responsibilities are evaluated to determine risk and required protection.

When there is a facility design change or an operations change, the **Management of Change** program provides a framework to review proposed work and confirm that it will not create unanticipated hazards or safety risks. The program also ensures that

safety and environmental information is updated to cover the changes in facilities or processes. The program was reviewed and several updates were made during 2012.

CPAI implemented in September 2012 an updated version of its **Operator Qualification (OC)** program. The purpose of this program is to ensure that the workforce is well qualified, thereby reducing the potential for human error and increasing the ability to respond quickly and effectively to any upset conditions.

CPAI continues to implement a **Public Awareness/Damage Prevention** program. In 2012 CPAI reviewed the program and made no changes. By increasing public understanding of North Slope pipelines, what they transport, how they work, and the importance of not damaging the pipe, CPAI hopes to decrease the potential for unintended damage to the pipe.

CPAI implements a **Drug and Alcohol** program, which includes testing, aimed at eliminating substance abuse in the workplace while providing a safe, healthy and productive work environment. Add info

CPAI, as part of its **Environmental Management** program and in partnership with BPXA, ENI, EMDC and Pioneer, produced the North Slope Environmental Field Handbook, last reissued in June 2011 . The handbook identifies practices that provide the foundation for sound environmental management. The practices include meeting applicable permit requirements, spill prevention practices, environmental restrictions, management of hazardous materials, waste management plans, vehicle maintenance, use of portable liners for all fluid transfers, and spill reporting.

CPAI conducts **Contractor HSE Management System Audits** on a regular basis. CPAI has chosen 12 management elements of the HSE management system on which to audit its contractors. Each element was graded by the traffic light system - green, yellow or red. All contractors audited received green or yellow marks which means they do not need a variance to continue working but must prepare a corrective action plan that will be closely monitored by CPAI for any elements receiving a yellow mark. In 2012 four major contractors for Kuparuk and Oliktok were audited. Three Alpine contractors were audited. All four scored yellow or green or yellow and can continue working without a variance.

CPAI Corrosion Control Programs

There are numerous elements to the CPAI corrosion control efforts aimed at ensuring mechanical integrity of the pipelines. Key corrosion control programs include the following:

CPAI's **Maintenance Pigging** program is designed to ensure that pipelines are free of solids, deposits and any water that has collected. A routine maintenance pig was run through the AOP, KPL, and the KPE approximately once a month. The AUP (treated seawater) was pigged 3 - 4 times a month. A maintenance pig was sent through the ADP approximately once every 2 - 3 months.

The **In-Line Inspection (ILI)** program employs a variety of smart, or instrumented, pigs. Smart pigs are scheduled to be run every two years on the APL, AUP, KPL and KPE.

Only the 14-inch segment of the AOP is piggable. The section from KPL to the VAL01 pig receiver is monitored with tangential radiography inspection (TRT), standard radiographic techniques (RT) or ultrasonic technology at least every three years. An ILI was run on the AUL in 2012. The next scheduled ILI for the AOP is scheduled for 2013. Follow-up on the questionable sites selected based on the 2011 ILI, both internal and external was completed during 2012 for both the AOP and the AUP. All were determined to be fit for service.

An ILI inspection was conducted on the KPL in 2011. Five internal sites and 71 external sites along the KPL were selected for follow-up evaluations. Integrity inspections were completed at all the internal and 56 of the external locations in 2012. Follow-up continues at the remaining external locations. ILI investigations were conducted on the KPE in May 2012. Eight of 12 external locations identified by the KPE ILI have already received follow-up inspections and showed no imminent threat to integrity. The ILI analysis of the KPE identified six internal locations for further evaluation. Follow-up inspections confirmed that the anomalies posed no threat to pipeline integrity.

The next ILI of the Oliktok pipeline is scheduled for 2013.

External Inspection of Unpiggable Sections

Where the pipeline cannot be pigged, various external inspections occur at regular intervals. The unpiggable sections of the AOL are scheduled for TRT examination in 2015. Seven elbows on the AOP were examined with RT in October 2012. One location was identified as an area with previously-identified damage, but pipeline integrity was ensured . Corrosion under insulation (CUI) inspections were completed on the AUP and no pipeline integrity issues were identified. The next AIP CUI inspections will take place in 2015. RT inspection was expanded to evaluate all the elbows due to the derating damage found on the 6-inch recycle line outside the AL06. There was a leak in the below grade section of the line and it was replaced in 2012.

The next inspection of the unpiggable sections of the KPL and OPL at CPF1 are scheduled for 2014. Inspection of the unpiggable section of the OPL at TAPS Pump Station 1 with TRT and UT was completed in 2012 with no repairs required. The next inspection of this area will be in 2015.

The **Corrosion Rate Monitoring (CRM)** program is intended to supplement other corrosion monitoring data in areas with previously identified internal corrosion. On the AOP these inspections were completed quarterly at four locations. All inspections confirmed pipeline integrity. The next inspections of areas with known corrosion on the Alpine Utility line are scheduled for inspection in 2013. Quarterly inspections took place on the KPL at 16 locations and no increased damage was noted. Inspections of

eight sites on the Oliktok pipeline were made quarterly; they too showed no increase in wall loss.

Once each year a **Below Grade Casing Inspection** is conducted on all the CPAI AS 38.35 pipelines to ensure that the casing is free from obstruction that could increase the potential for external corrosion.

The 2012 inspections for Alpine pipelines noted four action items. At one location on KPL and one on KPE the pipeline was found to be touching the casing. In both locations the pipe was cleaned and inspected and integrity ensured. The below-grade casing inspection of the Oliktok lines found no areas for follow-up.

Corrosion Coupons are used to determine the need for corrosion inhibitors and to determine the potential extent of any corrosion in buried or submerged pipelines. Rectifier readings are taken every six months on CPAI pipelines. No coupons on any of the CPAI pipelines indicated the need for action during 2012.

Evaluation of the **Cathodic Protection (CP)** system includes rectifier checks (to ensure casing isolation) every two months and an inspection depolarization test annually. Monitoring and tests showed that all the CP systems were functioning properly in 2012.

CPAI PERSONAL SAFETY PROGRAM

CPAI, as part of its Internal Safety Program and in partnership with other North Slope operators, publishes the Alaska Safety Handbook (ASH), which outlines uniform safety procedures to be followed when performing pipeline related work. It also outlines individual responsibilities. Understanding and following the ASH is a condition of employment. This book will be updated and revised during 2013 and reissued in January 2014.

CPAI has implemented a **Voluntary Protection Program (VPP)** in each operating area to increase employee commitment to occupational safety. Through the VPP, CPAI obtains employee feedback concerning various processes and procedures and each operating area's commitment to safety. The VPP program was reviewed by the Alaska OSHA team in 2007 and was rated at the high quality star level, qualifying CPAI for OSHA reassessment once every five years, the longest term allowed. In early 2012 CPAI submitted to Alaska OSHA the results of a 2011 self-audit of all pipelines in 2011. OSHA reviewed the data and determined that Kuparuk and Oliktok pipelines will continue under Star status. Employee feedback indicates noticable improvement in communications, especially during shift-change. OSHA will be conducting a comprehensive review in January 2014 before it issues a final determination.

USDOT/PHMSA has jurisdiction over pipeline integrity, including equipment requirement, design standards, maintenance, monitoring and inspections. CPAI has a main-

tenance schedule for different components and systems, including launchers and receivers and leak detection systems. In addition to scheduled maintenance, corrective maintenance is scheduled as needed.

CPAI performs scheduled **Pipeline Surveillance and Monitoring**. USDOT/PHMSA requires inspections (at intervals not exceeding three weeks and at least 26 times a year) of surface conditions on or adjacent to each pipeline for indication of leaks or other problems. In addition to USDOT/PHMSA-required inspections, CPAI conducts visual inspections on all above-ground pipelines with annual ground surveys.

Surveillance and Monitoring Results Summary

Alpine surveillance: Of the 84 aerial inspections conducted, 49 employed FLIR assessments. No immediate threats to pipeline integrity were identified during the 2012 USDOT/PHMSA surveys. The annual ground surveys found no significant changes that posed a threat to pipeline integrity. Minor issues were noted for correction. Some of the items noted were VSMs that were jacked or tilted, u-bolts that needed tightening, insulation jacketing that needed repair, and missing reflective tape and vibration dampeners. Several locations where saddles were not centered on the VSM and one location where an anchor had been previously modified were identified, but surveilances found no threats to pipeline integrity. Surveillances did not identifyany dents or bullet holes, and no structural damage such as cracks or broken parts.

The ground survey also examined road and river crossings and survey monuments. The Alpine pipelines cross three major rivers. The HDD crossing of the Colville River East Channel is monitored annually. This year's monitoring showed only minimal erosion on both the east bank (0.1 feet) and the west bank (5.4 feet). There was no evidence of significant scour, tilting, settling or jacking of the VSMs, and no erosion of the gravel pad. At both locations, the pipeline was in good condition.

Surveys of the above-ground crossings at the Kachemach and Miluveach Rivers are conducted every five years. They were both inspected in 2012. At both locations, the pipelines were in good condition with no leaks and the VSMs had no measurable impact on bank erosion or channel scour. There was no evidence of any threat to pipeline integrity. There was also no evidence that caribou movement had been significantly altered, and no brown or polar bear dens were identified within the right-of-way.

Kuparuk and Oliktok Surveillances: In addition to the drive-by surveys performed at the required rate, 78 aerial surveys were flown between CPF1 and PS1, 52 of which included FLIR assessments. Between CPF1 and CPF2 79 aerial surveys were flown with 53 employing FLIR evaluations. No immediate pipeline threats were identified during the USDOT/PHMSA surveys. Only minor issues were identified during the annual ground inspection. The minor issues include jacked or subsided VSMs, some locations where the VSM had less than the required 5 feet of ground clearance and are scheduled for modification, and some saddle movement. Most structures examined were in good repair. There was no evidence of pipeline movement, VSM tilting, significant insula-

tion damage, or excessive vibration or pipeline movement. Overall, no threats to pipeline integrity were identified. There was also no evidence that these pipelines blocked any wildlife movement. There were no brown or polar bear deans identified within the rights-of-way.

RIGHT-OF-WAY EVENTS/INCIDENTS/ISSUES

There were no unintended shutdowns or slowdowns of the Alpine, Kuparuk or Oliktok pipelines due to operations of the pipelines, with the exception of the AUP. There were some fluctuations in AUP flow rates due to operational and maintenance issues at the seawater treatment plant.

There was a mineral oil spill of approximately 2439 barrels during a transfer process along the AUP in November 2012. In April 2012 there was a problem with a crane contacting an 8-inch line within the AOP ROW. This incident caused no damage to any regulated pipeline.

There were five vehicle incidents within the KPL/OPL right-of-way. None of them involved any spills or injuries. There were four vehicle incidents within the KPE right-of-way. No spills or injuries resulted.

OIL AND HAZARDOUS DISCHARGES

The AUP seawater recycle line developed a leak due to corrosion. The spill occurred in the KPE ROW and the Alpine ROWs. Due to extreme cold weather the area was monitored and later flushed to reduce salinity. There were eight minor vehicle related spills in the KPL/KPE/OPL ROWs. All spills were to snow or gravel and were cleaned up. There was one spill during preventive maintenance work on a KPL valve where 0.5 cups of oil leaked onto the gravel pad. The contaminated gravel was cleaned up.

SPECIAL PROJECTS

The 2012 Alpine Caribou Survey combines data from calving and post calving aerial surveys and ongoing telemetry. Looking at the results in conjunction with previous surveys, pre- and post-construction, all indications are that caribou cross the Alpine pipelines frequently and without delay. During calving, caribou were distributed on both sides of the Alpine right-of-way with a higher density to the north. This suggests that caribou are crossing the pipeline successfully. The distribution pattern during calving correlates closely with data from other researchers showing that caribou densities are lower, but not absent, in the area 2 - 4 kilometers from an active road or facility. The reports confirm that there is no indication of displacement from infrastructure where there is no human activity during the calving period. Using GPS-collared animals, telemetry data confirmed ground observations that caribou may cross the Alpine pipelines multiple times in a day during insect season. The indications are that caribou do not avoid roads, pipelines or facilities during this period.

Aerial and road (Kuparuk) surveys for Spectacled Eiders have been conducted since 2004 from CPF-2 along the Alpine Pipeline route to the CD-1 facility in the Colville River delta. The survey area is dominated by drier habitat not commonly used by Spectacled Eiders, so the number of birds within the focused survey area is always small. Weather did not delay the arrival of Spectacled Eiders in 2012 as it did in 2011. By June 5, 2012, when the first road survey was conducted, Spectacled Eiders were already in the Kuparuk oilfield. Fifteen individuals at six locations were noted. The number of pre-nesting birds peaked around June 15, 2012. The Spectacled Eider is more abundant in the drier Kuparuk area than in the Alpine oilfield, which is dominated by wetlands. There has always been minimal use by Spectacled Eiders of the area along the Alpine pipeline. In mid-June a pair of Spectacled Eiders was sighted approximately 500 meters from the AOP. Several other spectacled eiders were sighted in subsequent surveys. Three observations of spectacled eiders near the AOP were made from the road during the Kuparuk surveys.

PROPOSED 2013 PLANS

In 2013, CPAI plans a corporate audit of all AS 38.35 pipelines for compliance with both state and federal regulations. Fire detection upgrades are planned at CPF2 for the APL. CPAI will also be conducting a corporate audit of HSE compliance and management systems for the greater Kuparuk area.

In terms of upcoming project work, there are some freeze suppressant chemical injections planned for the APL. During the scheduled Alpine maintenance shutdown there is a piping project scheduled to increase the flow rate to the breakout tank during periods of proration. Leak detection upgrades on KPL/KPE will be completed and commissioned by the end of second quarter 2013. Proactive refurbishing of weldpacks on KKPL will continue in 2013. CPAI is taking action to sleeve KPL in another 68 locations where there is external corrosion. This is part of a three-year project during which 56 sleeves have already been completed. OPL's NGL shippers no longer need the service of the OPL and it is scheduled to revert back to a fuel gas line, which was its function in the 1980s. The plan is for OPL NGL shipments to cease after 2013. The engineering and plan reviews necessary for the conversion back to fuel gas will be conducted during 2013.

KENAI KACHEMAK PIPELINE ANNUAL REPORT SUMMARY

The Kenai Kachemak Pipeline 2012 Annual Report was submitted on February 13, 2013. The SPCO reviewed the Kenai Kachemak Pipeline 2012 Annual Report and found that it provided sufficient information to satisfy the lease requirement (SPCO letter 13-072-AS).

The annual report is required by Stipulation 1.14 of the Lease and is intended to provide a clear picture of the state of the pipeline and the pipeline system. Because of its ties to lease requirements and the importance of the information presented, the report is thoroughly reviewed by the SPCO every year.

The summary below highlights just a few of the more significant KKPL activities, including One-Call program participation, corrosion-associated inspections, cathodic protection inspections and documentation of the regularly conducted aerial patrols.

Lessee Performance under the Lease
Throughout 2011, Marathon PipeLine Company, LLC (MPL), upheld the terms of the Kenai Kachemak Pipeline Right-of-Way Lease, ADL 228162. All lease reservations, conditions and limitations were adhered to, which includes right-of-way stipulations.

PIPELINE SURVEILLANCE AND MONITORING

Aerial and Ground Surveillance
There were 37 aerial surveillance flights of the KKPL right-of-way in 2011. During those flights and other drive-by inspections, personnel routinely checked the pipeline and the right-of-way for encroachments, construction activities and any unauthorized activities or change in condition. Aerial surveillance flights are done weekly, weather permitting, during the months of April, May, June, July, August, September and October. During the months of January, February, March, November and December aerial surveillance flights are conducted monthly due to inclement weather and reduced potential for third party damage. There were no conditions observed that were detrimental to the pipeline or the right-of-way in 2012.

In addition to aerial surveillance flights, MPL employees monitored the KKPL right-of-way during routine operations and maintenance activity. For example, during the leakage surveys personnel are trained to observe right-of-way conditions such as erosion, pipeline markers, etc.

RISK MANAGEMENT PROGRAMS

Corrosion Protection
To minimize the potential for internal corrosion, the operator regularly sampled gas for quality. Tests were performed to determine hydrogen sulfide (H2S) and water content. The operator monitors to the requirements of 49 CFR 192.475 and 49 CFR 192.477. The SPCO received data from the sampling efforts in the 2012 annual report. Data collected

from the pipeline's origin, gas production pads and at the terminus indicate that corrosive gas is not being transported by KKPL. The gas content was reported as consistently greater than 98 percent methane. Hydrogen sulfide is minimal and ranged from 0-0.7 parts per million.

Cathodic Protection
The operator inspects rectifiers a minimum of six times annually, with intervals not exceeding two and one-half months. The two rectifiers for KKPL were inspected 13 times in 2012. As part of the CP program, a pipe-to-soil survey is completed annually, with intervals not exceeding fifteen months. A pipe-to-soil survey was completed in July 2012 with 137 pipe-to-soil tests performed during the survey. Of the tests conducted, none yielded a reading outside of the range of acceptability.

Valve Inspection and Maintenance
Inspection and any required maintenance of KKPL mainline valves was conducted by MPL personnel in April and May 2012. These inspections were performed pursuant to 49 CFR Part 192, Subpart M – Maintenance. The inspections were to ensure that the valves were accessible and operable in the event of an emergency requiring the line to shutdown. All valve records were transferred to Hilcorp as part of the transfer-of-interest process.

Pressure Relief Devices and Regulating Stations
Inspection and testing of KKPL relief devices and pressure regulating stations, per 49 CFR Part 192, Subpart M – Maintenance, were conducted by MPL personnel in June 2012. Relief device and pressure regulating station records were transferred to Hilcorp as part of the transfer-of-interest process.

Leak Surveys
On-ground leakage surveys of the KKPL pipeline using leak detector equipment were conducted in January and again in July 2012. Minor leaks associated with packing were detected on four valves; however, none presented a hazard to the public, property or environment.

SAFETY PROGRAMS

MPL employee and contractor safety performance for 2011 resulted in zero OSHA recordable injuries and zero preventable motor vehicle accidents. Contractor services were used in 2011 to support KKPL operations. There were no known injuries experienced by contract personnel during the year. There were no known injuries to the public associated with the KKPL system in 2011.

In June of 2010, the MPL president announced a new strategic vision built around the theme "We Deliver by Being BEST" with BEST serving as an acronym representing: Business Focused, Excellent Operations, Safety Always, and Team. The initiative was furthered in 2011 by the introduction of Safety 1, a safety leadership philosophy promoting that all employees are responsible for not only their own safety but for that of others, employees and contractors.

As part of its public safety efforts, MPL participates in the Alaska Dig Line Inc. one-call damage prevention program. The One-Call program is important to the community for the prevention of third-party pipeline damage that could threaten public safety. There were 150 locate requests in 2011, which resulted in 18 onsite locates and 17 high-pressure standbys. In contrast to 2010, DigLine Notifications were down nearly 27 percent in 2011; On-Site Locates were down nearly 25 percent; and High-Pressure Standbys were up by 54 percent.

THROUGHPUT AND PIGGING

KKPL, LLC, reported pipeline throughput and pigging activities in its 2011 annual report. This information is summarized in the table below. Total throughput for KKPL had a 26 percent increase from the 2010 total throughput. Throughput for all of the SPCO jurisdictional pipelines can be found in Appendix I.

HAZARDOUS SUBSTANCES DISCHARGE

There were no discharges of oil or other hazardous substances on the KKPL right-of-way during 2012.

NIKISKI ALASKA PIPELINE ANNUAL REPORT SUMMARY

Tesoro submitted its 2012 Annual Comprehensive Report on Pipeline Activities and State of the Pipeline System on March 1, 2013.

The annual report is required by Section 6 and Stipulation 1.15.3 of the Lease and is intended to provide a clear picture of the state of the pipeline and the pipeline system. Because of its ties to lease requirements and the importance of the information presented, the SPCO thoroughly reviews the report every year. Elements of the lessee's 2012 Annual Comprehensive Report on Pipeline Activities and State of the Pipeline System are summarized below.

Lessee Performance under the Lease
During calendar year 2012, Tesoro was issued 17 surveillances with satisfactory findings and one surveillance with unsatisfactory findings.

SURVEILLANCE AND MONITORING

Brushing
Brushing activities were conducted within five feet of the Nikiski Alaska Pipeline centerline. This results in a total clearing distance of 10 feet around to the pipeline ROW. Right-of-way sections cleared in calendar year 2012 on the Kenai side were approximately 3,000 feet downstream of MLV 5. On the Anchorage side clearing was performed from station numbers 3252+54 to 3153+00, 3165+06 to 3252+07, 3228+25 to 3252+27, and 3294+02 to 3295+02.

Right-of-Way Inspections
Tesoro performs a pipeline right-of-way inspection at least 26 times each calendar year, not exceeding three weeks between inspections. Inspections are performed by aerial surveillance of the pipeline, driving segments of the ROW, and walking portions of the ROW from the Tesoro Refinery to the Port of Anchorage. In addition, if work is occurring at a given location, the section of ROW near that particular work site may be inspected in conjunction with that project. Tesoro reported that employees performed 49 total aerial ROW inspections and 45 ground patrols in 2012.

Inspections of Crossings under Navigable Waters
Tesoro inspects the sub-sea pipeline crossing under Turnagain Arm every five years. The inspection is performed by a company that specializes in this type of procedure. The side-scan sonar survey shows hazard conditions near the pipe. The most recent side-scan sonar survey of the underwater pipeline was performed in August, 2011. The survey data was reviewed by an engineering firm who made recommendations, which were received by Tesoro in November, 2011. Recommendations were made to provide additional support to two subsea spans to reduce the potential effects of vortex induced vibrations. Tesoro installed intermediate support (sandbags) in accordance with

the engineering recommendations in June, 2012. This action mitigated all outstanding concerns/recommendations from the survey.

RISK MANAGEMENT PROGRAMS

Operations and Maintenance Manual
Tesoro is required to have a written operations and maintenance manual and to review it once each calendar year, not to exceed 15 months. Based on this review, there may or may not be any revisions required. The last review and binder revision occurred in March, 2012.

Integrity Management Program
Tesoro's Integrity Management Program (IMP) specifies actions that Tesoro commits to take to insure pipeline integrity. Tesoro's IMP was audited by PHMSA in October of 2010. This IMP audit concluded with no open issues or findings. The Tesoro Integrity Management Program was last revised in March, 2012.

Pursuant to the IMP, the last In-Line Inspection (ILI) was conducted on the Nikiski Alaska Pipeline in December of 2010. All required actions were completed in 2011, and no outstanding issues remain.

In-Line Inspection Information
All required actions resulting from the most recent (12/2010) ILI were completed in 2011.

Corrosion Management
Tesoro monitors corrosion via the ILIs performed, as required, in Tesoro's Integrity Management Program. Tesoro takes all the anomaly information resulting from the ILIs and compares it to previous years' ILI information to monitor corrosion.

Cathodic Protection
The underground portions of the Tesoro pipeline are protected from external corrosion by an impressed current CP system. The CP system is inspected and tested annually to determine whether the level of cathodic protection is adequate per 49 CFR 195.573(a)(1). The 2011 Annual Cathodic Protection Survey contained four recommendations for adjustments and maintenance.

1. Repair TS-29 test lead.
Status: Engineering analysis determined that existing test leads were adequate to measure the effective of CP in this area. TS-29 test lead was retired on 12/20/12.

2. Replace the pre-cast concrete test station at TS-34 with a new junction box test station. Install a barricade around the test station to prevent future damage.
Status: Completed in 2011.

3. Repair anode test station ATS-14.
Status: Open. A new shallow well ground bed has been determined to be needed instead of repairing the damaged Anodeflex system. Install planned for 2014.

4. To assist in the interruption of all rectifiers in the area, install a permanent GPS synchronized current interrupter in all of the rectifiers at the KPL facility.
Status: Completed in December, 2012.

IMPACTS/RESPONSES TO INTEGRITY, ENVIRONMENT, SAFETY

Abnormal Operating Conditions

USDOT 49 CFR 195.402(d) defines abnormal operating conditions as events that exceed design limits, such as unintended valve closures, system shutdown, pressures or flow rates outside normal operating limits, loss of communications, or operation of a safety device. Tesoro experienced 42 events identified as potential Abnormal Operating Conditions in 2012 (Table 1). In summary these events included:

- Leak Alarms – 14 events of leak alarms. In response to a leak alarm, TAPL is immediately shutdown and a leak investigation is initiated. In all 14 cases, the leak alarm was determined to be false. Prior to resuming normal operations, the pipeline is pressured up and held at a steady state for at least 30 minutes, to verify that no leak exists.
- Communication Failure – 23 events of communication failure. In the event of a communication failure with a pipeline component or instrument system, Tesoro initiates an investigation to ensure that the pipeline remains within safe parameters. In cases where the communication failure inhibits Tesoro's ability to safely monitor pipeline parameters, then the pipeline is shutdown until repairs and/or mitigative actions can be taken.
- Component Malfunction – 1 event of component malfunction. TAPL experienced one even in which a remotely operated valve would not respond to commands to close. The pipeline was shutdown and the cause investigated.
- Natural Disaster – 1 occurrence of natural disaster (recorded as two events). On May 16, 2012, a 4.6 magnitude earthquake occurred under the Turnagain Arm. The pipeline was shutdown and monitored under static pressure to verify that no leak conditions existed. Each end of the pipeline operations (Kenai and Anchorage) investigated and recorded the event.
- Other – There were 2 events not otherwise classified. These events involved errors in the Daily Shipped and Received Report. These errors did not affect pipeline safety or operations.

One-Call Notifications

Tesoro participates in the One-Call damage prevention program through Alaska Digline. Notifications of excavation work being performed near the pipeline were sent to Tesoro for evaluation. There were 329 one-calls made in the vicinity of TAPL in 2012. There was no 3rd party excavation damage to TAPL in 2012.

Valve Maintenance

Tesoro inspects and maintains the nine mainline block valves twice each calendar year, not exceeding 7.5 months between inspections. These inspections insure that valves are in working order and functioning properly. All the valves were inspected at least two times in 2012.

THROUGHPUT, RELIABILITY, AND PIGGING

The Nikiski Alaska Pipeline transports a number of different products including aircraft fuel (Jet-A), unleaded gasoline, premium unleaded gasoline, and two types of ultra-low-sulfur diesel. The products are transported to the Port of Anchorage where they are used at Elmendorf Air Force Base, Ted Stevens Anchorage International Airport or transported for use at gas stations. The products are transported through the pipe in batches to prevent cross contamination. Tesoro reported reliability for the pipeline at 98.8 percent for 2012.

Batch pigs are used to separate batches of different products transported through the pipeline. Maintenance pigs are not routinely used. The table below provides total throughput, reliability, and pigging information for 2012.

Table 10: NAP Reliability and Pigging Information

Pipeline System	2011 Throughput	Reliability	Maintenance Pigging	Last Smart Pig Run
Nikiski Alaska	11,917,815 barrels	98.8%	No regular schedule	December 2010

SUMMARY OF DISCHARGES

Tesoro records all oil and hazardous substance discharges within the SAP Incident Management Database. In addition, an incident report is compiled to document the release date, substance, quantity, location, cause, and cleanup actions. No oil or hazardous substance discharges occurred along the Nikiski Alaska Pipeline right-of-way in 2012.

NORTH FORK PIPELINE ANNUAL REPORT SUMMARY

The 2012 North Fork Pipeline Lessee Annual Report was submitted on April 12, 2013. The SPCO found that the report provided sufficient information to satisfy the annual reporting lease requirement (SPCO Letter No. 13-158-AS).

The annual report is required by stipulation 1.13 of the Lease and is intended to provide a clear picture of the state of the pipeline and the pipeline system. Because of it's ties to lease requirements and the importance of the information presented, the report is thoroughly reviewed by the SPCO every year.

The summary below highlights just a few of the more significant North Fork Pipeline activities including ROW surveillances, leakage surveys, cathodic protection surveys, the quality assurance program, and the surveillance and monitoring program.

Lessee Performance under the Lease

Throughout calendar year 2012, Anchor Point Energy, LLC upheld the terms of the Right-of-Way (ROW) Lease # ADL 230928 for the North Fork Pipeline. All lease reservations, conditions, and limitations were adhered to, which includes ROW stipulations.

SURVEILLANCE AND MONITORING

Aerial and Ground Surveillance

There were 12 ROW surveillances of the North Fork ROW in 2012. Portions of the ROW are wetlands so during the summer ROW surveillances are conducted aerially. Winter surveillances are conducted using snowmachines. During these surveillances personnel routinely checked the pipeline and the ROW for encroachments, construction activities and any unauthorized activities or changes in the condition of the ROW. There were no conditions observed that were detrimental to the pipeline or the ROW in 2012.

RESTORATION AND REVEGETATION

Wetland Restoration

During construction segments of the North Fork Pipeline that lie in wetlands were cut into sod blocks and placed to the side of trenching activities. After the pipeline was placed in the trench, the trench was refilled and the sod blocks were placed on top of the trench. Because soils placed in the trench were not compacted and partially frozen, the sod blocks may have stuck up to one foot above the adjacent ground surface. These sod blocks are being monitored as they settle back into the wetlands.

RISK MANAGEMENT PROGRAMS

Cathodic Protection
An annual cathodic protection survey was performed on the North Fork Pipeline on June 25-27, 2012. Test results indicated that approximately a 250 foot section of the pipeline between Test Station 27 and Test Station 28 had depressed potentials. On September 6-9, 2012, the section of pipe was excavated and high potential magnesium anodes were added to each pipeline. A new test station was added to this section, Test Station 27A.

Valve Inspection and Maintenance
Valves are located on the North Fork Unit Pad, the blowdown station located one mile from the west end of the pipeline, and the terminus at the Enstar metering pad. Valves and pads are inspected monthly by the Operator.

Leak Surveys
On-ground leakage surveys of the North Fork Pipeline using leak detector equipment were conducted in June 2012 and again in January 2013. No leaks were found on the ROW in both surveys.

SAFETY PROGRAMS

Anchor Point Energy, LLC, employees' and contractors' safety performance for 2012 resulted in zero OSHA reportable incidents associated with operations. There were no events requiring an emergency response related to pipeline operation in 2012.

As part of its public safety efforts, Anchor Point Energy, LLC, participates in the Alaska Dig Line Inc. one-call damage prevention program. The One-Call program is important to the community for the prevention of third-party pipeline damage that could threaten public safety. There were two calls to the Alaska Digline in 2012. On July 17, 2012, Alaska Digline was contacted to install a pipeline for Enstar in the vicinity of the NFU pad. On September 6, 2012, Alaska Digline was contacted to notify that there was digging occurring near Spruce Road associated with the cathodic protection work. Both calls were made my Anchor Point Energy and there were no calls made by other parties in 2012.

THROUGHPUT AND PIGGING

Anchor Point Energy, LLC, reported pipeline throughput and pigging activities in its 2012 annual report. Throughput for all of the SPCO jurisdictional pipelines can be found in Appendix I.

HAZARDOUS SUBSTANCES DISCHARGE

There were no discharges of oil or other hazardous substances by Anchor Point Energy, LLC, on the North Fork Pipeline right-of-way during 2012.

NUIQSUT PIPELINE ANNUAL REPORT SUMMARY

The 2012 Nuiqsut Natural Gas Pipeline (NNGP) Annual Report covers a broad range of quality and risk management programs aimed at managing safety, pipeline integrity, environmental risks and worker and community safety. The North Slope Borough (NSB) places emphasis on preventive and corrective maintenance programs, employee and contractor training and public education. A number of programs are carried out by the NNGP operator to ensure operations and maintenance activities are in compliance with federal, state and local laws and regulations.

The State of Alaska, through the pipeline right-of-way leases, requires each lessee to submit annually a comprehensive report on the results of pipeline surveillance and monitoring programs; changes to the pipeline system; results from the various quality assurance programs; information on any new construction, operations, or maintenance activities; a summary of all incidents and issues that had the potential to affect the pipeline system; and a summary of any hazardous discharges and subsequent clean-ups. The NNGP annual report and its supplemental information are available for public review.

The following sections summarize key information included in the NNGP annual report to the SPCO.

PIPELINE INTEGRITY AND RISK MANAGEMENT

Quality Assurance Program (QAP)

The NNGP QAP provides a structure to ensure that all management goals are met and that all federal, state and local laws, as well as state right-of-way lease terms, are followed. The primary elements of the QAP are company organization and leadership, risk management, personnel and training, design and construction, operations and safety for employees and contractors, emergency preparedness, incident investigation and the management of change. Several changes to the QAP were reported to the SPCO by the NSB in a submittal supplementing the annual report. The changes include a change in operations management. WHPacific will be contracted for operations management. WHPacific will also be responsible for all personnel training. A comprehensive review of the NNGP safety program is in process and should be completed in 2013. The Management of Change process is under review and any proposed changes will have to be approved by the NSB.

Risk Management Programs

NNGP has numerous risk management programs in place to meet the comprehensive USDOT/PHMSA pipeline integrity monitoring requirements as well as the terms of the state lease. The major elements of the NSB risk management program for the NNGP are quality assurance, internal safety and external safety. Changes made to the risk management programs include a call for increased communications between the con-

tract operator and the NSB, establishing a new maintenance schedule that is more prescriptive with respect to time of year for specific items, initial removal of damaged pipe coating in 2013, implementation of the public education program by WHPacific, and completion of the NNGP safety program review.

Routine maintenance repairs and surveillance• NNGP maintenance and surveillance were conducted as required. Complete surveillance of the leasehold and pipeline is carried out by the NNGP operator a minimum of twice each year. A walk-through of the pressure-reducing valve (PRV) station is conducted daily by the gas utility operator. Both operators inspect for any indication of gas leaks, abnormal operating conditions. They also check the pipeline temperature and pressure. Inspection information compiled from the PRV is routinely provided to the Alpine control room operator. Operations in 2012 were normal.

Corrosion control and monitoring• A check of the cathodic protection (CP) system on the NNGP System was performed in June 2012 by Taku Engineering. The CP survey tested pipe-to-soil potentials at eight pipeline test stations. The spot checks at these eight stations indicated that most of the transmission pipeline is not cathodically protected in accordance with industry standards. Taku Engineering recommended that the anode lead wires at Test Station No. 2 and No. 3 be excavated and the pipe inspected for evidence of corrosion. The firm also recommended periodic monitoring and the use of telluric nulling equipment for future CP checks.

Reporting of safety conditions• There was no unsafe worker or public safety condition related to the operation of NNGP reported in 2012.

While there is no current threat to pipeline or worker safety from H2S levels, H2S was not anticipated in the design basis for the gas conditioning module. NSB engineering originally assumed there would be no measurable H2S in the Nuiqsut gas; however, in 2011-2012 H2S fluctuated from 0-15 ppm. An increase in H2S is expected to continue, but it is extremely unlikely that current and foreseeable levels of H2S could have an impact on workers or the public. It is also unlikely that levels will reach a level that could precipitate corrosion. H2S levels remain below 10ppm due to the use of a "scrubber" system, housed at Alpine, that reduces H2S in the gas stream. Alpine operators, in coordination with the NSB, monitor and test the gas stream for increases in H2S and provide results of tests to Nuiqsut operators. Gas stream monitoring and testing for H2S will continue and results will be reported through annual reporting. Plans for mitigating future increases in H2S are underway and in coordination with Alpine operations.

NNGP Safety Program• Workers receive safety training and use proper personal protection equipment. There were no reportable injuries for the year.

PIPELINE SURVEILLANCE AND MONITORING

The surveillance and monitoring program involves visual inspections of the pipe and the surrounding area to look for any equipment damage, or improper disturbance to adjacent habitat or are wildlife. Inspections occur in summer and winter. The surveillance inspection list includes such items as failed pipe anchors, any unauthorized construction within the right-of-way, VSM alignment, u-bolt condition, coating damage, survey monuments, pipeline vibration dampeners, any damage to the pipeline (dents, vandalism, or other structural damage), condition of the above/below ground transitions, presence of fire hazards, condition of vegetation, subsidence or heaving associated with buried pipe, bank erosion, fish blockage, improper waste disposal, or any damage to associated facilities.

Some of the 2012 surveillance findings included damage to pipe coating at numerous locations along the NNGP. A secondary support angle was found to be misaligned. Initial removal of the damaged pipe coating and realignment of the support angle are scheduled for summer 2013. No leaks were found. No external audits or self-assessments were conducted during 2012. Additionally, WHPacific, operator for the NNGP, plans on completing the following maintenance and surveillance items in June 2013.

1. Coordination with Alpine and Nuiqsut Utility Cooperative operations
2. Valve Maintenance on the three valves located at HDD west
3. Replacement of pipeline markers
4. Seal repairs at the pipe transition from above to below grade
5. Pipeline leak survey using a Heath Instruments F.I. Gas Detector
6. Pipeline visual survey
7. Nigliq channel erosion visual survey
8. Excavation of CP stations in the village to verify frost depth and perform a visual assessment of surface CP equipment
9. Inspection of resurfaced and abandoned pipe on the east side of the Nigliq channel
10. Assessment of subsidence along buried sections along the NNGP right-of-way

Most of the maintenance items will be addressed in August 2013.

RIGHT-OF-WAY EVENTS/INCIDENTS/ISSUES AND HAZARDOUS DISCHARGES

No hazardous substances were released in the right-of-way in 2012.

POINT THOMSON ANNUAL REPORT SUMMARY

The Point Thomson development project (PTP) is located approximately 60 miles east of Deadhorse and 60 miles west of Kaktovik along the Beaufort Sea coast. The project will utilize onshore drill pads and long-reach directional drilling to produce resources from off shore. Exxon received a State lease for the Point Thomson Export Pipeline (PTEP) on October 31, 2012. Once constructed, the pipeline will transport natural gas liquids 22 miles from the PTP Central Processing Facility to the point at which it connects with the Badami pipeline. Both the PTP and the PTEP are entirely on state lands. The PTEP is owned by the PTE Pipeline LLC, a joint venture between ExxonMobil Pipeline Company (68 percent) and BP Transportation (Alaska) Inc. (32 percent).

Permitting and Data Collection

Exxon acquired over 170 permits for the PTP, including the PTEP. The major milestones for the pipeline included the 404 permit from the USACE and ROW lease and the Notice to Proceed issued by the SPCO. Other approvals came from ADF&G, DMLW, for ice road construction that would support the initial work on the pipeline in early 2013.

Several long term monitoring programs began in late 2012. Caribou monitoring was initiated to study the effects, if any, of the export pipeline and the in-field gathering lines on caribou movements. A plan for polar bear and grizzly bear monitoring, as well as a human /bear interaction plan were put in place. The interaction plan was approved by the SPCO. Baseline studies of fish and sediment are scheduled to begin in 2013. The fish monitoring of near shore movements will continue once every five years after the baseline study is completed.

Engineering Procurement and Fabrication

Major progress was made on the pipeline engineering during 2012 and it is considered 90 percent complete and sufficient to support the winter 2012-2013 construction effort. Significant progress was also made on PTEP project-related procurement. Steel for the VSM's and HSMs was purchased and delivered to a shop in North Pole, AK for fabrication. Fabrication was completed in time for the first winter pipeline construction season (2012-2013). Procurement was initiated for the piggable wye, but will continue into 2013. The 12-inch PTEP pipe order was issued in October 2012. The pipe was scheduled for manufacture in 1Q 2013.

Risk Management Programs

As part of the Notice to Proceed (NTP) authorization from the SPCO, the operator had to have in place and accepted by the SPCO the following programs: risk management program, quality management system, a pipeline operations integrity management system (OIMS) matrix, and safety programs. There were no events incidents or issues related to pipeline integrity, worker of public safety or environmental protection during 2012. There were also no discharges of oil or hazardous substances during 2012. The PTEP plans to conduct an audit of the pipeline engineering contractor during 1Q 2013.

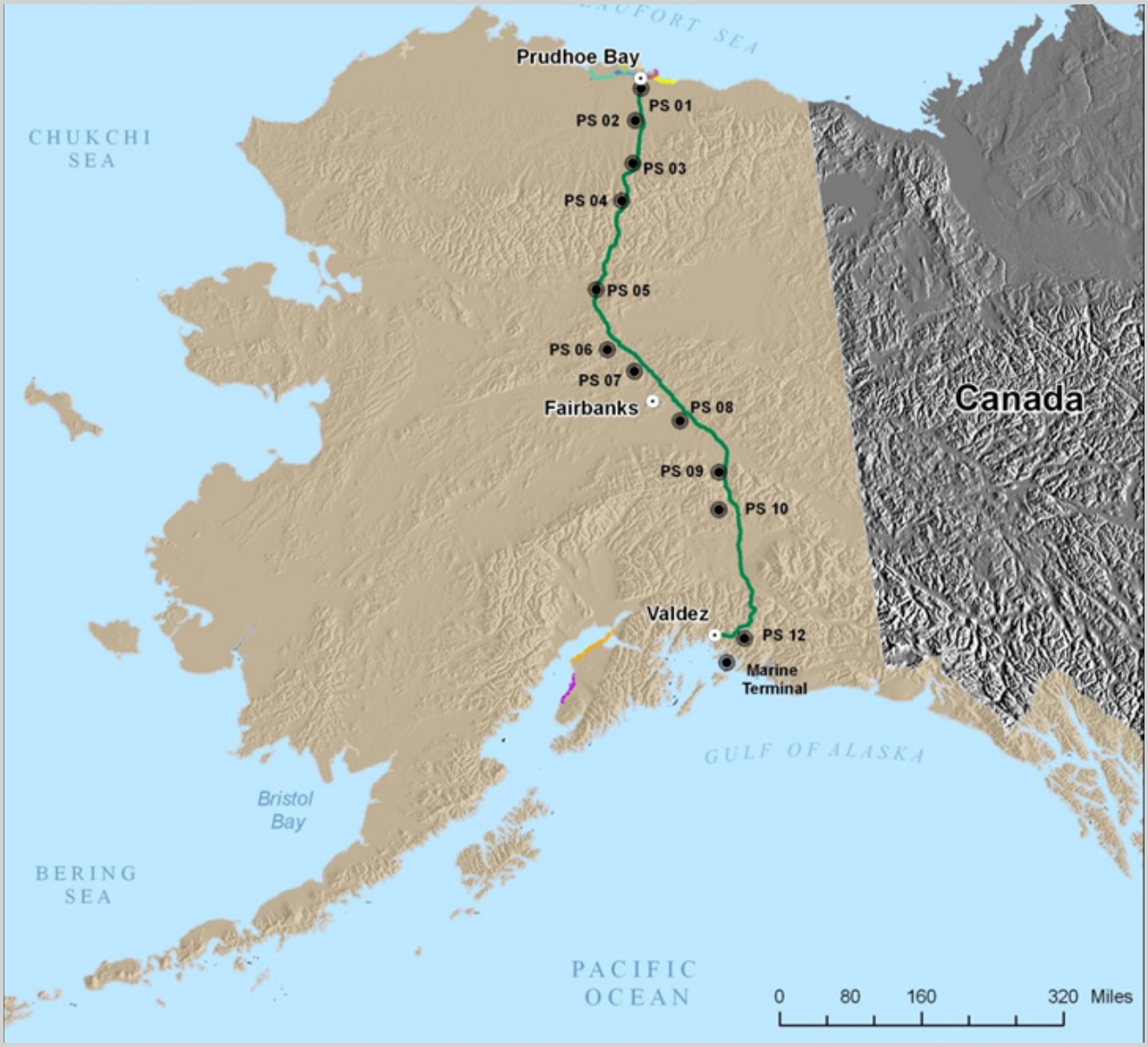
2013 Planned Activities

PTEP engineering work will be completed in 2013. This engineering effort includes a pair of additional vertical loops that were requested by USDOT/PHMSA, and modules for both ends of the pipeline. All the work should be completed by the end of summer 2013. Procurement of the piggable wye is scheduled to be finalized 1Q 2013. The purchase of three styles of HSM saddles is also scheduled for 1Q 2013. By the end of 2013 double jointing, coating, insulation and jacketing for the pipe and fabrication of the pipeline saddles and vibration dampeners should be completed.

Field surveys scheduled for 2013 include data collection necessary for conducting underground utility locates near the Badami telecommunication tower and on the Badami Unit in-field gravel access road. This will support the effort to mark all underground utilities prior to future PTEP construction efforts. Ice road routes and pad locations will be surveyed prior to construction so that disturbance to the tundra is minimized.

The significant PTEP activities during 2013 include: placing the camps for construction personnel at the Badami staging pad; construction of the supporting ice roads, spurs and pads along the PTEP route; and installation of HSMs and VSMs between Badami and Central pad. Data will continue to be collected by the various environmental monitoring programs including caribou and fish studies.

TAPS Annual Reports Summaries



APSC submitted the TAPS 2012 Integrity Management Program Annual Reports during spring/summer of 2013. Commonly referred to as the MP-166 reports, the integrity managements reports are:

- Mainline Aboveground Support Systems and Bridges Monitoring Program Report
- Fuel Gas Line Monitoring Report
- Mainline Integrity Monitoring Report
- Rivers, Floodplains, and Glacier Monitoring Program
- Right-of-Way and Facilities Civil Monitoring Program
- Aboveground Storage and Tank Monitoring Program
- Valve Monitoring Report

The MP-166 reports are produced to provide an annual update of the state of the pipeline and pipeline system. The SPCO reviews each report. Brief summaries of the reports can be found in the following section.

MAINLINE ABOVEGROUND SUPPORT SYSTEM AND BRIDGE REPORT SUMMARY

The Aboveground Monitoring Program consists of the Mainline Support System and Bridges Program and a slope stability component of the ROW and the Facilities Civil Monitoring Program. The APSC Aboveground Monitoring Program operates using information about the condition of the aboveground pipeline and bridge assets that is accumulated from a variety of sources by the Integrity Management Team. These sources include routine monitoring and maintenance activities, periodic ROW surveillances performed by the Pipeline and Civil Maintenance Coordinators (P&CMs) and Response Base Supervisors, annual line-walks, site-specific surveys and monitoring activities, and casual observations. The Integrity Management Team may, based on the collected information, prioritize maintenance and repair activities.

Alyeska Pipeline Service Company's Trans-Alaska Pipeline System (TAPS) 2012 Annual Report: Mainline Aboveground Support System and Bridges Program stated that nearly all of the routine monitoring and maintenance recommended in 2010 was completed, but fell short on several programs due to competing priorities.

The Aboveground Program Report provided detailed descriptions of the Mainline Aboveground Program activities in subsections based on whether the activities involve monitoring or maintenance.

2012 Monitoring
As part of the Aboveground Program Report, APSC provided details about monitoring activities. Below is a brief summary of several of those activities described by APSC in the Aboveground Program Report:

- Heat Pipes are analyzed by APSC on a 3-year cycle linewide. In 2012, APSC reported that a forward-looking infrared (FLIR) photographic analysis was performed on approximately 40,084 heat pipes (approximately 33 percent of total heat pipes). The 2012 FLIR analysis included 10,174 bents, anchors, and other supports along the pipeline ROW.

- Mainline Support System Monitoring in 2012 was composed of a comprehensive line-walk, shoe based inspection south of Atigun Pass, anchor position assessment, wildfire damage surveillance and a Denali fault crossing concrete grade beam analysis.

- The Site-Specific Geotechnical and Structural Analysis reported in 2012 included annual geotechnical monitoring, laser scan surveys for slope stability, biennial slope monitoring, VSM thermal stability data, insulation system monitoring, and an assessment of the remote gate valve (RGV) 118 avalanche diversion structure.

Site-specific Geotechnical and Structural Analysis
With the addition of a geotechnical engineer to the ROW Integrity Team, the annual geotechnical monitoring, laser scan surveys and the biennial slope monitoring programs have been moved to the ROW and Civil Monitoring MP 166 report.

Data pertinent to the VSM thermal stability program was collected in 2012 to monitor the thermal regimes of TAPS. FLIR photographic analysis was applied to more than 40,000 heat pipes to assess the ability of the heat pipe radiators to perform adequately.

Remote Gate Valve (RGV) 118 avalanche diversion structure continues to show displacement prompting APSC to analyze the movement and determine what would be the best fix for the structure. At this time there are several options to repair the structure and each are being weighed to determine the best course of action. A laser scan was not performed in 2012 however the digital data from 2011 and pervious years were compared in to help determine what type of a fix will be needed.

Insulation monitoring along TAPS is performed per MP-166-2.03 and requires moisture monitoring and physical conditions. No specific maintenance was targeted for the insulation system in 2012. The insulation system continues to degrade at an unknown rate. In an effort to determine the degradation to the insulation two instrumented test sites have been installed at Shaw Creek PLMPs 517.46, 523.10 and 530.68 and another at Glennallen PLMPs 653.87, 669.54 and 684.21.

Pipeline and Vehicle Bridges
Pipeline and vehicle bridges inspection sections included in the 2012 Aboveground Program Report contained information about pipeline bridge engineering inspections, vehicle bridge engineering inspections, annual bridge maintenance inspection, and multi-plate aboveground pipeline road crossing review.

The nine plate girder pipeline bridges received engineering level inspection in 2012 and were found to be in good condition. A comprehensive review of 30 years of inspection reports were reviewed prior to the engineering level inspections to re-create a depth of historical knowledge of the issues previously identified for the plate girders. No serious defects were noted during the review.

A laser scan of the Tanana River suspension bridge towers was not performed in 2012. The intent of the scan was to compare the scan from 2009 with the new scan to the level of benefit of performing this type of survey in conjunction with the 5-year engineering inspection cycle. All bridges not receiving an engineering level inspection had an annual inspection by the area P&CMs.

A comprehensive evaluation of the 10 multi-plate culvert road crossings was not completed in 2012. APCS and the Alaska Department of Transportation & Public Facilities have looked at possible guardrail changes on the road crossing under Goldstream Road. A decision on what will be done at this location will be determined before the roadway project in 2014 begins.

Split-ring Surveys, Load Testing and Adjustment
This section included information about split ring elevation surveys and load testing. As part of an ongoing target to survey all split ring elevations on a seven-year cycle, elevation surveys of continuous segments of the aboveground pipeline continued in 2012 with the aboveground segments between PLMP 312.90 and PLMP 439.27. A total of 85.5 miles of aboveground segments were surveyed. Elevation surveys were also completed at 17 areas where load rebalancing and re-leveling of crossbeams were performed in 2011.

Other maintenance and repair associated with the above ground support system in 2012:

VSM maintenance: load induced settlement – intentional overloading of select locations along TAPS where VSMs had excessive settlement and to determine if the rate of settlement has decreased has continued in 2012 with a scheduled completion date of 2014.

VSM Replacement at Squirrel Creek (PLMP 717.47 to 717.48) – the replacement of bents 196 & 197 was completed in 2012. New non-thermal driven VSM's were installed with greater embedment downslope of the existing VSM's.

Heat pipe repair - 3,407 heat pipes were converted to carbon dioxide in 2012. Another 265 heat pipes were recharged. Approximately 27,000 heat pipes have been converted to carbon dioxide sense 2001.

Shoe replacement, repair, and re-centering – Eleven minor shoe repair tasks were identified in 2012. None of them required immediate action and will be repaired when higher priority tasks come into those areas. Moderate fatigue cracking of the shoe bases downstream of Atigun Pass was found again in 2012. Slightly lower crude through put has resulted in less pressure induced shuddering at the slack line to pack line interface that was occurring in 2010 when the shoe damage was first observed. Repairs were necessary on 12 shoes this year compared to 11 in 2011 and 55 in 2010. Eleven other shoes were field repaired by welding minor cracks.

Anchor re-centering, re-leveling, and repair – No tripped anchors were discovered in 2012. One anchor frame was found out of level and is scheduled to be re-leveled by 2014 per MR-48 protocol.

Teflon slide plate peplacement – APSC maintenance strategy was changed from replacing side plates systematically bent-by-bent to replacing them where damage exceeds the MR-48 criteria. There are 44 reports of damaged slide plates in 2012 of which 35 were repaired. Eight other locations need split ring repairs as well and will be coordinated to have both fixed at the same time. The last plate was identified, but had previously been repaired.

VSM repair – According to the Aboveground Program Report, no issues were on the maintenance backlog in 2012. One VSM was identified as being split in the 2012 line-walk and will be prioritization for repairs against other maintenance projects.

VSM caps and weep holes – a pilot program was started in 2010 to determine the functionality of weep holes in the VSMs. Analysis is continuing to be done to determine if the blocked weep holes are a problem and when they are needed. In 2012 approximately 17,773 VSMs were checked in the aboveground segments of PLMP 376 to 485 and 675 to 736. Weep holes were found on 91 percent of these VSMs and approximately ¼ of these were obstructed.

RGV 118 avalanche diversion structure rehabilitation – a comprehensive analysis was not completed in 2012 and will be carried forward to 2013.

Pipeline bridge maintenance – minor maintenance occurred on several bridges along TAPS in 2012. This work included thing such as; loose bolt tightening, module flange covers were installed on approximately 1,980 feet of the pipe crossing over 5 plate girder bridges, concrete anchor blocks and tower foundations at Tanana and Tazlina River were pressure washed to resist weathering, pier caps on the Gulkana River Bridge were grouted, and the non-structural diagonal stabilizer cables on the Tanana River Bridge were re-tensioned.

Routine vehicle bridge maintenance (line-wide) – deteriorated running planks on nine access road bridge were replaced in 2012.

Split ring adjustments – adjustments were made on 31 bents in 2012. Shims were installed on an additional 20 shoe bases to maintain threaded riser stability and facilitate load balancing.

Recommendations for 2013 Aboveground Support System Program

- Perform a FLIR analysis along approximately 140 miles of aboveground pipe
- Perform a comprehensive line-walk of the aboveground segments of TAPS
- Complete a visual inspection of the shoe bases south of Atigun pass
- Check anchors for movement as needed after significant hydraulic or design contingency events
- Upgrade the engineering database management (EDM) system to increase its capabilities for analysis and trending
- Perform various monitoring activities to assess thermal stability of VSM's and other TAPS facilities dependent on heat pipes for structural stability
- Perform a laser scan of RGV-118 to evaluate the structure for future repairs or rehabilitation

- Obtain insulation moisture content from dataloggers in the Shaw Creek and Glennallen study areas and install a new study area north of the Brooks Range
- Perform a non-linear dynamic structural analysis of the Tazlina River Pipeline Bridge
- Repeat a laser scan survey of the Tanana River suspension bridge towers before the next engineering level inspection in 2016 to see if this type of survey is beneficial
- Complete a comprehensive evaluation of the aboveground road crossing multi-plate culverts for possible deviations from original design geometry
- Perform split ring elevation surveys between PLMP 169.10 and 307.48
- Continue to perform load testing along TAPS to determine rates of subsidence
- Perform bent maintenance to re-level crossbeams as necessary and restore overload conditions to induce settlement of the VSM's as a continuation of the action initiated in 2003
- Repair no less than 3,800 heat pipes, and repair 150 previously recharged heat pipes
- Replace, repair, or re-center shoes as conditions warrant
- Perform prioritized maintenance to re-center, re-level and repair anchors
- Replace Teflon slide plates as priorities warrant
- Re-tension, repair, or replace slip-critical bolts and intermediate bent seismic bolts as needed
- Continue weep hole remediation on approximately 17,400 VSMs
- Install module flange and expansion band covers to improve insulation system
- Initiate the design and implementation of rehabilitation of the four concrete grade beams at stations 31081+57, 31082+16, 31082+75, and 31083+35
- Complete backlogged maintenance tasks identified for pipeline and vehicle bridges
- Develop a plan to address the failing paint coatings of 20 Acrow bridges
- Perform routine monitoring of aboveground pipeline support system components such as split ring elevations, heat pipe performance, load distribution, and anchor displacement
- Perform pump station relief line load balancing

TAPS FUEL GAS LINE REPORT SUMMARY

In October 2011, APSC sent in-line inspection (ILI) devices (smart pigs) through the fuel gas line. The project required two different ILI devices because the fuel gas line has two segments with different diameters. The devices found four dents that required further investigation. APSC investigated two of the dents during 2012 and scheduled field investigation of the two other dents for summer 2013.

The primary procedures used for integrity work on the fuel are MP-166-3.04, Pipeline Integrity Pigging, MP-166-2.02, Fuel Gas Line Stability Monitoring, and MP-166-3.22, Pipeline Cathodic Protection Systems, Section 5.3. These incorporate requirements of the Grant and Lease stipulations, a Joint Pipeline Office agreement, USDOT/PHMSA requirements and other commitments.

During 2012, APSC conducted two "digs" to investigate anomalous data noted on the ILI runs. Both were to investigate dents in the PS1 area.

1. FGL MP 1.66. The ILI investigation predicted a 2.5 percent OD dent. The actual anomaly was a 2.05 percent and required repair.

2. FGL MP 11.37. ILI investigation predicted a 1.6 percent OD dent on a girth weld. The actual anomaly was a pipe weld joint misalignment. APSC determined that the pipe did not require repair.

During summer 2013, APSC plans to conduct two more digs near the northern end of the FGL, at MP 7.67 and MP 18.43. During 2012, APSC performed cathodic protection work on the FGL, but included it in another MP166 report so it will be discussed separately.

In addition, APSC evaluated pipeline depth of cover utilizing a LiDAR surface topology survey and data from the latest inertial guidance ILI (Geopig ®) runs. LiDAR is an airborne laser-ranging device that functions like radar and produces an accurate and highly detailed topographic survey showing surface elevations. Inertial guidance ILI produces a centerline survey of a pipeline. By calculating the difference between the two, a pipeline operator can determine burial depth at every point along a pipeline. Using this technique, APSC identified a number of locations requiring additional depth of cover. During 2012, the company remediated 47 of these locations.

MAINLINE INTEGRITY MONITORING PROGRAM REPORT SUMMARY

APSC performs integrity monitoring using a number of MP-166 procedures. These procedures are based on Grant and Lease stipulations, JPO agreements, regulatory requirements, and other commitments.

Highlights of the Mainline Integrity Investigations Program listed in the MP166 report include:

1. Surveys of belowground monitoring rods at selected locations and thermistor string data at selected locations

2. Performed ten belowground investigations but found that sleeves were needed at only two locations, at PLMP 648.94 and 775.95

3. Two aboveground investigations, at PLMP 457.53 and 502.70

4. An In-Line Inspection to identify and measure metal loss, deformation, curvature, and positioning of TAPS (This work is covered in a separate section)

APSC has monitored the elevation of belowground sections of TAPS since the construction of the mainline pipeline in 1974-1977. Of the 800 miles of TAPS, roughly half (380 miles) is belowground and half (420 miles) is aboveground. APSC monitors the curvature, elevation, and stresses created by movement of the belowground pipeline segment by surveying monitoring rods, measuring soil temperatures using thermistor strings, and periodically running an ILI device. This work comprises the basics of what APSC calls the Mainline Integrity Program, which is focused on the buried segments. The similar aboveground work is reported under the Aboveground Support System and Bridges Program.

During 2012, APSC surveyed 219 monitoring rods. Of these, 117 are located on sections of pipe where mechanical refrigeration units cool the soil around the mainline. APSC concluded that, "All monitoring rod sites surveyed in 2012 were confirmed to be stable or demonstrated little to no movement."

Based upon monitoring rod surveys, APSC identified seven location of special interest that they marked for closer follow-up in future years. Of these, three moved more than 0.10 foot since the last inspection. APSC concluded that, "[the recorded pipe movement] is not an immediate concern because the pipe is also periodically monitored with an ILI tool for indications of waveforms that are precursors to wrinkles and buckles. There are no such indications at this time requiring remediation. All locations will be reviewed from data obtained with the 2013 ILI."

APSC was able to read valid data from 53 thermistor strings. Four thermistor strings were either nonfunctional or partially functional. APSC said that they would work on

repairs. APSC reported that at the MLRs soil remains frozen beneath the pipe to the total depth of the thermistor strings.

For future remedial actions on the pipeline, APSC concluded that: "There are no sites requiring intervention as a result of this monitoring effort. New locations for monitoring and intervention will be based on the 2013 ILI survey." However, it increased the frequency of reading monitoring rods at five locations and thermistor strings at two locations.

During 2012, APSC conducted twelve "digs" (or investigations). These included assessing the condition of girth welds (GW) and/or longitudinal seam welds (LSW) at each belowground site and one sleeve investigation aboveground. APSC installed two mainline repair sleeves during 2012: one at MP 648.94 and one at MP 775.95. For 2013, APSC plans to investigate twelve belowground locations, all on the mainline; however, it acknowledged that work might have to be re-prioritized when data from the ILI run in April 2013 was returned.

In Government Letter No. 25049, APSC committed to perform an inspection of the existing mainline repair sleeve at MP 457.53. The operator completed it in May of 2012 and found no significant corrosion.

RIVERS, FLOODPLAINS, AND GLACIER MONITORING PROGRAM REPORT SUMMARY

The 2012 Rivers, Floodplains, and Glacier Monitoring Program Report (Rivers and Floodplains Report) provided a summary of APSC's annual monitoring of rivers and floodplains, major drainage structures, and glaciers. Fall flooding around the Copper River and Lowe River Basins created extensive damage along the ROW work pad with several low water crossings being damaged in the process. Stuart Creek at PLMP 754.18 had extensive bed load deposition, which resulted in the river moving to the overflow channel. The Rivers and Floodplains Report indicated that annual monitoring in 2012 produced no other findings that threatened TAPS integrity. The Rivers and Floodplains Program is based on ROW lease stipulations.

Rivers and floodplains monitoring includes an APSC Pipeline & Civil Maintenance (P&CM) Supervisor's biweekly aerial surveillance of the ROW in order to observe changes in river and floodplain environments that may affect TAPS. Unusual conditions noted along rivers and floodplains during the aerial surveillances prompt an on-the-ground visit and are reported according to the APSC Surveillance and Monitoring Manual, MS-31.

Rivers and floodplains monitoring also includes annual surveillances performed by APSC engineering department. Annual monitoring incorporates both aerial and ground surveillances performed by engineers in order to observe river, floodplain, and glacier environments, as well as glaciers that may affect TAPS.

According to the 2012 Rivers and Floodplains Report, the engineering monitoring surveillance noted that the spring breakup and aufeis floods along TAPS were mild along the entire length of the pipeline.

Summer and fall floods were normal along the Sagavanirktok River area. There was no significant bank erosion with the exception. Several sites along the Sagavanirktok River have minor erosion from year to year and will need predictive work in the near future to reduce the risk to the pipeline.

In the Dietrich and Koyukuk Rivers Drainage Basin there was no significant flood damage caused by summer or fall rains.

Flash flooding along the Delta River Drainage Basin resulted in some erosion in the Pump Station 10 area. Repairs were quickly made to stabilize sections of the ROW and low water crossings. Permanent repairs to Miller Creek (PLMP 589.5) will be completed to prevent scour around the vertical support members.

Record fall rain events along TAPS occurred in the Copper River Drainage Basin in 2012 affected only certain areas. Baseline crews made repairs to the ROW work pad as well as Stuart Creek to ensure flow was reestablished under the bridge and not around it. Lowe River Drainage Basin and the Valdez Marine Terminal experienced record rainfalls in September and October. The resulting flooding caused considerable damage to the ROW and several streams in the area. At Sheep Creek, the fiber optic cable along the ROW was exposed and the pipeline depth of cover was reduced to less than 30 inches, which is the minimum requirement per CFR 195.248. Unnamed Creek (PLMP 787.8) was also impacted by the flooding. High flows eroded parts of the bridge abutment and altered channel patterns. These repairs will be permanently repaired during the summer of 2013. All other damage to the ROW in this area was made in the fall of 2012 by APSC baseline crews.

Black Rapids, Castner, Fels, Canwell, and Worthington glaciers were monitored in 2010. No reportable conditions posing a threat to TAPS were found. Aerial imagery is taken of the glaciers on a five-year cycle to ensure do not pose an immediate threat to the mainline pipe.

Flooding in the Copper River and Lowe River Basins were caused by record rainfall along the coast of Alaska. The damage that occurred was quickly mitigated and repaired by baseline crews This damage was due to an above average snow pack that winter and an unseasonably warm spring causing the water to overtop the dikes. APSC Baseline crews quickly stabilized the dikes. During the summer the damaged dikes were permanently repaired and the reinforced with riprap.

RIGHT-OF-WAY AND CIVIL MONITORING REPORT SUMMARY

APSC lists the TAPS Grant and Lease, Memorandums of Understanding, 18 AAC 75, Oil and Other Hazardous Substances, 49 CFR 195.412, Inspection of Rights-of-Way programs as the primary guides for regulation of this program. It lists the following as the main internal procedures used in the work:

1. MP-166-2.05, Fault Monitoring
2. MP-166-2.07, Slope Stability Monitoring
3. MP-166-2.07V, Valdez Marine Terminal Slope Stability Monitoring
4. MP-166-2.08, Facility Monitoring
5. RCM Analyses

APSC's Civil Monitoring program consists of four primary areas.

Seismic Fault Monitoring
APSC reported that no notable seismic events occurred during the MP166 reporting period and photographed and documented all monitored monuments.

Mainline Slope-Stability Monitoring
APSC monitored seven instrumented slopes identified to have stability concerns and another one at Slate Creek that has tilted VSMs. The eight locations are:

PLMP 392.06 to 392.55	Lost Creek
PLMP 441.28 to 442.18	Treasure Hill
PLMP 685.81 to 685.91	GRB Hill (Pump Station 11)
PLMP 687.26 to 687.44	Tazlina River Hill
PLMP 698.02 to 698.25	Klutina River Hill
PLMP 716.83 to 717.27	Squirrel Creek Hill – north slope
PLMP 717.29 to 717.54	Squirrel Creek Hill – south slope
PLMP 408.17 to 408.57	Slate Creek

For the instrumented slopes, APSC concluded that, "analysis does not indicate a significant change in the stability of the monitored slopes that would affect the near-term integrity of the pipeline." For the tilted VSMs at Slate Creek, APSC wrote, "while not posing an immediate threat to pipeline integrity, slope movement will continue to require more frequent pipeline support adjustments to compensate for the changes in VSM position and alignment." In addition, APSC completed the scheduled biennial line-wide aerial surveillance of a 55 slopes of potential concern along the right-of-way from Fairbanks northward. The operator committed to completing the survey from Fairbanks southward in 2013.

Valdez Marine Terminal Slope-Stability Monitoring
APSC concluded that at the VMT "there is no immediate threat to static slope stability, secondary containment, or tank foundations from groundwater levels." It also

performed VMT surface drainage inspection, drainage maintenance work and removed loose rock. APSC concluded that, "there is no immediate threat to static slope stability, secondary containment, or tank foundations from groundwater levels."

Facility Monitoring

APSC performed survey monitoring at the VMT Biological Treatment Tanks (BTTs) and at selected locations at Pump Stations 1, 3, 4, 5, 6, 7 and 9. It surveyed some of these locations for vertical movement and some for both vertical and horizontal movement. For all monitored sites, APSC concluded that, "No corrective action is required on these monitored facilities;" however, the operator also recommended continued or more intensive monitoring at a few specific locations.

ABOVEGROUND STORAGE TANK MONITORING REPORT SUMMARY

APSC has a systematic program for tank maintenance and monitoring plan for external and internal inspections. External tank monitoring work in CY2012 included:

1. Monthly external tank inspections for tanks larger than 10,000 gallons.
2. Annual external tank inspections for tanks smaller than 10,000 gallons.
3. Installation of a leak detection system under TK-157 (turbine fuel storage) at PS5.
4. Inspection and repair of TK-110 (crude-oil storage, relief and balancing) at PS1.
5. Inspection and coating of TK-9 (crude-oil storage) at the VMT.
6. Inspection, repair and coating of TK-13 (crude-oil storage) at the VMT.
7. Inspection, repair and coating of TK-14 (crude-oil storage) at the VMT.
8. Visual inspection and cleaning of TK-16 (crude-oil storage) at the VMT.
9. Inspection, repair and coating of TK-93 (ballast water) at the VMT.

APSC's tank monitoring procedures require that tank inspections be conducted at regular scheduled frequencies. APSC procedures require a variety of inspections. These vary from an operator's visual checks to occasionally removing a tank from service and inspecting it inside and out per rigorous standards. For the more detailed inspections, APSC uses American Petroleum Institute (API) Standard for Tank Inspection, Repair, Alteration, and Reconstruction 653 and APSC's Procedure MP-166-3.20. Federal PHMSA (49 CFR 195) and State ADEC regulations (18 AAC 75) provide the general requirements for integrity checks. In addition, APSC conducts annual cathodic protection surveys on tanks, using as a guide the API 651, Cathodic Protection of Petroleum Storage Tanks.

APSC conducted an informal program evaluation at the conclusion of the 2012 Tank Program. Consequently, it made changes to MP-166-3.20. After the review, APSC concluded that "TAPS tanks are not susceptible to significant shell and roof corrosion."

The MP-166 report provided summaries on the tanks individually listed above. These were taken offline and inspected, cleaned and (if needed) recoated. The period covered by the MP166 reports, however, ends on December 31st. Since that time, APSC has successfully either isolated or returned to service the tanks featured in the report.

Highlighted repair projects in the report include:

1. During 2011, APSC inspected TK-157 for remaining thickness of the roof plate, shell, and floor, coating condition, and other items. During 2012, APSC repaired top-side annular plate pitting using puddle welding. This was the only identified repair. APSC installed an API650 under-tank leak detection monitoring tubes by slotting the tank floor and installing sloped monitoring tubes, and repaired the slots in the floor with steel plate.
2. During 2012, APSC inspected, cleaned, re-coated and repaired TK-110. It also installed a new annular ring. An annular ring is a thickened area next to the floor-wall interface used on some tanks to distribute the sidewall stress. The plate used in the new ring is thicker, one-inch thick, compared to the previous 0.325-inch. APSC also doubled the number of tank anodes and replaced failed grout in the area below the annular ring with an improved grout. This work was sufficient to qualify as a major repair under API 653. This standard requires proving major repairs with either a hydrotest or a Fitness for Service (FFS) evaluation. APSC performed an FFS evaluation. PS1 personnel were filling the tank at the end of June 2013, the end of this reporting period.
3. Inspections of four of the crude-storage tanks at the VMT found nothing requiring major repairs. Minor amounts of damage and corrosion are to be expected. However, there were a few items of note. TAPS Owners did not return TK16 to service. Instead, they isolated it. In performing the investigations, APSC utilized newer technology for detecting remaining metal. At the VMT, APSC selectively performed electromagnetic acoustic transducer (EMAT) and magnetic flux exclusion (MFE) inspections. APSC performed no major repairs on the tank sides, roof, or floors. However, they had to repair or replace some tank nozzle flanges and perform repairs on associated piping.
4. Inspection of the ballast-water tank showed "no significant corrosion loss in any of the courses" and "No shell repairs or plate replacements were required." However, APSC repaired coating and corrosion pitting on eighteen nozzle flanges or spool pieces and replaced three flanges. Because of corrosion, APSC installed patch plates on 61 internal columns.

APSC concluded that, "the 2012 internal inspection activities reveal low soil-side corrosion rates for TAPS tanks with the exception of the known corrosion on TK 110 annular plate, which was replaced. No leaks on any of the tanks were found."

APSC stated that it was continuing to refine Risk-Based Inspection (RBI) and API Standard 653 and Alaska State regulations. APSC employed a consultant to analyze inspection intervals under API 580 Risk-Based Inspection and 581 Risk-Based Inspection Technology and submitted a report with recommendations. During 2012, APSC and its consultants continued discussions over methodology with regulators.

VALVES MONITORING REPORT SUMMARY

APSC lists the following among the major regulatory requirements and internal procedures governing practices in the TAPS valve program:

1. P-193, Pipeline, Pump Station, and Terminal Valves in Crude Oil Service (API 6D Valves)

2. P-504, In-Service Performance Criteria: Primary Crude Block Valves

3. TV-222 through TV-225, Four Different Valve Maintenance Plans

4. TAPS PHMSA Valve Consent Agreement

5. Trans-Alaska Pipeline, Pipeline System Standards – Valves

6. 49 CFR Part §192.745 and Part §195.420, Valve Maintenance

The TAPS system has 176 remote gate valves (RGVs). APSC tests these valves in two primary ways. The valves must: (1) open and close upon command during the bi-annual DOT function tests, and (2) meet required sealing performance. APSC noted no major deficiencies in either category of testing during work performed this year.

APSC listed the following major actions in the MP-166 Valves Report:

1. Removed all station block valves (except for one) and blinded all relief valves at PS6, as part of the bypass project

2. Replaced 10 thermal-electrical generation units

3. Replaced three valves on the FGL. Moved the valves 50 feet further away from the Dalton Highway to mitigate the potential risk of vehicle impact

4. Replaced four valves at the Ballast Water Treatment facility

5. Tested 24 valves located between PS5 and PS7 and between Thompson Pass and the VMT

6. Completed goals for mainline gate valve and check valve winterization

7. Completed PHMSA valve movement tests and tested valve controls with special commands

In addition, APSC installed drag valves at PS7 and PS4 to improve recirculation of crude within the pump stations. The purpose was to decrease damage and wear to valves previously used to recirculate oil.

Report Correction, Retraction and Amendment Guidelines

To propose a correction to any information in this report, please follow these steps:

1. Submit a written request for a correction to the following address:
   Graham Smith
   State Pipeline Coordinator's Office
   411 W. 4th Avenue
   Anchorage, AK 99501

2. In the request, please include the following:
   - Contact address, telephone number and email address
   - The page number and, if applicable, the table number of the proposed change
   - Suggested and specific wording that would correct the alleged error
   - Supporting evidence and references

3. Upon receipt of the written request, the SPCO will send a written response acknowledging receipt of the suggestion.

4. The SPCO will evaluate every suggestion and provide a written response to the requestor describing the reasons that the request will be accepted or rejected. Alternatively, the SPCO may ask for additional information if the original request is deemed to have insufficient evidence for evaluation.

5. The SPCO will respond in writing with a determination directly to the requestor. If the SPCO determines that an error was made in this report, the SPCO will include the changes and retractions in the online version of the current annual report and in the next print edition.

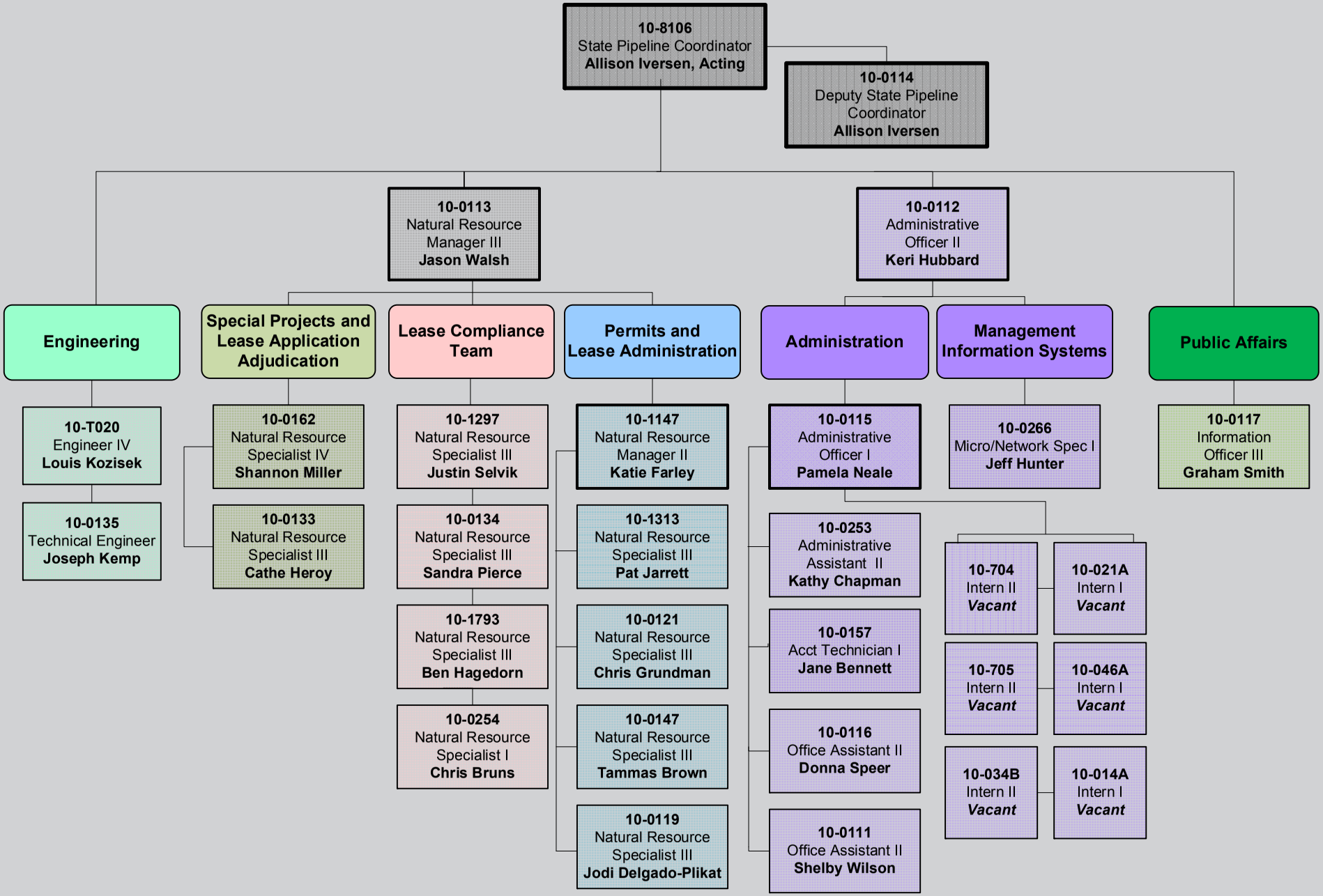
This publication was released by the Alaska Department of Natural Resources to provide information about the State Pipeline Coordinator's Office and its operations during fiscal year 2013 and to satisfy Finding No. 18 in State of Alaska Administrative Order No. 137. Two hundred copies were printed in Anchorage, AK, at a cost of $41.43 per copy.

APPENDIX A: ACRONYMS AND ABBREVIATIONS

ACF	Alpine Central Facility
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
AGDC	Alaska Gasline Development Corporation
AHFC	Alaska Housing Finance Corporation
ANGDA	Alaska Natural Gas Development Authority
APDES	Alaska Pollutant Discharge Elimination System
APSC	Alyeska Pipeline Service Company
AS	Alaska Statute
BEST	Behavior Enhanced Safety Techniques
BLM	Bureau of Land Management
bopd	barrels of oil per day
BPTA	BP Transportation (Alaska) Inc.
BPXA	BP Exploration (Alaska) Inc.
BWT	Ballast Water Treatment
CFP	Central Facilities Pad
CFR	Code of Federal Regulations
CIC	Corrosion, Inspection, and Chemical
CP	Cathodic Protection
CPAI	ConocoPhillips Alaska, Inc.
CPF	Central Processing Facility
C-Plan	Oil Discharge Prevention and Contingency Plan
DEIS	Draft Environmental Impact Statement
DNR	Alaska Department of Natural Resources
DOLWD	Alaska Department of Labor and Workforce Development
DOT&PF	Alaska Department of Transportation and Public Facilities
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
FGL	Fuel Gas Line (TAPS)
FLIR	Forward Looking Infrared
FY	Fiscal Year
GIS	Geographic Information System
GRB	Glennallen Response Base
H2S	Hydrogen Sulfide
HDD	Horizontal Directional Drilling
HSE	Health, Safety, and Environment
IFC	Issued for Construction
ILI	In-Line Inspection
IMP	Integrity Management Program
IMT	Incident Management Team
JPO	Joint Pipeline Office
KKPL	Kenai Kachemak Pipeline
KPE	Kuparuk Pipeline Extension
KPL	Kuparuk Pipeline
KRU	Kuparuk River Unit
LAS	Land Administration System
LEFM	Leading Edge Flow Meter
LiDAR	Light Detection and Ranging
MFL	Magnetic Flux Leakage
MOC	Management of Change
MP-166	APSC Monitoring Program
MPI	Main Production Island
NEC	National Electric Code
NNGP	Nuiqsut Natural Gas Pipeline
NOV	Notice of Violation
NPDES	Nation Pollutant Discharge Elimination System
NRM	Natural Resource Manager
NSB	North Slope Borough
OCC	Operations Control Center
OM&OQ	Operations, Maintenance and Operator Qualifications Manual
OPL	Oliktok Pipeline
OQ	Operator Qualification
OSHA	Occupational Safety and Health Administration
P&CM	Pipeline and Civil Maintenance Coordinator
PHA	Process Hazard Analysis
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLMP	Pipeline Milepost

PLQ	Permanent Living Quarters
PPE	Personal Protective Equipment
PS	Pump Station
PSIO	Petroleum Systems Integrity Office
PTEP	Point Thomson Export Pipeline
QAP	Quality Assurance Program
RGV	Remote Gate Valve
ROW	Right-of-Way
RTU	Remote Terminal Unit
SDI	Satellite Drilling Island
SERVS	Ship Escort Response Vessel System
SFMO	State Fire Marshal's Office
SPCO	State Pipeline Coordinator's Office
SR	Strategic Reconfiguration
SWD	Solid Waste Disposal
TAPS	Trans-Alaska Pipeline System
TG	Turbine Generator
USACE	U.S. Army Corps of Engineers
USCG	U.S. Coast Guard
USDOT	U.S. Department of Transportation
VMT	Valdez Marine Terminal
VSM	Vertical Support Member
WWS	Walking Speed Survey

Department of Natural Resources
State Pipeline Coordinator's Office



APPENDIX C: MAJOR SOURCE DOCUMENTS

1. **Alyeska Pipeline Service Company**. Trans Alaska Pipeline System (TAPS) 2012 Integrity Management Annual Reports: Mainline Aboveground Support System and Bridges Program. Anchorage: Alyeska Pipeline Service Company, 2013.
2. Trans Alaska Pipeline System (TAPS) 2012 Integrity Management Annual Reports: Fuel Gas Line Monitoring Program. Anchorage: Alyeska Pipeline Service Company, 2013.
3. Trans Alaska Pipeline System (TAPS) 2012 Integrity Management Annual Reports: Mainline Integrity Monitoring. Anchorage: Alyeska Pipeline Service Company, 2013.
4. Trans Alaska Pipeline System (TAPS) 2012 Integrity Management Annual Reports: Pipeline and Valdez Marine Terminal Facilities Corrosion Monitoring. Anchorage: Alyeska Pipeline Service Company, 2013.
5. Trans Alaska Pipeline System (TAPS) 2012 Integrity Management Annual Reports: Aboveground Storage and Tank Monitoring Program. Anchorage: Alyeska Pipeline Service Company, 2013.
6. Trans Alaska Pipeline System (TAPS) 2012 Integrity Management Annual Reports: Rivers, Floodplains, and Glacier Monitoring Program. Anchorage: Alyeska Pipeline Service Company, 2013.
7. Trans Alaska Pipeline System (TAPS) 2012 Integrity Management Annual Reports: Right-of-Way and Civil Monitoring Program. Anchorage: Alyeska Pipeline Service Company, 2013.
8. **BP Transportation (Alaska) Inc**. Badami Pipelines Rights-of-Way: 2012 Annual ADNR Surveillance and Monitoring Report. Anchorage: BP Transportation (Alaska) Inc., 2013.
9. **BP Transportation (Alaska) Inc.** Milne Point Pipelines Rights-of-Way: 2012 Annual ADNR Surveillance and Monitoring Report. Anchorage: BP Transportation (Alaska) Inc., 2013.
10. **Kuparuk Transportation Company**. 2012 Annual Comprehensive Report on Pipeline Activities for the Kuparuk Pipelines: ADL 402294, and ADL 409027. Anchorage: Kuparuk Transportation Company, 2013.
11. **BP Transportation (Alaska) Inc**. Endicott Pipeline Right-of-Way: 2013 Annual ADNR Surveillance and Monitoring Report. Anchorage: BP Transportation (Alaska) Inc., 2013.
12. **Northstar Pipelines.** Rights-of-Way: 2013 Annual ADNR Surveillance and Monitoring Report. Anchorage: BP Transportation (Alaska) Inc., 2013.
13. **ConocoPhillips**. 2013 Annual Comprehensive Report on Pipeline Activities for the Alpine Pipelines: ADL 414701, ADL 415932, and ADL 415857. Anchorage: ConocoPhillips, 2013.
14. **Marathon Pipe Line Company, LLC**. Kenai Kachemak Pipeline 2013 Annual Report. Kenai: Marathon Pipe Line Company, LLC, 2013.
15. **North Slope Borough**. Nuiqsut Natural Gas Pipeline: Annual Comprehensive Report on Pipeline Activities and the State of the Pipeline System. Anchorage: North Slope Borough, 2013.
16. **Oliktok Pipeline Company**. 2013 Annual Comprehensive Report on Pipeline Activities: Oliktok Pipeline ADL 411731. Anchorage: Oliktok Pipeline Company, 2013.
17. **Tesoro Alaska Pipeline Company**. 2013 Annual Comprehensive Report on Pipeline Activities and State of the Pipeline System for Tesoro Alaska Pipeline Company (Nikiski) Right -of- Way Lease - ADL 69354. San Antonio: Tesoro Refining & Marketing Company, 2013.

Appendix D: Acreage, Survey and Lease Information

ADL #	Pipeline Name	Lease Effective	Lease Expiration	Lessee	Acres on State Land	Survey Number
418997	**Alaska Stand Alone Gas Pipeline**	7/25/2011	7/25/2041	Alaska Gasline Development Corporation	4933[1]	NA
415932	**Alpine Diesel Pipeline**	12/15/1998	12/14/2018	ConocoPhillips Co.	148.45	EPF 2002-40A[2]
415701	**Alpine Oil Pipeline**	12/15/1998	12/14/2018	ConocoPhillips Co.	148.59	EPF 2002-40A[2]
415857[3]	**Alpine Utility Pipeline**	01/06/1999	01/05/2019	ConocoPhillips Co.	148.57	EPF 2002-40A[2]
415472	**Badami Sales Oil Pipeline**	12/15/1997	12/14/2022	BP Transportation (Alaska) Inc.	186.91[4]	EPF 2002-18 EPF 2008-09
415965	**Badami Utility Pipeline**	12/15/1997	12/14/2022	BP Transportation (Alaska) Inc.	232.72[5]	EPF 2002-18 & EPF 2008-06
410562	**Endicott Pipeline**	08/05/1986	05/02/2034	Endicott Pipeline Co.	1073.81	ASLS 84-96 EPF 2008-40
228162	**Kenai Kachemak Pipeline**	11/26/2002	11/25/2032	Kenai-Kachemak Pipeline, LLC	104.556	KKPL - EPF 2004-45 HVE - EPF 2005-41 KE - EPF 2007-04
402294	**Kuparuk Pipeline**	08/26/1980	05/02/2034	Kuparuk Transportation Co.	485.64	Tr. A, ASLS 87-15 (Amended) ASLS 2005-35 (0.06 acres)
409027	**Kuparuk Pipeline Extension**	04/18/1983	05/02/2034	Kuparuk Transportation Co.	159.13	Tr. D, ASLS 87-15 (Amended) EPF 2011-12 (Pending)
410221	**Milne Point Pipeline**	01/15/1985	05/02/2034	Milne Point Pipeline, LLC	186.92	ASLS 84-114
416172	**Milne Point Products Pipeline**	12/05/2000	12/04/2030	Milne Point Pipeline, LLC	186.96	EPF 2007-57
69354	**Nikiski Alaska Pipeline**	01/30/1976	01/29/2031	Tesoro Alaska Pipeline Co.	72.4[6]	ASLS 76-215 EPF 2006-01 (Pending)
230928	**North Fork Pipeline**	09/28/2010	09/27/2040	Anchor Point Energy, LLC	23.06[7]	EPF 2011-37 (Pending)
415975	**Northstar Gas Pipeline**	10/01/1999	09/30/2019	Northstar Pipeline Company, LLC	405.51	EPF 2002-17
415700	**Northstar Oil Pipeline**	10/01/1999	09/30/2019	Northstar Pipeline Company, LLC	419.13	EPF 2002-17
416202	**Nuiqsut Natural Gas Pipeline**	03/15/1999	03/14/2019	North Slope Borough	17.67	As-built Survey approved by DNR on 12/17/2003.
411731	**Oliktok Pipeline**	06/01/1986	05/02/2034	Oliktok Pipeline Co.	485.58	Tr. A , ASLS 87-15 (Amended)
418975	**Point Thomson**	10/31/2012	10/31/2042	PTE Pipeline LLC	1106.9	EPF 2012-71 (Pending)
63574	**Trans-Alaska Pipeline System**	05/03/1974	05/02/2034	TAPS Pipeline Owners[8]	6021.87[9]	Multiple Surveys[10]

[1] Alaska Stand Alone Gas Pipeline (ASAP) lease issued in 2011, construction acreage is an estimate; Lease construction width will be 100 ft., operation right-of-way width will be 30 ft.

[3] ADL 415857 is a right-of-way grant under AS 38.05.850.
[4] Release of Interest executed August 14, 2012. Acreage reflected is Operation and Maintenance Right-of-Way.
[5] Release of Interest effective December 19, 2012 and executed January 17, 2013. Acreage reflected is Operation and Maintenance Right-of-Way.
[6] Encompasses other landowner acreage.
[7] Acreage based on construction right-of-way acreage from lease, pending approval of survey and release of interest, expected FY 2014.
[8] Owners: BP Pipelines Alaska Inc., Conoco Phillips Alaska Transportation Inc., and Exxon/Mobil Pipeline Co.
[9] Per Appraisal 3165, DNR Summary of Appraisal dated 7/21/2006, and Memorandum of May 17, 2007, from Review Appraiser to the SPCO to add fuel gas line acreage.
[10] Includes Trans-Alaska Pipeline System centerline survey, surveys of pump stations on State land, and as-built surveys for right-of-way amendments.

Appendix E: Pipeline Right-of-Way Lease Appraisal Information

Pipeline	ADL #	ROW Status	Appraisal Acres	Rental Paid in FY 13	Appraisal Annual Rental	Next Appraisal Date
Alpine Diesel[1]	415932	Operations	148.51	$77,629.00	$77,629.00	12/15/2013
Alpine Oil[1]	415701	Operations	148.67	$77,713.00	$77,713.00	12/15/2013
Alpine Utility[1]	415857	Operations	148.65	$77,703.00	$77,703.00	01/06/2014
Badami Sales Oil	415472	Operations	186.91	$136,782.00	$136,782.00	12/15/2017
Badami Utility[2]	415965	Operations	232.72	$251,179.06	$247,281.00	12/15/2017
Endicott	410562	Operations	1073.82	$736,655.00	$736,655.00	08/05/2013
Kenai Kachemak	228162	Operations	104.56	$35,131.00	$35,131.00	11/26/2017
Kuparuk (Oil)[2]	402294	Operations	485.58	$84,516.00	$370,347.00	08/26/2013
Kuparuk Extension[3]	409027	Operations	159.09	$471,237.00	$471,237.00	04/18/2018
Milne Point (Oil)	410221	Operations	186.92	$553,672.00	$553,672.00	01/15/2018
Milne Point Products	416172	Operations	186.92	$553,672.00	$553,672.00	12/05/2015
Nikiski Alaska	69354	Operations Construction	63.710 8.724	$53,731.75	$53,731.75	01/30/2014
North Fork	230928	Construction	23.06	$2,194.00	$2,194.00	09/28/2015
Northstar Gas	415975	Operations	405.51	$252,429.00	$252,429.00	10/01/2014
Northstar Oil	415700	Operations	419.13	$317,456.00	$317,456.00	10/01/2014
Nuiqsut Natural Gas	416202	Operations	17.67	$11,120.00	$11,120.00	03/15/2014
Oliktok[3]	411731	Operations	485.58	$876,476.00	$876,476.00	01/01/2018
Point Thomson Export	418975	Construction	1106.90	$819,755.64	$819,755.64	10/31/2017
TAPS[3]	63574	Operations	6021.87	$220,956.00	$220,956.00	***
ASAP[4]	418997	Construction	1106.9	$188,600.00	$188,600.00	N/A

[1] Current appraisal is under appeal.
[2] The Badami Utility Pipeline Rental for FY 13 was pro-rated with Construction and Operations ROW lease rentals and paid in full.
[3] Appeal resolved, appraisal is due. Acreage and appraisal amounts do not include several approved right-of-way amendments pending acceptance of the as-built surveys.
[4] Signed into law on 5/21/2013, HB 4 now exempts the Alaska Gasline Development Corporation from annual rental and appraisal requirements.

Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines

Pipeline System	Diameter (Inches)	Normal Wall Thickness (Inches)	Product	Year Constructed	System Length/Length on State Lands (approx. miles)
Alaska Stand Alone Pipeline[1]	24 & 12	Tbd	Natural Gas	Tbd	737 / 407
Alpine Diesel	2.375	0.156	Product	1998-1999	34.2 / 23.7
Alpine Oil	14	0.312 0.438 @ Colville River	Crude Oil	1998-1999	34.2 / 23.7
Alpine Utility	12.75	0.330	Sea Water	1998-1999	34.2 / 23.7
Badami Sales Oil	12.75[2]	0.281 above ground 0.500 buried	Crude Oil	1998	25.1 / 25.1
Badami Utility	6.625	0.375 above ground 0.432 river crossings	Natural Gas & Product	1998	31 / 31
Endicott	16	0.372	Crude Oil	1987	26.1 / 26.1
Kenai Kachemak	12.75	0.330 0.500 @ wetlands	Natural Gas	2003-2004	46.2/ 37.3
Kenai Kachemak (Kasilof Extension)	6.625	0.280 0.432 @ HDD	Natural Gas	2006	4.2 / 4.1
Kuparuk Pipeline	24 (28 miles) 16 (0.03 miles)	0.406 (28 miles) 0.375 (0.03 miles)	Crude Oil	1984	28 / 28
Kuparuk Extension	18	0.375 (5 miles) 0.438 (4 miles)[3]	Crude Oil	1983	9 / 9
Milne Point (Oil)	14	0.312	Crude Oil	1984-1985	10.7 / 10.7
Milne Point Product[4]	8	0.277	Natural Gas Liquids	2000	10.4 / 10.4
Nikiski Alaska	10.75	0.188 to 0.625	Refined Petroleum Products	1976	52.5 / 21.5
North Fork	4.5 dual composite (6.3 miles) 4 steel (1.1 miles)	0.61	Natural Gas	2010-2011	7.4 / 6.6
Northstar Gas	10.15	0.307 or 0.274 On Shore, 0.594 Subsea	Natural Gas	2000-2001	16.4 / 16.4
Northstar Oil	10.75	0.307 or 0.279 On Shore, 0.594 Subsea	Crude Oil	2000-2001	17.4 / 17.4
Nuiqsut Natural Gas	3.5	0.203 , 0.216 @ Colville	Natural Gas	1998-2001	14.4 / 2.65
Oliktok	16	0.342, 0.75 @ Kuparuk River	Natural Gas Liquids	1980-1981	28 / 28
Point Thomson[5]	12.75[1]	0.406	Crude Oil	2013-2015	22/22
Trans-Alaska Pipeline System	48	0.462 (466 miles) 0.562 (334 miles)	Crude Oil	1975-1977	800 / 343[6]

[1] Right-of-Way issued, construction not yet began.
[2] Outer diameter
[3] Kuparuk Pipeline Extension – Original construction with wall thickness of 0.375 inches. 12-inch diameter pipe segment replaced with 18-inch diameter pipeline in 2009 with wall thickness of 0.438 inches.
[4] Pipeline operations temporarily discontinued service and disconnected in 2006.
[5] Construction began in 2013.
[6] Trans-Alaska Pipeline System: Total length 800 of which 376 miles cross Federal, 343 miles cross State, and 80 miles cross private lands.

SPCO/DNR FY13 Surveillance Reports (by Pipeline)

Surveillance Number	ADL	Pipeline (PLMP #)	Section/Stipulation	#	Title	Observation
13-SPCO-S-001	415932	Alpine Diesel Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-002	415932	Alpine Diesel Pipeline	Stipulation	1.4	Quality Assurance	Satisfactory
13-SPCO-S-003	415932	Alpine Diesel Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-004	415932	Alpine Diesel Pipeline	Stipulation	2.5	Zones of Restricted Activity	Satisfactory
13-SPCO-S-013	415932	Alpine Diesel Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-014	415932	Alpine Diesel Pipeline	Stipulation	1.4	Quality Assurance	Satisfactory
13-SPCO-S-015	415932	Alpine Diesel Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-016	415932	Alpine Diesel Pipeline	Stipulation	3.2	Pipeline Corrosion	Satisfactory
13-SPCO-S-106	415932	Alpine Diesel Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-107	415932	Alpine Diesel Pipeline	Stipulation	1.4.1	Quality Assurance	Satisfactory
13-SPCO-S-108	415932	Alpine Diesel Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-109	415932	Alpine Diesel Pipeline	Stipulation	2.2	Thermal Pollution	Satisfactory
13-SPCO-S-110	415932	Alpine Diesel Pipeline	Stipulation	3.1	Pipeline System Standards	Satisfactory
13-SPCO-S-155	415932	Alpine Diesel Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
13-SPCO-S-247	415932	Alpine Diesel Pipeline	Stipulation	1.2	Communications	Satisfactory
13-SPCO-S-248	415932	Alpine Diesel Pipeline	Stipulation	1.5	Conduct of Operations	Satisfactory
13-SPCO-S-249	415932	Alpine Diesel Pipeline	Stipulation	1.7	Health and Safety	Satisfactory
13-SPCO-S-250	415932	Alpine Diesel Pipeline	Stipulation	1.11	Regulation of Access	Satisfactory
13-SPCO-S-251	415932	Alpine Diesel Pipeline	Stipulation	1.13	Storage	Satisfactory
13-SPCO-S-005	415701	Alpine Oil Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-006	415701	Alpine Oil Pipeline	Stipulation	1.4	Quality Assurance	Satisfactory
13-SPCO-S-007	415701	Alpine Oil Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-008	415701	Alpine Oil Pipeline	Stipulation	2.5	Zones of Restricted Activity	Satisfactory
13-SPCO-S-017	415701	Alpine Oil Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-018	415701	Alpine Oil Pipeline	Stipulation	1.4	Quality Assurance	Satisfactory
13-SPCO-S-019	415701	Alpine Oil Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-020	415701	Alpine Oil Pipeline	Stipulation	3.2	Pipeline Corrosion	Satisfactory
13-SPCO-S-111	415701	Alpine Oil Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-112	415701	Alpine Oil Pipeline	Stipulation	1.4.1	Quality Assurance	Satisfactory
13-SPCO-S-113	415701	Alpine Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-114	415701	Alpine Oil Pipeline	Stipulation	2.2	Thermal Pollution	Satisfactory
13-SPCO-S-115	415701	Alpine Oil Pipeline	Stipulation	3.1	Pipeline System Standards	Satisfactory
13-SPCO-S-156	415701	Alpine Oil Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
13-SPCO-S-252	415701	Alpine Oil Pipeline	Stipulation	1.2	Communications	Satisfactory
13-SPCO-S-253	415701	Alpine Oil Pipeline	Stipulation	1.5	Conduct of Operations	Satisfactory
13-SPCO-S-254	415701	Alpine Oil Pipeline	Stipulation	1.7	Health and Safety	Satisfactory
13-SPCO-S-255	415701	Alpine Oil Pipeline	Stipulation	1.11	Regulation of Access	Satisfactory
13-SPCO-S-256	415701	Alpine Oil Pipeline	Stipulation	1.13	Storage	Satisfactory
13-SPCO-S-009	415857	Alpine Utility Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-010	415857	Alpine Utility Pipeline	Stipulation	1.4	Quality Assurance	Satisfactory
13-SPCO-S-011	415857	Alpine Utility Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-012	415857	Alpine Utility Pipeline	Stipulation	2.5	Zones of Restricted Activity	Satisfactory
13-SPCO-S-021	415857	Alpine Utility Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-022	415857	Alpine Utility Pipeline	Stipulation	1.4	Quality Assurance	Satisfactory

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Surveillance Number	ADL	Pipeline (PLMP #)	Section/Stipulation	#	Title	Observation
13-SPCO-S-023	415857	Alpine Utility Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-024	415857	Alpine Utility Pipeline	Stipulation	3.2	Pipeline Corrosion	Satisfactory
13-SPCO-S-116	415857	Alpine Utility Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-117	415857	Alpine Utility Pipeline	Stipulation	1.4.1	Quality Assurance	Satisfactory
13-SPCO-S-118	415857	Alpine Utility Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-119	415857	Alpine Utility Pipeline	Stipulation	2.2	Thermal Pollution	Satisfactory
13-SPCO-S-120	415857	Alpine Utility Pipeline	Stipulation	3.1	Pipeline System Standards	Satisfactory
13-SPCO-S-157	415857	Alpine Utility Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
13-SPCO-S-257	415857	Alpine Utility Pipeline	Stipulation	1.2	Communications	Satisfactory
13-SPCO-S-258	415857	Alpine Utility Pipeline	Stipulation	1.5	Conduct of Operations	Satisfactory
13-SPCO-S-259	415857	Alpine Utility Pipeline	Stipulation	1.7	Health and Safety	Satisfactory
13-SPCO-S-260	415857	Alpine Utility Pipeline	Stipulation	1.11	Regulation of Access	Satisfactory
13-SPCO-S-261	415857	Alpine Utility Pipeline	Stipulation	1.13	Storage	Satisfactory
13-SPCO-S-043	415472	Badami Oil Pipeline	Section	7 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-044	415472	Badami Oil Pipeline	Section	15 (b)	Conduct of Operations	Satisfactory
13-SPCO-S-045	415472	Badami Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-121	415472	Badami Oil Pipeline	Section	14 (a)	Plans and Permitting	Satisfactory
13-SPCO-S-186	415472	Badami Oil Pipeline	Section	8(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-187	415472	Badami Oil Pipeline	Section	15 (b)	Conduct of Operations	Satisfactory
13-SPCO-S-188	415472	Badami Oil Pipeline	Section	18 (b)	Orders by the Commissioner	Satisfactory
13-SPCO-S-189	415472	Badami Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-122	415965	Badami Utility Pipeline	Section	14 (a)	Plans and Permitting	Satisfactory
13-SPCO-S-139	415965	Badami Utility Pipeline	Section	6 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-140	415965	Badami Utility Pipeline	Section	8(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-141	415965	Badami Utility Pipeline	Section	15 (a) (b)	Conduct of Operations	Satisfactory
13-SPCO-S-142	415965	Badami Utility Pipeline	Section	18 (b)	Orders by the Commissioner	Satisfactory
13-SPCO-S-143	415965	Badami Utility Pipeline	Stipulation	1.4.1	Quality Assurance and Control	Satisfactory
13-SPCO-S-144	415965	Badami Utility Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-145	415965	Badami Utility Pipeline	Stipulation	1.11.2	Regulation of Access	Satisfactory
13-SPCO-S-146	415965	Badami Utility Pipeline	Stipulation	2.1.1	Environmental Briefings	Satisfactory
13-SPCO-S-147	415965	Badami Utility Pipeline	Stipulation	2.3.1.1	Erosion and Sedimentation Control	Satisfactory
13-SPCO-S-148	415965	Badami Utility Pipeline	Stipulation	2.8.1	Right-of-Way Traffic	Satisfactory
13-SPCO-S-190	415965	Badami Utility Pipeline	Section	8(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-191	415965	Badami Utility Pipeline	Section	15 (b)	Conduct of Operations	Satisfactory
13-SPCO-S-192	415965	Badami Utility Pipeline	Section	18 (b)	Orders by the Commissioner	Satisfactory
13-SPCO-S-193	415965	Badami Utility Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-046	410562	Endicott Pipeline	Section	7 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-047	410562	Endicott Pipeline	Stipulation	1.3.6	Responsibilities	Satisfactory
13-SPCO-S-048	410562	Endicott Pipeline	Stipulation	1.10.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-049	410562	Endicott Pipeline	Stipulation	2.4.6.1	Big Game Movements	Satisfactory
13-SPCO-S-079	410562	Endicott Pipeline	Section	4(c)(d)(h)	Covenants by Lessee	Satisfactory-COTS
13-SPCO-S-080	410562	Endicott Pipeline	Section	7 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-081	410562	Endicott Pipeline	Section	10 (a)	Duty of Lessee to Prevent or Abate	Satisfactory-COTS
13-SPCO-S-082	410562	Endicott Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory

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Surveillance Number	ADL	Pipeline (PLMP #)	Section/Stipulation	#	Title	Observation
13-SPCO-S-083	410562	Endicott Pipeline	Stipulation	1.3.6	Responsibilities	Satisfactory
13-SPCO-S-084	410562	Endicott Pipeline	Stipulation	1.9.1	Conduct of Operations	Satisfactory
13-SPCO-S-085	410562	Endicott Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory-COTS
13-SPCO-S-086	410562	Endicott Pipeline	Stipulation	2.4.6.1	Big Game Movements	Satisfactory
13-SPCO-S-123	410562	Endicott Pipeline	Section	6 (a)	Construction Plans and Quality Assurance	Satisfactory
13-SPCO-S-194	410562	Endicott Pipeline	Section	4(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-195	410562	Endicott Pipeline	Section	10 (a)	Duty of Lessee to Prevent or Abate	Satisfactory
13-SPCO-S-196	410562	Endicott Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory
13-SPCO-S-197	410562	Endicott Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-070	228162	Kenai Kachemak Pipeline	Section	4 (a)	Payment	Satisfactory
13-SPCO-S-071	228162	Kenai Kachemak Pipeline	Section	8 (j)	Covenants of the Lessee	Satisfactory
13-SPCO-S-072	228162	Kenai Kachemak Pipeline	Section	24 (b)	Reimbursement of State Expenses	Satisfactory
13-SPCO-S-073	228162	Kenai Kachemak Pipeline	Section	30	Authorized Representatives	Satisfactory
13-SPCO-S-074	228162	Kenai Kachemak Pipeline	Section	34 (b)	Correspondence	Satisfactory
13-SPCO-S-128	228162	Kenai Kachemak Pipeline	Section	6 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-129	228162	Kenai Kachemak Pipeline	Section	8(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-130	228162	Kenai Kachemak Pipeline	Section	15 (a)(b)	Conduct of Operations	Satisfactory
13-SPCO-S-131	228162	Kenai Kachemak Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-132	228162	Kenai Kachemak Pipeline	Stipulation	1.11.2	Regulation of Access	Satisfactory
13-SPCO-S-133	228162	Kenai Kachemak Pipeline	Stipulation	2.7.1	Lessee Shall Stabilize, Revegetate and Restore Disturbed Areas	Satisfactory
13-SPCO-S-134	228162	Kenai Kachemak Pipeline	Section	8 (c) (d)	Covenants of Lessee	Satisfactory
13-SPCO-S-135	228162	Kenai Kachemak Pipeline	Section	15 (b)	Conduct of Operations	Satisfactory
13-SPCO-S-136	228162	Kenai Kachemak Pipeline	Section	20	Information	Satisfactory
13-SPCO-S-137	228162	Kenai Kachemak Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-138	228162	Kenai Kachemak Pipeline	Stipulation	1.13	Reporting	Satisfactory
13-SPCO-S-158	409027	Kuparuk EXT Pipeline	Section	4 (c)	Covenants by Lessee	Satisfactory
13-SPCO-S-159	409027	Kuparuk EXT Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory
13-SPCO-S-160	409027	Kuparuk EXT Pipeline	Stipulation	1.8.3	Quality Assurance and Control	Satisfactory
13-SPCO-S-161	409027	Kuparuk EXT Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-224	409027	Kuparuk EXT Pipeline	Stipulation	1.6	Design Criteria, Plans and Programs	Satisfactory
13-SPCO-S-225	409027	Kuparuk EXT Pipeline	Stipulation	1.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-226	409027	Kuparuk EXT Pipeline	Stipulation	1.11	Health and Safety	Satisfactory
13-SPCO-S-227	409027	Kuparuk EXT Pipeline	Stipulation	1.14	Fire Prevention and Suppression	Satisfactory
13-SPCO-S-228	409027	Kuparuk EXT Pipeline	Stipulation	1.17	Regulation of Access	Satisfactory
13-SPCO-S-246	409027	Kuparuk EXT Pipeline	Stipulation	2.1	Reporting, Prevention, Control, Cleanup and Disposal of Oil and Hazardous Substances Discharges	Satisfactory
13-SPCO-S-025	402294	Kuparuk Pipeline	Section	10	Duty of Lessee to Abate	Satisfactory
13-SPCO-S-026	402294	Kuparuk Pipeline	Stipulation	1.4	Communications	Satisfactory
13-SPCO-S-027	402294	Kuparuk Pipeline	Stipulation	1.8	Quality Assurance and Control	Satisfactory
13-SPCO-S-028	402294	Kuparuk Pipeline	Stipulation	1.9	Conduct of Operations	Satisfactory
13-SPCO-S-029	402294	Kuparuk Pipeline	Stipulation	1.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-030	402294	Kuparuk Pipeline	Stipulation	1.11	Health and Safety	Satisfactory
13-SPCO-S-031	402294	Kuparuk Pipeline	Stipulation	1.17	Regulation of Access	Satisfactory

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Surveillance Number	ADL	Pipeline (PLMP #)	Section/Stipulation	#	Title	Observation
13-SPCO-S-032	402294	Kuparuk Pipeline	Stipulation	2.3	Crossings of Streams, Rivers, Flood Plains and Wetlands	Satisfactory
13-SPCO-S-033	402294	Kuparuk Pipeline	Stipulation	3.2	Work Pad	Satisfactory
13-SPCO-S-162	402294	Kuparuk Pipeline	Section	4 (c)	Covenants by Lessee	Satisfactory
13-SPCO-S-163	402294	Kuparuk Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory
13-SPCO-S-164	402294	Kuparuk Pipeline	Stipulation	1.8.3	Quality Assurance and Control	Satisfactory
13-SPCO-S-165	402294	Kuparuk Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-229	402294	Kuparuk Pipeline	Stipulation	1.6	Design Criteria, Plans and Programs	Satisfactory
13-SPCO-S-230	402294	Kuparuk Pipeline	Stipulation	1.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-231	402294	Kuparuk Pipeline	Stipulation	1.11	Health and Safety	Satisfactory
13-SPCO-S-232	402294	Kuparuk Pipeline	Stipulation	1.14	Fire Prevention and Suppression	Satisfactory
13-SPCO-S-233	402294	Kuparuk Pipeline	Stipulation	1.17	Regulation of Access	Satisfactory
13-SPCO-S-050	410221	Milne Point Oil Pipeline	Section	7 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-051	410221	Milne Point Oil Pipeline	Stipulation	1.3.6	Responsibilities	Satisfactory
13-SPCO-S-052	410221	Milne Point Oil Pipeline	Stipulation	2.4.6.1	Big Game Movements	Satisfactory
13-SPCO-S-087	410221	Milne Point Oil Pipeline	Section	4 (c)(d)(h)	Covenants by Lessee	Satisfactory-COTS
13-SPCO-S-088	410221	Milne Point Oil Pipeline	Section	7 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-089	410221	Milne Point Oil Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory
13-SPCO-S-090	410221	Milne Point Oil Pipeline	Stipulation	1.3.6	Responsibilities	Satisfactory
13-SPCO-S-091	410221	Milne Point Oil Pipeline	Stipulation	1.9.1	Conduct of Operations	Satisfactory
13-SPCO-S-092	410221	Milne Point Oil Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory-COTS
13-SPCO-S-093	410221	Milne Point Oil Pipeline	Stipulation	1.11.1	Health and Safety	Satisfactory
13-SPCO-S-094	410221	Milne Point Oil Pipeline	Stipulation	2.3.1.1	Erosion and Sedimentation Control	Satisfactory
13-SPCO-S-095	410221	Milne Point Oil Pipeline	Stipulation	2.4.6.1	Big Game Movements	Satisfactory
13-SPCO-S-125	410221	Milne Point Oil Pipeline	Section	6 (a)	Construction Plans and Quality Assurance	Satisfactory
13-SPCO-S-198	410221	Milne Point Oil Pipeline	Section	4(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-199	410221	Milne Point Oil Pipeline	Section	10 (a)	Duty of Lessee to Prevent or Abate	Satisfactory
13-SPCO-S-200	410221	Milne Point Oil Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory
13-SPCO-S-201	410221	Milne Point Oil Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-096	416172	Milne Point Products Pipeline	Section	6 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-097	416172	Milne Point Products Pipeline	Stipulation	2.4.1	Big Game Movements	Satisfactory
13-SPCO-S-124	416172	Milne Point Products Pipeline	Section	14 (a)	Plans and Permitting	Satisfactory
13-SPCO-S-202	416172	Milne Point Products Pipeline	Section	8 (c) (d) (h)	Covenants of Lessee	Satisfactory
13-SPCO-S-203	416172	Milne Point Products Pipeline	Section	20	Information	Satisfactory
13-SPCO-S-204	416172	Milne Point Products Pipeline	Stipulation	1.13.1	Reporting	Satisfactory
13-SPCO-S-063	69354	Nikiski Alaska Pipeline	Section	6	Books Accounts and Records	Satisfactory
13-SPCO-S-064	69354	Nikiski Alaska Pipeline	Section	17	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-065	69354	Nikiski Alaska Pipeline	Section	19	Duty of Lessee to Prevent or Abate	Satisfactory
13-SPCO-S-066	69354	Nikiski Alaska Pipeline	Stipulation	1.12.1	Regulation of Public Access	Satisfactory
13-SPCO-S-067	69354	Nikiski Alaska Pipeline	Stipulation	1.15.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-068	69354	Nikiski Alaska Pipeline	Stipulation	1.15.3	Surveillance and Maintenance	Satisfactory
13-SPCO-S-069	69354	Nikiski Alaska Pipeline	Stipulation	2.2.3.1	Stream, River and Inlet Crossings	Unsatisfactory
13-SPCO-S-075	69354	Nikiski Alaska Pipeline	Section	11	Appointment of Agent for Service of Process	Satisfactory
13-SPCO-S-076	69354	Nikiski Alaska Pipeline	Stipulation	1.4.2	Agent of Lessee	Satisfactory

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Surveillance Number	ADL	Pipeline (PLMP #)	Section/Stipulation	#	Title	Observation
13-SPCO-S-077	69354	Nikiski Alaska Pipeline	Stipulation	1.5.3	Authority of Representatives of Commissioner and Agent; Orders of Commissioner	Satisfactory
13-SPCO-S-078	69354	Nikiski Alaska Pipeline	Stipulation	1.6.5	Orders and Notices	Satisfactory
13-SPCO-S-149	69354	Nikiski Alaska Pipeline	Section	6 (a)	Books Accounts and Records; Access to Property and Records	Satisfactory
13-SPCO-S-150	69354	Nikiski Alaska Pipeline	Section	19 (a)	Duty of Lessee to Prevent or Abate	Satisfactory
13-SPCO-S-151	69354	Nikiski Alaska Pipeline	Stipulation	1.3.1	Commissioner	Satisfactory
13-SPCO-S-152	69354	Nikiski Alaska Pipeline	Stipulation	1.15.1, 1.15.3	Surveillance and Maintenance	Satisfactory
13-SPCO-S-153	69354	Nikiski Alaska Pipeline	Stipulation	1.16.1	Conduct of Operations	Satisfactory
13-SPCO-S-053	230928	North Fork Pipeline	Section	6 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-054	230928	North Fork Pipeline	Section	7	Access to Public Waters	Satisfactory
13-SPCO-S-055	230928	North Fork Pipeline	Section	8 (d) (h)	Covenants of the Lessee	Satisfactory
13-SPCO-S-056	230928	North Fork Pipeline	Section	15	Conduct of Operations	Satisfactory
13-SPCO-S-057	230928	North Fork Pipeline	Section	20	Information	Satisfactory
13-SPCO-S-058	230928	North Fork Pipeline	Section	40	Compliance	Satisfactory
13-SPCO-S-059	230928	North Fork Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-060	230928	North Fork Pipeline	Stipulation	1.11.2	Regulation of Access	Satisfactory
13-SPCO-S-061	230928	North Fork Pipeline	Stipulation	2.2	Erosion and Sedimentation Control	Satisfactory
13-SPCO-S-062	230928	North Fork Pipeline	Stipulation	2.3.2	Fish and Wildlife Protection	Satisfactory
13-SPCO-S-170	230928	North Fork Pipeline	Section	8(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-171	230928	North Fork Pipeline	Section	15 ©	Conduct of Operations	Satisfactory
13-SPCO-S-172	230928	North Fork Pipeline	Section	16 (a)	Environmental Compliance	Satisfactory
13-SPCO-S-173	230928	North Fork Pipeline	Section	20	Information	Satisfactory
13-SPCO-S-174	230928	North Fork Pipeline	Stipulation	1.6	Surveillance and Monitoring	Satisfactory
13-SPCO-S-240	230928	North Fork Pipeline	Section	6 (a) (c)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-241	230928	North Fork Pipeline	Section	8 (d) (h)	Covenants of the Lessee	Satisfactory
13-SPCO-S-242	230928	North Fork Pipeline	Section	16 (a)	Environmental Compliance	Satisfactory
13-SPCO-S-243	230928	North Fork Pipeline	Stipulation	1.11.2	Regulation of Access	Satisfactory
13-SPCO-S-244	230928	North Fork Pipeline	Stipulation	2.2	Erosion and Sedimentation Control	Satisfactory
13-SPCO-S-245	230928	North Fork Pipeline	Stipulation	2.3	Fish and Wildlife Protection	Satisfactory
13-SPCO-S-102	415975	Northstar Gas Pipeline	Section	6 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-103	415975	Northstar Gas Pipeline	Section	8 (h)	Covenants of Lessee	Satisfactory
13-SPCO-S-104	415975	Northstar Gas Pipeline	Stipulation	2.3.1.1	Erosion and Sedimentation Control	Satisfactory
13-SPCO-S-105	415975	Northstar Gas Pipeline	Stipulation	2.6.1	Big Game Movements	Satisfactory
13-SPCO-S-127	415975	Northstar Gas Pipeline	Section	14 (a)	Plans and Permitting	Satisfactory
13-SPCO-S-205	415975	Northstar Gas Pipeline	Section	8(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-206	415975	Northstar Gas Pipeline	Section	15 (b)	Conduct of Operations	Satisfactory
13-SPCO-S-207	415975	Northstar Gas Pipeline	Section	20	Information	Satisfactory
13-SPCO-S-208	415975	Northstar Gas Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-209	415975	Northstar Gas Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
13-SPCO-S-098	415700	Northstar Oil Pipeline	Section	6 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-099	415700	Northstar Oil Pipeline	Section	8 (h)	Covenants of Lessee	Satisfactory
13-SPCO-S-100	415700	Northstar Oil Pipeline	Stipulation	2.3.1.1	Erosion and Sedimentation Control	Satisfactory

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Surveillance Number	ADL	Pipeline (PLMP #)	Section/Stipulation	#	Title	Observation
13-SPCO-S-101	415700	Northstar Oil Pipeline	Stipulation	2.6.1	Big Game Movements	Satisfactory
13-SPCO-S-126	415700	Northstar Oil Pipeline	Section	14 (a)	Plans and Permitting	Satisfactory
13-SPCO-S-175	415700	Northstar Oil Pipeline	Section	6 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-176	415700	Northstar Oil Pipeline	Section	8(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-177	415700	Northstar Oil Pipeline	Section	15 (a) (b)	Conduct of Operations	Satisfactory
13-SPCO-S-178	415700	Northstar Oil Pipeline	Section	18 (b)	Orders by the Commissioner	Satisfactory
13-SPCO-S-179	415700	Northstar Oil Pipeline	Stipulation	1.4.1	Quality Assurance and Control	Satisfactory
13-SPCO-S-180	415700	Northstar Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-181	415700	Northstar Oil Pipeline	Stipulation	1.8.1	Survey Monuments	Satisfactory
13-SPCO-S-182	415700	Northstar Oil Pipeline	Stipulation	1.11.2	Regulation of Access	Satisfactory
13-SPCO-S-183	415700	Northstar Oil Pipeline	Stipulation	2.3.1.1	Erosion and Sedimentation Control	Satisfactory
13-SPCO-S-210	415700	Northstar Oil Pipeline	Section	8(c)(d)(h)	Covenants of Lessee	Satisfactory
13-SPCO-S-211	415700	Northstar Oil Pipeline	Section	15 (b)	Conduct of Operations	Satisfactory
13-SPCO-S-212	415700	Northstar Oil Pipeline	Section	20	Information	Satisfactory
13-SPCO-S-213	415700	Northstar Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
13-SPCO-S-214	415700	Northstar Oil Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
13-SPCO-S-154	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
13-SPCO-S-034	411731	Oliktok Pipeline	Section	10	Duty of the Lessee to Prevent or Abate	Satisfactory
13-SPCO-S-035	411731	Oliktok Pipeline	Stipulation	1.4	Communications	Satisfactory
13-SPCO-S-036	411731	Oliktok Pipeline	Stipulation	1.8	Quality Assurance and Control	Satisfactory
13-SPCO-S-037	411731	Oliktok Pipeline	Stipulation	1.9	Conduct of Operations	Satisfactory
13-SPCO-S-038	411731	Oliktok Pipeline	Stipulation	1.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-039	411731	Oliktok Pipeline	Stipulation	1.11	Health and Safety	Satisfactory
13-SPCO-S-040	411731	Oliktok Pipeline	Stipulation	1.17	Regulation of Access	Satisfactory
13-SPCO-S-041	411731	Oliktok Pipeline	Stipulation	2.3	Crossings of Streams, Rivers, Flood Plains and Wetlands	Satisfactory
13-SPCO-S-042	411731	Oliktok Pipeline	Stipulation	3.2	Work Pad	Satisfactory
13-SPCO-S-166	411731	Oliktok Pipeline	Section	4 (c)	Covenants by Lessee	Satisfactory
13-SPCO-S-167	411731	Oliktok Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory
13-SPCO-S-168	411731	Oliktok Pipeline	Stipulation	1.8.3	Quality Assurance and Control	Satisfactory
13-SPCO-S-169	411731	Oliktok Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-234	411731	Oliktok Pipeline	Stipulation	1.2	Applicability	Satisfactory
13-SPCO-S-235	411731	Oliktok Pipeline	Stipulation	1.6	Design Criteria, Plans and Programs	Satisfactory
13-SPCO-S-236	411731	Oliktok Pipeline	Stipulation	1.1	Surveillance and Maintenance	Satisfactory
13-SPCO-S-237	411731	Oliktok Pipeline	Stipulation	1.11	Health and Safety	Satisfactory
13-SPCO-S-238	411731	Oliktok Pipeline	Stipulation	1.14	Fire Prevention and Suppression	Satisfactory
13-SPCO-S-239	411731	Oliktok Pipeline	Stipulation	1.17	Regulation of Access	Satisfactory
13-SPCO-S-184	418975	Point Thomson Pipeline	Stipulation	1.9.1	Annual Report	Satisfactory
13-SPCO-S-185	418975	Point Thomson Pipeline	Stipulation	1.4.4.5	Quality Management Program	Satisfactory
13-SPCO-S-215	418975	Point Thomson Pipeline	Stipulation	1.4.4.5	Quality Management Program	Satisfactory
13-SPCO-S-216	418975	Point Thomson Pipeline	Stipulation	1.12.1	Lessee Support of State Oversight	Satisfactory
13-SPCO-S-217	418975	Point Thomson Pipeline	Stipulation	1.13.1-2	Access	Satisfactory
13-SPCO-S-218	418975	Point Thomson Pipeline	Stipulation	1.16	Health and Safety	Satisfactory
13-SPCO-S-219	418975	Point Thomson Pipeline	Stipulation	1.21	off ROW Traffic	Satisfactory

SPCO/DNR FY13 Surveillance Reports (by Pipeline)

Surveillance Number	ADL	Pipeline (PLMP #)	Section/Stipulation	#	Title	Observation
13-SPCO-S-220	418975	Point Thomson Pipeline	Stipulation	2.1	Environmental Briefing	Satisfactory
13-SPCO-S-221	418975	Point Thomson Pipeline	Section	6 (a)	Reservation of Certain Rights to the State	Satisfactory
13-SPCO-S-222	418975	Point Thomson Pipeline	Section	8 (d) (h)	Covenants of Lessee	Satisfactory
13-SPCO-S-223	418975	Point Thomson Pipeline	Stipulation	2.2.1	Pollution Control	Satisfactory

SPCO/DNR FY13 Compliance Reports and Assessments (by Pipeline)

Report/Assessment Number	Pipeline System	Topic	Signed Date
13-SPCO-R-005	Alpine Pipelines	Surveillance of the Alpine Pipelines Avian Survey	9/27/2012
13-SPCO-R-006	Alpine Pipelines	Surveillance of the Alpine Pipeline's Below Grade Casing Inspection	9/27/2012
13-SPCO-R-016	Alpine Pipelines	Surveillance of the Alpine Pipeline's Cathodic Protection System Testing and Soil Temperature Monitoring	12/14/2012
13-SPCO-R-036	Alpine Pipelines	Surveillance of the Alpine Diesel, Alpine Oil, and Alpine Utility Pipeline Right-of-Way	6/17/2013
13-SPCO-R-024	Badami Oil Pipeline Badami Utility Pipeline	Badami Pipelines Walking Speed Survey	4/1/2013
13-SPCO-R-004	Badami Oil Pipeline Endicott Oil Pipeline Milne Point Oil Pipeline	Badami Oil Pipeline, Endicott Oil Pipeline, and Milne Point Oil Pipeline Right-of-Way Surveillance	9/27/2012
13-SPCO-R-015	Endicott Oil Pipeline Milne Point Pipelines Northstar Pipelines	Surveillances of the Endicott Pipeline, Milne Point Oil Pipeline, Milne Point Products Pipeline, Northstar Oil Pipeline, and Northstar Gas Pipeline	1/14/2013
13-SPCO-R-020	Kenai-Kachemack Pipeline	KKPL Right-of-Way and Transfer of Ownership	2/25/2013
13-SPCO-R-022	Kenai-Kachemack Pipeline	Lease Transfer of Ownership	3/4/2013
13-SPCO-R-032	Kuparuk Pipeline Kuparuk EXT Pipeline Oliktok Pipeline	Surveillance of Kuparuk, Kuparuk Extension, and Oliktok Pipeline Right-of-Ways	5/28/2013
13-SPCO-R-003	Kuparuk Pipeline Oliktok Pipeline	Surveillance of Kuparuk and Oliktok Pipeline's Roads and Pad Maintenance Inspection Program and Erosion Mitigation Survey	1/7/2013
13-SPCO-R-011	Nikiski Alaska Pipeline	Lease Compliance Report and Surveillances of the Nikiski Alaska Pipeline	11/8/2012
13-SPCO-R-009	North Fork Pipeline	North Fork Right-of-Way Surveillance	10/10/2012
13-SPCO-R-034	North Fork Pipeline	North Fork Right-of-Way Surveillance for Width Reduction	6/6/2013
13-SPCO-R-025	Northstar Oil Pipeline Northstar Gas Pipeline	Northstar Pipelines Walking Speed Survey	4/8/2013
13-SPCO-R-029	Nuiqsut Natural Gas Pipeline	Nuiqsut Natural Gas Pipeline & Rights-of-Way Trip Report	5/23/2013
13-SPCO-R-027	Point Thomson Pipeline	PTEP Quality Assurance Surveillance	5/13/2013
13-SPCO-R-030	Point Thomson Pipeline	PTEP Season One Construction Activities	5/23/2013
13-SPCO-R-031	Point Thomson Pipeline	PTEP Construction and Right-of-Way Surveillance	5/14/2013
13-SPCO-R-001	Trans-Alaska Pipeline System	TAPS Right-of-Way Squirrel Creek	7/26/2012
13-SPCO-R-002	Trans-Alaska Pipeline System	TAPS Right-of-Way Summit Lake	9/4/2012
13-SPCO-R-007	Trans-Alaska Pipeline System	TAPS Right-of-Way Yukon Response Base	9/4/2012
13-SPCO-R-008	Trans-Alaska Pipeline System	TAPS Right-of-Way Pump Station 01	10/9/2012
13-SPCO-R-010	Trans-Alaska Pipeline System	Compliance Report on Pump Station 01, 03, 04 and Fuel Gas Line	11/6/2012
13-SPCO-R-012	Trans-Alaska Pipeline System	TAPS Yukon Response Base Piping Replacement	12/20/2012
13-SPCO-R-013	Trans-Alaska Pipeline System	TAPS Fuel Gas Line	12/19/2012
13-SPCO-R-014	Trans-Alaska Pipeline System	TAPS Pump Station 07 and Yukon Response Base	12/19/2012

SPCO/DNR FY13 Compliance Reports and Assessments (by Pipeline)

Report/Assessment Number	Pipeline System	Topic	Signed Date
13-SPCO-R-005	Alpine Pipelines	Surveillance of the Alpine Pipelines Avian Survey	9/27/2012
13-SPCO-R-006	Alpine Pipelines	Surveillance of the Alpine Pipeline's Below Grade Casing Inspection	9/27/2012
13-SPCO-R-016	Alpine Pipelines	Surveillance of the Alpine Pipeline's Cathodic Protection System Testing and Soil Temperature Monitoring	12/14/2012
13-SPCO-R-036	Alpine Pipelines	Surveillance of the Alpine Diesel, Alpine Oil, and Alpine Utility Pipeline Right-of-Way	6/17/2013
13-SPCO-R-024	Badami Oil Pipeline Badami Utility Pipeline	Badami Pipelines Walking Speed Survey	4/1/2013
13-SPCO-R-004	Badami Oil Pipeline Endicott Oil Pipeline Milne Point Oil Pipeline	Badami Oil Pipeline, Endicott Oil Pipeline, and Milne Point Oil Pipeline Right-of-Way Surveillance	9/27/2012
13-SPCO-R-015	Endicott Oil Pipeline Milne Point Pipelines Northstar Pipelines	Surveillances of the Endicott Pipeline, Milne Point Oil Pipeline, Milne Point Products Pipeline, Northstar Oil Pipeline, and Northstar Gas Pipeline	1/14/2013
13-SPCO-R-020	Kenai-Kachemack Pipeline	KKPL Right-of-Way and Transfer of Ownership	2/25/2013
13-SPCO-R-022	Kenai-Kachemack Pipeline	Lease Transfer of Ownership	3/4/2013
13-SPCO-R-032	Kuparuk Pipeline Kuparuk EXT Pipeline Oliktok Pipeline	Surveillance of Kuparuk, Kuparuk Extension, and Oliktok Pipeline Right-of-Ways	5/28/2013
13-SPCO-R-003	Kuparuk Pipeline Oliktok Pipeline	Surveillance of Kuparuk and Oliktok Pipeline's Roads and Pad Maintenance Inspection Program and Erosion Mitigation Survey	1/7/2013
13-SPCO-R-011	Nikiski Alaska Pipeline	Lease Compliance Report and Surveillances of the Nikiski Alaska Pipeline	11/8/2012
13-SPCO-R-009	North Fork Pipeline	North Fork Right-of-Way Surveillance	10/10/2012
13-SPCO-R-034	North Fork Pipeline	North Fork Right-of-Way Surveillance for Width Reduction	6/6/2013
13-SPCO-R-025	Northstar Oil Pipeline Northstar Gas Pipeline	Northstar Pipelines Walking Speed Survey	4/8/2013
13-SPCO-R-029	Nuiqsut Natural Gas Pipeline	Nuiqsut Natural Gas Pipeline & Rights-of-Way Trip Report	5/23/2013
13-SPCO-R-027	Point Thomson Pipeline	PTEP Quality Assurance Surveillance	5/13/2013
13-SPCO-R-030	Point Thomson Pipeline	PTEP Season One Construction Activities	5/23/2013
13-SPCO-R-031	Point Thomson Pipeline	PTEP Construction and Right-of-Way Surveillance	5/14/2013
13-SPCO-R-001	Trans-Alaska Pipeline System	TAPS Right-of-Way Squirrel Creek	7/26/2012
13-SPCO-R-002	Trans-Alaska Pipeline System	TAPS Right-of-Way Summit Lake	9/4/2012
13-SPCO-R-007	Trans-Alaska Pipeline System	TAPS Right-of-Way Yukon Response Base	9/4/2012
13-SPCO-R-008	Trans-Alaska Pipeline System	TAPS Right-of-Way Pump Station 01	10/9/2012
13-SPCO-R-010	Trans-Alaska Pipeline System	Compliance Report on Pump Station 01, 03, 04 and Fuel Gas Line	11/6/2012
13-SPCO-R-012	Trans-Alaska Pipeline System	TAPS Yukon Response Base Piping Replacement	12/20/2012
13-SPCO-R-013	Trans-Alaska Pipeline System	TAPS Fuel Gas Line	12/19/2012
13-SPCO-R-014	Trans-Alaska Pipeline System	TAPS Pump Station 07 and Yukon Response Base	12/19/2012

SPCO/DNR FY13 Engineering Opinions and Reports

Report/Assessment Number	ADL	Pipeline	Title
13-SPCO-E-006	402294	Kuparuk Pipeline	Installation of sleeves, April 15-16, 2013
13-SPCO-E-004	418975	Point Thomson Export Pipeline	Point Thomson Export Pipeline Trip Report
13-SPCO-E-001	63574	Trans-Alaska Pipeline System	Remote Gate Valve 118
13-SPCO-E-002	63574	Trans-Alaska Pipeline System	Pump Station 3 Trip Report, August 9, 2012
13-SPCO-E-003	63574	Trans-Alaska Pipeline System	Tank 110
13-SPCO-E-005	63574	Trans-Alaska Pipeline System	Pump Station 3 and 4 Follow up Vibration May 20, 2013
13-SPCO-E-007	63574	Trans-Alaska Pipeline System	Sag River Flooding and Low Cover

SPCO/DNR FY13 TAPS Surveillance Reports

Surveillance Number	ADL	Section/Stipulation	#	Title	Observation
12-TAPS-S-046	63574	Section	16	Construction Plans and Quality Assurance	Satisfactory
12-TAPS-S-048	63574	Stipulation	1.18	Surveillance and Maintenance	Satisfactory
12-TAPS-S-050	63574	Stipulation	1.21	Conduct of Operations	Satisfactory
13-TAPS-S-001	63574	Stipulation	2.13.1	Reporting of Oil Discharge or Other Pollutant	Satisfactory
13-TAPS-S-002	63574	Stipulation	3.5.1	Slope Stability	Satisfactory
13-TAPS-S-005	63574	Section	6 (a)	Books, Accounts and Records	Satisfactory
13-TAPS-S-006	63574	Section	16 (c)	Construction Plans. and Quality Assurance	Satisfactory
13-TAPS-S-007	63574	Stipulation	3.2.1.1(2)	General Standards	Satisfactory
13-TAPS-S-008	63574	Stipulation	3.2.2.4	Special Stipulations	Satisfactory
13-TAPS-S-011	63574	Section	10 (b)	Damage and Destruction of Leasehold or Other Property	Satisfactory
13-TAPS-S-012	63574	Stipulation	2.4.4.1	Seeding	Satisfactory
13-TAPS-S-013	63574	Stipulation	3.2.2.3	Pipeline System Standards – Special Standards	Satisfactory
13-TAPS-S-014	63574	Stipulation	3.6.2.2	Erosion	Satisfactory
13-TAPS-S-015	63574	Stipulation	3.11.2	Containment of Spills	Satisfactory
13-TAPS-S-021	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-024	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-025	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-026	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-027	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-028	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-030	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-032	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-033	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-034	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-035	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-036	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-037	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-038	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-039	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-040	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-041	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-042	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-043	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-044	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-045	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-046	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-047	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-048	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-049	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-050	63574	Stipulation	2.6	Material Sites	Satisfactory
13-TAPS-S-064	63574	Stipulation	2.2.1.1	Pollution Control - General	Unsatisfactory (Minor)

SPCO/DNR FY13 TAPS Surveillance Reports

Surveillance Number	ADL	Section/Stipulation	#	Title	Observation
13-TAPS-S-065	63574	Section	10 (a)	Damage or Destruction of Leasehold	Satisfactory
13-TAPS-S-066	63574	Stipulation	2.4.1.1	Erosion Control - General	Satisfactory
13-TAPS-S-067	63574	Stipulation	2.4.3.1	Crossing of Streams, Rivers or Floodplains	Satisfactory
13-TAPS-S-068	63574	Stipulation	2.9.1	Off Right-of-Way Traffic	Satisfactory
13-TAPS-S-069	63574	Stipulation	3.2.2.2	Special Standards	Satisfactory
13-TAPS-S-075	63574	Section	10 (a)	Damage or Destruction of Leasehold	Satisfactory
13-TAPS-S-076	63574	Section	17 (a)	Reservation of Certain Rights to the State	Satisfactory
13-TAPS-S-102	63574	Stipulation	2.2.2.1	Pollution Control	Satisfactory
13-TAPS-S-103	63574	Stipulation	1.3.1	Pipeline Coordinator	Satisfactory
13-TAPS-S-148	63574	Section	22 (b)	Duty to prevent and abate	Satisfactory
13-TAPS-S-149	63574	Stipulation	1.11.1	Public Improvements	Satisfactory
13-TAPS-S-150	63574	Stipulation	1.12.1	Public Access	Satisfactory
13-TAPS-S-151	63574	Section	1 (d) (ii)	Grant of Right of Way	Satisfactory
13-TAPS-S-171	63574	Section	10 (b)	Damage or Destruction of Leasehold	Satisfactory
13-TAPS-S-172	63574	Stipulation	1.21.1	Conduct of Operation	Satisfactory
13-TAPS-S-173	63574	Section	16 (a)	Construction Plans. and Quality Assurance	Satisfactory
13-TAPS-S-174	63574	Section	10 (a)	Damage or Destruction of Leasehold or Other Property	Satisfactory
13-TAPS-S-175	63574	Section	17 (a)	Resrevation of Certain Rights to the State	Satisfactory
13-TAPS-S-176	63574	Section	16 (c)	Constuction Plans and quality assurance	Satisfactory
13-TAPS-S-177	63574	Section	22 (a)	Duty of Lessee to Prevent or Abate	Satisfactory
13-TAPS-S-178	63574	Stipulation	1.21	Conduct of Operations	Satisfactory
13-TAPS-S-189	63574	Section	22 (a)	Duty to prevent and abate	Satisfactory
13-TAPS-S-190	63574	Section	16 (c) (iv)	Constuction Plans and quality assurance	Satisfactory
13-TAPS-S-191	63574	Section	16 (c) (vi)	Constuction Plans and quality assurance	Satisfactory
13-TAPS-S-192	63574	Section	12	Appointment of Agent for Service of Process	Satisfactory
13-TAPS-S-193	63574	Section	10 (a)	Damage or Destruction of Leasehold or Other Property	Satisfactory
13-TAPS-S-194	63574	Section	17	Reservation of Certain Rights to State	Satisfactory
13-TAPS-S-204	63574	Stipulation	1.18	Surveillance and Maintenance	Satisfactory
13-TAPS-S-205	63574	Stipulation	3.10.1	Pipeline Corrosion	Satisfactory
13-TAPS-S-206	63574	Stipulation	1.18.1	Surveillance and Maintenance	Satisfactory
13-TAPS-S-207	63574	Section	22 (a)	Duty of Lessees to Prevent or Abate	Satisfactory
13-TAPS-S-208	63574	Stipulation	1.21.1	Conduct of Operations	Unsatisfactory (Minor)
13-TAPS-S-212	63574	Section	16 (c) (i)	Construction Plans and Quality Assurance	Satisfactory
13-TAPS-S-213	63574	Section	22 (a)	Duty to Prevent and Abate	Satisfactory
13-TAPS-S-214	63574	Stipulation	1.18.1	Surveillance and Maintenance	Satisfactory
13-TAPS-S-215	63574	Stipulation	3.2.2.1	Special Standards	Satisfactory

SPCO/DF&G FY13 TAPS Surveillance Reports

Report Number	ADL	TAPS PLMP	Stipulations	Observation
13-TAPS-S-051	AA 05847	PLMP 618.19	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-052	63574	PLMP 489.6	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-053	63574	PLMP 491.4	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-054	FF 12505	PLMP 480.7	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-055	FF 12505	PLMP 484.93	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-056	FF 12505	PLMP 485.3	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-057	FF 12505	PLMP 485.5	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-058	FF 12505	PLMP 485.7	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-059	FF 12505	PLMP 488.23	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-060	AA 05847	PLMP 579.9	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-061	AA 05847	PLMP 581.81	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-062	AA 05847	PLMP 583.92	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-063	AA 05847	PMP 642.48	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-077	63574	PLMP .18	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-078	63574	PLMP .99	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-079	63574	PLMP 1.94	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-080	63574	PLMP 3.9	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-081	63574	PLMP 4.12	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-082	63574	PLMP 6.36	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-083	63574	PLMP 7.17	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-084	63574	PLMP 8.44	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-085	63574	PLMP 11.08	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Unsatisfactory (Minor)
13-TAPS-S-086	63574	PLMP 17.99	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-087	FF 12505	PLMP 145.67	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-088	FF 12505	PLMP 145.76	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-089	FF 12505	PLMP 146.48	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-090	FF 12505	PLMP 147.39	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-091	FF 12505	PLMP 152.19	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Unsatisfactory (Minor)
13-TAPS-S-092	FF 12505	PLMP 153.04	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Unsatisfactory (Minor)
13-TAPS-S-093	FF 12505	PLMP 152.23,153.59	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Unsatisfactory (Minor)
13-TAPS-S-094	FF 12505	PLMP 135.11	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory

Report Number	ADL	TAPS PLMP	Stipulations	Observation
13-TAPS-S-095	FF 12505	PLMP 133.48	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-096	FF 12505	PLMP 128.62	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-104	FF 12505	PLMP 127.17	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-105	FF 12505	PLMP 127.04	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-106	FF 12505	PLMP 126.45	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-107	FF 12505	PLMP 124.8	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Unsatisfactory (Minor)
13-TAPS-S-108	63574	PLMP 115.76	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-109	63574	PLMP 114.86	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-110	63574	PLMP 102.45	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-111	63574	PLMP 100.81	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Unsatisfactory (Minor)
13-TAPS-S-112	63574	PLMP 100.31	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Unsatisfactory (Minor)
13-TAPS-S-113	63574	PLMP 99.99	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory-COTS
13-TAPS-S-114	63574	PLMP 99.07	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory-COTS
13-TAPS-S-115	63574	PLMP 96.12	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory-COTS
13-TAPS-S-116	63574	PLMP 95.79	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory-COTS
13-TAPS-S-117	63574	PLMP 92.96	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-118	63574	PLMP 91.93	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-119	63574	PLMP 86.94	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-120	63574	PLMP 74.5	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-121	63574	PLMP 53.12	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-122	63574	PLMP 52.97	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-123	63574	PLMP 52.16	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-124	63574	PLMP 51.44	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-125	63574	PLMP 50.78	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-126	63574	PLMP 50.46	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-127	63574	PLMP 50.07	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-128	63574	PLMP 48.93	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-129	63574	PLMP 239.75	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory-COTS
13-TAPS-S-130	FF 12505	PLMP 240.13	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-131	FF 12505	PLMP 240.26	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-132	FF 12505	PLMP 242.80	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-133	FF 12505	PLMP 243.41	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-134	FF 12505	PLMP 243.94	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory

Report Number	ADL	TAPS PLMP	Stipulations	Observation
13-TAPS-S-135	FF 12505	PLMP 270.41	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-136	FF 12505	PLMP 312.11	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-137	FF 12505	PLMP 312.99	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory-COTS
13-TAPS-S-138	FF 12505	PLMP 314.81	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory-COTS
13-TAPS-S-139	FF 12505	PLMP 315.24	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-140	FF 12505	PLMP 325.26	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-141	63574	PLMP 400.50	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-142	63574	PLMP 405.41	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-143	63574	PLMP 424.45	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-144	63574	PLMP 423.68	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-145	63574	PLMP 420.70	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-146	63574	PLMP 421.70	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-147	63574	PLMP 420.63	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-152	FF 12505	PLMP 176.11	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-153	FF 12505	PLMP 186	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-154	FF 12505	PLMP 189.92	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-155	FF 12505	PLMP 190.39	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-156	FF 12505	PLMP 191.80	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-157	FF 12505	PLMP 196.98	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-158	FF 12505	PLMP 197.08	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-159	FF 12505	PLMP 198.56	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-160	FF 12505	PLMP 200.17	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-161	FF 12505	PLMP 200.03	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-162	FF 12505	PLMP 216.59	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-163	FF 12505	PLMP 217.49	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-164	FF 12505	PLMP 219.08	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-165	FF 12505	PLMP 219.52	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-166	FF 12505	PLMP 223.19	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-167	FF 12505	PLMP 224.23	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-168	63574	PLMP 234.29	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-169	63574	PLMP 235,64	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory
13-TAPS-S-170	63574	PLMP 237.04	2.5.1.1, 2.4.3.1, 2.4.4.1 and 2.12.1	Satisfactory

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Report Number	Location	Stipulation	Type	Observation
13-TAPS-S-003	PS 6	1.2	Mainline By-Pass	Satisfactory
13-TAPS-S-004	PS 1	1.2	Various Projects	Satisfactory
13-TAPS-S-009	Valdez Marine Terminal	1.2	Berth 4 Overhaul	Satisfactory
13-TAPS-S-010	Valdez Marine Terminal	1.2	IWWS Project	Satisfactory
13-TAPS-S-016	PS 6	1.2	Mainline By-Pass	Satisfactory
13-TAPS-S-017	PS 4	1.2	Waste Heat Project	Satisfactory
13-TAPS-S-018	PS 3	1.2	Fuel Gas Valve Project	Satisfactory
13-TAPS-S-019	PS 1	1.2	Tank 110	Satisfactory
13-TAPS-S-070	Gas PLMP 25	1.2	CP Upgrades	Satisfactory
13-TAPS-S-071	MGV 5	1.2	Relocated MGV 5	Satisfactory
13-TAPS-S-072	MGV 7	1.2	Relocated MGV 7	Satisfactory-COTS
13-TAPS-S-073	MGV 9	1.2	Relocated MGV 9	Satisfactory
13-TAPS-S-074	PLMP 776	1.2	Integrity Dig	Satisfactory
13-TAPS-S-097	PS 1	1.2	Safety Inspection	Satisfactory
13-TAPS-S-098	PS 1	1.2	Safety Inspection	Satisfactory
13-TAPS-S-099	PS 2	1.2	Safety Inspection	Satisfactory
13-TAPS-S-100	PS 3	1.2	Safety Inspection	Satisfactory
13-TAPS-S-101	PS 4	1.2	Safety Inspection	Satisfactory-COTS
13-TAPS-S-179	PS 8	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-180	North Pole Metering	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-181	Nordale Yard	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-182	Van Horn Facility	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-183	PS 9	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-184	PS 10	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-185	Fairbanks Equipment Shop	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-186	Fairbanks Materials Warehouse	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-187	Rotating Equipment Shop	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-188	Fairbanks Fab Shop	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-195	PLMP 238	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-196	PS 5	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-197	PS 6	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-198	PS 7	1.2	Annual Safety Inspection	Satisfactory

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Report Number	Location	Stipulation	Type	Observation
13-TAPS-S-003	PS 6	1.2	Mainline By-Pass	Satisfactory
13-TAPS-S-004	PS 1	1.2	Various Projects	Satisfactory
13-TAPS-S-009	Valdez Marine Terminal	1.2	Berth 4 Overhaul	Satisfactory
13-TAPS-S-010	Valdez Marine Terminal	1.2	IWWS Project	Satisfactory
13-TAPS-S-016	PS 6	1.2	Mainline By-Pass	Satisfactory
13-TAPS-S-017	PS 4	1.2	Waste Heat Project	Satisfactory
13-TAPS-S-018	PS 3	1.2	Fuel Gas Valve Project	Satisfactory
13-TAPS-S-019	PS 1	1.2	Tank 110	Satisfactory
13-TAPS-S-070	Gas PLMP 25	1.2	CP Upgrades	Satisfactory
13-TAPS-S-071	MGV 5	1.2	Relocated MGV 5	Satisfactory
13-TAPS-S-072	MGV 7	1.2	Relocated MGV 7	Satisfactory-COTS
13-TAPS-S-073	MGV 9	1.2	Relocated MGV 9	Satisfactory
13-TAPS-S-074	PLMP 776	1.2	Integrity Dig	Satisfactory
13-TAPS-S-097	PS 1	1.2	Safety Inspection	Satisfactory
13-TAPS-S-098	PS 1	1.2	Safety Inspection	Satisfactory
13-TAPS-S-099	PS 2	1.2	Safety Inspection	Satisfactory
13-TAPS-S-100	PS 3	1.2	Safety Inspection	Satisfactory
13-TAPS-S-101	PS 4	1.2	Safety Inspection	Satisfactory-COTS
13-TAPS-S-179	PS 8	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-180	North Pole Metering	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-181	Nordale Yard	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-182	Van Horn Facility	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-183	PS 9	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-184	PS 10	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-185	Fairbanks Equipment Shop	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-186	Fairbanks Materials Warehouse	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-187	Rotating Equipment Shop	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-188	Fairbanks Fab Shop	1.2	Annual Safety Inspection	Satisfactory-COTS
13-TAPS-S-195	PLMP 238	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-196	PS 5	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-197	PS 6	1.2	Annual Safety Inspection	Satisfactory
13-TAPS-S-198	PS 7	1.2	Annual Safety Inspection	Satisfactory

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DO070912-1	Pump Station 8	Courtesy Inspection	7/9/2012
DO071012-1	Pump Station 9	Courtesy Inspection	7/10/2012
DO071012-2	Pump Station 9	Fire Alarm Upgrades	7/10/2012
DO071012-3	Pump Station 9	Security Upgrades	7/10/2012
DO071012-4	Pump Station 10	Courtesy Inspection	7/10/2012
DO071012-5	GRB/PS11	Courtesy Inspection	7/10/2012
DO071112-1	Pump Station 12	Courtesy Inspection	7/11/2012
DO071112-2	VMT	Z533 Power Upgrades	7/11/2012
DO071112-3	VMT	Z559 Overhaul of Berth 4	7/11/2012
DO072312-1	North Pole Metering	Courtesy Inspection	7/23/2012
DO072412-1	YRB/PS6	Courtesy Inspection	7/24/2012
DO072412-2	YRB/PS6	Bypass Project	7/24/2012
DO072412-3	YRB/PS6	New Generators	7/24/2012
DO072412-4	YRB/PS6	COF Check	7/24/2012
DO072612-1	Pump Station 7	Courtesy Inspection	7/26/2012
DO080612-1	Pump Station 8	Courtesy Inspection	8/6/2012
DO080712-1	Pump Station 9	Courtesy Inspection	8/7/2012
DO080712-2	Pump Station 9	Security Upgrades	8/7/2012
DO080712-3	Pump Station 10	Courtesy Inspection	8/7/2012
DO080712-4	GRB/Pump Station 11	Courtesy Inspection	8/7/2012
DO080812-1	Pump Station 12	Courtesy Inspection	8/8/2012
DO080812-2	VMT	Z533 Power Upgrades	8/8/2012
DO080812-3	VMT	HLVE BULLETIN	8/8/2012
DO080812-4	VMT	License check	8/8/2012
DO082112-1	Pump Station 4	Courtesy Inspection	8/21/2012
DO082112-2	Pump Station 3	Courtesy Inspection	8/21/2012
DO082112-3	Pump Station 2	Courtesy Inspection	8/21/2012
DO082212-1	Pump Station 1	E & A Project S120	8/22/2012
DO082212-2	Pump Station 1	COF Check	8/22/2012
DO082312-1	Pump Station 1	Courtesy Inspection	8/22/2012
DO092412-1	Pump Station 8	Courtesy Inspection	9/24/2012
DO092512-1	Pump Station 5	Courtesy Inspection	9/25/2012
DO092512-2	Pump Station 5	COF Check	9/25/2012
DO092612-1	YRB/PS6	Courtesy Inspection	9/26/2012
DO092612-2	Pump Station 7	Courtesy Inspection	9/26/2012
DO121112-1	Pump Station 2	Courtesy Inspection	12/11/2012
DO121212-1	Pump Station 1	**Notice of Violation**	12/12/2012
DO121212-2	Pump Station 1	Tank 110 Project	12/12/2012
DO121212-3	Pump Station 1	COF Check	12/12/2012
DO121212-4	Pump Station 1	E & A Project S120	12/12/2012
DO121212-5	Pump Station 1	COF Check	12/12/2012
DO020513-1	Pump Station 9	Courtesy Inspection	2/5/2013
DO020513-2	Pump Station 8	Courtesy Inspection	2/5/2013
DO020513-3	Pump Station 8	COF Check	2/5/2013
DO020613-1	Pump Station 7	Courtesy Inspection	2/6/2013
DO020613-2	YRB/PS6	Courtesy Inspection	2/6/2013

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DO030413-1	Pump Station 9	Courtesy Inspection	3/4/2013
DO030413-2	GRB	Project F663	3/4/2013
DO030413-3	GRB	Integrity Digs	3/4/2013
DO030513-1	VMT	Courtesy Inspection	3/5/2013
DO030513-2	Pump Station 12	Courtesy Inspection	3/5/2013
DO030613-1	Pump Station 10	Courtesy Inspection	3/6/2013
DO030613-2	Pump Station 8	Courtesy Inspection	3/6/2013
DO040913-1	Pump Station 2	Courtesy Inspection	4/9/2013
DO040913-2	Pump Station 3	Courtesy Inspection	4/9/2013
DO040913-3	Pump Station 3	COF Check	4/9/2013
DO040913-4	Pump Station 4	Courtesy Inspection	4/9/2013
DO041013-1	Pump Station 1	E & A Project S120	4/10/2013
DO041013-2	Pump Station 1	Tank Farm Project F599	4/10/2013
DO041013-3	Pump Station 1	Courtesy Inspection	4/10/2013
DO041013-4	Pump Station 1	COF Check	4/10/2013
DO042213-1	Pump Station 8	Courtesy Inspection	4/22/2013
DO042213-2	North Pole Metering	Courtesy Inspection	4/22/2013
DO042313-1	Pump Station 7	Courtesy Inspection	4/23/2013
DO042413-1	YRB/PS6	Courtesy Inspection	4/24/2013
DO050613-1	Pump Station 9	Courtesy Inspection	5/6/2013
DO050713-1	VMT	PS1 DCVR P006	5/7/2013
DO050713-2	VMT	Project Z559 Berth 4	5/7/2013
DO050713-3	Pump Station 12	Cold Restart Project	5/7/2013
DO050713-4	Pump Station 12	COF Check	5/7/2013
DO050713-5	GRB/PS11	Courtesy Inspection	5/7/2013
DO050713-6	GRB/PS11	COF Check	5/7/2013
DO050813-1	Pump Station 10	Project WY017	5/8/2013
DO052113-1	Pump Station 1	**Corrections to Abate NOV**	5/21/2013
DO052113-2	Pump Station 1	E & A Project S120	5/21/2013
DO052113-3	Pump Station 1	Courtesy Inspection	5/21/2013
DO052113-4	Pump Station 1	COF Check	5/21/2013
DO052213-1	Pump Station 2	Courtesy Inspection	5/22/2013
DO052213-2	Pump Station 3	Courtesy Inspection	5/22/2013
DO052213-3	Pump Station 3	COF Check	5/22/2013
DO052213-4	Pump Station 4	Courtesy Inspection	5/22/2013
DO060313-1	Pump Station 7	Project F807	6/3/2013
DO060313-2	Pump Station 7	Project X613	6/3/2013
DO060413-1	Pump Station 9	Courtesy Inspection	6/4/2013
DO060413-2	Pump Station 9	COF Check	6/4/2013
DO060413-3	Pump Station 8	Courtesy Inspection	6/4/2013
DO060513-1	Pump Station 5	Courtesy Inspection	6/5/2013
DO060513-2	YRB/PS6	Courtesy Inspection	6/5/2013
DO061713-1	GRB/PS11	Courtesy Inspection	6/17/2013
DO061813-1	VMT	Project Z559	6/18/2013
DO061813-2	VMT	Project Z621	6/18/2013
DO061813-3	Pump Station 12	Cold Restart Project	6/18/2013
DO061913-1	Pump Station 10	Project W/Y017	6/19/2013

Appendix H: Authorizations, Rights-of-Way, and Permits Issued

Permit Number	Date	Location	Description
TWUP P2012-4	7/16/2012	NW4, Section 22, T2S, R1E, CRM. Latitude 61.68391 N / Longitude 145.21490 W; WSW4, Section 22, T2S, R1E, CRM. Latitude 61.67549 N / Longitude 145.21465 W; NW4, Section 3, T3S, R1E, CRM. Longitude 61.64216 N / Latitude 145.21859 W	Temporary water use permit (TWUP) issued to Alyeska Pipeline Service Company (APSC) to withdraw up to 10,000 gallons per day (gpd) from each of the three sites at Pipeline Mile Posts (PLMP) 717.72, 718.35, and 720.60. This permit expires October 31, 2016.
LAS 28640	8/5/2012	N2, Section 31, T6S, R8E, FM.	Land use permit (LUP) issued to APSC for the installation of a repeater at the Minton Creek Repeater site. This permit expired August 8, 2012.
ADL 63574 (Amended)	8/9/2012	NW4, Section 21, T2S, R14E, UM; SW4, Section 9, T7S, R14E, UM; NW4, Section 16, T7S, R14E, UM.	Amendment to the Trans Alaska Pipeline System (TAPS) Right-of-Way (ROW) lease issued to APSC to include additional lands need to accommodate two above ground fuel gas line manual gate valves replacement set and to modify Pump Station 3 lateral piping.
LAS 28607	9/12/2012	NE4, Section 4, T9S, R3W, CRM.	LUP issued to APSC to excavate around TAPS to investigate mainline integrity at the base of Thompson Pass and adjacent to Richardson Highway (RHMP) 20.3, at PLMP 775.95. This permit expires September 11, 2013.
LAS 28729	10/26/2012	Sections 16, 20, 21, 29, 31, & 32, T1S, R6W, FM; Section 13, T12N, R11W, FM; Section 20, T15S, 6W, FM.	LUP issued to Alaska Gasline Development Corporation (AGDC) to collect geotechnical data along the Alaska Stand Alone Pipeline (ASAP) alignment to delineate frost heave potential to support engineering activities for the ASAP project. This permit expires January 31, 2013.
TWUP P2012-5	11/20/2012	NW4SE4, Section 19, T7N, R14E, UM. Latitude 69° 56' 38 / Longitude: -148° 43' 51; SE4NE4, Section 1, T6N, R14E, UM. Latitude 69° 54' 12 / Longitude -148 ° 45' 32; SE4NW4, Section 12, T6N, R14E, UM. Latitude 69° 53' 24 / Longitude -148° 46' 45	TWUP issued to APSC to withdraw up to 10,000 gpd from three locations, Check Valve Vaults #6 and #7 and material site pond on access road 133APL/AMS-3, for ice/snow road construction, and dust suppression. This permit expires November 19, 2017.

Appendix H: Authorizations, Rights-of-Way, and Permits Issued

Permit Number	Date	Location	Description
TWUP P2012-6	11/20/2012	NW4NW4, Section 16, T7S, R14E, UM. Latitude 68° 50' 30 / Longitude -148° 49' 30	TWUP issued to APSC to withdraw up to 30,000 gpd from an unnamed creek along Pump Station 3 (PS03) Access Road 120-APS/AMS-3 for ice/snow road construction, pad maintenance, dust suppression, and other projects and maintenance activities around PS03. This permit expires November 19, 2017.
TWUP P2012-7	11/20/2012	SW4SW4, Section 20, T10N, R7W, FM. Latitude 65° 40' 23 / Longitude -149° 4' 11; NW4NE4, Section 3, T9N, R7W, FM. Latitude 65° 38' 7 / Longitude -148° 58' 42; NW4NE4, Section 16, T8N, R6W, FM. Latitude 65° 31' 36 / Longitude -148° 47' 30	TWUP issued to APSC to withdraw up to 10,000 gpd from Hess Creek, Erickson Creek, and Lost Creek for Right-of-Way maintenance and project related activities along TAPS. This permit expires October 31, 2017.
TWUP P2012-8	11/20/2012	NW4SE4, Section 17, T5S, R6E, FM. Latitude 64° 28’ 47 / Longitude -146° 35’ 40	TWUP issued to APSC to withdraw up to 35,000 gpd from a pond within OMS 53-2. This permit expires November 19, 2017.
TWUP P2012-9	11/20/2012	SW4SW4, Section 31, T14S, R10E, FM. Latitude 63° 39’ 14 / Longitude -145° 53’ 13	TWUP issued to APSC to withdraw up to 35,000 gpd from a pond within OMS 41-1R. This permit expires November 19, 2017.
TWUP P2012-10	11/20/2012	SW4NE4, Section 32, T4S, R5E, FM. Latitude 64° 30' 31 / Longitude -146° 44' 8	TWUP issued to APSC to withdraw up to 15,000 gpd from the Little Salcha River for ROW maintenance and project activities from PLMP 490.84 to 495.83. This permit expires October 31, 2017.
LAS 28738	1/1/2013	W2SW4, W2E2SW4, Section 31, T3S, R1E, CRM.	LUP issued to APSC to store mined material, non-hazardous material, and equipment in OMS 14-0/DOTPF MS 71-1006-5. This permit expires January 31, 2017.
TWUP P2012-11	1/10/2013	NW4NW4, Section 17, T1S, R2E, FM. Latitude 64° 49' 55 / Longitude -147° 24' 9	TWUP issued to APSC to withdraw up to 15,000 gpd from the Gettinger Gravel Pit, located at the Nordale Yard, for road maintenance, projects, and dust suppression in the vicinity of the Nordale Yard area. This permit expires October 31, 2017.

Appendix H: Authorizations, Rights-of-Way, and Permits Issued

Permit Number	Date	Location	Description
TWUP P2012-7 (Amended)	1/10/2013	SW4SW4 Section 20, T10N, R7W, FM. Latitude 65° 40' 23 / Longitude -149° 4' 11 NW4NE4, Section 3, T9N, R7W, FM. Latitude 65° 38' 7 / Longitude -148° 58' 42 NW4NE4, Section 16, T8N, R6W, FM. Latitude 65° 31' 36 / Longitude -148° 47' 30	TWUP issued to APSC to withdraw up to 10,000 gpd from Hess Creek, Erickson Creek, and Lost Creek. TWUP was amended to correct the legal description of the Erickson Creek location.
TWUP P2013-1	3/8/2013	S2NE4, N2SE4, Section 12, T12N, R11W, FM. Latitude 65.87971 N / Longitude 149.74132 W	TWUP issued to AGDC to withdraw up to 4,800 gpd from Yukon River Mile 811 in support of drilling boreholes related to LUP LAS 28729. This permit expires April 30, 2017.
TWUP P2012-10 (Amended)	3/8/2013	SW4NE4, Section 32, T4S, R5E, FM. Latitude 64 ° 30' 31 / Longitude -146° 44' 8	TWUP issued to APSC to withdraw 15,000 gpd from the Little Salcha River for general maintenance and operations within PLMP 480 to PLMP 496. The start date of water use was amended from May 1, 2013 to April 1, 2013. This permit expires December 31, 2013.
LAS 28729 (Amended)	3/8/2013	SW4SW4, Section 16, T1S, R6W, FM. Latitude 64.82039 N / Longitude 148.78037 W; NE4NE4, Section 20, T1S, R6W, FM. Latitude 64.81957 N / Longitude 148.78458 W; SW4NE4, Section 29, T1S, R6W, FM. Latitude 64.79901 N / Longitude 148.79338 W; NE4SE4, Section 31, T1S, R6W, FM. Latitude 64.78269 N / Longitude 148.81930 W; NW4SW4, Section 32, T1S, R6W, FM. Latitude 64.78200 N / Longitude 148.81540 W; NE4SE4, Section 13, T12N, R11W, FM. Latitude 65.86492 N / Longitude 149.73916 W; NE4SE4, Section 13, T12N, R11W, FM. Latitude 65.86397 N / Longitude 149.73555 W; Additional, 10 bore hole sites within S2NE4, N2SE4, Section 12, T12N, R11W, FM.	LUP issued to AGDC to install and operate thermistors at seven sites to support activities associated with the ASAP alignment. LUP was amended to add ten additional borehole sites. This permit expires December 31, 2013.

Appendix H: Authorizations, Rights-of-Way, and Permits Issued

Permit Number	Date	Location	Description
LAS 28830	3/15/2013	SE4NW4, Section 32, T4S, R5E, FM.	LUP issued to APSC for staging equipment and materials in support of the TAPS Oil Discharge Prevention and Contingency Plan Preparedness on Little Salcha River. This permit expires December 31, 2013.
LAS 28993	4/2/2013	Multiple.	LUP issued to Donlin Gold, LLC to conduct their 2013 Natural Gas Pipeline Study Area within the Jones Realignment. Activities include drilling boreholes and installing two VHF repeaters and data collectors. This permit expires April 1, 2018.
LAS 29006	4/23/2013	SE4, Section 4, T7S, R8E, FM. Latitude 61.08047 N / Longitude 146.32932 W; NE4, Section 34, T9S, R4W, CRM. Latitude 61.05008 N / Longitude 145.90626 W; NE4, Section 24, T9S, R6W, CRM. Latitude 61.07551 N / Longitude 146.20990 W; N2N2, Section 20, T9S, R6W, CRM. Latitude 61.08047 N / Longitude 146.32932 W	LUP issued to APSC to excavate four sections of buried pipe at PLMPs 515.4, 783.61, 794.64, and 798.97 to investigate the integrity of the pipe. This permit expires April 23, 2014.
LAS 29070	4/25/2013	Multiple.	LUP issued to AGDC to conduct their 2013 Borehole Campaign to support the ASAP Project. This permit expires December 31, 2013.
TWUP P2013-2	4/25/2013	Section 24, T2N, R6W, FM. Latitude 64.979 N / Longitude 148.680 W; Section 31, T1S, R6W, FM. Latitude 64.779 N / Longitude 148.824 W; Section 14, T8S, R9W, FM. Latitude 64.221 N / Longitude 149.280 W; Section 15, T24N, R5W, SM. Latitude 62.172 N / Longitude 150.177 W; Section 10, T16N, R5W, SM. Latitude 61.487 N / Longitude 150.151 W	TWUP issued to AGDC to withdraw up to 5,000 gpd from four sites at the Chatanika River, the Goldstream River, the Susitna River, the Little Susitna River, and the Nenana River. This permit expires May 1, 2014.

Appendix H: Authorizations, Rights-of-Way, and Permits Issued

Permit Number	Date	Location	Description
TWUP P2010-7 (Amended)	4/30/2012	NE4SE4, Section 17, T23N, R14W, FM. Latitude 66.81865 N / Longitude 150.63395 W	TWUP issued to APSC was amended to authorize additional uses of the water. This permit expires October 31, 2014.
LAS 29049	4/30/2013	Section 6, Section 7, Section 17, Section 18, Section 19, Section 20, Section 21, & Section 28, T14N, R9W, SM; Section 29, & Section 33, T14N, R10W, SM; Section 36, T15N, R10W, SM; Section 30 & Section 31, T15N, R9W, SM.	LUP issued to Donlin Gold, LLC for engineering field studies including digging boreholes and installing data collectors. This permit expires April 30, 2018.
LAS 29070 (Amended)	5/20/2013	Multiple.	LUP issued to AGDC was amended to include an additional 212 borehole locations. This permit expires December 31, 2015.
ADL 63574 (Amended, PLMP 24.7)	6/6/2013	E2, Section 31, T7N, R14E, UM.	Amendment to the TAPS lease issued to APSC to include additional lands for construction and maintenance of the channel plug in the flood plain of the Sagavanirktok River at PLMP 24.7.
ADL 63574 (Amended, PLMP 777.7)	6/20/2013	NW4NW4, Section 8, T9S, R3W, CRM	Amendment to the TAPS lease issued to APSC to add an additional 6.2 acres of land. The purpose of adding this land is to install two buried rock grad-control structures a the pipeline crossing of Sheep Creek at PLMP 777.7 to prevent exposure of the buried pipe due to streambed erosion.
ADL 63574 (Amended, PLMP 787.8)	6/20/2013	NW4SE4, Section 36, T9S, R5W, CRM.	Amendment to the TAPS lease issued to APSC to add 3.8 acres of land located within the floodplain of an unnamed creek south of Lowe River at PLMP 787.8. This land will be necessary to accommodate flood repair work and support the existing pipeline system at the bridge over the unnamed creek.
ADL 419956	6/25/2013	N2, Section 30, T14S, R10E, FM.	Material sale contract issued to APSC to mine 5,500 cubic yard of riprap from OMS 41-3.

Appendix H: Authorizations, Rights-of-Way, and Permits Issued

Permit Number	Date	Location	Description
ADL 419923	6/25/2013	NE4, Section 31, T7N, R14E, UM.	Material sale contract issued to APSC to remove gravel from a gravel bar in the Sagavanirktok River floodplain to construct an extension to the channel plug at PLMP 24.7.
ADL 63574 (Amended, PLMP 579.2)	6/26/2013	NW4, Section 29, T16S, R10E, FM.	Amendment to the TAPS lease issued to APSC to add approximately 0.25 miles of land east of Delta River and Suzy Q Creek to install new magnesium rods to improve cathodic protection along the buried mainline pipe in the PLMP 579.2 area.
LAS 29085	6/27/2013	NE4 Section 3, T9S, R3W, CRM. S2, Section 34 & SW4, Section 35, T8S, R3W, CRM.	LUP issued to APSC to brush an existing ATV trail up 15 feet wide from the Richardson Highway at Thompson Pass down to TAPS near PLMP 775.5 for access for the cathodic protection survey team.

APPENDIX I: 2011 THROUGHPUT FOR SPCO JURISDICTIONAL PIPELINES

Alpine Diesel Pipeline	3,370,892 gal
Alpine Oil Pipeline	25,856,275 bbl
Alpine Utility Pipeline	27,653,593 bbl
Badami Sales Oil Pipeline	480,515 gross bbl
Badami Utility Pipeline	127,523 Mscf
Endicott Pipeline	3,522,511 gross bbl
Kenai Kachemak Pipeline (KKPL)	16,060 MMcf
Kenai Kachemak Pipeline (HV)	
Kenai Kachemak Pipeline (KE)	
Kuparuk Pipeline	78,721,740 bbl
Kuparuk Pipeline Extension	47,340,759 bbl
Milne Point Pipeline	6,425,288 gross bbl
Milne Point Products Pipeline	none
Nikiski Alaska Pipeline	11,917,815 bbl
Northstar Gas Pipeline	6,325,631 Mscf
Northstar Oil Pipeline	3,030,500 gross bbl
North Fork Pipeline	1,481 MMscf
Nuiqsut Natural Gas Pipeline	95,806,000 scf
Oliktok Pipeline	5,872,284 bbl
Trans-Alaska Pipeline System	200,518,907 bbl

Mscf = thousands of standard cubic feet
MMcf = millions of standard cubic feet
scf = Standard Cubic Feet

Appendix J: Lease Required Contact Information

Pipeline	Registered Agent	Authorized Representative	Field Representative
Alaska Stand Alone	Joe Dubler Vice President & Chief Financial Officer Alaska Gasline Development Corp. 3301 C Street, Ste. 100 Anchorage, AK 99503	Dan Fauske President Alaska Gasline Development Corp. 3301 C Street, Ste. 100 Anchorage, AK 99503	Ken Vassar Alaska Gasline Development Corp. 3301 C Street, Ste. 100 Anchorage, AK 99503
Alpine Pipelines	Barry Romberg Engineering & Operations Manager ConocoPhillips Alaska, Inc. P.O. Box 100360, ATO 908 Anchorage, AK 99510-0360	Barry Romberg Engineering & Operations Manager ConocoPhillips Alaska, Inc. P.O. Box 100360, ATO 908 Anchorage, AK 99510-0360	Philip Susen / Dennis Melton CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105 NSK 22 Anchorage, AK 99519-6105
Badami Pipelines	CT Corporation System Re: BP Transportation (Alaska) Inc. 9360 Glacier Highway, Ste. 202 Juneau, AK 99801	Don Turner Vice President BP Transportation (Alaska) Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Bruce W. Robinson / T.J. Barnes BP Exploration (Alaska) Inc. Mail Stop END 900 E. Benson Blvd. Anchorage, AK 99508
Endicott	CT Corporation System Re: BP Transportation (Alaska) Inc. 9360 Glacier Highway, Ste. 202 Juneau, AK 99801	Don Turner Vice President BP Transportation (Alaska) Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Bruce W. Robinson / T.J. Barnes BP Exploration (Alaska) Inc. Mail Stop END 900 E. Benson Blvd. Anchorage, AK 99508
Kenai Kachemak	Ed Jaroch Pipeline Manager Hilcorp Alaska, LLC 3800 Centerpoint Drive, Suite 100 Anchorage, AK 99503	Ed Jaroch Pipeline Manager Hilcorp Alaska, LLC 3800 Centerpoint Drive, Suite 100 Anchorage, AK 99503	Erin McKay Regulatory Coordinator Hilcorp Alaska, LLC 3800 Centerpoint Drive, Suite 100 Anchorage, AK 99503

Kuparuk Kuparuk Extension	Barry Romberg Engineering & Operations Manager Kuparuk Transportation Company P.O. Box 100360, ATO 908 Anchorage, AK 99510-0360	Barry Romberg Engineering & Operations Manager Kuparuk Transportation Company P.O. Box 100360, ATO 908 Anchorage, AK 99510-0360	Philip Susen / Dennis Melton CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105 NSK 22 Anchorage, AK 99519-6105
Milne Point Pipelines	CT Corporation System Re: BP Transportation (Alaska) Inc. 9360 Glacier Highway, Ste. 202 Juneau, AK 99801	Don Turner Vice President BP Transportation (Alaska) Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Jeff Michels / Kenton Schoch BP Exploration (Alaska) Inc. Mail Stop MPU 900 E. Benson Blvd. Anchorage AK 99508
Nikiski Alaska	Shawn Brown Tesoro Alaska Pipeline Company P.O. Box 3369 Kenai, AK 99611	Rick Weyen Vice President, Logistics Tesoro Refining & Marketing Co. 19100 Ridgewood Parkway San Antonio, TX 78259	Shawn Brown Tesoro Alaska Pipeline Company P.O. Box 3369 Kenai, AK 99611
North Fork	CT Corporation System Re: Anchor Point Energy, LLC 9360 Glacier Highway, Ste. 202 Juneau, AK 99801	Ed Kerr Vice President Anchor Point Energy, LLC 1421 Blake Street Denver, CO 80202	Chuck Johnson Armstrong Operations North Fork Facility Anchor Point, AK
Northstar Pipelines	CT Corporation System Re: BP Transportation (Alaska) Inc. 9360 Glacier Highway, Ste. 202 Juneau, AK 99801	Don Turner Vice President BP Transportation (Alaska) Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Wayne Kuykendall / Gary Herring BP Exploration (Alaska) Inc. Mail Stop Northstar 900 E. Benson Blvd. Anchorage, AK 99508
Nuiqsut Natural Gas	Morris Lemen Jr. Deputy Director North Slope Borough P.O. Box 69 Barrow, AK 99723	Charlotte E. Brower Mayor North Slope Borough P.O. Box 69 Barrow, AK 99723	Charlotte E. Brower Mayor North Slope Borough P.O. Box 69 Barrow, AK 99723

Oliktok	Barry Romberg Engineering & Operations Manager ConocoPhillips Company P.O. Box 100360, ATO 908 Anchorage, AK 99510-0360	Barry Romberg Engineering & Operations Manager ConocoPhillips Company P.O. Box 100360, ATO 908 Anchorage, AK 99510-0360	Philip Susen / Dennis Melton CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105 NSK 22 Anchorage, AK 99519-6105
Pt. Thomson Export Pipeline	Corporate Service Company Re: Point Thompson Export Pipeline 9360 Glacier Highway, Ste. 202 Juneau, AK 99801	Meredith D. West President 800 Bell Street., PL-EMB-647F Houston, TX 77002	Person In Charge P.O. Box 4876 Houston, TX 77002-4876
Trans-Alaska Pipeline System	Thomas J. Barrett President Alyeska Pipeline Service Company P.O. Box 196660 Anchorage, AK 99519-6660	Joseph Robertson Director of Regulatory Affairs Alyeska Pipeline Service Company P.O. Box 196660, MS 502 Anchorage, AK 99519-6660	N/A