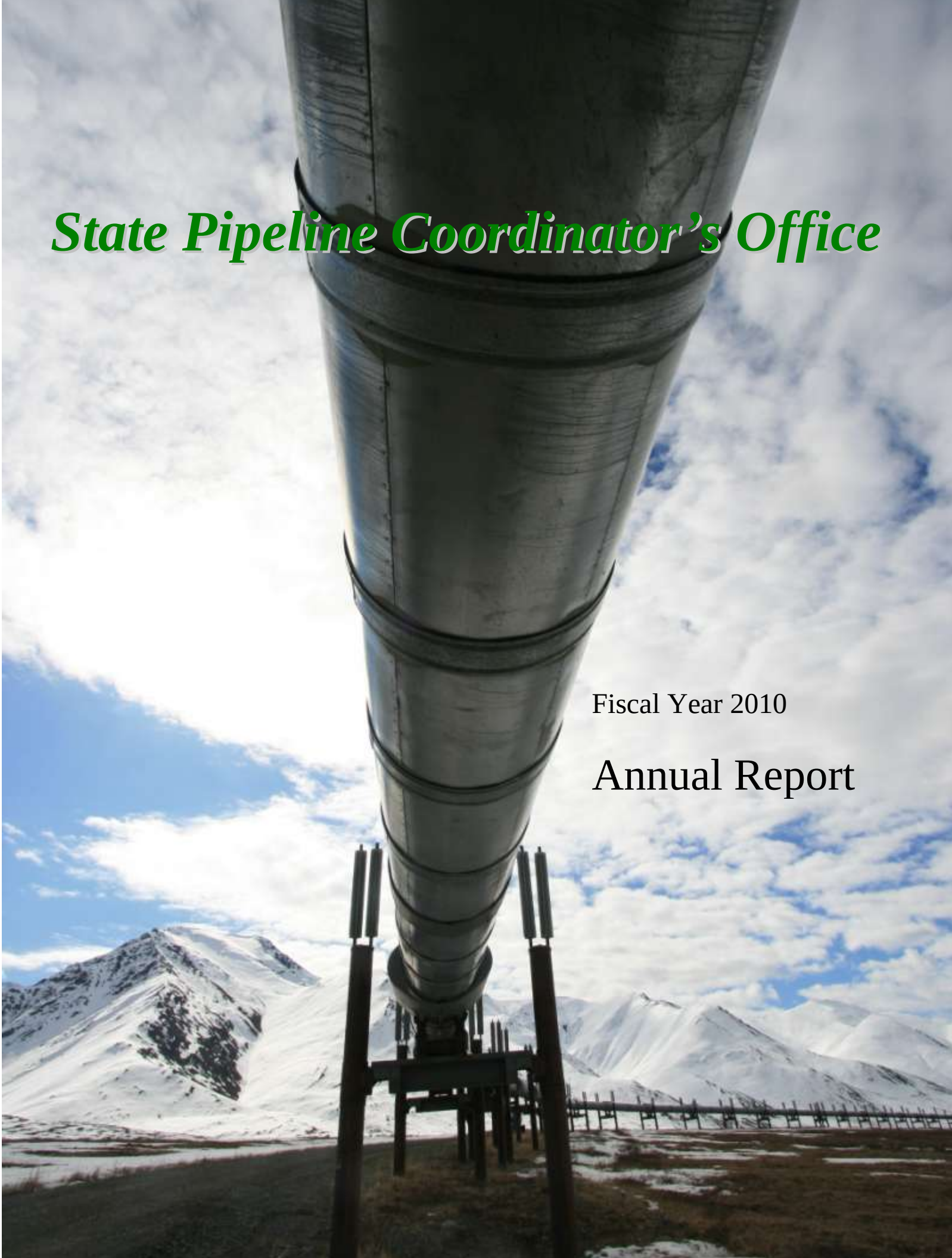

State Pipeline Coordinator's Office

Fiscal Year 2010

Annual Report

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Cover Photograph

Cover photograph of TAPS, by Benjamin Hagedorn, located just south of pipeline milepost 169 (Atigun Pass) on May 20, 2010.

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Acronyms and Abbreviations

ACF	Alpine Central Facility
ACMP	Alaska Coastal Management Program
ADF&G	Alaska Department of Fish and Game
AGDC	Alaska Gasline Development Corporation
AHFC	Alaska Housing Finance Corporation
AMS	Alyeska Management System
ANGDA	Alaska Natural Gas Development Authority
AO	Authorized Officer (BLM/OPM)
APDES	Alaska Pollutant Discharge Elimination System
APSC	Alyeska Pipeline Service Company
AQ	Air Quality
AS	Alaska Statute
ATP	Authorized to Proceed
B2F	Beluga to Fairbanks Pipeline
BEAR	Behavior Eliminates All Risk
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
CISPRI	Cook Inlet Spill Prevention and Response Inc.
COTS	Corrected On-the-Spot
COTU	Crude Oil Topping Unit
CP	Cathodic Protection
CPAI	ConocoPhillips Alaska, Inc.
CPC	ConocoPhillips Company
CPF	Central Processing Facility
C-Plan	Oil Discharge Prevention and Contingency Plan
CY	Calendar Year
DCOM	Division of Coastal and Ocean Management
DEC	Alaska Department of Environmental Conservation
DEIS	Draft Environmental Impact Statement
DMA	Dalton Management Area
DMLW	Division of Mining, Land and Water
DNR	Alaska Department of Natural Resources

DOI	U.S. Department of the Interior
DOLWD	Alaska Department of Labor and Workforce Development
DOT&PF	Alaska Department of Transportation and Public Facilities
DPS	Alaska Department of Public Safety
DRA	Drag Reducing Agent
DTS	Document Tracking System
EA	Electrification and Automation
ECDA	External Corrosion Direct Assessments
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
FAA	Federal Aviation Administration
FCO	Functional Check-Out
FGL	Fuel Gas Line (TAPS)
FLIR	Forward Looking Infrared
FOIA	Freedom of Information Act
FOSC	Federal On-Scene Coordinator
FRA	Formal Risk Assessment
FRB	Fairbanks Response Base
FS	Flow Station
FY	Fiscal Year
gHSEr	getting Health, Safety, and Environment right
GIS	Geographic Information System
GRB	Glennallen Response Base
H2S	Hydrogen Sulfide
HCA	High Consequence Areas
HDD	Horizontal Directional Drilling
HDPE	High-Density Polyethylene
HSE	Health, Safety, and Environment
HSEMSS	Health, Safety, and Environmental Management System Standard
HSM	Horizontal Support Member
HVE	Happy Valley Extension
IFC	Issued for Construction
ILI	In-Line Inspection
IMP	Integrity Management Program
IMT	Incident Management Team
JPO	Joint Pipeline Office
KE	Kasilof Extension
KKPL	Kenai Kachemak Pipeline
KPB	Kenai Peninsula Borough
KPE	Kuparuk Pipeline Extension
KPL	Kuparuk Pipeline

KRU	Kuparuk River Unit
kW	Kilowatt
LAS	Land Administration System
LEFM	Leading Edge Flow Meter
LiDAR	Light Detection and Ranging
LNO	Letter of Non-Objection
LUP	Land Use Permit
LWC	Low Water Crossing
MAC	Management Actions and Commitments
MFL	Magnetic Flux Leakage
MLR	Mainline Refrigeration unit
MOA	Municipality of Anchorage
MOC	Management of Change
MP-166	APSC Monitoring Program
MPI	Main Production Island
mW	Megawatt
NACE	National Association of Corrosion Engineers
NDT	Non-Destructive Testing
NEC	National Electric Code
NF	North Fork
NFPA	National Fire Protection Association
NNGP	Nuiqsut Natural Gas Pipeline
NOV	Notice of Violation
NPDES	Nation Pollutant Discharge Elimination System
NPMS	North Pole Metering Station
NRM	Natural Resource Manager
NSB	North Slope Borough
OCC	Operations Control Center
ODPCP	Oil Discharge Prevention and Contingency Plan
OFC	Office of the Federal Coordinator
OM&OQ	Operations, Maintenance and Operator Qualifications Manual
OMS	Operations Material Sites
OPL	Oliktok Pipeline
OPM	Office of Pipeline Monitoring
OQ	Operator Qualification
OSCP	Oil Spill Contingency Plan
OSHA	Occupational Safety and Health Administration
OTL	Oil Transit Line
P&CM	Pipeline and Civil Maintenance Coordinators
PDC	Power Distribution Center
PHA	Process Hazard Analysis

PHMSA	Pipeline and Hazardous Materials Safety Administration
PICV	Pressure Indicating Control Valve
PIT	Pipeline Integrity Testing
PLC	Programmable Logic Controller
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
RCM	Reliability Centered Maintenance
RFI	Request for Information
RGV	Remote Gate Valve
ROW	Right-of-Way
RPS	Response Planning Standard
RT	Radiographic Testing
RTU	Remote Terminal Unit
SAT	Satisfactory
SCADA	Supervisory Control and Data Acquisition
SCRO	Southcentral Regional Office
SDI	Satellite Drilling Island
SERVS	Ship Escort Response Vessel System
SFMO	State Fire Marshall's Office
SME	Subject Matter Expert
SMP	Surveillance and Monitoring (or Maintenance) Program
SOC	Safety Observations and Conversations
SOSC	State On-Scene Coordinator
SPC	State Pipeline Coordinator
SPCO	State Pipeline Coordinator's Office
SPM	Supplier Performance Management
SR	Strategic Reconfiguration
SSA	Shared Services Aviation
STP	Seawater Treatment Plant
SWD	Solid Waste Disposal
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TG	Turbine Generator
TOFD	Time of Flight Diffraction
TSA	Transportation Security Administration
TWIC	Transportation Workers Identification Card

TWUP	Temporary Water Use Permit
UNSAT	Unsatisfactory
USACE	U.S. Army Corps of Engineers
USCG	U.S. Coast Guard
USDHS	U.S. Department of Homeland Security
USDOT	U.S. Department of Transportation
UT	Ultrasonic Testing
VFD	Variable-Frequency Drive
VMT	Valdez Marine Terminal
VSM	Vertical Support Member
WF	West Fork
WWS	Walking Speed Survey
YPC	Yukon Pacific Corporation

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INTRODUCTION

Federal/State Joint Pipeline Office

The State-Federal Joint Pipeline Office (JPO) was created in March 1990 to provide full partnership for state and federal agencies in monitoring and overseeing the Tran-Alaska Pipeline System (TAPS) and a 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 of the participating agencies or agency divisions. The mission statement of the JPO is, "*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 JPO is composed of representatives from the following agencies:

- Alaska Department of Environmental Conservation (DEC)
- Alaska Department of Fish and Game (ADF&G)
- Alaska Department of Labor and Workforce Development (DOLWD)
- Alaska Department of Natural Resources (DNR)
    - State Pipeline Coordinator's Office (SPCO)
    - Division of Coastal and Ocean Management (DCOM)
- Alaska Department of Public Safety (DPS)
    - Division of Fire and Life Safety, State Fire Marshall's Office (SFMO)
- Alaska Department of Transportation and Public Facilities (DOT&PF)
- U.S. Department of the Interior (DOI)
    - Bureau of Land Management (BLM)
        - Office of Pipeline Monitoring (OPM)
    - Mineral Management Service (MMS)
- U.S. Department of Homeland Security (USDHS)
    - Transportation Security Administration (TSA)
    - U.S. Coast Guard (USCG)
- U.S. Department of Transportation (USDOT)
    - Pipeline and Hazardous Materials Safety Administration (PHMSA)
- U.S. Environmental Protection Agency (EPA)

The cooperating agencies share a desire to develop a system-wide approach to pipeline oversight. The *Executive Council Agreement to Support the State-Federal Joint Pipeline Office* can be found on the JPO website (http://www.jpo.doi.gov). 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 at the JPO is the BLM, represented by the Office of Pipeline Monitoring. The lead state agency is the DNR, represented by the SPCO.

The JPO was formed to provide better service to the public and industry by eliminating duplication of work; coordinating activities; improving communication between agencies,

industry, and the public; sharing expenses; and streamlining the permitting process. While all agencies retain their individual authorities, agencies collaborate and frequently work together on administrative, technical, and regulatory issues regarding jurisdictional oil and gas infrastructure, the terms of these collaborative activities are described in the *Operating Agreement for the Joint Pipeline Office* and can be found on the JPO website (http://www.jpo.doi.gov).

During fiscal year 2010 (FY10), BLM, DNR, DOLWD, DEC, ADF&G and DPS shared office space at 411 West Fourth Avenue in Anchorage. In FY11, BLM will move to a new Anchorage location at 188 West Northern Lights Boulevard. State and federal agencies have worked together on a transition plan to maintain effective communication and coordination. The JPO electronic Document Tracking System (DTS), website, and the ability to share internal documents will be maintained through a BLM-hosted IT environment. This system might provide additional resources to other state and federal agencies such as the Office of the Federal Coordinator (OFC) the DNR Petroleum Systems Integrity Office (PSIO) by allowing access to relevant information that, under the old system, was not readily available.

State Pipeline Coordinator's Office

The State of Alaska's policy, as set out in Alaska Statute (AS) 38.35.010, is that development, use, and control of a pipeline transportation system make the maximum contribution to the development of the human resources of this state, increase the standard of living for all its residents, advance existing and potential sectors of its economy, strengthen free competition in its private enterprise system and carefully protect its incomparable natural environment. The Commissioner has been given all powers necessary and proper to implement this policy and to issue leases of 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 further delegated the authority and responsibility, as allowed by AS 38.35.210, to administer right-of-way (ROW) leases to the State Pipeline Coordinator.

The SPCO was established within the Department of Natural Resources by Administrative Order in 1987. That and subsequent Administrative Orders established the SPCO as the lead agency for the State in processing pipeline ROW leases under AS 38.35, the Right-of-Way Leasing Act (Administrative Order 134 and 187).[1] This responsibility included coordination of the State's efforts related to the federal ROW process. The SPCO also coordinates the State's oversight of preconstruction, construction, operation and termination of jurisdictional pipelines.

The SPCO currently co-locates staff from the Department of Natural Resources (SPCO and DCOM), ADF&G (Habitat Division), the DOLWD (Safety and Electrical Inspectors), DEC (Spill Prevention and Response Division, Industry Preparedness Program), and DPS (State Fire Marshal's Office), see Appendix A: SPCO Staff Resources.

A ROW lease between the State of Alaska and a lessee covers a wide range of activities and governs the conduct between the parties. Each lease covers the full life of a pipeline: construction, operations, maintenance, and termination. The underlying theme throughout a

[1] Administrative Orders can be found at http://gov.state.ak.us/admin-orders/index.php

lease is protection of human health, safety and the environment, established by safe pipeline operations and mitigation of environmental impacts.

Each lease also incorporates a comprehensive set of stipulations that impose general, environmental, and technical conditions on a lessee in order to assure that pipeline activities are conducted in a safe manner that complies with the lease, applicable laws, and regulations. The stipulations also require each lessee to establish specific processes, programs, and systems for pipeline operations. The implementation of these programs and systems helps to insure the integrity of the pipeline, the pipeline system, and pipeline operations.

Within each lease there are sections and stipulations that impose requirements that are duplicative with local, state, and/or federal laws and regulations. These requirements are often within the jurisdictional authority of a separate regulatory agency, and in cases where another regulatory agency's program monitors and enforces compliance with those lease requirements; the SPCO relies primarily on that agency's focused regulatory enforcement and subject matter expertise to assure compliance with the related lease requirements. This approach limits duplication of efforts while utilizing the subject matter expertise of each regulatory agency.

Department of Natural Resources

State Pipeline Coordinator's Office

Administration Section

The SPCO Administration Section provides clerical support to SPCO staff such as managing incoming and outgoing correspondence; file management of right-of-way case files; records management of financial, procurement, and various administrative records; as well as assisting with public information requests. In addition to clerical support, the SPCO Administration Section is responsible for managing and performing all administrative functions relating to personnel, payroll, recruitment, budgeting, grants and contracts, accounting, facility management, property control, procurement of goods and services, and travel. During FY10, SPCO administrative staff coordinated and finalized over 200 travel arrangements for SPCO's Subject Matter Experts (SME) to conduct compliance, assessment, and inspection activities on SPCO Jurisdictional Pipelines throughout Alaska. At the end of the fiscal year, the SPCO Administration Section expanded services to include managing user support for computer related issues.

The SPCO budget is revenue based and primarily funded via reimbursements from industry (Figure 1). State agency representatives are supported through reimbursable service agreements administered by the SPCO. Participation by other state agencies in pipeline oversight allows the SPCO to integrate the expertise and authority of various agencies into one coordinated office. Combined program costs for SPCO during the State of Alaska's FY10 totaled $3,820,972.

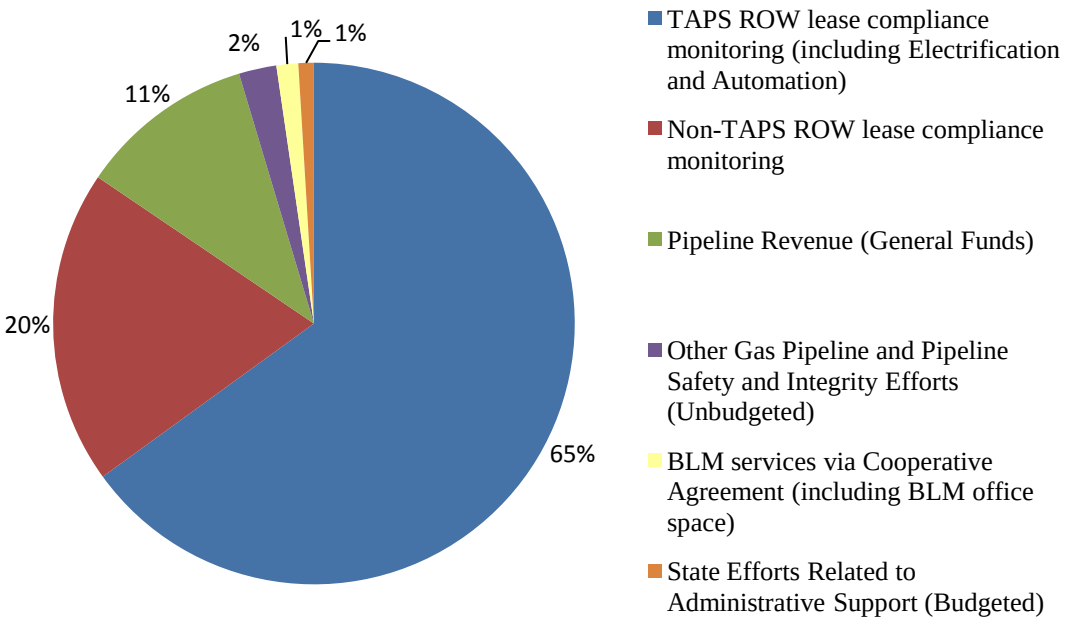


Figure 1: SPCO FY10 Budget Expenditures, $3,820,972

General Fund/Program Receipts, also known as pipeline revenues, are monies collected on behalf of the State by the SPCO from lease payments, material sales, and application fees. This revenue is deposited directly into the State's general fund. Each year, the Legislature appropriates some general fund monies to the SPCO which are used to support non-pipeline specific operations. In FY10 the net deposit to the State's general fund (revenue collected minus legislative appropriation to the SPCO) was $2.57 million dollars (Figure 2).

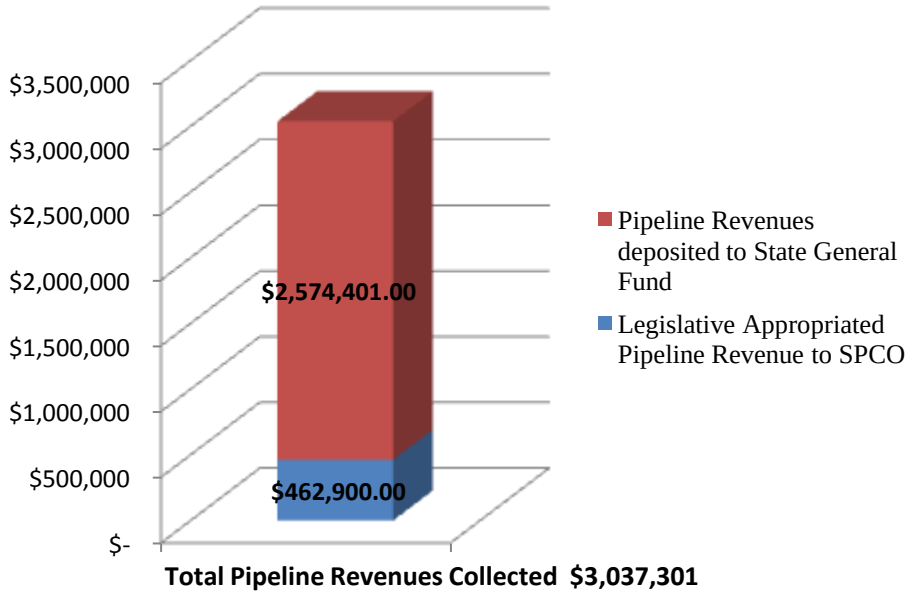


Figure 2: SPCO General Fund Revenues Collected vs. Expended

Lease Compliance Section

The SPCO is responsible for the administration and oversight of pipeline ROW leases issued under AS 38.35, the "Alaska Right-of-Way Leasing Act." The role of the Lease Compliance Section (Compliance Section) is to monitor pipelines administered by the SPCO for compliance with the requirements of the ROW leases.

In general, the lease compliance program integrates three separate but related elements.

1) Compliance monitoring
2) Lessee annual reporting
3) The State Pipeline Coordinator's Annual Report

1) Compliance Monitoring

The purpose of lease compliance monitoring is to evaluate compliance with active lease requirements at a frequency prescribed by the State Pipeline Coordinator. To achieve this goal it is necessary to evaluate each requirement and determine the functional status relative to annual surveillance efforts. For example, many lease provisions are definitions or clarifications of legal/administrative points that require no surveillance, while other provisions apply only to a certain activity phase such as construction or termination. Some provisions are invoked only after an action initiated by the lessee or State Pipeline Coordinator. These provisions are referred to as "conditional".

A matrix of all the requirements (sections and stipulations), and the respective surveillance determination and frequency was developed for each lease. An example matrix is included in this report as Appendix B: Lease Compliance Monitoring Matrix. Each matrix summarizes three decision criteria:

1. What activity phase (administrative, construction, operation, maintenance, termination or any combination of the four) does each requirement apply to;
2. Is a surveillance required (if not, why) and;
3. If surveillance of a requirement is required, what is the necessary frequency?

When possible, a draft matrix is provided to the lessee for review and comment. This is important because the lessee is required to develop an internal Quality Assurance Program (QAP) that implements the processes and procedures necessary to maintain compliance with lease conditions and requirements. This coordination provides the SPCO and lessees common expectations with respect to both internal and external oversight programs.

The compliance monitoring program is intended to be dynamic and subject to an annual internal review to facilitate program improvements or other modifications necessary to reflect changing conditions.

Lease requirements cover a broad range of subjects and the Compliance Section uses the expertise provided by the Engineering and ROW sections of the SPCO, as well as other agencies as necessary. The need for external expertise requires members of the Compliance Section to effectively communicate with other agencies and sections within the SPCO on a wide variety of topics.

The SPCO compliance monitoring activities primarily fall into three primary categories:

(1) *Project review and monitoring.* Lessees, on a quarterly or annual basis, submit proposals for significant construction and maintenance projects for review. Projects are generally differentiated from baseline work by the requirement for project-specific regulatory permits, and the consequent need for engineering analysis and design.

For larger and more complex projects, SPCO staff (permitters, land managers, subject matter experts and engineers) and the lessee's staff (engineers, subject matter experts and land managers) conduct project specific meetings. The benefit of meeting early in the planning stage of complex projects is the identification of specific concerns, such as impacts to fish and wildlife habitat, so that engineers can design the project to avoid or mitigate these impacts.

After the project final design, SPCO staff efforts shift from the planning/permitting phase to a surveillance/verification phase. Compliance monitoring is conducted from a multi-disciplinary perspective because many projects encompass a broad spectrum of lease requirements such as safety, engineering, and environmental as well as specific agency permit stipulations. Staff use the lessee's Issued for Construction (IFC) package, permit requirements and the lease to develop SPCO Surveillance Checklists (surveillance reports) that contain individual requirements (attributes) identified for compliance verification. For some projects, the entire process, from issue identification to project completion, may take a several years.

(2) *Surveillance monitoring.* In addition to project-based monitoring, the Compliance Section also conducts surveillances. Surveillances may be designed to serve as an independent stand-alone compliance evaluation; as the factual basis for an assessment report or technical report; and in support of an agency permit issuance determination or verification. The Compliance Section conducts both planned and unplanned surveillances. The results of surveillances are generally recorded in surveillance reports and/or lease compliance reports.

(3) *Assessments.* The assessments are broader in scope than surveillance reports and tend to focus on processes or systems rather than individual requirements. As previously mentioned, surveillances are typically used as component parts of an assessment process. An assessment requires extensive planning to identify the scope, appropriate level of sampling, and the resources required. For example, an assessment of a lessee's ROW surveillance and monitoring program (SMP) would likely be planned and implemented as follows:

- Identify the lease requirements.
- Determine assessment purpose - usually verification of compliance.
- Define assessment scope – will the assessment review the entire surveillance and monitoring program or only a specific portion? The scope will also identify the specific lessee facilities, activities, documents and employees included in the assessment.
- Identify methods –establish the specific data collection methods, which may include conducting new surveillances, using past monitoring records to evaluate compliance trends, interviews of lessee employees, review of lessee's documentation, or other appropriate methods.

- Analyze data – integrate the available information and evaluate compliance with the requirements.
- Write assessment report – produce a report summarizing the process, analysis and results of the assessment. The report may also include observations, recommendations or findings.

2 Lessee's Annual Report

The lessees' annual reports, submitted by the end of January[2] each year, play an important role in SPCO lease compliance oversight. The Compliance Section's primary focus every February is to review the annual reports provided by the lessees. Each of the lessee's annual reports is checked for requirements found in the corresponding lease and expectations laid out by the State Pipeline Coordinator.

1. The results of the lessee's surveillance and monitoring program during the preceding year, including annual and cumulative changes in facilities and operations, the effects of the changes, and proposed actions to be taken as a result of the noted changes:
   - Provide a summary of the scope of all surveillances, audits, self-assessments or other internal evaluations performed by the lessee.
   - Summarize findings, action items and other observations identified as a result of all surveillances, audits, self-assessments or other internal evaluations performed by the lessee.
   - Describe corrective and preventative actions planned or implemented as a result of surveillances, audits, self-assessments or other internal evaluations performed by the lessee.
   - To the extent known, list by quarter, those surveillances, audits, self-assessments or other internal evaluations planned for next year.
2. The state of, changes to, and results from the last year of the lessee's risk management program, QAP, and internal and external safety programs.
3. Lessee's performance under the ROW lease, including stipulations.
4. 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.
5. A summary of all events, incidents and issues which had the potential to or actually did adversely impact pipeline system integrity, the environment, or worker or public safety and a summary of the lessee's response.
6. A summary of all oil and hazardous substance discharges including date, substance, quantity, location, cause, and cleanup actions undertaken. Minor discharges below agreed upon thresholds may be grouped into monthly total amounts, provided the number of separate incidents is reported.
7. Any additional information requested by the State Pipeline Coordinator.

[2] In FY11 the due date for lessee's annual reports was changed from January 31 to March 1.

After review, clarification, and select verification, the information from the annual reports is summarized for inclusion in this report. Additionally, Compliance Section field activities are reassessed to include planned activities and events provided in the lessees' reports.

2) State Pipeline Coordinator's Annual Report

The purpose of the State Pipeline Coordinator's Annual Report is to summarize annual lessee and SPCO activities associated with each ROW lease. The report generally provides some level of background information, a summary of each lessee's annual report, status of issues identified in previous years monitoring, a summary of the current year SPCO oversight program, and conclusions/recommendations. Major source documents for the SPCO Annual Report can be found in Appendix C: FY10 Annual Report Major Source Documents.

For jurisdictional pipelines, the SPCO works with the lessees, through their quality assurance programs, to make certain that the information necessary to document compliance with lease requirements is identified and available for review upon request. Several lessees have developed internal compliance matrices that list the lease requirement, the process to manage the requirement, the records expected from the process, responsible party and the applicable activities subject to the requirement. The lessee's compliance matrix is compatible with the SPCO compliance matrix and results in common expectations with respect to requirements and the necessary documentation needed to support the SPCO compliance oversight program.

Many lease sections and stipulations impose requirements that are the same as, or overlapped by legal requirements of state and/or federal laws and regulations, and thus administered and enforced by separate regulatory agencies. In cases where another regulatory agency's program monitors and enforces compliance with requirements that include the requirements of a specific lease section or stipulation, the SPCO relies primarily on that agency's focused regulatory enforcement to assure compliance with the lease requirements. This reliance further limits duplication of efforts while utilizing the subject matter expertise of each regulatory agency to best effect. Each agency determines the appropriate level of compliance monitoring with their respective regulations/requirements based on staffing level, budget, mission, etc. The SPCO monitors and reports on these activities as they relate to specific lease requirements.

Engineering Section

The Engineering Section has three main goals.

1. Provide technical oversight of facilities, equipment, infrastructure, and activities on pipeline leases
2. Provide technical engineering assistance to the SPCO and liaison agencies
3. Provide engineering recommendations to the DNR Commissioner and the SPC

The Engineering Section is responsible for verifying that technical requirements of each ROW lease are met. In particular, the Engineering Section's work ensures that "the applicant has the technical and financial capability to protect state and private property interests[3]," that

[3] AS 38.35.100(a)(2) Decision On Application

the lessee "maintain the leasehold and pipeline in good repair[4]," and that lessee "promptly repair or remedy any damage to the leasehold[5]." In addition, Engineering helps ensure that each lessee conforms to applicable technical codes and regulations. The Engineering Section performs code reviews and accepts a design basis for new pipelines or changes to the design basis of existing pipelines. The Engineering Section also coordinates with other agencies to provide technical assistance, if requested.

In general, the efforts of engineering fall into one of four categories.

Lease Pre-Application.

The pre-application activities typically involve gathering information on the technical portion of the project. Often, this is accomplished by producing a design basis that is mutually acceptable both to the lease applicant and to the SPCO. The design basis depends upon general descriptions of the work and relies upon the commitment to design and build to relevant design codes, standards and regulations. The purpose is to ensure that the proposed pipeline and facilities will be a high-quality installation that adheres to industry standards and legal requirements, and that protects the environment and the land while ensuring safety. Much of the work at this stage of the lease involves gathering sufficient information to evaluate a lease based on the technical capabilities of the applicant in design, construction and maintenance.

Lease Processing

The focus at this stage is to evaluate the capabilities of the lease applicant and prepare a recommendation to the SPC or the Commissioner and identify any conditions or requirements for approval.

Lease Monitoring

The bulk of the Engineering Section's work is the technical evaluation of the pipeline and facilities on the leaseholds. This work involves reviewing major maintenance, repairs and construction. The purpose is to provide an independent engineering opinion on activities being performed on the leases. An example is the engineering report in the TAPS section of this document.

Special Projects

There are occasional work items that do not have a direct relationship to the leases. In the past year, this type of work included items such as

- Providing assistance to other state organizations
- Providing assistance to the State's support of an appeal of the denial of a permit by the US Army Corps of Engineers (USACE) at CD5
- Participation in a technical working group on CO2 mitigation

[4] AS 38.35.120(8)(a) Covenants Required to Be Included in Lease
[5] AS 38.35.120(8)(b) Covenants Required to Be Included in Lease

Right-of-Way and Permits Section

The SPCO Right-of-Way and Permits Section (ROW Section) processes ROW lease applications and amendments, implements public processes (as outlined in 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 other functions as necessary. The status of the ROW lease determines the level of involvement of the ROW Section.

Pre-lease

The ROW Section encourages applicants to meet with the SPCO before the formal submittal of a ROW application. Pre-lease meetings help to coordinate future timelines, discuss foreseeable issues, coordinate the public process, discuss acceptable information, and begin early mitigation of environmental and/or public concerns. Once an application is received and determined to be complete a public notice is issued by the SPCO. A Commissioner's Analysis and Proposed Decision is written and a second public notice is issued. Any public comment received by the SPCO is considered and addressed in the Commissioner's Final Decision. The lease is then offered to the applicant.

The ROW Section also coordinates permitting for pre-lease applicants to help with field research, exploration, and route alignment. If a finding of "fit, willing, and able" found then a lease can be issued.

Lease Issuance

After the draft lease is negotiated and the applicant signs the document it is sent to the Commissioner. Once the Commissioner signs the document it becomes a fully executed lease. The SPCO then sends one original of the executed lease to the lessee and one original is kept in the case file for that lease.

AS 38.35 pipeline ROW leases and ROW lease amendments can be viewed in portable digital format at http://www.jpo.doi.gov/SPCO/SPCO.htm.

Lease Administration

The ROW Section is responsible for permitting (or coordinating) any activity associated with the lease. The ROW section is the main point-of-contact within the SPCO for the lessee for land use and pipeline ROW.

Permitting

The ROW Section issues ROW lease authorizations for all AS 38.35 pipelines. For TAPS, the ROW Section also issues Land Use Permits (LUP), Temporary Water Use Permits (TWUP), and ROWs for roads and boat launches necessary for operations and maintenance activities and special projects. The permit review process can involve a significant amount of coordination. Each project can involve unique lease or permit requirements depending on several factors.

- Type of work activity
- Project details (schedule, location, special circumstances)
- Land ownership

- Public notice requirements
- Public comment
- Whether the project is located within a coastal zone
- Presence of navigable waters
- Water use needs
- Need to coordinate with other state, federal, and local agencies
- Enforcement and jurisdictional implications
- Effects to habitats and wetlands
- Impacts to fish and wildlife
- Engineering and surveying standards
- Land appraisals
- Evaluation of the potential to disturb historic, prehistoric and archaeological resources

Amendments
The ROW Section evaluates and adjudicates any necessary amendments to leases under the jurisdiction of the SPCO. In general, the lease amendment process is used to add lands to the existing ROW for maintenance and operation purposes, as well as changes to the existing language of AS 38.35 ROW leases. This process includes a Commissioner's Decision and a public notice.

Other Administrative Duties
The ROW Section keeps the pipeline ROW case files up-to-date, makes sure rental schedules are current, directs and processes payments, documenting pipeline activities, updates the State of Alaska electronic files, communicates with lessees for annual documentation requirements, updates legal descriptions, and performs any additional tasks associated with lease administration for AS 38.35 pipeline ROW leases.

The ROW Section periodically conducts surveillance inspections of the Operations Material Sites (OMS) for which the ROW Section has issued material sale contracts for TAPS.

State Pipeline Coordinator's Office Liaison/State Agency Representatives

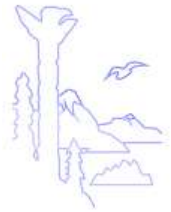
Department of Natural Resources – Division of Coastal and Ocean Management

The SPCO supports a liaison from the Division of Coastal and Ocean Management at the SPCO. The Alaska Coastal Management Program (ACMP) provides stewardship for Alaska's rich and diverse coastal resources to ensure a healthy and vibrant Alaskan coast that efficiently sustains long-term economic and environmental productivity.

The DCOM liaison to the SPCO coordinates the State of Alaska's review of onshore oil and gas exploration and development projects and common carrier pipelines for consistency with the ACMP. The DCOM liaison works closely with state/federal/coastal district agencies to coordinate consistency reviews and properly implement the ACMP, as well as assisting agencies in coordinating internal procedures with the consistency review process. The DCOM liaison aids government representatives, industry (applicants), and the public with the permitting process. On behalf of the SPCO, the DCOM Liaison typically coordinates coastal

zone reviews of new construction and routine maintenance and repair activities for TAPS and associated pipelines.

Alaska Department of Environmental Conservation



The broad mission of DEC is to conserve, improve, and protect Alaska's natural resources and environment and to control water, land, and air pollution to enhance the health, safety, and welfare of the people of the State of Alaska and their overall economic and social well-being. As a participating member of the JPO, and as a SPCO liaison agency, the DEC accomplishes its mission through implementing state statutes and regulations governing jurisdictional pipelines and facilities throughout Alaska. Three full-time DEC positions are co-located within the SPCO: a designated DEC Liaison who provides overall coordination as well as specific technical and policy advice and two Environmental Program Specialists whose duties center on oversight of oil spill prevention and response readiness.

The DEC liaison provides coordination and policy guidance for the implementation of requirements of the Air Quality, Water, Environmental Health, and Contaminated Sites Divisions of DEC. These divisions oversee wastewater operations and permits, solid waste operations and permits, air quality permits, water quality permits and management of contaminated sites. The DEC liaison works with SPCO staff to ensure authorizations or permits from the SPCO are consistent with DEC statutes and regulations. The DEC liaison is also a member of the JPO Management Team.

The DEC's two Environmental Program Specialists focus exclusively on oil discharge prevention and contingency plan (C-Plan) requirements for the TAPS Pipeline and the Valdez Marine Terminal (VMT). As part of the DEC Spill Prevention and Response Division's Industry Preparedness Program, they review and approve the C-plans for the Pipeline and the VMT on a five-year basis. The Environmental Program Specialists review and approve amendments for the Pipeline and VMT C-Plans and ensure oversight for compliance with DEC's prevention regulations. Oversight of C-plan activities includes facility and response equipment inspections, records audits, and conducting and evaluating oil spill response exercises. DEC's prevention regulations provide for direct oversight of specific items such as facility piping, crude oil storage tanks, secondary containment, and the TAPS mainline. For technical analysis of compliance with prevention regulations, the Environmental Program Specialists are actively supported by the DEC Industry Preparedness Program's licensed professional engineering staff as well as the engineering staff within the JPO. Both of these positions are part of the Oil Spill Team within the JPO, along with representatives from the BLM, DEC, and EPA.

Alaska Department of Fish and Game

The ADF&G liaison acts as staff assistant to the Director of the Habitat Division of the ADF&G for TAPS. The liaison administers the Fish Habitat Permit Program under AS 16.05.841 and AS 16.05.871, which includes issuing permits, commenting on other agency permits, conducting compliance inspections (using SPCO surveillance procedures), and when

necessary, taking enforcement actions.

The 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. To do this the liaison works with state and federal agencies and Alyeska Pipeline Service Company (APSC) 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 liaison, in addition to reviewing TAPS and VMT oil spill contingency plans and participating in oil spill response for spills potentially impacting fish and wildlife populations or habitat, prepares surveillance reports and assessments that document the Lessee's compliance with environmental and other stipulations of the Lease and/or Grant.

Figure 3: Dennis Gnath, Former ADF&G Liaison[6]

Figure 4: Lee McKinley, New ADF&G Liaison

Alaska Department of Labor and Workforce Development

The DOLWD has two positions, a Safety Liaison and an Electrical Inspector, co-located at the SPCO. Both of these positions address issues regarding TAPS.

The DOLWD Safety Liaison serves as the SPCO program manager for worker safety and DOLWD technical and policy objectives. This position conducts annual safety inspections of

[6] On June 1, 2010, Dennis Gnath (Figure 3), ADF&G Liaison to the Joint Pipeline Office, retired from State Service, and Lee McKinley (Figure 4) was hired. Mr. McKinley brings a solid background of experience with ADF&G to this position. He has been with the Department since 1994 working for the Commercial Fisheries Division and has been with the Division of Habitat since 2004 managing our interest in the Kenai River Center.

TAPS facilities, conducts worksite safety inspections, reviews project safety plans, monitors APSC accident statistics, and consults with JPO staff on employee safety issues. This position also serves as the SPCO safety manager, conducting safety training for JPO staff and maintaining the JPO safety manual.

The DOLWD Electrical Inspector Liaison (Electrical Liaison) serves as the SPCO electrical safety program manager for compliance with electrical codes and licensing requirements in the State of Alaska. The duties of this position are to enforce compliance with Alaska statutes and administrative codes for electrical safety codes, standards, and licensing requirements for electricians, electrical contractors, and electrical administrators. This position conducts random on-site electrical inspections of new construction projects, as well as modifications and maintenance of existing electrical systems. The Electrical Liaison is a resource and the legal authority for SPCO, BLM/OPM, and USDOT/PHMSA staff, as well as APSC employees, for electrical codes and licensing issues. This authority comes from

- Alaska Statutes Title 8, 18, 23
- Alaska Administrative Code Title 8, Chapter 70 and Title 12, Chapter 2

Incorporated by reference in the Alaska Administrative Code is the National Fire Protection Association (NFPA), National Electrical Code (NEC). This makes The National Electrical Code enforceable in the State of Alaska. This part of the Alaska Administrative Code is updated every three years, and is signed into law by the Governor, or the Lieutenant Governor, after the new NEC is adopted by the NFPA.

The Electrical Liaison, who serves as the SPCO electrical safety program manager, is one of four electrical inspectors employed by the State of Alaska, DOLWD, Labor Standards and Safety, Mechanical Inspection Section: ***http://labor.state.ak.us/lss/mihome.htm***. Each of the four State of Alaska electrical inspectors has jurisdiction for the entire State of Alaska. The Electrical Liaison's specific assignment is as a liaison to the SPCO, with a geographic assignment to the TAPS ROW and other pipelines as assigned by the SPC.

The current DOLWD Electrical Inspector assigned to the SPCO is a member of the International Association of Electrical Inspectors, and regularly attends meetings and training provided by the International Association of Electrical Inspectors. He participates in continuing education training on the requirements of the existing and upcoming NEC, maintains current licenses as a Journeyman Electrician (Alaska Certificate of Fitness), and is licensed as a State of Alaska Electrical Administrator.

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

The Department of Public Safety, State Fire Marshall's Office Liaison works under the authority of AS 18.70 Fire Protection, 13 AAC 50 through 13 AAC 55, and the ROW leases. The duties of the SFMO Liaison include, but are not limited to, fire inspections, construction/building inspections, and building/fire system plan reviews. The SFMO Liaison conducts inspections of facilities related to 17 pipelines with ROW leases administered by the SPCO.

SPCO Jurisdictional Pipelines

Table 1: Pipelines Subject to SPCO Monitoring and Oversight

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

* The lengths in the table are the approximate total length of the pipeline or proposed pipeline centerline. The length of pipeline on state-leased ROW lands may be shorter. For more information about state lands in a particular pipeline, go to the section of this report for that pipeline.

** BP Pipelines (Alaska) Inc.(46.93%), ConocoPhillips Alaska Transportation Inc. (28.29%), ExxonMobil Transportation Company (20.34%), Unocal Pipeline Company (1.36%), Koch Alaska Pipeline Co. LLC (3.08%).

Table 2: Proposed Pipelines in the ROW Pre-application or Application Phase of Development

ROW Applications	ADL #	Location	Length/ Miles	Applicant	Application Status
Alaska Stand Alone Gas Pipeline Project	418997	Prudhoe Bay-Southcentral Alaska	735	State of Alaska	Application Received August 31, 2010*
Dayville Road Pipeline A	229284	Valdez		Petro Star Incorporated	Application
Dayville Road Pipeline B	229285			Petro Star Incorporated	Application
Dayville Road Pipeline C	229286			Petro Star Incorporated	Application
Denali - The Alaska Gas Pipeline	n/a	North Slope to Alberta	794	Denali - The Alaska Gas Pipeline, LLC	Pre-application
Donlin Creek	n/a	Cook Inlet to Donlin Creek Mine	315		Pre-application
Eastern North Slope Oil Pipeline	417577	North Slope	45	DNR, Office of Project Management and Permitting	Application
Eastern North Slope Gas Pipeline	417578	North Slope	45	DNR, Office of Project Management and Permitting	Application
Glennallen to Palmer (Spur Gas) Pipeline	229297	Southcentral	148	Alaska Natural Gas Development Authority (ANGDA)	Conditional lease issued July 20, 2006
Glennallen-Palmer Pipeline (Amendment)	229297	Southcentral		ANGDA	Pre-application**
North Fork Pipeline	230928	North Fork to Anchor Point	7.4	Anchor Point Energy, LLC	Issued September 28, 2010*
Point Thomson	418975	Prudhoe Bay	22	Exxon Mobil	Application Received August 4, 2010*
Trans-Alaska Gas System (TAGS)	413342	Prudhoe Bay to Valdez	797	Yukon Pacific Corporation (YPC)	Conditional lease terminated
TAGS	415224	Varies	797	YPC	Federal Grant (Waiver of Administration)
TransCanada/ExxonMobil	n/a	Specific route not fully determined	n/a	TransCanada/ExxonMobil	Pre-application

*Activity outside of FY10 **Beluga to Fairbanks Permit Application withdrawn June 24, 2010

STATEWIDE PIPELINES

TAPS is the only SPCO administered pipeline classified as a statewide pipeline.

Trans-Alaska Pipeline System

Figure 5: TAPS Route Map

Right-of-Way Lease and Pipeline System Overview

Oil was discovered at Prudhoe Bay in 1968. The owner companies operating at Prudhoe Bay established Alyeska Pipeline Service Company in 1970 to build and operate the Trans-Alaska Pipeline System. The State of Alaska ROW lease agreement for TAPS was executed on May 3, 1974, and renewed for another 30 years on November 26, 2002. More information regarding acreage, surveys, and the lease can be found in Appendix D: Acreage, Survey, and Lease Information.

Today the owner companies, or Lessees, are:

- BP Pipelines (Alaska) Inc. (46.93%)
- ConocoPhillips Alaska Transportation Inc. (28.29%)
- Exxon/Mobil Transportation Company (20.34%)
- Unocal Pipeline Company (1.36%)
- Koch Alaska Pipeline Co. LLC (3.08%)

The Lease applies to the approximately 344 miles of state-owned land in the TAPS ROW. Information about the ROW Lease appraisal for TAPS 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 ROW, primarily consisting of lands associated with Pump Stations (PS) 1, 8 and 9 and the VMT. Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines presents information about the physical characteristics of TAPS and other pipelines.

North Slope oil enters TAPS at PS 1 in Prudhoe Bay, immediately northwest of Deadhorse. The Trans-Alaska Pipeline System crosses three major mountain ranges before reaching its terminus at the VMT. Three of the four active pump stations, PS 1, 3, and 4 maintain the pressure necessary to pump crude oil over Atigun Pass – the highest elevation point along TAPS at an altitude of 4,739 feet (the elevation at PS 1 is 22 feet above sea level). Pump Station 5 provides pressure relief as crude oil descends in elevation south of Atigun Pass. Pump Station 7 was placed in warm standby mode in 2007. The fourth active pump station, PS 9, provides the pressure necessary to push the crude oil over the Alaska Range and Thompson Pass and complete its passage to the VMT. Figure 5 on the previous page shows the route that TAPS travels from the North Slope to Valdez.

TAPS is composed of an 800-mile, 48-inch-diameter pipeline, the VMT, 11 pump stations (original plans specified 12 pump stations, but only 11 were actually constructed), and various support facilities. To support construction of the pipeline, a permanent "haul road" was constructed from the Yukon River to Prudhoe Bay in 1974. Management of this road was transferred to the State of Alaska in 1978 and named the James B. Dalton Highway in 1981. Most of the remainder of the pipeline was supported by existing state road infrastructure.

TAPS has 177 pipeline valves strategically placed along the pipeline to isolate sections of the pipeline and to minimize the size of potential spills 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 quick closure would be necessary in an emergency.

The VMT is the southern terminus of TAPS. The VMT spans approximately 1,000 acres and is located on Prince William Sound near the Port of Valdez. At the VMT, oil is loaded onto tankers 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.

The oil throughput in TAPS peaked in 1988. A decline in flow rate triggered an evaluation of future operating conditions by APSC and TAPS owners. Conceptual modifications were reported in the Final Environmental Impact Statement for the TAPS ROW renewal in 2002 and a conceptual engineering review was developed in 2003. The Lessees approved changes to the pump station configurations, referred to as Strategic Reconfiguration (SR). The work at PS 1 was postponed while the rest of SR was finalized. The upgrades at PS 1 will be part of the Electrification and Automation (EA) project. The work performed under the SR project began in 2002.

State Pipeline Coordinator's Office Summary of Alyeska Pipeline Service Company's CY09 Trans-Alaska Pipeline System Annual Reports

Alyeska Pipeline Service Company submitted the *TAPS 2009 Integrity Management Program Annual Reports* on June 4, 2010. The Integrity Management Program reports (commonly referred to as the MP-166 reports) include seven individual monitoring program reports that describe activities relating to

- The Mainline Aboveground Support Systems and Bridges Monitoring Program
- The Fuel Gas Line Monitoring Program
- The Mainline Integrity Monitoring Program
- The Pipeline and VMT Corrosion Monitoring Program
- The Rivers, Floodplains, and Glacier Monitoring Program
- The ROW and Facilities Civil Monitoring Program
- The Aboveground Storage and Tank Monitoring Program

The reports are 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 annually. Elements of the reports are summarized or excerpted below.

Mainline Aboveground Support System and Bridges Program Report Summary

The Aboveground Monitoring Program consists of the Mainline Support System and Bridges Program (a slope stability component of the ROW) and the Facilities Civil Monitoring Program(1). 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 Program Engineer. 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 Program Engineer may, based on the collected information, prioritize maintenance and repair activities.

Alyeska Pipeline Service Company's *Trans-Alaska Pipeline System (TAPS) 2009 Annual Report: Mainline Aboveground Support System and Bridges Program* (Aboveground Program Report) stated that nearly all of the routine monitoring and maintenance recommended in 2008 was completed. In the 2009 Aboveground Program Report APSC

ranked the overall performance of the TAPS mainline support system and bridges as satisfactory based on current data and methods of measurement. The Aboveground Program Report also stated that the majority of the aboveground pipeline system, 44 of the 46 vehicle bridges, and 12 pipeline bridges remain in good-to-excellent condition.

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

Monitoring Conducted in 2009

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 2009, APSC reported that a forward-looking infrared (FLIR) photographic analysis was performed on approximately 52,000 heat pipes (over 33% of total heat pipes). The 2009 FLIR analysis included 13,133 bents, anchors, and other supports along the pipeline ROW.
- Mainline Support System Monitoring in 2009 was composed of an anchor position assessment, wildfire damage surveillance, and the annual comprehensive line-walk. The Line-walk found 112, out of more than 78,000 vertical support members (VSMs), with a tilt of 3° or more. The maximum tilt reported was 11.1° (approximately 19.7%). APSC does not define a specific "must fix" threshold for VSM tilt, but remediates VSM tilt when conventional maintenance techniques (e.g., split ring adjustments) can no longer be performed.
- The Site-Specific Geotechnical and Structural Analysis reported in 2009 included annual geotechnical monitoring, laser scan surveys for slope stability, VSM thermal stability data, and an assessment of the remote gate valve (RGV) 118 avalanche diversion structure.

Annual geotechnical monitoring involves slope stability monitoring at seven specific slopes along TAPS. APSC reported that conditions at the seven slopes had no major new problems; however, soil instability at these slopes continues to displace and tilt many of the VSMs with historic values. No practical measures have been identified to arrest the soil movement. Frequent routine maintenance and periodic major maintenance will be required during the life of the pipeline to ensure the pipeline remains within operational parameters.

- Pipeline and Vehicle Bridges Inspections included in the 2009 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.

Engineering inspections were conducted on the Gulkana River and Tazlina River pipeline bridges. No structural deficiencies were observed on either pipeline bridge and the overall condition of both was good. Work on the bridges included spot painting the worst areas of coating failure and non-destructive testing of the fracture-critical arch-rib-to-tie-girder welds.

No anomalies were detected. A 2004 recommendation to recoat all superstructure members was revised to monitor for rust blooms.

- Split Ring Survey, Load Testing, and Split Ring Adjustment Maintenance information in the Aboveground Program Report included information about split ring elevation surveys and load testing. As part of an ongoing target to survey all split ring elevations on a 7-year cycle, elevation surveys of continuous segments of the aboveground pipeline continued in 2009 with the aboveground segments between pipeline milepost (PLMP) 253.15 and PS 1 (PLMP 0). A total of 132.3 miles of aboveground segments were surveyed. According to APSC's report, "all aboveground segments have been surveyed recently based on the new permanent benchmark network established using stable anchor platforms."

Maintenance and Repair in 2009

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

- VSM replacement at Jim River - Bent 30 at Jim River (PLMP 271.45) was replaced in 2009. The site was supplemented with additional freestanding heat pipes surrounding the new VSMs to provide additional soil-cooling capacity.

- Heat pipe repair - 2,483 of approximately 124,300 heat pipes were converted to carbon dioxide in 2009. Another 208 heat pipes were recharged. Eighteen shoes were identified as needing to be re-centered. Most field-repairs were completed, but four were deferred for various reasons.

- Anchor re-centering, re-leveling, and repair – According to the Aboveground Program Report APSC prioritized the resetting of five offset anchors in 2009. APSC reported that three anchors were actually reset in 2009 and 2 were deferred until 2010.

- Teflon Slide Plate Replacement – APSC reported that 3,400 plates (1,700 shoes) were identified for replacement. Of those identified for replacement, 2,258 replacements were completed. To date, the shoes along 106.9 miles of 420 miles of aboveground pipeline (more than 9,600 shoes) were replaced. Approximately 51,400 plates still require replacement.

- VSM repair – According to the Aboveground Program Report, the 2009 annual line-walk identified two split VSMs, one at PLMP 564.66 and one at PLMP 565.21. APSC reported that, the VSM caps were defective and the weep holes were either clogged or not present. Critical volumes of water repeatedly froze and expanded the VSMs leading to failure. Sections of the two split VSMs were replaced the others in the area will be monitored for similar problems.

- Pipeline Bridge Maintenance - APSC stated in the Aboveground Program Report that, "all significant backlogged maintenance at the Tanana River Pipeline Bridge has been completed." Several items that were deferred; including evaluation of the repair of the maintenance-trolley suspension cables and the safety cable strung atop the mainline. Maintenance at the Gulkana River pipeline bridge was completed except

for addressing the uncoated structural fasteners. Further action regarding the fasteners will be deferred until the next engineering-level inspection is conducted in 2014. Previously backlogged maintenance at the Tazlina River pipeline bridge was completed.

Self-Assessment

The Aboveground Program Report stated, "The Aboveground Monitoring Program is generally performing well. Its scope is generally understood within the [APSC] engineering and ROW maintenance organizations so that appropriate work requests and observations are routinely routed to the Program Engineer."

Recommended for 2010

The 2009 Aboveground Program Report stated that APSC's aboveground integrity team recommended several actions for 2010.

- Design replacement support structures for two bents at Squirrel Creek
- Perform heat pipe repairs
- Perform prioritized maintenance at intermediate and anchor bents
- Perform prioritized maintenance at the pipeline and vehicle bridges in accordance with the bridge maintenance plans
- Reevaluate the applicability of guardrail requirements at two publicly accessible vehicle bridges
- Replace the Little Salcha River workpad vehicle bridge to restore spill response capability to 4½ miles of ROW and the north bank of the Salcha River
- Rebalance pump station relief line load
- Perform the annual line-walk surveillance to inventory key engineering parameters of the aboveground pipeline support system
- Perform annual monitoring at slopes of concern where geotechnical instability continues to affect the aboveground pipeline support system
- Perform routine monitoring of aboveground pipeline support system components such as split ring elevations, heat pipe performance, load distribution, and anchor displacement
- Conduct comprehensive engineering-level inspections of a portion of the vehicle bridge inventory
- Replace the gabion basket retaining wall at the GRB Hill
- Complete a comprehensive assessment and rehabilitation plan for the o-ring seals at the intermediate and anchor bent modules

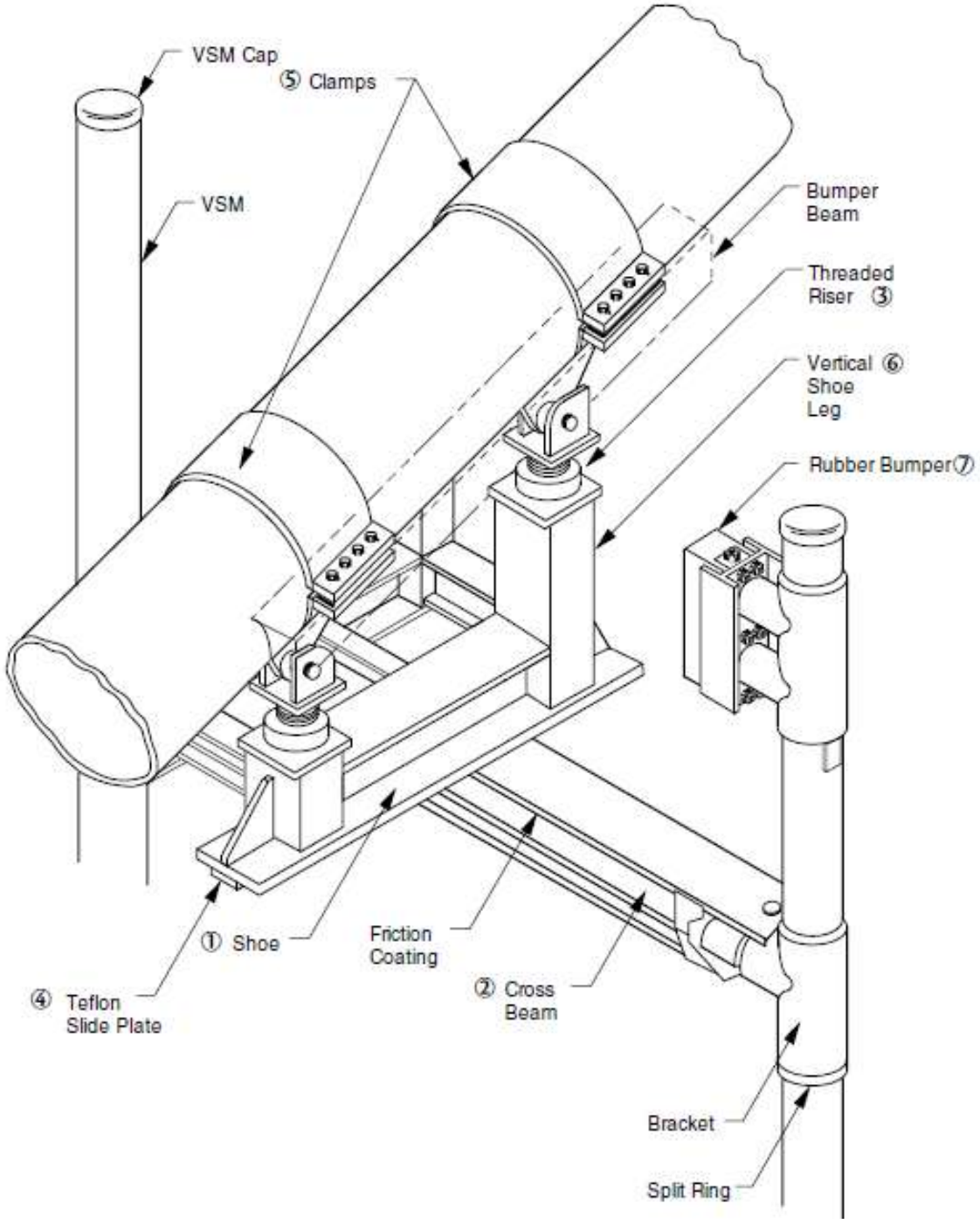


Figure 6: Intermediate Support Assembly Diagram for TAPS (Provided by APSC)

Fuel Gas Line Monitoring Program Report Summary

The *Trans Alaska Pipeline System (TAPS) 2009 Annual Report: Fuel Gas Line* (FGL Report) summarized the significant results of monitoring and maintenance activities conducted on the TAPS Fuel Gas Line (FGL) in 2009(2). The report included recommendations for future monitoring and maintenance necessary for continued operational safety and integrity of the FGL. The work performed in 2009 was part of the Cathodic Protection Monitoring and Maintenance Program or the FGL Monitoring and Maintenance Program.

FGL Cathodic Protection Monitoring and Maintenance and Maintenance Program

The FGL Cathodic Protection Monitoring and Maintenance Program provides necessary monitoring and maintenance to ensure adequate cathodic protection (CP) to the FGL. Three different inspection activities are conducted to achieve this goal.

1. A bimonthly inspection of the impressed current CP systems that influence CP levels on the FGL
2. Annual monitoring of CP levels at test stations on the FGL
3. Visual inspections and "incidental" test station repairs, as necessary

In 2009, the CP rectifier/anode bed systems that protect the FGL were monitored every two months. Potential readings were taken at 69 test stations as part of the test station CP level survey. Results indicated that 66 of the 69 test stations were receiving adequate protection. The remaining three test stations did not meet criterion. Four testing stations could not be tested because construction activities had limited access, one test station could not be located, and two no longer had pipe leads connected to the pipe. The overall result of the CP survey showed 96% protection, which is a passing level.

The FGL Report recommended continued monitoring of the 73 operational test stations in 2010. The one missing and two damaged test stations are scheduled to be replaced and 91 new test stations are scheduled to be installed in 2010.

FGL Integrity Monitoring and Maintenance Program

The FGL Integrity Monitoring and Maintenance Program requires the monitoring and correction of conditions that may affect the integrity of the FGL under normal operating conditions. Four activities support this program.

1. Scheduled in-line inspections
2. Investigation and repair of anomalies
3. Analysis of depth of cover
4. Placement of protective cover over the pipe when required

In 2008, a magnetic flux leakage (MFL) ILI tool was run on the FGL. The inertial navigation data from the ILI was analyzed in 2009 to determine bending strain. The data indicated that there were no locations that needed remediation. A light detection and ranging (LiDAR) survey was also completed. Inertial navigation data gathered from the ILI run was correlated with data from the LiDAR survey to determine depth of cover for the FGL route. Twenty-one locations were identified as needing increased depth of cover and were remediated in 2009.

The FGL report recommended that two locations identified by the MFL ILI corrosion data analysis be investigated, and that bypass piping at 12 FGL valve sites be coated to protect against corrosion.

Mainline Integrity Monitoring Program Report Summary

Alyeska Pipeline Service Company's Mainline Integrity Monitoring Program Report (Mainline Integrity Report) describes the Mainline Integrity Program activities in three sections(3).

1. Belowground Monitoring
2. Cathodic Protection Monitoring
3. Mainline Integrity

Belowground Monitoring

Since construction of the pipeline APSC has monitored 380 miles of belowground pipe as part of the belowground stability monitoring program. Belowground stability monitoring requires analyzing the belowground pipe elevation and thermal state of the surrounding soils in areas where pipe instability has been documented. This is done by surveying monitoring rods, measuring soil temperature and periodically running a geopig. The objective of these analyses is to identify changes in pipe curvature that may result in conditions detrimental to the belowground pipe integrity. This is achieved through ILI runs, annual elevation monitoring, thermal data collection and trend analysis.

According to APSC's Mainline Integrity Report, elevation changes at eight locations were monitored with 187 monitoring rods in 2009. Little to no movement was confirmed at the monitoring rod sites surveyed in 2009. Thermistor strings were used to monitor belowground temperature at some sites; the sites monitored showed stable temperature readings. Thermistor string data for Mainline Refrigeration unit (MLR) 1 and MLR 2 indicated that the soil was frozen beneath the pipe to the total depth of the string. APSC concluded that no sites required intervention and annual monitoring should continue.

Cathodic Protection Monitoring and Maintenance

According to the 2009 Mainline Integrity Report, the Cathodic Protection Monitoring and Maintenance Program's goal is, "to collect and evaluate potential readings from various cathodic protection appurtenances and Close Interval Surveys along TAPS." The stated objective of the program is, "to ensure proper cathodic protection system operation and ensure adequate levels of cathodic protection are provided to the belowground sections of TAPS."(3 p. 5)

Some of the CP monitoring and maintenance actions that APSC reported in 2009 include, but are not limited to

- Monitored CP at 788 linewide coupon test stations and 30 cased road crossings
- Completed a current interrupted close interval survey of the below grade mainline between PS 5 and 10 (PLMP 278.28 to 585.53 or 145 miles of close internal survey)
- Obtained potential readings at test stations between PS 5 and 10 (PLMP 278.28 to 585.53)
- Repaired 4 CP generators, and upgraded rectifiers at PLMP 448

- Visually inspected approximately 1,018 linewide test stations and completed incidental repairs as needed
- Removed two road-crossing casings at PLMP 248 and PLMP 579 under project Y025 to address potential CP electrical shorts between the carrier pipe and casings

Recommended future cathodic protection maintenance actions described in the report included issuing work orders to repair destroyed test stations, removal of another 2 road casings, and the completion of several projects intended to maintain or upgrade the cathodic protection system.

Mainline Integrity Investigations

APSC reports that the 2009 integrity program resulted in four belowground investigations based on data from several previous ILI runs. One location was investigated for a 2% dent on a weld, and three locations for corrosion on girth welds. These integrity investigations resulted in the installation of sleeves at two of those locations. Future locations for investigation include a long seam weld at PLMP 585, five girth welds in MLRs, and additional locations identified from data collected in the 2009 ILI run.

Pipeline and VMT Corrosion Monitoring Program Report Summary

The 2009 MP-166 report for the Pipeline and Valdez Marine Terminal Facilities Corrosion Monitoring (Corrosion Monitoring Report) summarizes the findings and recommendations that result from monitoring, inspection, and maintenance activities conducted on TAPS piping and structures associated with the pump stations and VMT(4). MP-166, Integrity Management Engineering Monitoring Program procedures were followed during all monitoring and maintenance activities performed in 2009.

APSC reported that, "the work that was conducted in 2009 concludes that the overall health of the system is in satisfactory condition." 2009 activities were divided into four categories.

1. Corrosion Inhibitor and Internal Corrosion Monitoring
2. Facility Pipe Integrity Testing (PIT Program)
3. Cathodic Protection (CP) Monitoring and Maintenance
4. Berth Underwater Inspections

Corrosion Inhibitor and Internal Corrosion Monitoring Program

The Corrosion Inhibitor and Internal Corrosion Monitoring Program is designed to ensure the integrity of the piping systems. Coupons from the Corrosion Monitoring Program are categorized in accordance with the National Association of Corrosion Engineers (NACE) standards. The NACE defines four categories; low, moderate, high, and severe. All coupons have the average corrosion rate calculated, the maximum pit depth graded, and a mil (thousands of an inch) per year corrosion rate calculated. Locations exhibiting recent corrosion activity were included on the corrosion coupon watch list.

Corrosion inhibitor is injected at pump stations, the VMT, and dead legs (sections of piping with little or no flow). In 2009, the pump stations had 1,847 corrosion inhibitor injections and the VMT had 474 corrosion inhibitor injections. Dead legs at PS 4, 6, 10, and 11 had corrosion inhibitor injections in August of 2009.

In April of 2009, 70 corrosion coupon locations were pulled at the pump station, and 69 coupon locations were pulled in October of 2009. The locations monitored at the pump stations were not exhibiting significant corrosion rates. At the VMT 65 coupons were pulled in May 2009, and 65 were pulled in November 2009.

The Integrity Management Engineering Department recommended an evaluation of the effectiveness of the current corrosion inhibitor in use on TAPS.

Facility Corrosion Integrity Monitoring Program

The Facility Corrosion Integrity Monitoring Program, or Pipeline Integrity Testing (PIT) Program, is intended to test and monitor the piping systems in order to ensure system integrity and identify corrosion. Non-destructive testing (NDT) is performed on crude and gas mainline valve bypass piping and facility piping located at the pump stations, North Pole Metering, the Glennallen Response Base (GRB), Petro Star Metering; and the VMT. The above piping systems are divided into line segments which are referred to as legs. The legs are examined to determine the "most probable areas of corrosion". That information is used to select areas to be examined using ultrasonic testing (UT) and/or radiographic testing (RT).

When appropriate, APSC modeled the PIT Program inspections after the American Petroleum Institute 570, *Piping Inspection Code*. The Corrosion Monitoring Report stated that, "Corrosion is evaluated based upon the piping service and the remaining wall thickness in its capacity to maintain the normal operating pressure of the system. Corrosion related wall loss of 20% or greater is deemed to be 'actionable'." Actions that may be initiated consist of additional inspection, increased inspection frequencies, coupon monitoring, corrosion inhibitor injection, and material replacement.

A total of 382 sites were inspected as part of the PIT Program in 2009. Additional UT technology and equipment were included in the PIT Program in 2009. The Corrosion Monitoring Report stated that, "the use of ultrasonic phased array scanning along with a Time of Flight Diffraction (TOFD) technique for measuring and monitoring internal pipe and weld material profile was utilized." APSC anticipates that accessibility to locations that were previously difficult to examine will be improved with the new technique.

Crude Oil Mainline and Fuel Gas Mainline Valve By-Pass Piping

In 2009, 19 crude mainline valves were tested, and eight valves were inspected on the FGL. Visual atmospheric corrosion control inspections were conducted on 30 mainline valves and eight fuel gas mainline valves. All piping tested on the FGL was found to be in good condition, and no corrosion was noted.

Belowground Investigation

A belowground investigation was conducted on a remote gate valve (RGV) in 2009. The inspection included mechanical, manual, and automated UT and RT. APSC reported that, "the results of the inspections revealed that the 36 inch branch piping is not experiencing internal or external corrosion detrimental to continued service."

Facility Inspections
The following tables depict the number of inspection sites at facilities along TAPS.

Table 3: Number of Inspection Sites at TAPS Facilities

Facility	Crude Oil Piping Inspection Sites	FGL Piping / Fuel Oil Piping Inspection Sites	Vapor Recovery Piping Inspection Sites	Therminol Piping Inspection Sites	Girth Welds Inspected
PS 1	54	12 FGL	7	6	10
PS 3	10	1 FGL	N/A	N/A	N/A
PS 4	23	5 FGL	N/A	N/A	N/A
PS 5	14	N/A	N/A	N/A	N/A
PS 6	13	N/A	N/A	N/A	N/A
PS 7	17	N/A	N/A	N/A	N/A
PS 8	5	N/A	N/A	N/A	N/A
PS 9	24	4 Fuel Oil Piping	N/A	N/A	N/A
PS 10	12	1 Fuel Oil Piping	N/A	N/A	N/A
PS 11	3	N/A	N/A	N/A	N/A
PS 12	3	N/A	N/A	N/A	N/A
North Pole Metering	7	N/A	N/A	N/A	N/A
Petro Star Metering	10	N/A	N/A	N/A	N/A

Table 4: Number of Inspection Sites at the VMT

VMT Area	Inspection Sites
Marine	3
OM&S	42
Ballast Water Treatment (BWT)	16
Power Vapor	43

TAPS Facilities Cathodic Protection Program

The TAPS Facilities Cathodic Protection Program was created to ensure that the facility piping, bottom of tanks, and miscellaneous metal structures at the pump stations and the VMT have adequate CP. In 2009, a contractor completed a CP survey of the pump stations, the VMT, and the Ship Escort Response Vessel Services (SERVS) facility. The Corrosion Monitoring Report suggested three future actions.

1. Continue the annual CP survey
2. Balance CP systems as necessary
3. Consider focusing future testing efforts on locations with depressed potentials.

VMT Facility Underwater Inspection Program

The VMT Facility Underwater Inspection Program provides annual underwater inspections that evaluate the structural integrity and operability of the loading berths, the small boat harbor and tug docking structures, the firewater system intake devices, and the CP systems for those locations. In 2009, the tug dock and the primary and secondary berthing dolphin structures at Berth 4 and Berth 5 were inspected. The firewater intake assemblies for Berth 4

and Berth 5 were cleaned, inspected, and maintained. Along with the inspections at Berth 4 and Berth 5, a CP survey was completed, and repairs were made to the CP system.

Aboveground Storage and Tank Monitoring Program Report Summary

The 2009 Aboveground Storage and Tank Monitoring Report (Tank Monitoring Report) provides information on storage tank inspections; from daily inspections to comprehensive out-of-service API 653 inspections(5). APSC's tank monitoring program includes *External (in-service) Inspections*, and *Internal (out-of-service) Inspections*, for various aboveground storage tanks used for storing liquids at atmospheric pressure. Federal (*49 CFR 195*) and state regulations (*18 AAC 75*) provide the general requirements for this monitoring process.

External Inspections

Non-invasive external inspections are performed on "in-service" tanks. Tank inspections are high-level visual checks for potential problems; no hard data is analyzed.

According to the Tank Monitoring Report, APSC conducts **daily** external tank inspections of tanks within tank farms, **monthly** external tank inspections of tanks with greater than 10,000 gallon capacity, **annual** external tank inspection of tanks with less than 10,000 gallon capacity, and **five-year** inspections of tanks with greater than 10,000 gallon capacity that were scheduled for inspection**.**

Internal Inspections

APSC performs internal inspections on regulated bulk storage tanks with a capacity of 10,000 gallons or more. Exceptions to this general rule include tanks not returning to service, and tanks where more than 50% of the bottom is accessible from the exterior.

APSC reported entering three tanks in 2009.

1. 33-TK-137 (diesel storage) at PS 3 was visually inspected, isolated and removed from operations. The coating showed no sign of deterioration and required no work.
2. 54-TK-4 (crude storage) at the VMT received an API 653 out-of-service internal inspection and was repaired, internally lined, and re-commissioned. No shell repairs or plate replacement were required. Minor coating and corrosion pitting repairs were made on three of the nozzles, and one floor plate patch was installed over a manufacturing defect. APSC has scheduled the next internal inspection for Tank 4 for 2029.
3. 54-TK-6 (crude storage) at the VMT received an API 653 out-of-service internal inspection and was repaired, internally lined, and re-commissioned. No significant corrosion loss was found during non-destructive testing of the shell; however, five nozzles or spool pieces required coating, lining or corrosion pitting repairs. Corrosion was found on the ENRAF flanges and one tee section from the deluge line; they were replaced. Fourteen puddle weld repairs were completed on the floor plate. APSC scheduled the next internal inspection for Tank 6 for 2029.

The results of the 2009 internal inspection activities document low soil-side corrosion rates for TAPS tanks that were inspected. No leaks were found. The 2009 Aboveground Storage

and Tank Monitoring Report recommends continued inspections per program requirements, evaluating inspection intervals for subject tanks, coordinating inspections with other projects and regulatory guidelines, and completion of approved maintenance projects.

Rivers, Floodplains, and Glacier Monitoring Program Report Summary

The 2009 Rivers, Floodplains and Glacial Monitoring Program Report (Rivers and Floodplains Report) provided a summary of APSC's annual monitoring of rivers and floodplains, major drainage structures, and glaciers(6). The Rivers and Floodplains Report indicated that annual monitoring in 2009 produced no findings that threaten TAPS integrity. The Rivers and Floodplains Monitoring Program is based on ROW lease stipulations and federal regulations.[7]

Rivers and floodplains monitoring includes a P&CM's biweekly aerial surveillance of the ROW in order to observe changes in river and floodplain environments that may affect the TAPS. Unusual conditions noted along rivers and floodplains during these 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 the ASPC engineering department annual monitoring surveillance. 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 2009 Report, the engineering monitoring surveillance noted that the spring breakup and aufeis floods along TAPS were moderate to mild. The typically heavy aufeis areas in Mark Creek (between PLMP 68 and PLMP 76) in the Sagavanirktok River basin exhibited minor damage from breakup. Spring breakup was also moderate to mild south of the Brooks Range to Valdez. There was no noticeable damage from spring breakup in the section damaged during the 2006 flood from Squirrel Creek south to Valdez.

Summer floods were normal in the Sagavanirktok River area. There was no significant bank erosion with the exception of PLMP 32, 47, and 72. The bank near check valve 12 is eroding due to channel changes in the PLMP 47 spur field upstream of Spur Dike No. 6. A buried sill is being installed in 2010 at PLMP 47 to prevent additional erosion. The bank is continuing to erode upstream of the revetments at PLMP 32 and 72, but is not considered to be an integrity issue at this time.

In the Dietrich and Koyukuk Rivers Drainage Basin there was a summer flood on the Middle Fork Koyukuk. The flood caused additional erosion at the PLMP 208 pipeline crossing and PLMP 218 revetment. A buried rock trench was installed in late summer 2009 on the north bank at PLMP 208 to prevent additional erosion. There were no major floods or erosion in the Delta River Drainage Basin.

[7] Stipulation 1.18, *Surveillance and Maintenance*, Stipulation 3.6, *Stream and Floodplain Crossings and Erosion*, Stipulation 3.8, *Glacier Surges and*, 49 CFR Part 195, Section 412, *Inspection of Rights-of-way and Crossings Under Navigable Waters*

In the Copper River Drainage Basin, a summer high water event caused erosion on the workpad in the PS 12 area. Tributaries of the Tsina River such as Boulder Creek (PLMP 748), Bear Creek (PLMP 761), and 27 Mile Glacier stream (PLMP 773.3) had high flows which caused damage to the low water crossings (LWC), drivelane, and existing guidebanks. The damage was repaired but more fixes may be required in the future. The Tazlina River at PLMP 686 had intermittent erosion due to a meander bend cutoff downstream and periodic glacier dammed lake outburst floods. It was also noted that there is increased erosion at the confluence of Moose Creek and the Tazlina River.

During August, precipitation was higher than normal in the Lowe River Drainage Basin and VMT with several days of intense rain showers. At Unnamed Creek (PLMP 787.8) floodwaters flowed around a grade control structure installed on a relief channel. This impeded vehicle passage across a LWC until repairs could be made and vehicle access restored.

Fels, Canwell, Castner, Black Rapids, and Worthington glaciers were monitored in 2009. No reportable conditions posing a threat to TAPS were found. Aerial imagery was taken of the five glaciers listed above. The ortho-rectified aerial photographs are taken every five years.

ROW and Facilities Civil Monitoring Program Report Summary

The 2009 ROW and Facilities Civil Monitoring Program Report addresses monitoring, maintenance, and repairs performed on the TAPS ROW in 2009(7). The information used to direct this program is accumulated from a various sources, among them ROW maintenance surveillances, engineering inspections and reconnaissance, surveys, and project activities following requirements described in the Integrity Management Engineering Monitoring Program. Civil monitoring is conducted to evaluate and trend the condition of TAPS civil assets per ROW Lease stipulations and federal regulations.[8]

APSC stated in the 2009 ROW and Facilities Civil Monitoring Program Report that there were no notable seismic events along the TAPS corridor, nor was there significant ground movement in 2009. In December 2008 a new earthquake monitoring system was put in service. APSC reported that the new earthquake monitoring system is functioning well.

There are several highlights of the 2009 slope and stability monitoring efforts.

- APSC predicts that there will be no slope stability issues affecting pipeline integrity "in the near future."
- APSC conducted piezometer readings at the VMT and concluded that there was no immediate threat to static slope stability, secondary containment, or tank foundations from groundwater levels.
- Work orders include the recommended actions of rock scaling, rock bolt tightening, removal of vegetation above the slope, and cleaning of weep holes.
- Elevation changes at the PS 1 control building, PS 5 Manifold Building and at PS 6

[8] Alaska Administrative Code, 18 AAC 75, *Oil and Other Hazardous Substances Pollution Control,* Stipulation 1.18.1, *Surveillance and Maintenance,* Stipulation 3.3.1, *Construction Mode Requirements,* Stipulation 3.4.2, *Fault Displacements,* Stipulation 3.5, *Slope Stability,* 49 CFR 195.412, *Inspection of Rights-of-Way*

Fuel Pump House will require continued monitoring in 2010.

- Annual engineering evaluations were completed for the seven active slopes at Lost Creek (PLMP 392), Treasure Creek Slope (PLMP 442), the GRB Hill (PLMP 686), Tazlina River Hill (PLMP 687), Klutina River Hill (PLMP 698.1), Squirrel Creek North Slope (PLMP 717.0), and Squirrel Creek South Slope (PLMP 717.4). The evaluations indicated that there were no major changes. Slope displacement rates at Treasure Creek, the GRB Hill, and the south slope of Squirrel Creek were above the historic averages.
- There were two new inclinometers installed at Lost Creek in 2009.
- Creep and thaw consolidation of weaker soils below the zone of influence of the heat pipes at Lost Creek was the primary source of progressive ground deformation at Lost Creek.
- In order to help understand the seasonal affects on slope movement; quarterly monitoring was performed at Lost Creek and the GRB Hill.
- Conditions at Slate Creek (PLMP 408) were assessed to determine if mass soil movement was the cause of progressive VSM tilt. More data is needed to trend the information.
- Seventeen slopes were assessed in order to identify deficiencies in site-specific drainage and groundwater management. No significant deficiencies were identified.

Valdez slope monitoring conducted in 2009 included piezometer readings taken to monitor groundwater levels in the rock slopes at Power/Vapor, the BWT Plant, West Manifold, and East and West Tank Farms. The readings indicated no significant increases in levels from 2008 to 2009. Evaluation of the 2009 groundwater levels were based on historical trends and the redundancy provided by multiple piezometers in each area. The 2009 groundwater levels exceeded the pre-defined "flag" levels but the evaluation indicated no static slope instability or immediate threats to secondary containment.

Survey monitoring of Tanks A and B, the Biological Treatment Tanks at the VMT, have shown that settlement rates have slowed and are less than the rate projected by a 1998 engineering study conducted by Golder Associates. Horizontal movement measured in 2009 was also within acceptable limits.

At PS 1, surveys conducted in 2009 showed movements were within the acceptable range for all the facilities monitored. One monitoring point at the primary generator room at Facility 1003 that was measured in 2008 indicated an increased net upward movement warranting continued monitoring in 2010.

Facility movements measured at PS 3 indicate generally stable conditions requiring no corrective actions. Given historical movement however, two foundation pipe supports at Facility 3006 will continue to be monitored. Benchmarks of the new turbine generator modules were taken to establish a baseline for future monitoring. The facilities at PS 4 were classified as stable and no actions were required.

Measurements taken at PS 5 facilities indicated acceptable movements with the exception of the manifold building. Follow-up monitoring and a site evaluation of the manifold building are required in 2010. Fifty-four points were surveyed at Facility 5006 Manifold Building in

2009. From 1977 to 2009, the southeast corner of the facility had upward movements greater than 0.1 feet at three points. In 2010, the points will be monitored again and a field assessment will be performed to determine if predictive actions such as additional inspections and/or repairs are needed.

At PS 6, settlement/heave continued at Facility 6042, the fuel pump house; penetrations to the building were modified with flexible pipes and conduits to accommodate the movements. No actions were required at PS 8 or PS 12; the facility movements deemed were stable.

Movements were found to be acceptable for all surveyed facilities at the VMT. Biological Treatment Tanks facility monitoring will continue in 2009 due to past historical movement of these structures.

State Pipeline Coordinator's Office TAPS Related Activities, FY10 Summary

(*This section provides a summary of SPCO activities during FY10. Information in this section reflects work efforts of the SPCO and is not taken from the APSC reports. Due to the nature of the SPCO oversight efforts there may be some duplication of information.*)

The agencies that are a part of the SPCO spent a total of 283 days in the field conducting TAPS-related business. Figure 7 shows each agency's total number of days spent in the field in FY10. A list of all reports completed by the SPCO can be found in Appendix G: SPCO Reports Issued in FY10.

SPCO FY10 Days in the Field, TAPS (283 total days)

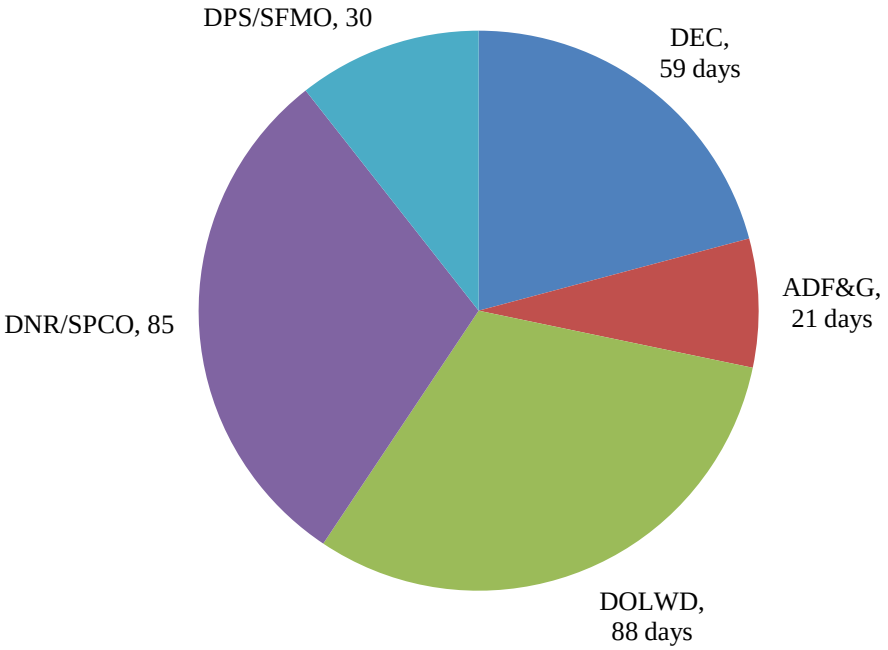


Figure 7: SPCO FY10 Days in the Field Pie Chart

Department of Natural Resources – State Pipeline Coordinator's Office

Three of the SPCO sections conduct field work and other reportable activities related to TAPS. Those activities that took place in FY10 are summarized below.

Compliance Section FY10 TAPS Oversight Activities

The Lease Compliance Section's activities in FY10 yielded 20 surveillance reports, three lease compliance reports, and one assessment. Surveillances were conducted at multiple project sites along TAPS, and along the ROW and related facilities line-wide throughout the fiscal year.

Projects

Some examples of projects monitored by the Compliance Section in FY10 include the integrity investigations and scheduled shut down described below:

Integrity Investigations

An integrity investigation dig conducted at PLMP 792.5 was one of four integrity investigation digs conducted along the length of the pipeline in 2009 under the APSC project number F909. The dig at PLMP 792.5 was initiated when an anomaly was found by an ILI. According to APSC staff, the anomaly was caused by a dent on the pipe that was less than 2% of pipe diameter. The dig revealed that the dent was caused by a very large rock that had, for unknown reasons, come in contact with the pipeline.

The work site was situated on steep slopes (approximately 28% grade). Access to the work site required traveling several very steep hills. The SPCO issued a LUP for the project because use of state land outside of the ROW was needed for a temporary access road to bypass the excavation and settling ponds. A lease compliance report and eight surveillance reports with satisfactory findings were generated from observations made during the integrity investigation at PLMP 792.5 on August 4, 2009 (SPCO letter 09-035-CT). Figure 8 shows work crews as they operate a rotary drill near the pipeline to remove the rock in contact with the pipe at PLMP 792.5.

An integrity inspection of RGV 125 was prompted by a vulnerable pipe configuration rather than ILI data. The investigation entailed excavating around RGV 125 (including adjoining mainline and ancillary piping), cleaning the piping, and conducting integrity testing. Compliance staff monitored the investigation of RGV 125 on September 21, 2009, and compiled a lease compliance report and two satisfactory surveillance reports (SPCO letter 09-040-CT). Figure 9 shows the downstream (of RGV 125) side of the dig where the mainline, additional piping and gate valve had been exposed. The upstream side was under a hooch tent. RGV125 was surrounded by scaffolding.

Figure 8: Work crew at PLMP 792.5 Integrity Dig Site

Figure 9: RGV 125 During an Integrity Investigation

TAPS Maintenance Shutdown

Compliance staff traveled to PS 7 on June 18 and 19, 2010, to observe preparations and the execution of the maintenance projects planned for a scheduled shutdown of TAPS.

The work planned for the scheduled shutdown at PS 7 was part of APSC project F628. This project entailed tank decommissioning, cleaning, inspection, repair and preparation of the 55,000 barrel crude storage tank, TK-170, for a cold restart event. Work planned for the shutdown included the removal of crossover piping to the relief valves and the installation of

blinds to the relief block valves and pressure indicating control valve (PICV) flanges. Also planned for removal and blinding during shutdown was a 6-inch relief bypass pipe, and the installation of a blind on piping to the booster pump. Installing blinds to the above-mentioned pipe flanges is required in order to clean, inspect and further prepare TK-170 for a cold restart event.

During drain-down of the 6-inch relief bypass line, an incident occurred which caused an employee to be spayed with crude and a spill of a ½ gallon of crude to the ground. Figure 10 shows crews unbolting and lifting relief crossover piping while monitoring the air quality at PS 7. APSC Incident Report #17226 states that, "unexpected pressure from suspected plug in M3 6-inch bypass line caused crude oil to spray out of a vent plug when opened. Crude sprayed onto the wall of BD-17B, the walkway and associated piping, and the [pump station] pad. Approximately half a gallon of crude sprayed onto the pad." The spill occurred as a quick burst of spray and was not sustained.

Under the supervision of the Fire Safety/Industrial Hygiene Coordinator, the employee who was sprayed with oil immediately left the area, was cleaned up (decontaminated), changed clothes, and examined by the Medic at PS 7. The employee was wearing personal protective equipment (PPE) that included safety glasses and a hard hat that potentially prevented a serious injury. The employee returned to work after taking a brief break. Other employees began cleaning up the spill immediately.

APSC addressed the need to anticipate potential for stored energy as part of the "lessons learned" process from the incident. Observations made by Compliance staff resulted in a lease compliance report, three satisfactory surveillance reports, and one surveillance report with a significant unsatisfactory observation (SPCO letter 10-298-AS).

Figure 10: Crews Working at PS 7 During the June Maintenance Shutdown

Special Projects

Security Personnel

In February of 2010 Compliance staff traveled from Fairbanks to Deadhorse, to meet with security personnel, particularly those positioned at the front gates of facilities in what are referred to as *guard shacks*. The purpose of the trip was to collect information about some of the current responsibilities of security personnel. Observations made by Compliance staff were recorded in a lease compliance report and six surveillance reports (10-096-AS). Although securing the pipeline is the top priority for all security personnel, they have multiple responsibilities that may be considered non-critical to pipeline security. These ancillary functions are considered "non-security sensitive" and therefore reportable.

Many of the ancillary functions performed by security personnel reach beyond the scope of core-security functions and into day-to-day operations of TAPS. These responsibilities can range from oil spill contingency activities to operating generators for power supply. All of these various responsibilities contribute to the safe and efficient operation of the pipeline. Observations made regarding the duties performed by security personnel became part of a SPCO assessment (10-SPCO-A-001) that evaluated the impacts associated with the removal of security personnel.

Specifically, the assessment evaluated how the removal of security personnel affects compliance to the ROW Lease and the quality assurance programs previously approved by the State Pipeline Coordinator. The assessment also evaluated information regarding the removal of security personnel along TAPS for the purpose of documenting the change and analyzing the change in terms of lease compliance.

The assessment found that without more extensive planning, future removal of security personnel from security guard shacks located at front gates of manned APSC facilities may compromise compliance with the programs and/or processes that APSC utilizes as methods of lease compliance. Because many of these programs and/or processes are part of the QAP, or other programs designed to maintain compliance to the terms of the ROW lease, plans to decommission security guard shacks may affect APSC's compliance to the lease.

The assessment recommended coordination among APSC managers and supervisors and documenting a management of change (MOC) that demonstrates coverage of "non-core" security functions, be executed prior to changes to security personnel. The assessment also recommended that APSC ensure that procedures and manuals are updated to reflect the recent changes to security personnel and systems, including, but not limited to, comprehensive, cross-functional programs such as SA-38, the *Alyeska Safety Manual*. The assessment further recommended that the decommissioning of security guard shacks at the gates of APSC facilities be executed with careful planning and comprehensive documentation. Documentation should demonstrate that all functions of the personnel currently positioned in security guard shacks that contribute to the safe operation of the pipeline will be covered.

Right of Way and Related Facilities

In addition of observing project work, the Compliance Section conducts surveillances of the TAPS pipeline ROW and related facilities. On September 22, 2009, and in cooperation with

the BLM/OPM, Compliance staff conducted surveillances at eight unmanned mountain top communication sites located along the southern portion of TAPS. The communication sites used for the operation of TAPS require line-of-site to each other and so their positioning is influenced by topography and distance. In order to achieve line-of-site, remote communication sites are generally located at high points in the topography, which in many cases is near the top of a mountain. The remote communication sites that support the operation of TAPS are located on lands owned by the United States of America, the State of Alaska, and other private organizations, and are accessed by helicopter. Figure 11 is a photograph taken during the surveillance of the Roundtop communication site. The Roundtop communication site is on state-owned land.

Figure 11: Overhead View of Roundtop Communication Site

The observations made that day yielded a lease compliance report and one surveillance report with a satisfactory finding. The surveillance report noted that the TAPS communications sites are regularly maintained to ensure that the TAPS communications system remains operational. The operation of a communication system that ensures the transmission of information required for the safe operation of the pipeline demonstrates compliance with Stipulation 1.18.2.

Compliance staff also participated in an aerial surveillance conducted on May 21, 2010, with BLM/OPM. This aerial surveillance was conducted along the TAPS ROW from Fairbanks to Valdez in a Helio Courier fixed wing aircraft. Observations made that day produced a lease compliance report and two surveillance reports. The surveillance reports indicated that, in general, on May 21, 2010 the pipeline ROW appeared to be in a condition that complies with requirements set forth by the TAPS ROW lease, ADL 63574.

SPCO staff traveled various parts of the ROW from Prudhoe Bay to Valdez in order to make visual observations of the general condition of pipeline and the ground upon/below which it lies. There were no major or immediate concerns noted from these observations.

Projects Initiated in FY10 and Scheduled for completion in FY11

PS 3 Strategic Reconfiguration Technical Drawings

During FY10 Compliance staff initiated an assessment on the status of technical documents for the SR project at PS 3. The assessment evaluated APSC's compliance with requirements of the state ROW lease, specifically: Sections 6, 16, and 23 and Stipulation 1.18. On May 19, 2010, the BLM/OPM `issued a letter, 10-060-RN, which required that APSC complete and issue all APSC drawings by November 1, 2010, complete all vendor drawings and associated documents by December 6, 2010, and complete all ancillary documentation by December 13, 2010. Subsequently, the SPCO issued a scope on June 2, 2010, for the PS 3 technical document assessment.

The assessment started with a review of procedures and plans, and then discussions with APSC staff to define project processes and the handling of drawings throughout the project. Documentation for key project hand-off steps were examined and found to be appropriately executed. These steps included the transition at mechanical completion and following the functional check-out (FCO). This research extended into FY11.

Access to technical documents and drawings was also examined as a part of the assessment with a field trip to PS 3 by SPCO staff. This field trip resulted in a lease compliance report and two surveillance reports that will be counted in the FY11 SPCO annual report. While at the pump station, SPCO staff requested 11 drawings.

- Two piping and instrumentation diagrams
- Two fire and gas drawings
- Two general arrangement (main layout) drawings
- Two piping drawings
- One electrical power drawing
- One instrumentation drawing
- The Dooley-Tackaberry drawing of pressure-release heads for the water mist system in the Siemens turbine enclosure.

The Dooley-Tackaberry drawing was selected due to its critical nature and the fact that it is a document supplied by a subcontractor and material supplier.

Through the assessment three positive findings were identified under Section 6, Books, Accounts and Records; Access to Property and Records. APSC kept records to demonstrate effective tracking of project drawings and documents, and appropriate hand-off of SR system responsibility throughout the project. APSC made records and information related to this assessment readily available to the SPCO and demonstrated that staff and contractors had access to drawings and documents through several sources.

When evaluated under Section 16, Construction Plans and Quality Assurance, two positive findings were identified. APSC ensured that staff and contractors had access to the most current drawings and other documents which may be critical to the safe operations and maintenance of the pipeline system. APSC demonstrated effective management of project drawings and documents by following transfer of custody and through the use of APSC records management systems.

APSC failed to comply with the Lease for elements evaluated under Section 23, Compliance with Notices to Proceed, Stipulation 1.18 Surveillance and Maintenance, and part of Section 16, Construction Plans and Quality Assurance, by failing to update the PS 3 SR drawings within 180 days.

Both Section 23 and Stipulation 1.18, through Memorandum of Agreement 18, require APSC to complete the drawing process within 180 days. By not requesting an extension or allocating the necessary resources to complete the drawings within the required time, APSC failed to comply with Section 16 by not demonstrating effective change management, as required under their QAP.

In addition to the findings, the report made several non-finding observations. Based on one of those observations, the SPCO will request information which explains how APSC determined acceptable download/printing times and legibility for documents, such as technical drawings, needed in the field for operations and maintenance activities and emergency response.

It is critical that APSC include an evaluation of the scope of work and personnel resources necessary for a timely completion of the technical drawing and document process on all future project work,

Although research was conducted during fiscal year 2010, additional research was conducted and the assessment was issued in fiscal year 2011. The assessment and report numbers will be recorded in the spreadsheet of SPCO reports issued in FY11.

PS 1 Incident Investigation:

Another assessment initiated by Compliance staff in FY10 documented APSC's progress in accomplishing the recommendations generated by the *TAPS Pump Station 1 Sadlerochit Stream Gas Excursion Incident Investigation Report*, dated February 23, 2009. The incident investigation report was produced in the wake of an incident at PS 1 where crude containing a high volume of gas was introduced from the Prudhoe Bay Unit East Operating Area transit line during a non-routine de-oiling operation. The incident investigation generated recommendations that were derived from a root cause analysis conducted as part of APSC's investigation and analysis process.

The SPCO assessment examined APSC's progress in completing the corrective actions recommended by the Incident Investigation Report and how APSC is taking measures to minimize the likelihood or consequence of any future delivery of crude to PS 1 that is outside of the delivery specifications and/or the design basis for PS 1.

The assessment included information gathered during FY10, including a letter dated August 13, 2009, from APSC and addressed to the DNR Commissioner. The letter was received by the SPCO on August 18th, 2009 and serialized as JPO Document Tracking System # 20090825-1. This letter was sent by APSC to update the DNR Commissioner of the progress APSC had made, at that time, to prevent the events of January 15, 2009 from occurring in the future. Further information for the assessment was obtained at a meeting conducted on April 7, 2010, to update the DNR Commissioner of APSC's progress in

addressing the incident investigation, and a meeting conducted on June 29, 2010 between SPCO and the APSC engineering operations group to discuss the scope of the assessment and present questions to APSC developed by SPCO. The assessment also used information from numerous APSC procedures, manuals, and documentation from a system called the Management Actions and Commitments (MAC) process.

By following through with the investigation recommendations and updating procedures and manuals that help to protect PS 1 and human health, APSC has worked to improve the safety of personnel. In addition, physical or engineered modifications to the pump station that improve safety and protect assets, such as the tank foam blanket system, are being planned. Through the course of this assessment it was not determined how, in the unlikely event that a large volume of vapor is delivered to PS 1, the engineered solutions planned by APSC will avert a venting incident that may cause serious harm to human health and the environment.

APSC has procedures that suggest prorating producers based on vapor pressure and isolating connecting pipelines from PS 1 in the event of an emergency. The process of isolating PS 1 from connecting pipelines is a reaction to an emergency, rather than a method of prevention. APSC would need to engineer major modifications for PS 1 to improve its gas handling capabilities in order to avoid venting upon the delivery of large gas excursions. Without immense capitol expenditures, APSC employees can prevent a large vapor slug from venting at PS 1 by predicting the occurrence and preparing for it through administrative controls such as notification processes.

The assessment found that the North Slope operators with connections to PS 1 (Connectors) are still in the process of developing and documenting notification protocols. BPXA has several procedures in place and a MOC document that developed as a result of the PS 1 venting incident. These documents require advising process safety experts if the potential to impact the specifications of crude delivered to PS 1 exists, but do not indicate when or how the Connector would isolate its system from TAPS in the event of a gas excursion. The assessment found that, although APSC personnel have maintained communications with Connectors in regards to the development of notification protocols, APSC personnel's understanding of Connectors' notification protocols is not documented.

APSC stated verbally and in writing that communications between APSC and Connectors occurs prior to any project work conducted upstream of PS 1 that may affect PS 1. The assessment found that APSC's review of upstream activities is not documented. In addition, the procedures APSC uses to guide review of upstream activities are not specific to reviewing upstream activities and that these procedures do not clearly define APSC's role in review processes of projects on assets not operated by APSC. In addition, the assessment found that APSC has not kept training records regarding Connector facility reviews and training of APSC personnel, or PS 1 facility review and training of Connectors. APSC has not documented APSC personnel's understanding of upstream equipment, operations, or hazard mitigations.

Although research was conducted during fiscal year 2010, additional research was conducted and the assessment was issued in fiscal year 2011. The assessment and report numbers will be recorded in the FY11 summary of SPCO reports issued in fiscal year 2011.

Engineering Section FY10 Activities Related to TAPS

The technical/engineering activity on TAPS during the past year included continued work on a major venting incident at PS 1, continued work on the new SR Facilities at PS 3, PS 4 and PS 9, continued evaluation of low-flow issues, remediation of low CP potentials, continued automation and reduction of operators, de-manning of various pump station sites, ILI or "smart pigging" of the mainline, geopigging of the FGL, and continued optimization of facilities, such as improvement in gas supply.

SPCO Engineering Section Overview of TAPS Strategic Reconfiguration

SR was intended to update TAPS for lower flow rates. The original design basis listed a maximum throughput from the original 2.1 million barrels of oil per day (bopd) and minimum 300,000 bopd. The design basis for SR lists a maximum of 1.14 million bopd and a minimum of 300,000 bopd. APSC has twice utilized impulse, or on-again/off-again pumping techniques to achieve even lower rates.

SPCO Engineering believes that in warmer conditions, the new equipment can achieve lower rates than the published minimums. In colder temperatures, however, low fluid temperatures could make low flow more problematic.

Several major pieces of equipment are installed or planned for each SR Pump Station.

- PS 9: three pumps, three Variable-Frequency Drives (VFDs) to throttle the pumps, three electric motors to drive the pumps, and two 2.25- Megawatt (mW) backup diesel generators, a 65 Kilowatt (kW) emergency generator and an electrical connection to the commercial power grid.
- PS 3 and PS 4: two 12-mW turbine generators (TGs), three pumps, three VFDs to throttle the pumps, three electric motors to drive the pumps, and one 2.25-mW diesel generator, a 65 kW emergency generator and an electrical connection to the commercial power grid. An additional 2.25 mW black-start diesel generator is being procured and will be installed at each of these pump stations.
- APSC has restarted limited work for conversion of PS 1 to complete SR. They have reorganized the project and now call it PS 1 EA. It consists of the addition of two electric-motor drives and VFDs to two booster pumps, three mainline pumps, three electric motor pump drivers, one 12-mW TG, a 65 kW emergency generator and a backup connection to the Prudhoe Bay proprietary electrical grid. A 5-mW turbine generator may be added to the project scope.

More information on the technical upgrades of TAPS by the SR project can be found at the following website: http://alyeska-pipeline.com/sr.html

After PS 9 and PS 3 SR facilities had experienced one or more winters of operation, the piping tie-ins to the old legacy equipment were disconnected at both pump stations. During the past year, the piping connections to the legacy equipment at PS 4 were also removed. PS 9, PS 3 and PS 4 now have full isolation of legacy equipment and PS 1 is still operating its original legacy equipment.

SPCO Engineering Section Discussion of TAPS Strategic Reconfiguration Reliability
A matter of continuing interest for the State remains the reliability of the new SR equipment. The SPCO has monitored this issue and provides the following information, which is condensed from TAPS reports issued by APSC. Appendix K: Strategic Reconfiguration Related Shutdowns of TAPS includes two tables that list shutdowns related to SR; Table 28 covers PS 3 and Table 29 covers PS 4.

Figure 12: Availability of Pump Station 3, Strategic Reconfiguration

The short-duration shutdowns at PS 3 and PS 4 can be can be characterized as minor because none, to date, have reduced the total throughput of TAPS. Storage tanks located at points within the system can hold oil for a period, and flow south of Atigun Pass is not affected by short-duration shutdowns at PS 9. Pump Station 1 can store significant volumes of oil during shutdowns of the northern section, transporting the extra oil once flow resumes. The longest idle time at PS 3 was six hours and 14 minutes; the shortest was one minute. The longest idle time at PS4 was 2 hours, 37 minutes, and the shortest was 16 minutes.

Although SR facilities at PS 9, PS 3, and PS 4 have experienced short-duration outages and failures, these have resulted in little throughput loss. It is difficult to make direct comparisons regarding the reliability of pre- and post-SR facilities, because the original equipment had the benefit of three decades of upgrades and improvements.

The SPCO has been tracking throughput disruptions since the first SR pump station came online in February of 2009. The records indicate that in more than three years of operations, two hours of net lost throughput can be directly attributed to the new facilities. The term *net throughput* is used to characterize lost oil due to unscheduled slowdowns or shutdowns that could not be recouped via the storage or hydraulic elasticity of the system. This loss was caused by one incident at PS9 in the summer of 2007. It should be noted that this analysis does not attribute the May 25, 2010, TK-190 overflow incident as an SR-caused shutdown. This incident was attributed to several different causes, only one of which included an uninterruptable power supply installed under SR.

SPCO Engineering Section Discussion of Pump Station 3 De-manning
During the past year, APSC proceeded with plans to de-man PS 3. Many of the support facilities, including the PLQ, are being shut down. The fly camps will be kept to provide project housing on an as-needed basis. In the previous year, the control room at PS 3 was de-manned and its functions transferred to the new OCC in Anchorage. Maintenance crews remain on site at PS 3 most of the time, but they are housed at PS 4. The fly camps provide overflow housing for construction and repair crews. Emergency crews will be available at PS 4. APSC upgraded its security systems and installed magnetic card access to accommodate de-manning.

APSC's plans to remove personnel from various sites throughout TAPS, including PS3, remains controversial both within and outside of APSC. There has been some rethinking of the philosophy of lowered manning and de-manning. Following the PS 9 TK 190 incident, APSC announced that the facility would have increased manning; however, they have not committed to a permanent upgrade of manning.

Discussion of In-Line Inspection (Smart Pigging)
During the past year, APSC completed two ILI runs. The first was from PS 1, near Prudhoe Bay, to PS 4, in the Brooks Range. The second was from PS 4 to the VMT. The northern run from PS 1 to PS 4 (144 miles) takes 2.5 days and the southern run from PS 4 to Valdez (656 miles) takes 12.5 days. The full length of TAPS, 800 miles, was covered with the inspections.

Under an agreement with the JPO, an ILI tool is required to be run every three years to inspect for corrosion, dents, and other mechanical damage. An ILI tool to determine pipeline movement is run every five years.

The ILI tool used for this year's run was a combination tool and utilized three measurement technologies (corrosion, mechanical damage, and movement) on one tool. The data from this inspection is used to locate, prioritize, and investigate pipeline features that may need repair or remediation. Under PHMSA regulations, time limits are set for repairing different types of defects.

The primary challenge to this year's pig run was preparation. In-line inspection tools require a certain level of cleanliness to work, and the less accumulated material in the pipe, the more accurate the results. As throughput decreases, it becomes difficult to clean wax, asphaltenes and other sediment from the pipeline walls. Cleaning pigs were run on 4-day increments for one month preceding the ILI run. Despite these challenges, APSC reported that the ILI runs were successful. They are using the data in prioritizing their digging program, which investigates and remediates the most serious defects.

TAPS Throughput and Operational Issues
The average TAPS daily throughput in 2009 was 672,028 barrels of oil per day (bopd). This represents about 33% of the highest average daily throughput of 2,033,082 barrels per day in 1988. Operating TAPS will become more challenging as North Slope crude oil production continues to decline. Long transit times to the VMT, crude oil composition changes, additional wax and asphaltenes deposition, and temperature are a few of the concerns. The

most critical challenge may be ice formation at fluid temperatures below 28°F, the point at which saline ice begins to nucleate.

Depending upon ambient temperatures along the route on a typical winter day, oil temperatures can drop to 70°F by the time it reaches Fairbanks and can continue to fall 60°F by the time it arrives at terminus at the VMT. The refinery provides a significant boost to the temperature of the oil. Unlike many refineries, the Flint Hills facility returns product to its supply pipeline. It uses only certain components and returns the rest at higher temperatures.

Today, the temperatures exiting PS 1 are largely unchanged. In some extreme cases, minimum fluid temperatures have decreased to 40-45°F at the coldest section of the pipeline, (PS 7 to North Pole).

TAPS has experienced incidents that provide a glimpse of the problems anticipated for the future. In November 2006, low output from Prudhoe Bay caused fluid temperatures in TAPS to drop to about 40°F. Although no major operational problems resulted from the low temperatures, APSC was forced to use intermittent pumping for the first time.

In December 2008, low temperatures due to sustained high winds at the VMT disrupted tanker loading. For the second time, APSC employed intermittent pumping.

APSC recently completed a number of tests and analyses on operational challenges and is currently condensing the results into a report. The report is expected to be completed by the end of 2010. The work is expected primarily to investigate:

1. **Ice Formation**. At fluid temperatures of 28°F or below, the potential for saline ice to form in TAPS increases. At 28°F, the water in TAPS will begin to freeze into saline ice that could damage pumps, clog screens, and disable instrumentation.
2. **Bulk Paraffin and other deposits**. As fluid temperatures in TAPS decrease, greater amounts of wax and asphaltenes (dense petroleum) will begin to drop out of solution. Wax buildup has caused APSC has caused problems in ILI. APSC has increased its maintenance pigging frequency.
3. **Viscosity Changes**. Lower temperature oil will result in greater pressure loss, which will affect the hydraulic gradient and energy requirements for shipping oil.
4. **Gelling**. Wax will also precipitate out as a matrix within the solution, transforming oil into a gel. This is important because a gelled fluid is a thixotropic substance. It does not flow as easily or predictably as a typical crude oil, which is a Newtonian fluid. Gelled oil will cause more extreme pressure drops and even higher energy requirements than high viscosity oil.

Atigun Pipeline Vibrations

The pipeline vibration issues at Atigun are similar to those experienced at Thompson Pass more than a decade ago. The same fundamental mechanism is responsible at both sites, but there are important differences between the two. Figure 13 provides a graphic depiction of the theorized mechanism of vibrations found at Atigun Pass.

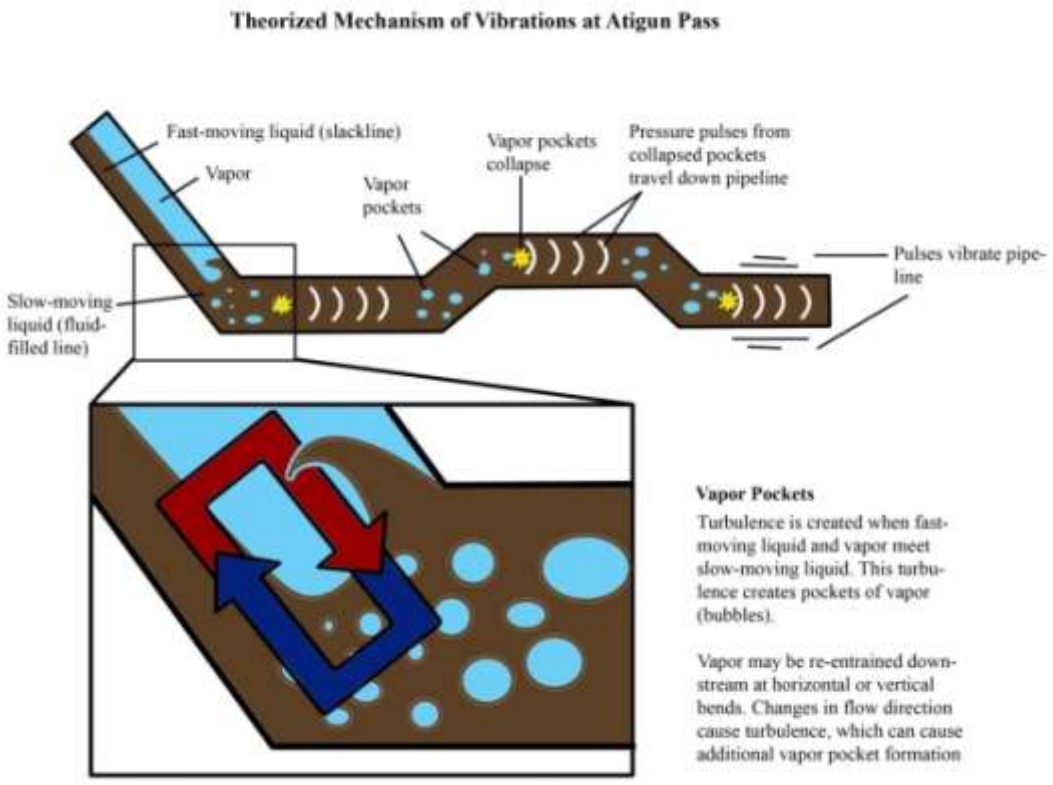


Figure 13: Theorized Mechanism of Vibration at Atigun Pass

Ten years ago, lower throughput caused vibrations at Thompson Pass that were felt as far away as Valdez. This problem was remediated by supplying backpressure at the bottom of the slope, which caused the liquid level in the pipe to rise and the elevation drop in the slackline to be reduced.

The vibrations at Atigun are of lower amplitude and are consequently less severe than the vibrations were at Thompson Pass. The vibrations at Atigun are likely caused by the lowered throughput creating a longer section of slackline in the area, and hence a longer drop for fluids as they crest the top of the pass and cascade downhill to a liquid-filled section of line. Continued changes in the flow rates of TAPS may result in greater or lesser vibrations.

Vibrations create fatigue in the welds and the parent metal. They typically act in a mathematically predictable manner, based upon the number and amplitude of fatigue cycles. Using the data collected, APSC issued a draft report that recommended no action in the near future.

APSC instrumented four adjacent pipeline spans at one location at Atigun Pass (see Figure 14 on the next page). APSC analyzed the amplitudes and frequency at this location and came to the preliminary conclusion that the vibrations did not present a threat within the near or intermediate future.

The SPCO is reviewing the report. It is unclear whether or not the instrumentation of four spans in one location is sufficient to characterize the worst vibration in the section. A field

trip to Atigun Pass found that the vibrations extended for at least six miles, in an area where the TAPS makes multiple transitions up and down from below-ground to above-ground modes.

The situation is more complex at Atigun Pass than that at Thompson Pass. The interface between the slackline and the fluid-filled section at Thompson is relatively short. At Atigun, the area of concern is at the Chandalar Shelf. The interface area covers a long run of relatively flat terrain. This could create a fairly long interface area, with complex interactions.

During May 2010, APSC found cracks in approximately 42 shoes (see Figure 6 on page 23 to see a diagram of the intermediate support assembly for TAPS). These were located in the area of the highest vibrations in Atigun Pass. APSC determined that most or all of these were stress cracks emanating from the original welds performed in a fabrication shop during original construction. It is theorized that the additional energy input by the vibration caused the growth and/or creation of cracks in high-stress areas of structural welds. As a contingency, APSC installed temporary cribbing near some of the cracked shoes during May and June. The primary purpose of the cribbing was to limit the drop distance of the mainline if the shoe failed structurally. By the end of summer, all stacks of cribbing had been removed and the cracked shoes were repaired, replaced, or marked for further monitoring.

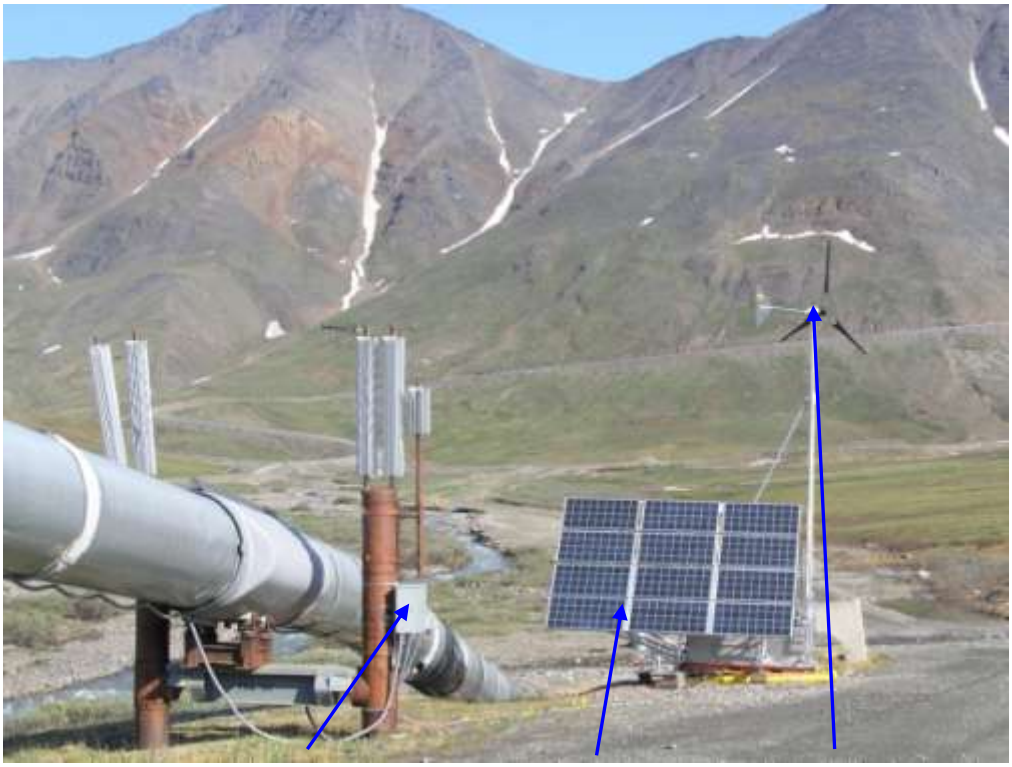


Figure 14: Data Logger Instrumentation, Solar Panel, and Wind Generator at Atigun Pass[9]

[9] The transition from below to above ground modes, or horizontal and vertical bends, can interrupt flow and cause the creation of vapor pockets, which can create vibrations when they collapse. APSC installed instrumentation, powered by solar and wind generators, to monitor vibrations at this location in Atigun Pass.

PS 1 Producer Pipelines
Several pipelines from processing facilities across the North Slope converge at PS 1. All of these, except the Oil Transit Line (OTL) 501 from Prudhoe Bay and the Lisburne Pipeline are on State of Alaska AS 38.35 ROW leases and subject to monitoring by the SPCO.

Two of these pipelines, the single transit line from Skid 50 (the 501 Transit Line) and the Kuparuk Pipeline, are buried or encased in concrete within the boundaries of PS 1 and are difficult to inspect using direct assessment methods. The Skid 50 pipeline section is being replaced by BP Transportation; the Kuparuk Pipeline is being replaced by ConocoPhillips. Both pipeline operators continue work to replace the underground sections at PS 1 and have targeted completion during the coming year.

Pump Station 9, Tank TK-190 Overflow Incident
On May 25, 2010, Tank TK-190 at PS 9 overflowed into a containment area during shutdown activities. This incident was classified as not having serious environmental repercussions because the overflow was limited to a secondary containment area, and therefore (according to regulatory definitions) was not a spill to the environment.

The incident had repercussions in the operations arena. Numerous people were onsite at PS 9 prior to and during the incident. The tank provides a volume into which the mainline can drain oil to avoid over-pressurization. As is typical with relief systems, the valves to the tank failed open during a power outage. How the open valves and the steadily filling tank were not recognized either by operations personnel onsite or the Operations Control Center (OCC) in Anchorage is still not fully understood. APSC's prepared a root-cause analysis report which provided some insight into the events that caused the tank overfill situation. Regulatory personnel have made complaints that they were denied access to areas and to personnel during the cleanup and response phase. At the end of this reporting period, this incident remains an open investigation with PHMSA and the SPCO following further developments. APSC has developed a Management Action Plan that addresses the shortcomings.

The Management Action Plan includes addressing cultural changes, training, organizational improvements and a complete replacement of the UPS systems, including the electrical supply. This change will be implemented at PS 9 and all pump stations with this design. The SPCO Compliance Section will conduct an assessment of APSC's implementation of the Management Action Plan, which will be reported on in the FY11 SPCO Annual Report.

APSC also established an Operations and Maintenance Incident Prevention Board in response to the PS 9 incident. Its stated purpose is to learn "as much as possible from significant incidents and to incorporate those lessons … to prevent recurring incidents," and to "… advance the culture with respect to Operational Discipline and Situational Awareness on TAPS".(8)

SPCO Engineering Section Discussion of APSC 2009 MP-166 Reports
The SPCO Engineer reviewed the MP-166 reports and provided the following commentary.

Mainline Aboveground Support Systems and Bridges

The 2009 Mainline Aboveground Support System and Bridges Monitoring Program Report showed an increase of 370% over the 2008 numbers of crossbeams more than 1° out of level and a 1,460% increase from the 2007 numbers. The SPCO Engineer believes that this is not a real trend, but instead is a variation in the techniques used by the work crews.

APSC performed no formal surveys of depressions around VSMs. Nor did it perform a formal survey of jacket insulation damage, Teflon pad damage or VSM freeze damage. These issues were omitted from the 2009 line-walk scope. It is unknown why APSC decided that annual and comprehensive cataloguing of these physical attributes is not warranted. Each of these can result in problems. Insufficiencies in pipeline jacketing can result in rainwater intrusion and increased external corrosion. Teflon pads not operating as designed can result in increased pipe stresses. Two freeze-damaged VSMs were reported in 2009, possibly a result of water intrusion through damaged VSM caps. It should be noted that incidental aerial and ground surveys could find major problems.

The SPCO Engineer also noted that the 2009 Mainline Aboveground Support System and Bridges Monitoring Program Report did not indicate the reasoning behind the reduction in the corrosion protection criteria.

Fuel Gas Line

Following review of the 2009 FGL Report; the SPCO Engineer noted that comparison of the LiDAR survey surface profile and the pipeline centerline geopig information is provides a means to assess the depth of cover of the FGL on a foot-by-foot basis for the first time in its history. This is an important step forward, but the usefulness of the new data will be of limited if remediation efforts are not fully funded. The SPCO will continue to monitor maintenance on this pipeline, most of which is on a State issued ROW lease.

Mainline Integrity

In 2009, the PIT Program incorporated the use of newer types of ultrasonic equipment. The program identified weld locations for testing on the 48-inch crude oil header piping inside the tank farm at PS 1. The test revealed discoveries of corrosion preferential to the weld and heat affected zone of various welds. For the first time, ultrasonic phased array scanning along with a TOFD technique for measuring and monitoring internal pipe and weld material profile was performed on TAPS. This technique improves accessibility to previously obscure or inaccessible locations at the inside diameter of larger bore, butt-welded connections. The initial results from this new equipment caused concern that other areas in TAPS in intermittent or low flow service may have increased corrosion. Inspection at other suspect sites revealed that the corrosion found at the PS 1 tank area was not typical of other places with low flow.

Aboveground Storage and Tank

APSC reported that 49 CFR 195 and 18 AAC 75 provide the general requirements for tank monitoring. The SPCO Engineer noted that DNR considers the pre-eminent agencies in these areas to be, respectively, PHMSA and DEC. A number of permanent and mobile tanks do not fall under these agencies' jurisdiction and the lease has certain requirements for tank construction and for the lease adhering to regulatory requirements. DNR has limited

involvement with tank integrity and monitoring.

APSC reported that no formal trending or performance analyses were performed, and explained that, "inspections do not produce hard data and merely provide a high level visual inspection for potential problems," a statement the SPCO Engineer would hesitate to endorse. The SPCO Engineer noted that Tank 4 has a 20-year inspection interval which is twice as long as typical and pointed out two other areas of concern.

1. APSC does not provide trending analysis in their tank program. The apparent lack of trending was explained in the MP166 tank report: "Inspections do not produce hard data and merely provide a high level visual inspection for potential problems." The SPCO Engineer asserts that the core of ASME inspection methodology is hard data.
2. Extending tank inspections beyond the typical ASME interval of 10 years could be problematic. Many changes can occur over a period of 11-20 years, including changes to physical oil characteristics, as the mixture of oil from various North Slope oilfields change. It should be noted that most of the larger tanks are under the jurisdiction of DEC. PHMSA is also involved in tanks used for pressure relief. The SPCO is primarily responsible for smaller tanks located on the leasehold. The SPCO continues to monitor tank operations and maintenance with the understanding that many items are under the jurisdiction of other agencies.

During CY09, the SPCO approved a Lease amendment allowing use of UL 142 tanks on the TAPS. UL 142, the standard for steel aboveground tanks for flammable liquids, is typically used for tanks with volumes between 100 and 10,000 gallons. These tanks have gained widespread acceptance for commercial and industrial applications during the decades since the Lease was executed. At the time the Lease was drafted there was no standard for inspecting these types of tanks. An inspection standard was developed in 1995.

Lease Stipulation 3.2.1.1 specified use of only API codes for oil tanks. Tank construction standards have changed in the intervening decades. The widespread use of the UL 142 standard for smaller tanks and fuel oil storage is now recognized. The Engineering Section recommended this amendment to recognize modern methods and practices. It should be noted that the Lease requirements generally cover smaller tanks that do not fall within either DEC or PHMSA jurisdictions.

Right-of-Way Section FY10 Activities Related to TAPS

Lease Amendments, Permits, and other Authorizations

During FY10, the SPCO ROW Section completed 29 authorizations in support of TAPS maintenance and repair activities.

- 6 Temporary Water Use Permits or Amendments
- 9 Material Sale Contracts
- 10 Land Use Permits
- 2 Authorizations to operate equipment outside the ROW per Lease Stipulation 2.9.1
- 1 TAPS Right-of-Way Lease Amendment at PLMP 200.8, see below, and
- 1 ROW Lease Amendment, ADL 418713, issued under AS 38.05.850, see below for the below ordinary high water portion of the Jim River Boat Launch near Dalton

Highway milepost 138

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

Land Use Permits (LUP)

The ROW Section is responsible for administering the permitting process at the SPCO. APSC applies for LUPs for various maintenance and construction activities along TAPS when additional land use area, outside the existing ROW, is required to perform the projects. These activities include, but are not limited to, LWC and pipeline workpad maintenance, excavation of below-ground pipe, soil investigations, mineral material storage, and oil spill contingency sites and conex storage.

APSC tracks projects that require permitting and applies in advance for the permits. Other permit applications result from observations or surveillances by either APSC or SPCO staff, as well as from unexpected events such as floods and wind storms.

Temporary Water Use Permits of Amendments (TWUP)

The ROW Section authorizes TWUPs for the use of water resources on state land related to the TAPS ROW. If the water source is considered anadromous, then special requirements are added to the permit to protect fish and other wildlife. These provisions include, but are not limited to, intake placement, special screening requirements, and water intake velocity. These efforts are coordinated with the SPCO ADF&G Liaison.

TAPS Right-of-Way Amendment - Dietrich River Guidebank Extension at PLMP 200.8

The "Amendment of the Right-of-Way Lease for the Trans-Alaska Pipeline, ADL 63574, Dietrich River Guidebank Extension, PLMP 200.8" was issued to APSC on September 8, 2009. This amendment was issued to accommodate the construction of an extended guidebank at this location (see Figure 15 below). The uplands are federal lands managed by the BLM/OPM and the State claims the bed of the Dietrich River. This amendment was issued for the portion of the project lying below ordinary high water.

Figure 15: Dietrich River Guidebank Extension, PLMP 200.8

The aboveground pipe in this area is protected by an 800-foot long riprap guidebank installed in 1985 during the PLMP 200 reroute. Progressive erosion upstream of this guidebank raised concerns about pipeline integrity as the river was only 90 feet from the centerline of the pipe. This project extended the existing guidebank approximately 300 feet upstream. A gravel base core and Class III riprap were keyed into the bank on the upstream end.

Right-of-Way, ADL 418713, Jim River Boat Launch

APSC submitted an application for a ROW Permit for a boat launch (see Figure 16 below) located outside the TAPS right-of-way on the left (south) bank of Jim River, approximately one mile north of PS 5, near Dalton Highway Mile Post 138, just northwest of the DOT&PF Jim River Maintenance Facility. The purpose of the project was to establish reliable access to the Jim River for oil spill response and training to support the TAPS Oil Discharge Prevention and Contingency Plan.

SPCO coordinated efforts with BLM/OPM to permit the boat launch. The uplands are federal lands managed by BLM/OPM., who issued a new ROW to APSC from the Dalton Highway to Jim River. SPCO issued ADL 418713 for the portion of the new boat launch on Jim River located below ordinary high water.

Figure 16: Jim River Boat Launch

Mineral Material Site Surveillance

The ROW Section in FY10 conducted inspections and completed surveillance reports for nine of the 29 operating material sale sites on state land along TAPS between Valdez and Fairbanks (surveillance report numbers 09-TAPS-S-116 through 09-TAPS-S-125). A list of all surveillance reports completed by the SPCO in FY10 can be found in Appendix G. The OMS locations between Deadhorse and Fairbanks were not inspected during the 2009 field season due to the fact that no new mining was scheduled for those pits. The sites between

Valdez and Fairbanks were inspected in July 2009 to determine compliance with the material sale contracts, mining and reclamation plans, and TAPS Lease Stipulation 2.6, Material Sites. Two sites were not visited due to drivelane conditions and time constraints. The material sites met requirements and were found to be generally clean and well-maintained.

The lack of signs in place to warn of the steep slopes at OMS 14-0 and OMS 41-3 resulted in minor unsatisfactory observations on the related surveillance reports. APSC addressed the unsatisfactory observations (APSC Letter No. 18650 dated June 1, 2009) and the SPCO re-inspected the sites in July 2009 and closed out the unsatisfactory observations (SPCO Letter 10-103-AS).

A separate observation question was raised in FY09 regarding OMS 41-3, the Donnelly Pit (Figure 17), regarding several lengths of what appeared to be primer cord (Figure 18) found on the pit floor. APSC confirmed it was spent shock tube that had no explosive potential. This observation and the follow-up discussions with APSC led APSC to update the "APSC Mineral Mining Project OMS Pre/Post Work Inspection Checklist" by adding another block to specifically address mining material as a separate line item from other debris. APSC also updated their flowchart titled "Blasting Procedures and Safe Practices, Mineral Mining material, Process Flow and Administrative Checkpoints" to include the site mitigation standards to be met after a blasting operation. This observation question was resolved by the APSC OMS checklist completed September 16, 2009 in which the APSC representative stated he could find no further evidence of spent shock tube on his walk through of the pit. This observation was closed by SPCO Letter 10-103-AS, dated April 19, 2010.

Figure 17: OMS 41-3

Figure 18: Cord at OMS 41-3

Records and file maintenance

The ROW Section is responsible for updating and maintaining the administrative records for all AS 38.35 ROW Leases. Two major projects were assigned to ROW Section staff in FY10.

The first project was the auditing and updating of the State's web-based filing system known as the Land Administrative System (LAS), for each pipeline. Each case file related to individual pipelines is reflected in LAS and is referenced by ADL number. The status and legal description of each pipeline is provided along with numerous other transactions that

document ownership, decisions, and amendments. LAS is one of the land management tools used by DNR to describe how state land is used and to help mitigate competing/conflicting land uses. The ROW Section is responsible for insuring that the hard case file is fully represented in LAS and for correcting discrepancies as needed. To access LAS please visit: http://dnr.alaska.gov/projects/las/lasmenu.cfm

The second project was the compiling of all of TAPS as-builts that have been submitted to the SPCO for amendments to the TAPS ROW. These are submitted to the State Survey Section for review in order to incorporate them into the existing TAPS ROW survey. This allows the Survey Section to review the as-built survey process and write as-built survey instructions for future ROW amendments for TAPS and other AS 38.35 pipelines. This keeps the case files updated and provides a way to reduce future costs for both the lessees and DNR.

Liaisons

Department of Environmental Conservation FY10 Activities Related to TAPS

Oil Discharge Prevention and Contingency Planning (C-Plan)

C-Plans are required by State of Alaska pollution prevention statutes and regulations, the Lease, and the Grant. Variations of spill prevention and response plans are also required by multiple federal agencies, including PHMSA, USCG, and the EPA. DEC staff at the SPCO review and enforce compliance with C-Plans for the TAPS Pipeline and the VMT as required by state law. In so doing, they support the SPCO in fulfilling Lease Stipulation 2.14, Contingency Plans. State C-Plans are required to have five parts:

1. Response Plan
2. Prevention Plan
3. Supplemental Information,
4. Best Available Technology Analysis
5. Response Planning Standard (RPS) Calculation.

Each portion of a C-Plan is reviewed for compliance with State of Alaska regulations in 18 AAC 75, Article 4. Once approved, C-Plans must be renewed and undergo a full review every five years. The operator may submit both major and routine amendments during the five-year approval period for DEC's review and approval. DEC conducts its review of the TAPS Pipeline and VMT C-Plans in coordination with BLM and with input from other JPO agencies. Oversight of compliance with C-Plans includes reviewing the plan application, conducting and evaluating spill response exercises, and conducting audits and inspections.

TAPS Pipeline C-Plan

The TAPS Response Planning Group composed of APSC, DEC, and JPO personnel regularly meet to facilitate on-going oversight of compliance with the C-Plans and with Alaska statutes and regulations. The purpose of the meetings is to coordinate C-Plan amendments, drills and exercises, inspections, audits and emerging issues among the various oversight agencies and APSC.

The most recent renewal of the TAPS Pipeline C-Plan was approved on November 30, 2006. There was one major amendment to the TAPS Pipeline C-plan in FY10. This amendment was an update to the APSC Drill and Exercise Program, and was required by a condition in the 2006 plan approval. Twelve minor amendments were submitted for consideration and eight were approved. An amendment is considered minor if it is determined that it does not diminish the plan holder's ability to respond to an oil discharge. Eleven Response Planning Group meetings were held in FY10.

A formal hearing was concluded in early FY09 concerning a challenge to the TAPS Pipeline C-Plan approval from 2006 and final written arguments were submitted to an Administrative Hearing Officer. To date, a proposed decision has not been issued; the administrative hearing process will continue into FY11.

VMT C-Plan

The VMT C-Plan Coordination Group meets quarterly to discuss on-going oversight and coordination of activities, compliance, emerging issues, and scheduling for drills, exercises, and inspections. DEC and BLM staff always participate in these meetings, and when available, USCG personnel provide additional agency oversight and participation. For response to a spill originating at the VMT, the USCG would fill the role of Federal On-Scene Coordinator (FOSC); the USCG has specific jurisdictional oversight of certain VMT activities. The Prince William Sound Regional Citizens' Advisory Council is also a member of the VMT C-Plan Coordination Group and participates regularly in meetings and review of the VMT C-Plan.

The VMT C-Plan was renewed at the end of FY08. Five routine amendments to the VMT C-Plan were reviewed and approved in FY10. An amendment is considered minor if it is determined that it does not diminish the plan holder's ability to respond to an oil discharge. Another amendment submitted for review in FY10 is still pending.

APSC included an initiative in the VMT C-Plan to rewrite the RPS Scenario, known as Scenario 5. Scenario 5 in the VMT C-Plan depicts the resources, schedule, strategies, and tactics that APSC could use to respond to a discharge of oil to the land and waters of the State of Alaska. Two workshops involving the VMT C-Plan Coordination Group and other subject matter experts from within the agencies and APSC were convened to consider response alternatives for Scenario 5.

In January of 2010, the DEC determined that the Fishing Vessel program which is an integral part of the VMT C-Plan was not adequately resourced, as demonstrated by a failure to have the required numbers of vessels available for response. APSC subsequently submitted a notice of non-readiness based on this fishing vessel shortfall along with proposed interim mitigation measures pending corrective action. APSC reached compliance with this program on July 27, 2010, and further action from the DEC is still pending.

Other Activities

Early in FY09, DEC and the JPO became aware of leaking catch basins and manholes in the secondary containment systems at the VMT. Secondary containment is required by State regulation in 18 AAC 75.75 and by Stipulation 3.11, Containment of Oil Spills, in the Lease and Grant. DEC and BLM/OPM both issued enforcement actions requiring corrective plans and action for the faulty components of the secondary containment systems. In the summer and fall of 2009 APSC performed repairs to catch basin, sump, and manhole penetrations in secondary containment, with recognition that on-going assessment and evaluation of corrective measures was warranted. This on-going assessment identified the need for further repairs and testing which will take place during the summer and fall of 2010. Subsequently, as part of scheduled testing and maintenance of the Industrial Wastewater Piping, additional leaks were discovered downstream of the manholes in some cells. Since it is not isolated DEC considers this to be part of the secondary containment system. DEC participated in a risk assessment to determine the best way to proceed and subsequently approved temporary mitigations pending final repairs. DEC's Notice of Violation is still active pending completion of final repairs and agreement for future maintenance, inspection schedules, and plans.

In January of 2010, the DEC determined that the Fishing Vessel program, an integral part of the VMT C-plan, was not being adequately resourced as demonstrated by a failure to have the required numbers of vessels available for response. APSC subsequently submitted a notice of non readiness based on this fishing vessel shortfall along with proposed interim mitigation measures pending corrective action. Compliance with the required number of fishing vessels was reached on July 27, 2010, and further action from the DEC on this issue is still pending.

Drills and Inspections

One of the oversight authorities DEC brings to the SPCO is the regulatory authority to require C-Plan holders to conduct oil spill response exercises.[10] Specific requirements for exercises are incorporated into the TAPS Pipeline and VMT C-Plans and are enforceable through the Lease and Grant. DEC staff participated in 14 major spill response exercises at the TAPS Pipeline and VMT in FY10. There are many types of spill response exercises, including local tabletop exercises, local field deployment exercises, pipeline reconnaissance exercises, local training exercises, combined resource field deployment exercises (multiple response bases responding to a pipeline scenario), terminal field deployment exercises, and Incident Management Team (IMT) exercises. Table 5 provides a summary of major oil discharge response exercises conducted in FY10.

[10] See 18 AAC 75.485, *Discharge exercises*.

Table 5: Major Oil Discharge Response Exercises, FY10

Date	Facility	Exercise Type	Location	DEC/JPO Participation
July 29-30 2009	TAPS Pipeline	Combined Resource Field Deployment	Kanuti River	Yes w/ BLM
August 26, 2009	TAPS Pipeline	Source Control, Combined Resource Field Deployment	Klutina River	Yes w/BLM
October 13-15, 2009	TAPS w/ SERVS	IMT w/ field deployment.	Lowe River, Valdez Emergency Operations Center	Yes
September 30, 2009	TAPS Pipeline	Joint APSC/JPO/DEC Initiated Fairbanks Response Base Initial Response Team Callout Exercise	DIF and Nordale Yard, Fairbanks	Yes w/ BLM
September 24, 2009	TAPS Pipeline	Unannounced, Joint JPO/DEC Initiated Delta Response Base Initial Response Team Callout Exercise	PS 9	Yes w/ BLM
November 5, 2009	VMT	IMT w/ field deployment Scenario 2 – 50 bbl spill to water at Berth 5	VMT, Valdez Emergency Operations Center	Yes w/BLM
January 19, 2010	VMT	Trans Rec 350 Skimmer/Barge Deployment	SERVS, Port Valdez	Yes w/ ADEC Marine Vessels
February 10, 2010	TAPS Pipeline	Unannounced, Joint JPO/DEC Initiated Fairbanks Response Base Initial Response Team Callout Exercise	Fairbanks Response Base	Yes w/ BLM
April 20-22, 2010	VMT	IMT w/ field deployment. Scenario 4, - 90,000 bbl spill from piping - all to water	VMT, Valdez Emergency Operations Center	Yes w/BLM
May 26, 2010	TAPS Pipeline	TAPS Local Fairbanks Response Base Field Deployment Exercise	Chatanika River	Yes w/ BLM

Each facility holds at least one IMT exercise per year. At these exercises, DEC's response team is led by one of the agency's regional State On-Scene Coordinators (SOSC). The SOSC, FOSC, and Incident Commander (with their respective staff) form the Unified Command. The Unified Command is responsible for executing an effective response.

Figure 19 was taken on May 26, 2010 during a TAPS Fairbanks Response Base (FRB) field deployment exercise. The photograph shows APSC Oil Spill Responders preparing to remove insulation during a simulated bullet strike along the Chatanika River.

Figure 19: APSC Oil Spill Responders During a May 2010 Simulated Bullet Strike

DEC has the statutory and regulatory authority to conduct inspections for compliance with C-Plan commitments and prevention requirements as well as to determine response readiness. Part of overseeing drills and exercises involves assessment of readiness and training for response. In addition, DEC conducts inspections based on priorities established in cooperation with the JPO Oil Spill Team. During FY10, DEC staff conducted field inspections, which are summarized in Table 6.

Table 6: DEC Field Inspections, FY10

Date	Facility	Focus	Location	DEC participants
July 20-22, 2010	PS 5,6 & 7	Equipment, Containment Sites, and Facilities Inspections	PS 5,6&7	Bill Haese w/ADF&G
August 27, 2010	VMT	Unannounced Secondary Containment Repairs	VMT, East Tank Farm	Bill Haese,
October 27, 2009	VMT	Unannounced Trans Rec and Grahm Rec Equipment and Boom Deployment	SERVS, Port Valdez	Bill Haese w/DEC marine Vessels
January 12-13, 2010	VMT	Secondary Containment Risk Assessment and Inspection	VMT, East Tank Farm	Graham Wood Bill Haese
February 11,2010	TAPS	Unannounced Equipment and Cold Weather Storage Inspection	Nordale Base, Fairbanks & PS 9	Graham Wood Bill Haese w/ BLM
March 9, 2010	TAPS	Unannounced Equipment and Cold Weather Storage Inspection	PS 1	Graham Wood w/ BLM
May 23-24, 2010	TAPS Pipeline	Source Control and Fire Control and Proximity Training and Equipment Inspection	Nordale Base and Fairbanks International	Bill Haese w/BLM
May 25-27, 2010	TAPS Pipeline PS 9	Release to secondary containment from Tank 190	PS 9	Bill Haese w/ DOLWD & DNR

Solid Waste Disposal Sites on TAPS[11]

The DEC Division of Environmental Health regulates drinking water, food and sanitary practices. DEC Environmental Health involvement wtih TAPS includes permitting for solid waste, pesticides, drinking water, and food service activities and covers the entire TAPS, including pump stations, response bases, support facilities, work pads, and temporary camps.

There are three DEC-permitted solid waste disposal (SWD) sites associated with TAPS: SWD 38-1, SWD 117-1B, and SWD 124-1. The APSC Solid Waste SME administers the DEC permits for these facilities and the local P&CM is tasked with the proper collection, storage, and dispose of solid waste into the APSC permitted facilities. There were no problems or permit issues at these facilities in FY10. During the permit renewal process for these three sites, APSC incorporated site-specific operational requirements for each permitted SWD site into APSC environmental procedures to better utilize the facilities and ensure compliance with both DEC and Lease and Grant requirements. The permits for these facilities expire in July 2011.

APSC is embarking on a project to retire assets along TAPS that are no longer required due to the recently completed the SR Project. A contractor will review existing and anticipated future needs for solid waste disposal and disposal sites. The APSC project will include an evaluation of what waste is expected to be generated during asset retirement and the waste disposal options available to APSC. The options include hauling waste to another permitted (non-APSC) facility and closing all the SWD sites, keeping only the SWD sites that APSC anticipates will be needed in the future, or a long term lease of the land from the BLM. DEC will continue to monitor the facilities and ensure they are operated in accordance with applicable state requirements.

Pesticides[12]

The mission of DEC's Pesticide Control is to regulate and allow the safe use of pesticides in Alaska in order to protect human health and the environment.

Stipulation 2.2.5.1 of the Lease and Grant requires that APSC receive approval from the SPC and the AO prior to use of any pesticides on TAPS. Alaska pesticide control regulations, 18 AAC 90, require application permits for the use of pesticides within the State's ROW. The regulations also require that any government official or agency that approves, directs, or conditions the use of a pesticide be certified to apply the pesticide being considered. Close coordination between DEC and the JPO is necessary to ensure all requirements of Alaska law and the Lease and Grant stipulations are understood and fulfilled.

APSC submitted one permit application during FY10 for the use of a pesticide. The project plan included the use of a wood preservative associated with a bridge repair project on the Little Salcha River Bridge near Fairbanks. The DEC Liaison coordinated with the DEC's Pesticides Program, APSC, ADF&G, the SPCO, and other agencies of the JPO to ensure the project was kept on-course and the interests of the State and other agencies were addressed. APSC ultimately decided to use a non-pesticide wood treatment product for which no DEC

[11] Oversight Authority: 18 AAC 60 and Lease and Grant Stipulations 2.2.6.2 and 4.1
[12] 18 AAC 90 & Lease and Grant Stipulations 2.2.5.1 and 4.1

permit was required.

Pesticides use along TAPS is an ongoing area of coordination between DEC and the JPO. The BLM met with the JPO and APSC late in FY10 to discuss invasive weed control in the BLM's Dalton Management Area (DMA) north of the Yukon River and along the TAPS corridor. The BLM plan includes the option of using herbicides to control targeted weeds in this area along the TAPS ROW. The DEC reviewed the plan and made comments to BLM. The DEC notified the BLM and JPO that any pesticide application requires DEC review and oversight. At this time, there is no definitive date for implementation of the control plan. Any future plans may also require the review of the DEC Division of Water to ensure water quality criteria and protections are addressed.

APSC began working with the DEC Liaison in FY09 to review pesticide use policies and permitting requirements to ensure both the DEC and JPO Lease and Grant requirements are addressed. This process continued through FY10, on-going coordination will assist APSC project planning and strengthen JPO oversight.

Drinking Water[13]

The Environmental Health Division, Drinking Water Program, ensures that systems that supply water for drinking meet the minimum health-based standards as required by the Federal Safe Drinking Water Act. DEC provides oversight of system design, installation, operation, and maintenance of drinking water facilities. Activities include review of project descriptions and engineered plans for new and modified systems. Oversight is executed at pump stations, response bases, support facilities, and temporary camps associated with TAPS.

Each drinking water system on APSC facilities is permitted by DEC and must comply with regulatory requirements. Each system's monitoring plan provides a uniquely tailored testing plan that demonstrates the water distributed is safe for consumption and meets all department standards. DEC oversight is accomplished through preliminary system review and by monitoring required operational records and water test results. The DEC routinely conducts Sanitary Surveys of the permitted systems to ensure proper system construction, operation, repairs, and that the system is safe to use. APSC maintains 17 permits for Drinking Water Systems associated with TAPS. Ten of these systems are in inactive status.

Food Service[14]

DEC's Environmental Health, Food Safety and Sanitation Program's mission is to protect public health at regulated facilities and to prevent illness, injury, and loss of life caused by unsafe sanitary practices.

Every food service facility associated with TAPS, both permanent and temporary, is required to maintain a current DEC Food Service Permit. At temporary facilities (camps), DEC's Drinking Water, Solid Waste, and Food Safety and Sanitation Programs all coordinate with the DEC Liaison to accomplish necessary approvals for these camps along TAPS.

[13] 18 AAC 80 & Grant and Lease Stipulations 1.20.1 and 4.1
[14] 18 AAC 31 and Lease and Grant Stipulations 1.20.1 and 4.1

The TAPS pump stations with food service operations and supporting personnel (PS 4, 5, 6, and 7) were all inspected by DEC in FY10. All of the issues identified during the inspection were corrected and the facilities continued to operate in compliance with DEC regulations.

Division of Water[15]
The DEC's Water Division oversees compliance to several Water Quality Permits formally administered under the Federal National Pollutant Discharge Elimination System (NPDES) program. These permits are now facilitated under the Alaska Pollutant Discharge Elimination System (APDES) and 18 AAC 83. While many of the activities conducted on TAPS are overseen under this permit process, the requirements of 18 AAC 70 and 72 also apply. The transition of primacy to DEC was planned in four phases.

APDES Phase II took place on October 31, 2009, and included discharges from federal facilities, miscellaneous discharges (e.g., utilities, ship and dry dock, filter backwash, transportation, and seawater treatment), pretreatment program (for industrial and commercial discharges to publicly owned treatment works), and storm water program. Phase III is expected to be accomplished October of 2010. Phase IV, which will include permits associated with the oil and gas industry, will complete in October of 2011. Existing EPA permits for facilities and activities will be transferred to DEC on the approval of the various phases. Transferred permits will remain in effect (along with the State certifications) until DEC issues an APDES permit to replace the EPA-issued permit.

The DEC Liaison conducted field observations of APSC activities in FY10 and reported wastewater disposal activities along TAPS and the VMT to the Division of Water, Permits and Enforcement programs as appropriate. Each activity with approved wastewater discharge was reviewed for compliance in FY10. The SWD sites and active operations material sites were also reviewed for storm water requirements. There were no compliance issues identified in FY10.

APSC continues to work on the VMT BWT redesign (project Z576). The Division of Water continues oversight and coordination with applicable JPO agencies. The NPDES permit for the BWT facility expired in 2009. Renewal of BWT NPDES permit will be managed by the EPA.

Division of Air Quality[16]
The mission of the Air Permits Program is to protect the Alaskan environment by ensuring that air emissions from industrial operations in the State do not create unhealthy air.

There are three outstanding DEC complaints related to Air Quality for TAPS from FY10. The complaints remain open and are related to violations of reporting requirements. Further information was not available for this report. The complaints involve PS 7, issued April 28, 2010; PS 5, issued June 29, 2010; and PS 12, issued May 2010. These cases will be followed and the disposition reported to the SPCO when closed.

[15] Water Quality, 18 AAC 70; Wastewater, 18 AAC 72; Alaska Pollution Discharge Elimination System (APDES), 18 AAC 83; Lease and Grant Stipulations 2.2.2.1 and 4.1
[16] Air Permits Program: 18 AAC 50 and Lease and Grant Stipulations 2.2.1.1, 2.2.4.1, 2.2.4.2, and 4.1

The DEC Liaison participated in a comprehensive review of the DEC Air Quality (AQ) permits on TAPS and the VMT in FY10. The effort was to review the various program requirements for APSC facilities and visit all of the APSC facilities to ensure compliance to the requirements of regulations and the Lease and Grant. The secondary effort of the review concentrated on APSC compliance with internal policies and procedures outlined in EN-43. The DEC Liaison collaborated on the review with DEC Air Permits Program staff and the JPO. Only one issue arose from the TAPS review. The issue concerned the engine being stored at PS 12 intended to be used should APSC need to implement the currently approved "TAPS Cold Restart" contingency plan. The team felt that the engine no longer met the definition of a Non-Road engine under 18 AAC 50, and would be required to have a DEC issued operations permit and petitioned the department's AQ program for a review of the issue.

APSC made commitments to the SPC and the AO concerning APSC's ability to implement a cold restart plan and prevent the problems associated with a prolonged stoppage of oil flow in TAPS during extreme winter weather. The main concern of the JPO was that the engine to be used to implement the plan in the PS 12 area was being stored at the GRB. Under this scenario, APSC would be required to move the engine to PS 12 and install the engine and associated piping before they could implement the cold restart plan. APSC committed to accomplishing this within 72 hours of need.

The JPO expressed concern to APSC about the length of time required to relocate and install the engine, and hesitated to agree that the process could be accomplished within the allotted 72 hour time. APSC responded to the JPO that if they were to move the engine to PS 12, the engine would be required to obtain a DEC AQ permit. The DEC Liaison coordinated a review of the Cold Restart Plan and use of the identified engine with the AQ Division. After its review the AQ permits group determined that the engine, as defined by APSC, would require a permit even if it was being stored at the GRB. The JPO is reviewing actions that would require APSC to install the engine at PS 12 to ensure that it is operational within the 72 hour timeframe ASPC has committed to.

Open burning and dust suppression continue to be the most prevalent activities requiring DEC's AQ oversight on TAPS. Both activities are regulated by 18 AAC 50. Open burning requires a permit from DEC. Open burning is typically conducted by APSC to reduce the volume of wood waste, which allows for more efficient use of space in SWD sites along TAPS. Each of the three permitted SWD sites have provisions for open burning. Dust suppression is routinely conducted at TAPS pump stations and at pipeline project sites. Some of these dust control efforts are governed under general permits issued by the program which stipulate control measures and methods for dust control. These activities and requirements are coordinated between JPO and DEC.

Contaminated Sites[17]

APSC began to initiate plans In FY10 that will lead to the dismantling and removal of facilities and equipment no longer required for the operation of TAPS. This is referred to as "asset retirement" by APSC and "completion of use" by JPO. There are many questions

[17] Contaminated Sites Program: 18 AAC 75, Lease and Grant Stipulations 1.18.3, 2.2.1.1 and 4.1

related to this process regarding historic spills and contaminated sites that have occurred along TAPS from construction to the present and what level of "cleanup" will be required by the land managers before property is released from ROW requirements. The DEC Liaison coordinated with the Contaminated Sites program to provide JPO with a copy of the DEC's database records that reference the current contaminated sites along TAPS. A conference between the department Contaminated Sites Program and JPO managers and staff to outline program information and policies and answer questions related to DEC policy is being developed. This is an opportunity for department personnel to understand the needs of the JPO, to better facilitate collaboration between the agencies, and to help ensure the sites are returned to the land managers in an acceptable condition.

Department of Fish and Game FY10 Activities in Related to TAPS

Field Inspections

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. Pre- and post-project sites were visited and written surveillance reports were completed at a representative sample of the locations. Solutions were discussed for construction, maintenance, and project timing to avoid or minimize impacts to fish resources and habitats.

The ADF&G Liaison's surveillances activities revealed that APSC Baseline Crews have been actively maintaining LWCs and culvert structures along the ROW in compliance with the conditions and stipulations of Fish Habitat Permit FH 09-SPO-0011 to ensure efficient fish passage. The ADF&G Liaison completed 30 written surveillance reports in FY10 (see Appendix G: SPCO Reports Issued in FY10 for a full list of reports).

APSC Environmental Surveillances and Repairs

Fish stream surveillances were conducted at 648 sites along TAPS. The APSC ROW and Civil Maintenance group worked on 79 of those drainage structures in 2009; 11 sites (1.7%) required extensive repair (and Fish Habitat Permits issued by this office) to provide long-term fish passage; and 68 sites (10.5%) required routine maintenance (under the linewide Fish Habitat Permit); the remaining 569 sites (87.8%) required no work.

Environmental Issues of Interest to the JPO

Fish Passage Improvement Projects:

Milky Creek is located approximately 22 miles north of PS 3 and approximately 82 miles south of Prudhoe Bay. In this area the Dalton Highway and FGL follow the west side of the Sagavanirktok River. Milky Creek is an entrenched and meandering stream that flows through wet tundra. The soils in the area are thaw-unstable and ice-rich gravels and silts. The FGL rose in elevation, lost its depth of cover, and became a barrier to fish passage. APSC restored fish passage over the FGL in Milky Creek by installing three riffle grade control structures. The photograph on the next page (Figure 20) was taken after the completion of project work to install the riffle grade control structures. The riffles were constructed with approximately 200 cubic yards of class I-III riprap and 100 cubic yards of gravel. Tundra mats were used during project access to protect fragile plant communities.

Figure 20: Milky Creek (After Project Completion)

Climb Creek is located approximately 4 miles north of PS 3 and approximately 100 miles south of Prudhoe Bay. In this area the Dalton Highway and the pipeline follow the west side of the Sagavanirktok River. The elevation is 1,400 feet. Climb Creek is a minor tributary of the Sagavanirktok River and, much like Milky Creek, is an entrenched and meandering stream that flows through wet tundra. The soils in the area are thaw unstable and ice-rich gravels and silts. At the project site, Climb Creek ranges between 10 and 20 feet in width, with banks about 8 feet in height. The FGL is 8 inches in diameter at this location.

APSC restored the depth of cover required for the FGL where it crosses underneath Climb Creek. The project also installed culverts across the drivelane to restore northbound and southbound vehicle access to nearby portions of the ROW. Figure 21 illustrates the state of the culverts before the project and Figure 22 shows the new culverts after project completion. The culvert barrel was backfilled with class I-II riprap and gravel. Boulder clusters were placed randomly within the barrel to enhance fish passage; steam tubes were installed to help prevent icing. An additional riffle was installed downstream of the culvert outlet to provide additional outlet control (to slow water velocity in the culvert barrel and to provide backwatering at low flows).

Figure 21: Climb Creek Culverts (Before Project Work)

Figure 22: Climb Creek Culverts (After Project Completion)

The West Fork (WF) of the North Fork (NF) of Chandalar River site is located on the east side of the river valley approximately 35 miles south of PS 4 and 60 miles north of Coldfoot. Soils consist of frozen silty sand, sand, gravel, and frozen silts which are susceptible to thermal and hydraulic erosion. At this location, the Chandalar River is a wide braided gravel bed stream with multiple sub-channels across the width of the floodplain.

Progressive bank erosion diminished the buffer between the river and the above ground pipeline (Figure 23). The bank height of the eroding toe at this location ranges from three to eight feet. Bank protection was needed to prevent further erosion because a major flood could reduce the remaining buffer. The project required the eroding toe slope to be filled with rock and the structure to be incorporated with layers of willow plants. A vegetated rock toe structure about 240 feet in length was constructed. The core of the rock toe consists primarily of riprap; gravel fill was used in the interstitial spaces to promote additional revegetation (Figure 24). After constructing the core, one or more layers of willows were installed (approximately 6-8 willows per foot). Each layer was roughly three feet apart on the slope. Willow planting should have been conducted in accordance with ADF&G guidelines for streambank revegetation, which includes trimming the above-ground plant stems. The plants were not immediately trimmed. APSC Environmental Coordinators retroactively trimmed the willow stems in 2009, following a site inspection by the ADF&G Liaison.

Figure 23: WF NF Chandalar River (Before Project Work)

Figure 24: WF NF Chandalar River (After Project Completion)

Table 7 ADF&G Work Plan Accomplishments for FY07 through FY10

Permit & Field Activity Summary	**FY07**	**FY08**	**FY09**	**FY10**
Fish Habitat Permits Issued	54	43	39	18
Hazing Permits Issued	0	0	0	2
"No Permit Required" Letters	1	3	0	3
Fish Habitat Permit Denials	0	0	0	0
Withdrawn Applications	2	0	0	0
Written Comments on Other Agency Permits	11	5	5	5
Compliance Reviews – Permits, Lease, Grant	49	54	47	40
Total Reviews and Permits Issued	**68**	**51**	**44**	**26**
Total Field Reviews	66	124	77	82
Total Field Days	15	14	13	11

Permit Issuance and Field Activity Summary
The ADF&G processed 26 total reviews and permits in FY10 (18 Fish Habitat Permits, 3 no permit required letters, and 5 written comments on other agency permits). The ADF&G Liaison traveled the entire 800 miles on, or adjacent to the pipeline corridor visually inspecting a representative sample of cross-channel structures, and writing a detailed surveillance report on a subset of those inspections).

River and Floodplain Monitoring
Maintenance Coordinators and Engineers for APSC have conducted River and Floodplain Monitoring since construction of TAPS. This monitoring program is accomplished by using aerial surveillance specifically to observe and document changes in river environments that may affect the TAPS. The ADF&G received the list of preliminary recommendations of sites needing "corrective maintenance" and "predictive maintenance" (corrective maintenance was recommended in 2009; predictive maintenance needs to be prioritized,

planned and scheduled in 2010 or later years). APSC requested ADF&G input on project timing and scope to avoid or minimize impact to fish and wildlife resources and habitats. During FY10, the ADF&G provided the requested information to APSC during the early planning stages of those future projects.

Strategic Reconfiguration
APSC has progressed with their "Plans" to upgrade and modernize TAPS through SR. The reconfiguration program includes projects such as SCADA (supervisory control and data acquisition), telecommunications, control system upgrades, electrification of pump stations, Oil Spill and Maintenance Plan revisions, development of Human Resource plans, review of all environmental reports, and review of Transportation Plans. The goal of these changes is to increase efficiency and lower the cost of oil transportation by taking advantage of current technology. The Plan was finalized and approved by the State Pipeline Coordinator and the Authorized Officer on June 30, 2003. Plan reviews and the corresponding approvals have been ongoing since November 2003. The ADF&G Liaison regularly attends update meetings (when they occur) and remains committed to this effort.

2009 Capital CP Upgrades (Project F573) –
Four sections of the buried sections of TAPS did not meet the criteria for cathodic protection. Cathodic Protection upgrades were required to ensure that these areas are adequately protected to conform to federal regulatory requirements for CP. In addition to issuing Fish Habitat Permits the ADF&G Liaison reviewed DEC's "Notice of Disposal" in FY10 in accordance with Part A., Section I of NPDES Permit No. AK-005056-3.

Resource Documents Updated –
The ADF&G Liaison updated the *BLM Alaska Open File Report 105, Fish Streams Along the Trans-Alaska Pipeline System*. This report serves as the source document for updating a list of areas under state and federal administration where pipeline activities may have to be restricted to protect fish breeding, spawning and major migration. The open file format was chosen to more easily facilitate additions or corrections resulting from any future state, federal, APSC, or other studies of pipeline streams. The ADF&G Liaison is also updating *Open File Report 104, Zones of Restricted Activity for Protection of Key Fish Areas Along the Trans-Alaska Pipeline System on Federally Administered Lands*. The TAPS Grant Stipulation 2.5.3 list only includes streams in areas of federal pipeline administration and was issued to the Permittees' agent, APSC. This cooperative effort will continue to protect valuable fish resources and habitats important to the State of Alaska.

<u>Department of Labor and Workforce Development FY10 Activities Related to TAPS</u>

Safety
The DOLWD Safety Liaison conducted 35 annual safety inspections of APSC facilities for compliance with Lease and Grant stipulation 1.20, Health and Safety. Federal Occupational Safety and Health Standards (29 CFR 1910 and 29 CFR 1926) were used for an inspection standard. The facilities inspected included each pump station, the response bases, DRA injection site at PLMP 238, the Fairbanks area shops and storage facilities, and the VMT.

In addition to annual inspections, the DOLWD Safety Liaison conducted 11 work site inspections for compliance with Lease and Grant stipulation 1.20 Health and Safety (see

Appendix G Appendix G: SPCO Reports Issued in FY10for a full list of reports). The inspection standard for a work site is the same as annual inspections, with more emphasis on safety programs and procedures.

The DOLWD Safety Liaison also reviewed the monthly accident statistics for APSC and APSC contractors. Table 8 below breaks down the DOLWD Safety Liaisons activities into seven categories.

Table 8: DOLWD Safety Liaison FY10 Activities

Work Plan Activity	FY10 Total
Annual Stipulation 1.20 Surveillance	35
Work Site Stipulation 1.20 Surveillance	11
Review Project Safety Plans	0
Review Monthly Accident Statistics	12
Assessments	0
Technical Reports	0
Accidents Investigated	0

Injuries

APSC reported one recordable injury during FY10. A "Recordable Injury" is any injury requiring medical treatment. The recordable injury occurred on September 20, 2009 - an APSC employee was flying back to work on a Shared Services Flight. The employee was asleep in a reclined position in the assigned seat with head resting on the side of the seat back next to them which was in an upright position. A passenger in the row behind the employee got up and pushed the reclined seat forward to have enough room to pass. This resulted in the employee instantly waking up with neck pain and the sensation of the wind being knocked out of them.

December 23.2009 - a Crowley employee's right index finger was pinched between two objects, resulting in a tuft fracture.

On July 25, 2009 - a CASI employee's left ankle was rolled when the employee stepped away from a step ladder, which strained the ankle and required medical treatment.

March 3, 2010 - a Crowley Marine Services employee stowed a trash bag into a trash tote. The crew member reached into the tote to move another bag to create more room and a can lacerated the employee's left hand. The employee received prescription medication resulting in a recordable injury.

April 8, 2010 - a Doyon employee was checking the south access gate at 65-APL-1 South Wickersham Dome access. The employee slipped on a snow covered patch of ice, fell and fractured a rib.

May 9, 2010 - a Houston Contracting employee at PS 4 was moving a length of 4-inch pipe into final position for bolting, when the individual felt a pull between the shoulders. The individual was given prescription medicine.

ADOL Enforcement Activities (other than electrical)

OSH issued a citation on an overhead hoist at PS 1 and was later vacated.

Electrical Inspections

There were several major developments in electrical projects and innumerable small projects on the TAPS in FY10.

- Linewide - Work continued on the new Control, Automation, Communications, and Security systems. Most of the work at unmanned and ramped-down pump stations is complete, but work at the staffed facilities was postponed. Work is now in progress at the North Pole Metering Station (Figure 25), several river crossings, and the GRB.

Figure 25: North Pole Metering Station

- PS 1 - The SR Project was delayed and renamed the Trans-Alaska Pipeline EA Project
- PS 3 – Post-SR project work and work on the security system is ongoing.
- PS 4 – Post-SR project work is still ongoing.
- Petro Star Metering Facility in Valdez - APSC installed a new larger capacity metering facility (Figure 26) to accommodate the increased capacity of the rebuilt Petro-Star refinery. The installation included updated equipment consistent with the control and automation upgrades linewide.

Figure 26: New Petro Star Metering in Valdez

- Permanent Living Quarters (PLQ) Kitchen remodels - APSC is remodeling the kitchens in the occupied PLQs. PS 5 and 6 are complete, with PS 4 next on the schedule. Figure 27 shows the PS 5 kitchen in progress; Figure 28 shows the PS 6 kitchen near completion.

Figure 27: PS 5 Kitchen Remodeling

Figure 28: PS 6 Kitchen Remodeling

- APSC remodeled a portion of the first floor of the VMT office to enlarge and modernize the accommodations for security and EMT personnel.

The DOLWD Electrical Inspector also tracks code violations, issues Notices of Violation, and verifies the corrections with follow-up inspections. The Electrical Inspector confirms that electricians and contractors are licensed. The inspector 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 FY10, the

Electrical Inspector performed 72 inspections, issued four notices of violation (all have been corrected) and reviewed 26 Certificates of Fitness. The Electrical Inspector also provides code interpretations, both verbal and written, and JPO engineering staff consultations. A list of all FY10 inspection reports can be found in Appendix G.

State Fire Marshall's Office FY10 Activities Related to TAPS[18]

The State Fire Marshal's Office Liaison, under the authority of the State Fire Marshal and pursuant to the provisions and stipulations of the TAPS Grant and Lease, conducts fire and building inspections, building construction inspections, fire life safety inspections, building plan reviews, fire system plan reviews, and other related activities.

TAPS Fire Inspections

The annual TAPS inspections were conducted in May and June of FY10. The inspections covered the entire length of the pipeline from PS 1 to the VMT and included SERVS, Galbraith Airport, Prospect Airport, Fairbanks Response Base, North Pole Metering, and Petro Star Metering. Altogether 279 buildings were inspected and 84 hazards were identified for corrective action. The number of items requiring corrective action was greater in FY10 than FY09; however, this year's corrections were minor in nature and most were corrected on the spot (COTS).

Plan Reviews

APSC submitted 33 plan reviews for FY10, one of which is still pending and was put on hold by the APSC project team.

Significant Issues (TAPS)

- Smoke detector activation failed to shut down power to the Power Distribution Center (PDC) module and PS 3 during the July 2009 shutdown. An order to correct was drafted in cooperation with the BLM/OPM staff and submitted to APSC in response to the incident at PS 3. APSC responded with a plan of action.
- The main fire panel at PS 4 failed during the weekend of October 10, 2009, resulting in a trouble signal that was acknowledged but no corrective action was taken. The cause was identified as failure of the battery back-up for the panel. APSC was issued a Notice to Correct which identified a concern that the process for properly identifying the system malfunction and initiating corrective actions was not carried out in a timely manner. APSC responded with a plan of action and resolved the problem.
- FCO work was completed for the TGs at PS 3 and PS 4 and the PDC Module at PS 4. A Notice to Correct was sent to APSC requesting final documentation, cause and effect matrixes, and commissioning documents no later than March 18, 2010. APSC responded with working FCO documentation. Final certification of fire systems was

[18] Note: The Division of Fire and Life Safety recently implemented a new automated permit program called Hansen. The inspection module of the program was utilized to generate several of the SFMO Liaison's reports. Several issues are being addressed (letter/report dates may not match actual inspection dates), however, all notices to correct were submitted within two weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

requested and received.

- A Halon dump occurred in the hallways of PS 6, this was an isolated event and it was not connected to the overall fire system. A portable heater in the hallway triggered a thermal detector; the fire suppression system responded to by releasing Halon.
- A Request for Information (RFI) (Letter 10-141-AS) was issued on May 20, 2010 regarding fire system testing at PS 3 and 4 during the May 18 mini-shutdown. The RFI also addressed the pipeline shutdown that occurred as a result of fire system maintenance at PS 4 on May 3, 2010. Response is pending.
- A RFI (SPCO letter 10-154-AS) was issued on May 26, 2010 requesting the results from fire system testing required by BLM/OPM letter 10-033-RN.
- A spill occurred at PS 9 in May 2010 when Tank 190 overflowed during fire testing of the PDC Module requested by the BLM/OPM. A report from APSC is pending.
- APSC is installing a Marioff Fine Water Mist sprinkler system in the PLQ at PS 6 and is replacing the kitchen hood and duct systems for PS 4, 5, and 6. APSC plans to install similar sprinkler system at PS 4 and 5. The SFMO Liaison is conducting mechanical and fire inspections on this project.

Significant Issues (VMT)

- APSC issued a request in December of 2009 to shut down the redundant fire lines to berths 4 and 5 at the VMT. APSC plans to perform a risk assessment early next year. A risk assessment was completed and submitted by this office for review.
- In November 2009, the Fire Marshal was informed of budget cuts affecting the fire team at the VMT. A letter of concern was sent to APSC in January 2010 and APSC responded in March. A meeting took place and APSC sent a letter addressing the final concerns of the State Fire Marshall in late April. The issue is closed.

Miscellaneous Activities:

The SFMO Liaison accompanied a BLM/OPM representative to PS 4 this past February to witness the FCO process for the Turbine Generators. In July 2009, the SFMO Liaison witnessed the FCO for the Gas Building at PS 1. In May 2010, the SFMO Liaison was called to the spill event at PS 9 to ensure that fire safety procedures in use were compliant with current fire codes and NFPA standards during transfer of crude oil to tank trucks. The SFMO Liaison attended the annual State Fire Marshal's Forum, Edu-Code training, and the National Fire Academy in Emmetsburg, Md.

SOUTHCENTRAL PIPELINES

This section of this report focuses on the Southcentral pipeline systems over which the SPCO exercises jurisdiction – the Kenai Kachemak Pipeline (KKPL), operated by Marathon Pipe Line, LLC, and the Nikiski Alaska Pipeline, operated by Tesoro Alaska Pipeline Co. These pipelines are authorized by ROW leases granted under AS 38.35. The routes of these pipelines are depicted below in Figure 29. The discussion of each system includes an overview, highlights from the lessee's annual report, and a summary of SPCO activity for that particular pipeline system.

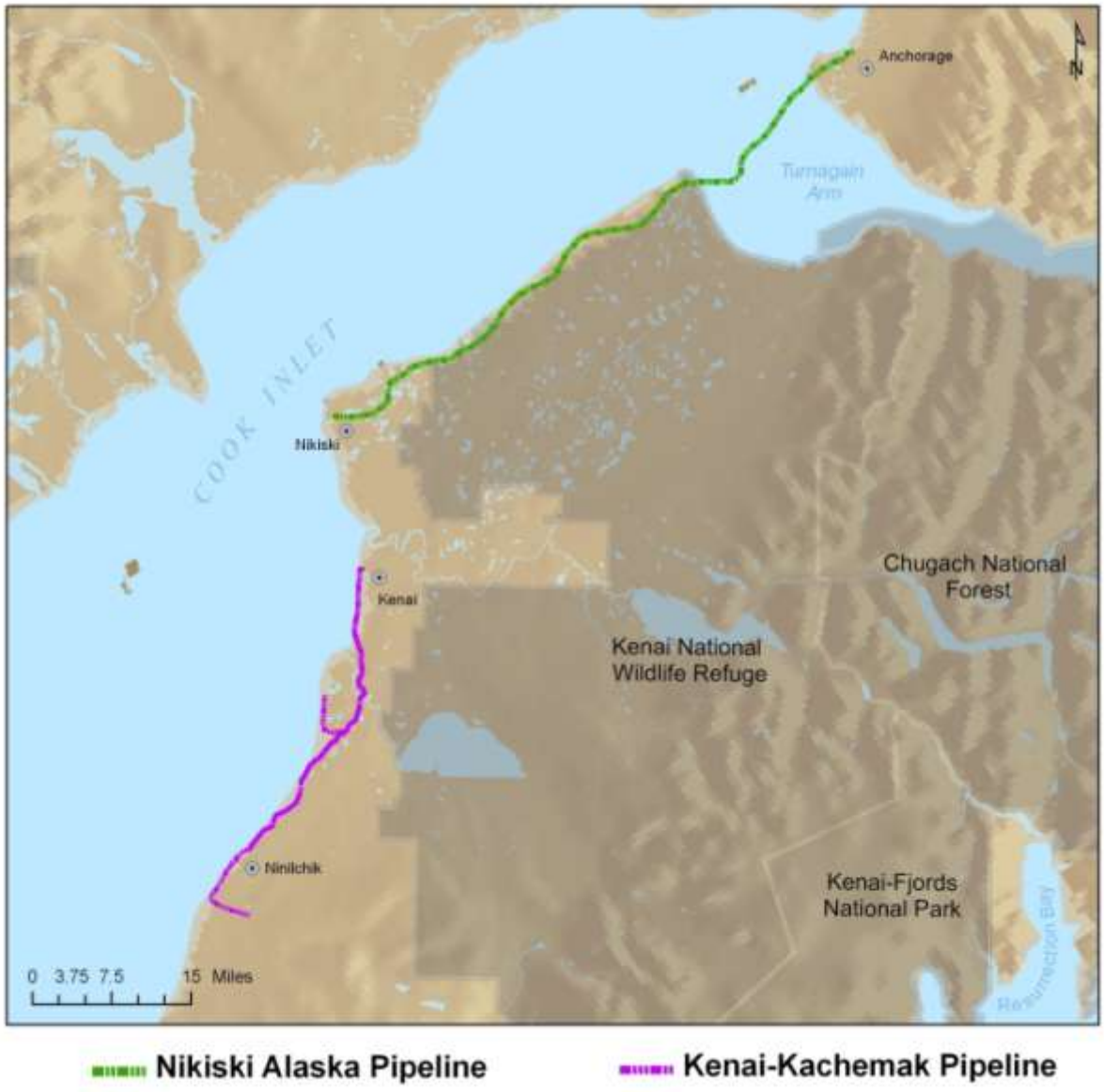


Figure 29: Area Map of SPCO Jurisdictional Pipelines in Southcentral Alaska

SPCO representatives made nine trips to the field for the Kenai Kachemak Pipeline, the Nikiski Alaska Pipeline, and the proposed North Fork Pipeline (Figure 30).

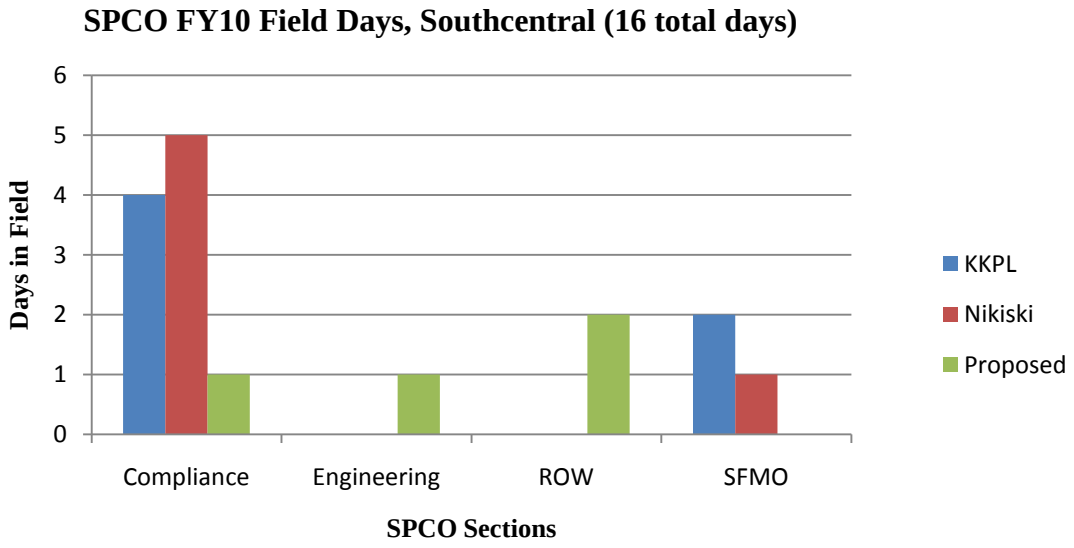


Figure 30: Chart of SPCO FY10 Field Days, Southcentral Pipelines

Kenai Kachemak Pipeline

Figure 31: Pig Receiver and KKPL Terminus Building

Right-of-Way Lease and Pipeline System Overview

The Kenai Kachemak Pipeline 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 0.500-inch wall thickness, and is rated for a maximum allowable operating pressure of 1,480 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 (see Figure 31 above). A route map of the pipeline can be found on the next page (Figure 32). Seven Cook Inlet wells currently transport natural gas through KKPL. Some natural gas is distributed from KKPL for local use.

The original ROW 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 ROW 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).

Figure 32: KKPL Route Map

The *ROW Release of Interest* was finalized in FY09 and reduced the ROW from the construction width of 60-feet to the operational width of 20-feet. Specific acreage amounts associated with the construction and operational ROW width are provided in Appendix D: Acreage, Survey, and Lease Information. Information about rental and appraisals can be found in Appendix E: Pipeline Right-of-Way Lease Appraisal Information.

State Pipeline Coordinator's Office Summary of Marathon Pipe Line Company's CY09 Annual Report for the Kenai Kachemak Pipeline

The *Kenai Kachemak Pipeline 2009 Annual Report* was submitted in January 2010 and amended on March 9, 2010. The SPCO reviewed the Kenai Kachemak Pipeline 2009 Annual Report and found that it provided sufficient information to satisfy the lease requirement (SPCO Letter No. 10-169-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, excerpted from the Annual Report.

Throughput and Pigging

KKPL, LLC, reported pipeline throughput and pigging activities in their 2009 annual report. This information is summarized in Table 9. Throughput for all of the SPCO jurisdictional pipelines can be found in Appendix I.

Table 9 Throughput and Pigging Information for KKPL, CY09

Pipeline System	2008 Throughput	Maximum Operating Pressure (MOP)	Maintenance Pigging	Last Smart Pig Run	Pipeline Operator
KKPL	19,982 MMcf	1,480 psig	No regular schedule	2005	Marathon Pipe Line

Safety

The KKPL operator reported no lost time incidents or recordable accidents/injuries during 2009, for either operator personnel or contractors and material providers. It was also reported that there were no discharges of oil or hazardous substances by Marathon Pipe Line during 2009.

During 2009, Marathon Pipe Line introduced a change in the implementation of its safety program, terming it the "Structured Safety Process" or SSP. The SSP philosophy is one where "safety" is not driven down from the top of the organization but rather driven up from the bottom. It is designed to further engage workers who know the realities of the work performed and the environment in which it takes place. The idea is that safety issues are resolved at the lowest possible level and the issues and resolution are elevated and communicated throughout the Marathon Pipe Line organization.

As part of its public safety efforts, the operator participates in the *One-Call* damage prevention program. There were 166 locate requests in 2009, which resulted in 23 onsite locates and 12 high-pressure standbys. The One-Call program is important to the community for the prevention of third-party pipeline damage that could threaten public safety.

Corrosion Protection

To minimize the potential for internal corrosion, the operator regularly sampled gas for quality, 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 2009 annual report. The gas content was reported as consistently greater than 99% methane. Hydrogen sulfide is minimal and ranged from 0-0.3 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 rectifiers for KKPL were inspected 13 times in 2009. As part of the CP program, a pipe-to-soil survey is completed annually, with intervals not exceeding fifteen months, and coupon current readings are taken periodically at four locations along the KKPL and every mile of the KE. A pipe-to-soil survey was completed in July 2009.

Valve Inspection and Maintenance

Inspection and maintenance of KKPL mainline valves was conducted by MPL personnel in July 2009. All greaseable valves were lubricated, checked for leaks and operated. No deficiencies (e.g., leaks, improper operation, security issues, etc.) were noted on any of the mainline valves. Valve records are kept on file at Marathon Pipe Line's Kenai, AK office.

Leak Surveys

On-ground leakage surveys of the KKPL pipeline using leak detector equipment were conducted in February and again in September 2009. Two leaks were found during the February survey, both of which were in underground vaults at the HVE and Paxton laterals. The leaks were repaired and no gas was detected during the September survey.

Aerial and Ground Surveillance

There were 44 aerial patrols of the KKPL in 2009. During those flights, and other drive-by inspections, 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 major findings in 2009.

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(*This section provides a summary of SPCO activities during FY10. The information in this section reflects work conducted by the SPCO and was not taken from the lessee's annual report. By the nature of the SPCO oversight activities there may be some overlap of information.*)

During FY10, the SPCO focused on the Surveillance and Monitoring Program (SMP), construction ROW relinquishment, appraisal and rental adjustments, and operator transition. These activities are presented, in more detail, below:

Compliance Section FY10 Activities

September 29, 2009 Aerial ROW Inspection

SPCO staff traveled to Kenai to observe Marathon's contracted pilot perform an aerial inspection of the KKPL Right-of-Way. Marathon performs a pipeline ROW inspection at least 26 times each calendar year, not exceeding 3 weeks between inspections. A document check related to Marathon's QAP and the SMP was also conducted while at Marathon's operations center. Specific foci on the programs included water-related pipeline crossings, valve pad inspections, occupational injury and illness reporting, vender qualifications, pilot qualifications, and past aerial surveillances. Five surveillance reports were completed for the trip and all reflected satisfactory conditions (SPCO Letter 09-042-CT). Figure 33 below is a photograph of the Happy Valley production pad taken during the September trip.

Figure 33: Happy Valley Production Pad

March 17, 2010 KKPL Document Check in Kenai

SPCO staff traveled to Kenai to meet with the Marathon Pipe Line, LLC Kenai Area Manager and the Kenai Area Operations Supervisor to perform a document check related to the General Stipulations section of the KKPL Lease. Topics of discussion included the SMP, the QAP, fire prevention and suppression, KKPL's communication system, and electronically operated devices. Five surveillance reports were completed for the trip and all reflected satisfactory conditions (SPCO Letter 10-117-AS).

Lease Required Contact Information

The SPCO received a notification letter on April 30, 2010, stating that effective May 17, 2010, there would be a new Area Manager for Marathon Pipe Line in Kenai. Included in the letter was the new contact information as required by the lease (Appendix J). Five surveillance reports were generated from this action all of which showed satisfactory observations (SPCO Letter 10-140-AS).

June 14, 2010 KKPL Annual Valve Testing Observation

SPCO staff traveled to Kenai to observe annual valve testing at the KKPL terminus and to observe the ROW from the northern terminus to the southern origin at the Happy Valley production pad. Marathon performs annual testing of the pressure relief valves at the terminus of the pipeline. USDOT, 49 CFR 195.428, requires that pressure relief valves be inspected annually, not to exceed 15 months between any two tests. Pressure relief valves provide mainline pressure relief at the station. These valves are used to control pipeline pressure surges and, during normal operations, prevent exceeding a certain pre-set pipeline pressure level. There were five relief valves located in the KKPL terminus module (see Figure 34 below) that required the annual test.

After witnessing the valve testing SPCO staff traveled with the Marathon Kenai Area Manager to the southern origin of the pipeline. The route went south on the Sterling Highway, as the majority of the ROW is adjacent to the highway. Stops were made at all the valve stations where the well pads tie back into the primary pipeline, including the Happy Valley production pad, Paxton Lateral Pad, Susan Dionne Pad, State Pad, G. Oskolkoff Pad,

Falls Creek Pad and the Kasilof South Pad.

No obstructions were noted by SPCO staff while driving the ROW. The ROW appeared to be brushed and maintained. The aboveground pipeline valves located within fenced enclosures were in good condition and well marked. A compliance report and six surveillance reports were completed for the trip and all reflected satisfactory conditions (SPCO Letter 10-304-AS).

Figure 34: Inside the KKPL Terminus; Two Tested Spring Valves

Engineering Section FY10 Activities, KKPL

The Kenai Kachemak Pipeline had no major incidents during this reporting period. The new operator, Marathon Pipe Line LLC, continued transition into managing the operations of the pipeline. The pipeline will have increased flow from the new North Fork development by mid 2011. ENSTAR is planning to connect a new pipeline, the Anchor River Pipeline, to KKPL. This new line will connect to the terminus of another new pipeline, the Anchor Point Energy, LLC, pipeline. Both pipelines will transport natural gas from a development at North Fork.

State Fire Marshal's Office Liaison FY10 Activities[19]

Annual Fire inspections for facilities associated with the Kenai Kachemak Pipeline were conducted on September 9 and 10, 2009. A total of 13 facilities associated with this pipeline were inspected including East Forelands, KKPL Terminus, and KKPL Junction. Three of the 13 facilities were found to have a total of 10 violations that have since been corrected.

[19] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

Nikiski Alaska Pipeline

Figure 35: Tesoro Refinery in Nikiski

Right-of-Way Lease and Pipeline System Overview

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 ROW for the remainder of the route, terminating at the Port of Anchorage. Figure 35 above, is an aerial photograph of the Tesoro Refinery in Nikiski, Alaska.

The ROW 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 ROW 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 of State land (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 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.

State Pipeline Coordinator's Office Summary of Tesoro Alaska Pipeline Company's CY09 Annual Report for the Nikiski Alaska Pipeline

Tesoro submitted its *2009 Annual Comprehensive Report on Pipeline Activities and State of the Pipeline System for Tesoro Alaska Pipeline Company (Nikiski) Right-of- Way Lease - ADL 69354* on January 25, 2010. The report was reviewed against minimum annual reporting requirements, as described on page 7 of this report, and requested additional information on the state of the pipeline system in SPCO Letter 10-072-CT. Tesoro provided the information on March 9, 2010.

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 *2009 Annual Comprehensive Report on Pipeline Activities for Tesoro Alaska Pipeline Company (Nikiski) Right-of- Way Lease - ADL 6935* are summarized below.

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. Table 10 breaks down throughput for each product transported in 2009. 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 98.83% for 2009.

Table 10: 2009 Refined Product Throughput, Nikiski Alaska Pipeline

Product	2009 Throughput
Jet-A	5,242,557 barrels
Unleaded gasoline	3,453,281 barrels
Premium unleaded	591,262 barrels
Ultra-low-sulfur Diesel (ULSD)#1	1,492,935 barrels
ULSD #2	626,677 barrels
Total	*11,406,712 barrels*

The Nikiski Alaska Pipeline was last inspected with a smart pig in January 2007. Batch pigs are used to separate batches of different products transported through the pipeline. Maintenance pigs are not routinely used. Table 11 provides total throughput, reliability, and pigging information for 2009 (see Appendix I: Throughput for SPCO Jurisdictional Pipelines, 2009).

Table 11: 2009 Throughput, Reliability, and Pigging Information, Nikiski Alaska Pipeline

Pipeline System	2009 Throughput	Reliability	Maintenance Pigging	Last Smart Pig Run
Nikiski Alaska	11,406,712 barrels	98.83%	No regular schedule	January 2007

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 288 one-calls regarding dig activities in the vicinity of the Nikiski Alaska Pipeline in 2009; 138 originated in the Anchorage area and 150 originated in the Kenai area.

The only one-calls that resulted in exposure of the Nikiski Alaska Pipeline in Anchorage were the one-calls initiated by Tesoro. These one-calls were in support of the CP test coupon station installation project. Tesoro installed seven CP test coupon stations for this project; three of the test coupon stations were on the ASIG Spur pipeline section of the Nikiski Alaska Pipeline, and four of these stations were on the main Nikiski Alaska Pipeline.

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 11 Abnormal Operating Conditions in 2009 (Table 12). Every Abnormal Operating Condition event was investigated and verified as a routine equipment switch error with no operating limits being exceeded, and this was documented as "cleared." Tesoro is actively pursuing a resolution to this problem.

Table 12: Summary of 2009 Abnormal Operating Conditions

Date	Abnormal Operating Condition Description	Status
7-19-09	MLV-9 communication failure	cleared
7-19-09	MLV-6 communication failure	cleared
7-20-09	MLV-6 communication failure	cleared
7-22-09	MLV-6 communication failure	cleared
7-25-09	Power outage – shutdown pipeline until restored	cleared
7-30-09	MLV-6 communication status	cleared
8-04-09	Power outage – shutdown pipeline until restored	cleared
8-28-09	MLV-5 Battery volt alarm & communication failure; replaced card	cleared
9-02-09	RTD 5 is bad. Found loose connection to control board; repaired	cleared
9-02-09	MLV-3 low voltage on battery – new control card/installed new action Packmodulator	cleared
11-23-09	Drive coil shorted – replaced with new pneumatic actuator	cleared

Per USDOT 49 CFR 195.402(a), Tesoro is required to have a written operations and maintenance manual and to review it once each calendar year. Based on this review, there may or may not be any revisions required. The last review and binder revision occurred on July 1, 2009.

Corrosion Management

Tesoro recorded rectifier readings monthly. The annual cathodic protection survey was completed during June-July of 2009. The survey consisted of field testing, minor test station repairs, and visual examinations. The 2009 Annual Cathodic Protection Survey contained seven recommendations for adjustments and maintenance. An ILI assessment of the ASIG lateral pipeline segment occurred in February of 2009. There were no USDOT Integrity Management Program (IMP) required repairs. One "heavy weld anomaly" was noted in the

report. The anomaly was investigated and was reported to be a non-issue. This pipeline section was re-taped upon investigation completion.

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). Tesoro's 2009 survey provided Tesoro with recommendations for CP adjustments and maintenance.

The 2008 and 2009 Annual CP Survey Reports contained several recommendations for adjustments and maintenance

- Continue the installation of coupon monitoring stations on the Anchorage side of the pipeline system (this is an ongoing action).
- Install coupon test stations with test leads to the pipeline and/or casing, near the corner of Wisconsin St. and Northern Lights Blvd. The test station was installed in October 2009. Casing test leads were also installed at this location.
- When the casings are exposed, perform additional testing to determine if the pipeline is shorted to any of the casings. Coordinate this activity with ENSTAR as its pipeline shares the same ROW in this area. No casings are indicated as shorted per the 2009 annual CP survey. Test leads will be installed as needed and inspections will be made during any excavations.
- Install a coupon test station with test leads to the Tesoro and Flint pipelines and casing located at this site. Install a shunt to measure the bond current between the pipelines. A new coupon test station was installed at the site to meet this requirement.
- Install coupon monitoring stations on the ASIG lateral. Coupon test stations were installed at the ASIG lateral in July 2009.
- Continue performing and recording monthly rectifier readings. Rectifiers were read monthly. This item is ongoing for 2010.
- Continue performing and recording annual cathodic protection surveys. Annual survey was performed in summer 2009 and will be performed in June-July 2010.

ROW Maintenance Activities

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 2009 were from pipeline mile post 15 to 46.

Tesoro reported that employees performed 61 ROW inspections in 2009. There were four findings noted during ROW inspections (Table 13). With the exception of one item which is scheduled for repair, all deficiencies have been corrected.

Table 13: 2009 Nikiski Alaska Pipeline ROW Inspection Findings

Date	Findings
05-15-09	Replaced two damaged ROW markers @ Tesoro Brand line tie-in to AFSC; no other deficiencies noted-Anchorage
10-19-09	Deficiencies noted-Anchorage; ground patrol; several trees on ROW at Clithrow Center; trees were removed during ROW inspection
10-29-09	Deficiencies noted- Anchorage; ground patrol several trees on ROW from winds @ MLV #9; trees were removed during ROW inspection
11-19-09	Deficiencies noted-Anchorage; ground patrol; Test coupon station #44 is damaged; contractor has been contacted to repair it

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, performed in 2006, indicated no features near the submerged pipeline that would pose a risk.

Summary of Discharges

Tesoro records all oil and hazardous substance discharges within the Logistics Incident Database. 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 Tesoro Nikiski Pipeline ROW in 2009.

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(*This section provides a summary of SPCO activities during FY10. The information in this section reflects work conducted by the SPCO and was not taken from the lessee's annual report. By the nature of the SPCO oversight efforts there may be some overlap of information.*)

Compliance Section FY10 Activities, Nikiski Alaska Pipeline

In addition to ROW usage, the Compliance Section focused on the SMP and the QAP in FY10. A list of all reports produced by the SPCO in FY10 can be found in Appendix G.

August 10, 2009 Quality Assurance Program On-site Document Checks

SPCO staff traveled to Kenai to examine a sampling of the programs listed in the Tesoro Quality Assurance Program Elements Matrix. Five requests were made that required action from Tesoro. On October 15, 2009, the SPCO held a follow-up meeting with Tesoro's USDOT Specialist, the Anchorage Pipeline Manger and the Pipeline and Terminal Manager to further discuss the QAP and ROW usage. It was agreed that Tesoro would provide the SPCO with a QAP that provides more detail and create a method for addressing Lease requirements with contractors and subcontractors. The SPCO received the revised QAP on December 28, 2009; it was accepted on January 15, 2010 (SPCO Letter 10-026-AS).

December 9, 2009 Oil Spill Drill Observation

SPCO staff attended a Tesoro spill drill in Nikiski. Multiple agencies participated, but the majority of individuals were Tesoro employees or their contracted spill response company Cook Inlet Spill Prevention and Response Inc. (CISPRI). The spill scenario consisted of a spill occurring where the Nikiski Alaska Pipeline crosses the Swanson River (Figure 36 below). SPCO staff spent time in the Incident Command Center and traveled to the site of the hypothetical spill to observe field responders. Four surveillance reports were completed for the trip; all reflected satisfactory conditions (SPCO Letter 10-060-AS).

Figure 36: Mainline Valve 2 on the Southern Side of the Swanson River Crossing

April 16, 2010 Aerial ROW Surveillance Observation

SPCO staff monitored an aerial surveillance of the Nikiski Alaska Pipeline, from Nikiski to the Port of Anchorage. Tesoro performs a pipeline ROW inspection at least 26 times annualy, not exceeding 3 weeks between inspections. Items to be reported during the inspection include the following:

- Any possible leaks detected by soil discolorations in the vicinity of the ROW
- Washouts or erosion
- Potential construction encroachments within the confines of the pipeline ROW
- Any acts of persons or equipment near or on the pipeline ROW

Items of concern from ROW inspections are reported to Tesoro's pipeline supervisor for further investigation. In addition, missing or damaged milepost markers, fences, notification signs, and other necessary pipeline appurtenances are replaced or repaired. Nine surveillance reports were completed for the trip; all reflected satisfactory conditions (SPCO Letter 10-134-AS).

June 17, 2010 Cathodic Protection Testing Observation

SPCO staff observed a contractor perform CP testing on the Nikiski Alaska Pipeline. Tests were taken at all CP test stations between the refinery and approximately pipeline mile post eight at Daniels Creek. The rest of the pipeline was tested prior to SPCO staff arriving in Kenai. Figure 37 below was taken during the June 17, 2010 surveillance trip. Surveillance reports for this trip were completed in FY11.

Figure 37: The Nikiski Alaska Pipeline ROW and Signage

Engineering Section FY10 Activities, Nikiski Alaska Pipeline

The Tesoro pipeline mitigates 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). In 2008, Tesoro installed a deep well anode to replace an anode ground bed, near Mainline Valve No. 5 at Point Possession. This was the first full year of operation of the new CP system. The testing indicated that the system was operating per federal requirements. However, a consultant made a few significant recommendations in an annual corrosion report.

(1) Replace a coupon test station
(2) Electrically isolate the ASIG Tank Farm from the ASIG lateral pipeline
(3) Consider replacing the Captain Cook groundbed (2/3 of the anodes passivated and therefore not fully functional)

Right-of-Way Section FY10 Activities, Nikiski Alaska Pipeline

The ROW Section conducted an audit of the lands across which the Nikiski Alaska Pipeline is situated. This audit was initiated by a request from the Municipality of Anchorage (MOA) regarding information about MOA lands near the Ted Stevens Anchorage International Airport. When the Lease originated, the State of Alaska was in the process of assisting the Kenai Peninsula Borough (KPB) and the Greater Anchorage Borough (later the MOA) with land selections. It was known at the time of the Lease development that much of the land

would be conveyed from State to Borough ownership. However, in order to keep the management of the Lease comprehensive, it was decided that the Lease and the authorities of AS 38.35 should be maintained by the State. Therefore, all lands conveyed to the KPB and MOA were made subject to, via patent, the ADL 69354 Nikiski Alaska Pipeline ROW Lease. The State and the KPB entered into a Property Management Agreement and the ROW was included in the title documents.

The land audit, performed by SPCO, was necessary to bring decades of transitional land ownership up-to-date for the ROW Lease and to continue to ensure the comprehensive management of the pipeline. The audit confirmed that the KPB is the majority land owner along the pipeline ROW with the MOA owning the least amount of lands, but those appraised at the highest value. The primary areas of ownership for the State of Alaska are contained within the Captain Cook State Recreation Area and those submerged lands under the Turnagain Arm.

The land audit and review of the file also revealed that the Property Management Agreement with the KPB, while functional, is outdated. Work on a Property Management Agreement with the MOA was never completed. The ROW Section is currently working on bringing all Property Management Agreements up-do-date and establishing future parameters for appraisal of the pipeline via AS 38.35.

State Fire Marshal's Office Liaison FY10 Activities, Nikiski Alaska Pipeline[20]

The SFMO Liaison's annual inspections for the Nikiski Alaska Pipeline took place in August 2009. Three Anchorage facilities were inspected; two violations were noted and have since been corrected.

[20] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

NORTH SLOPE PIPELINES

There are seven pipeline systems across the North Slope authorized by a ROW lease granted under AS 38.35. These pipelines cross state lands and fall within the jurisdiction of the SPCO. The operators of these pipelines are ConocoPhillips Alaska, Inc. (CPAI), BP Exploration (Alaska), Inc (BPXA), and the North Slope Borough (NSB). The systems are Alpine, Badami, Endicott, Kuparuk, Milne Point, Northstar, and Nuiqsut. The general route of these pipelines is depicted below in Figure 38.

A description of programs and systems that apply to all of an operator's pipelines, are presented in the operator overview. Each pipeline subsection includes an overview of the pipeline system, highlights from the lessee's CY09 annual report, and a description of SPCO activity related to the pipeline system and conducted during FY10.

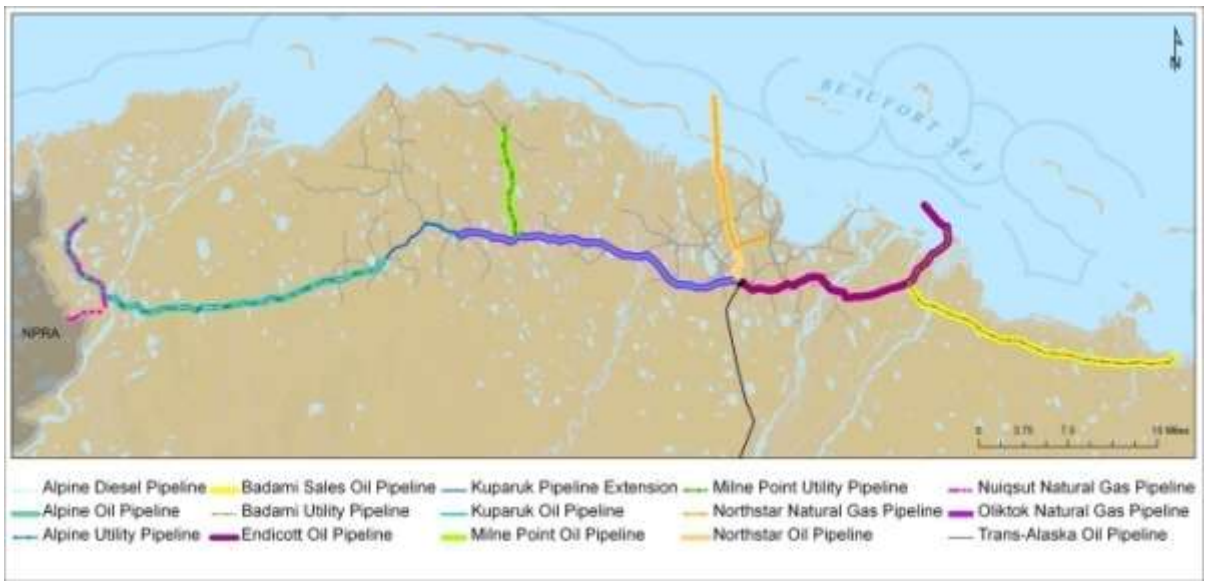


Figure 38: Route Map of North Slope Pipelines under SPCO Jurisdiction

SPCO representatives made 19 trips to the field for the Alpine, Badami, Endicott, Kuparuk, Kuparuk Extension, Milne Point, Northstar, Nuiqsut, and Oliktok pipelines in FY10 (see Figure 39)

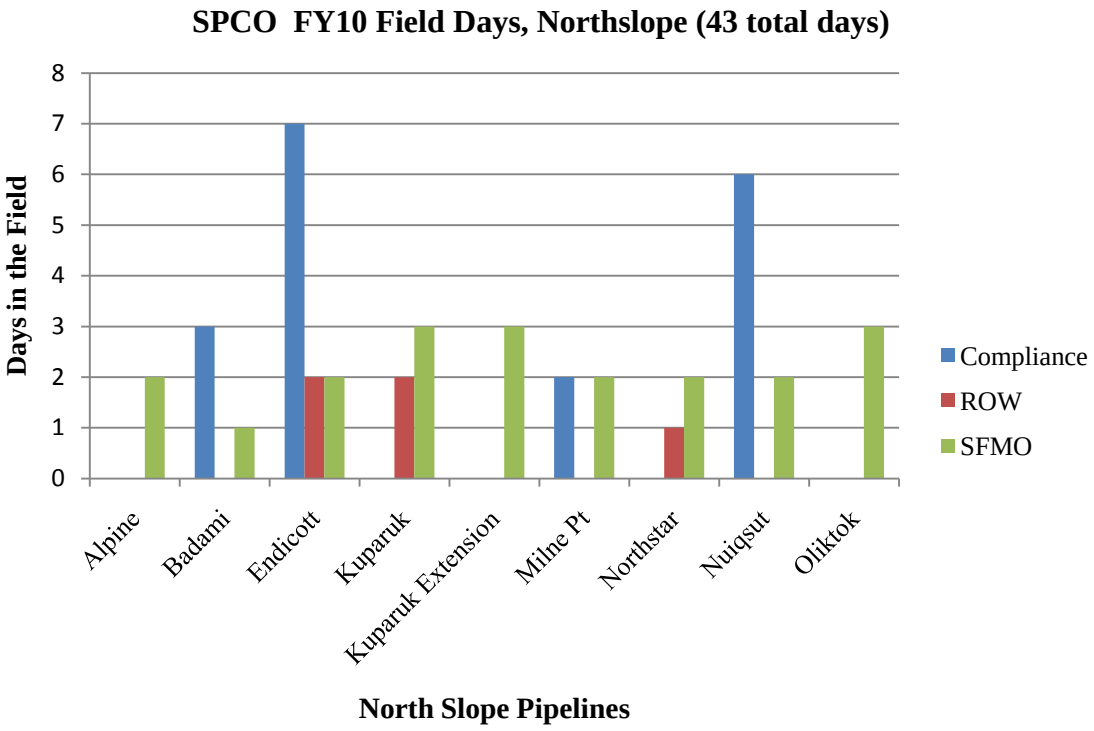


Figure 39: SPCO FY10 Days in the Field, North Slope Pipelines

BP Exploration (Alaska), Inc. Operated Pipelines

This section provides a high-level description of programs and systems that apply to all the BP Exploration (Alaska), Inc. (BPXA) operated pipelines and activities related to those programs and systems that were reported in 2009.

The programs and systems developed by the lessees and BPXA are used to manage operational and maintenance activities in a manner that addresses personnel safety, environmental protection, the integrity of the infrastructure, and adequate preparation for responses to unanticipated events. BPXA, as pipeline operator for the lessees, implements those programs and systems.

BPXA operates numerous associated with ROW leases

- Badami Sales Oil Pipeline, ADL 415472
- Badami Utility Pipeline, ADL 415965
- Endicott Pipeline, ADL 410562
- Milne Pt Pipeline, ADL 410221
- Milne Pt Product Pipeline, ADL 416172
- Northstar Gas Pipeline, ADL 415700
- Northstar Oil Pipeline, ADL 415975

Risk Management Programs

The risk management programs address risks to health, safety, the environment, and pipeline integrity. Some of the risk management programs have components that provide assurance; however, there is no "Assurance Program" section in the reports provided to the SPCO.

Integrity Management Program

An IMP is required by USDOT for all hazardous liquid pipeline operators; this includes all AS 38.35 jurisdictional pipelines.

In accordance with BP's Pipeline IMP, Formal Risk Assessments (FRA) are conducted annually for each USDOT regulated pipeline in order to meet Integrity Management requirements under 49 CFR Part 195.452. The FRA process, as reported in the CY09 annual reports, was structured to identify potential threats to the integrity of the pipeline and system, the likelihood the potential threat identified would occur and those consequences associated with the identified threat. A key output of the assessment is the identification and development of preventative and mitigative measures (P&Ms). These measures, when implemented, prevent and/or mitigate the likelihood of a pipeline failure that could affect a High Consequence Area as defined by 49 CFR 195.452.

A P&M measure identified in the 2008 FRA recommended hiring four USDOT coordinators; two for the Alaska Consolidated Team and two for the Greater Prudhoe Bay. Two of the Alaska Consolidated Team Coordinators were hired in 2009.

The 2009 FRA was completed on April 16, 2009, and fully covered the BPXA operated pipelines subject to AS 38.35.

Review of the continuous improvement requirement resulted in the following lessons learned:

- Operations should lead the FRA for their pipeline
- Tools for effective analysis and communication to facilitate future FRAs should be:
    - New Risk Scoring Model
    - New Risk Matrix
    - Pipeline Alignment Sheets
    - Geographic Information System (GIS)
- Clearly define preparation requirements for SMEs in advance of the FRA meetings

The FRA for 2009 did not identify any new P&Ms for AS 38.35 regulated pipelines. The BPXA operated pipelines were determined to be fit for continued operation by the BPXA Pipeline Technical Authority in accordance with CRT-AK-43-49 4.2, "Criteria for Pipeline Integrity Management System" and the BP Integrity Management Standards.

Based on the FRA, and conforming with "Criteria for Pipeline Integrity Management System" and BP Integrity Management Standards, the BPXA operated pipelines regulated by PHMSA's Integrity Management Rule 195.452, were determined to be fit for continued operation.[21]

The USDOT performed an IMP audit in May of 2009 and noted improvements in checklist evaluation and baseline assessments. USDOT issued no findings during 2009.

Operator Qualifications

A pipeline Operator Qualification (OQ) program ensures that personnel have the appropriate training, knowledge, and skills to safely perform assigned tasks and can recognize and respond to abnormal situations. OQ records are tracked through BP's Virtual Training Assistant, and ISNetworld monitors training and qualifications. Contractors are required to keep OQ training up-to-date in ISNetworld, which is a secure, web-based records repository and reporting database. BP project managers verify and review contractor qualifications before and during a project using ISNetworld.

Public Awareness/Damage Prevention Program

The Public Awareness/Damage Prevention Program is targeted for those who may live or work near USDOT regulated pipelines. Current objectives of this program are too increase public awareness and understanding of pipeline operations, to determine the public outreach method and frequency of messages, to measure and evaluate the program and to identify four stakeholder audiences.

1. Affected public and general business
2. Excavators
3. Emergency officials
4. Public officials.

[21] SPCO jurisdictional pipelines include: Badami Oil Pipeline, Endicott Pipeline, Northstar Oil Pipeline, and Milne Point Oil Pipeline.

These objectives are continually evaluated and refined to meet the needs of stakeholders.

Corrosion Inspection Program

The BPXA Corrosion Program addresses internal and external corrosion of pipelines through integration and analysis of inspection and monitoring data. The Corrosion Program is divided into separate elements with different purposes and inspection frequencies. Inspection intervals are based on equipment condition, corrosion rate, and the operating environment. BPXA's Corrosion Program is composed of several subsections.

Corrosion Rate Monitoring Program

The Corrosion Rate Monitoring Program applies to cross-county pipelines in "corrosive service," and has a fixed scope and inspection interval. Areas of active corrosion and locations such as elbows, girth welds, long seam welds, and bottom of line sections that are more susceptible to corrosion are inspected twice a year.

Erosion Rate Monitoring Program

The Erosion Rate Monitoring Program is similar to the Corrosion Rate Monitoring Program, but examines different damage mechanisms. The program monitors production variables, such as production rates, solids loading, velocity limits and any well work that could lead to or "trigger" erosion. If triggers are present then inspections are performed on a monthly to quarterly basis until it is determined that erosion is not occurring.

Frequent Inspection Program

The Frequent Inspection Program manages mechanical integrity at locations where significant corrosion has been noted. If a location is nearing a repair or "derate" criteria, or if an unusually high level of corrosion or erosion is detected, then it is added to the frequent inspection program. These locations are inspected frequently until they are repaired, replaced, derated, taken out of service, or corrosion/erosion rates are reduced. The intervals of inspection for this program vary dependant upon corrosion/erosion rates and how close the location is to meeting the repair or derate criteria.

Comprehensive Integrity Program

The Comprehensive Integrity Program was developed to detect new corrosion mechanisms, find new corrosion locations, and monitor known corrosion locations. The inspection rate for this program is annual and covers all equipment, but not all equipment is inspected annually.

ILI Program

The ILI Program inspects for internal and external corrosion and monitors the rate of change at locations where corrosion has been detected. In-line inspections collect data used in developing a preventative and mitigative maintenance plan.

Below Grade Piping Program

The Below Grade Piping Program is focused on using the best available technology to examine below grade piping segments (cased piping, direct buried piping, piping vaults, and utiliways) that may by subject to external corrosion.

Quality Assurance/Operating Management System Program

The comprehensive QAP, required by all leases, was approved by the SPCO on December 21, 2004. The lessees plan to request approval from the SPCO in 2010 for an amendment to the previously approved QAP. In order to ensure that QAP elements are met, BP utilized a system called "getting Health, Safety, and Environment right" (gHSEr). The system provides the basis for developing local/site/facility health, safety and environmental (HSE) management systems to help line managers focus on critical HSE needs, forecast and allocate resources, set direction for HSE activities, and consistently deliver improved HSE performance.

In CY09, BPXA replaced their gHSEr system framework with BP's Worldwide Operating Management System framework. As part of a MOC procedure for each BPXA operated AS 38.35 pipeline, the gHSEr elements were mapped to the Operating Management System to ensure the new system had equivalent controls in place, continuing to protect the health and safety of people and the environment and ensure the integrity of each pipeline and related facility. The Operating Management System describes the operating requirements all BP entities are expected to attain and provides for consistent standards and processes that all BP entities are required to follow.

For more information about the Operating Management System framework please refer to the subsection titled *State Pipeline Coordinator's Office Oversight Activities, FY10 Summary* in the Badami Sales Oil and Utility Pipelines section of this report.

Safety Programs

BPXA implements programs to increase safety awareness among employees and contractors. Both the Internal Safety Program and Contractor Safety Oversight Program are intended to reduce the number of incidents attributable to human error. Each pipeline takes ownership of its own version of this program, and specific results related to those programs are reported in the individual pipeline sections of this report.

The safety programs are administered by managers and supervisors who monitor employee and contractor safety through Safety Observations and Conversations (SOCs). SOC focuses on personal impact, addresses risk, and increases visibility of the process of managing safety hazards and risks. SOCs are tracked by location in BP's worldwide-computerized tracking system called Tr@ction. The results of the program are recorded in the Tr@ction database.

Internal Safety

The Internal Safety Program is a form of peer monitoring in which employees formally monitor each other's safety behavior. Employees record safety observations and include suggestions for reducing potentially unsafe behavior and use positive reinforcement when good practices are observed. Each BPXA operated pipeline system has a unique safety program. The results of those programs are reported in the individual pipeline system sections.

External Safety (Contractor Safety)

The Contractor Safety Oversight program, managed by BPXA's Internal Safety Program, focuses on contractor safety during work. Each contractor is required to actively participate

in the contractor safety program as part of the agreement to perform work on any BPXA operated pipeline. Controls set in place focus on contractor accountability.

Contractors must obtain a signed *Authorization to Proceed* (ATP) from a BPXA Operations Supervisor, BPXA HSE Representative, the Contract Project Lead, a Project Manager, and the Job Supervisor prior to any project, construction or major maintenance. When appropriate the contractor and work crew perform a *Task Hazard Analyses* to gather the necessary information to protect employees prior to the start of work. The ATP process and Task Hazard Analyses are used to mitigate potential safety issues.

Venting Incident

A venting incident at PS 1, listed under activities in 2009, led to a review of processes and procedures and a heightened focus on coordination between companies, to ensure safe actions and preparedness.

Health, Safety, and Environmental Management System

The BPXA Health, Safety and Environmental Management System goals is, "no accidents, no harm to people and no damage to the environment." The company hopes to achieve that goal by continuing to mitigate the environmental and health impact of operations with increased energy efficiency and by reducing waste, emissions and discharges. The HSE Management Systems calls for an annual ranking of environmental risks for activities performed on each pipeline ROW. Any activity determined to be high risk is evaluated to ensure that the planned protective measures in place are sufficient. The HSE management system is certified each year, and has been certified for the past 10 years by an ISO 14001 registered firm. The ISO 14001 registered firm provides the requirements for environmental management systems and general guidelines for proper environmental stewardship.

Oil Discharge Prevention and Contingency Plan

The DEC-approved ODPCP include identification of potential risks along the pipeline ROW, preventative measures, communication protocols, and pre-staging of response equipment. The North Slope Plans were approved on December 17, 2008 by the USDOT Office of Public Safety. These plans meet the requirements of the Oil Pollution Act of 1990 (OPA 90) for facility response plans.

Risk Management Tools

In addition to the risk management programs, BPXA employs three risk management tools to ensure regulatory compliance of operations and maintenance activities. These tools are the Compliance Tracking Manager, Field Handbooks, and Communications.

The Compliance Tracking Manager is a web-based matrix that identifies regulatory requirements, responsible parties, and operational controls. BPXA uses standardized field handbooks that include the *2009 BP Alaska Safety Handbook*, the *North Slope Environmental Handbook*, and the *Alaska Waste Disposal Reuse Guide.* Each of the handbooks is used to ensure a standardized approach to meeting regulatory requirements.

Communications encompasses redundant communication systems required for safe pipeline operation, as well as day-to-day communication vehicles such as telephones, radio

equipment, and cellular phones. Equipment used by BPXA is compatible with Alaska Clean Seas and BPXA communication equipment located in Anchorage. Repeaters were installed across the North Slope to facilitate coverage from Alpine to Badami.

Surveillance and Monitoring Program

The SMP is designed to detect and abate situations that endanger health, safety, environment, or pipeline integrity. The program was reviewed and received final approval by the SPCO on April 15, 2009 (SPCO letter 09-019-CT). Surveillance and Monitoring involves visual inspections of each pipeline specifically focusing on structural components of the pipeline, related facilities and the surrounding area so that any abnormal situation or unexpected change is detected and evaluated before it can cause a problem.

Surveillance

Both ground (drive-by and walking) and aerial (visual and FLIR detection) surveillance are used to perform qualitative inspections. Any indications of a problem, unexpected condition, or leak are reported immediately. After evaluation, the appropriate action is taken to correct or mitigate the situation. Some conditions or environmental changes do not require immediate action, but continue to be monitored.

Monitoring

Monitoring is based on the acquisition and evaluation of quantitative data over time and is used to identify trends and unexpected or cumulative changes before they pose a threat to safety, the environment or pipeline integrity. Each pipeline receives an annual walking speed survey that provides for a detailed ground-level inspection of the pipeline. The AS 38.35 leases require the lessees to submit a SMP for approval. The SPCO gave final approval of the lessees' SMP on April 15, 2009.

Pipeline Specific Information

The following sections provide an overview of each BPXA operated pipeline system, highlights from the lessee's CY 2009 annual report, and a description of SPCO activity related to the pipeline system and conducted during FY10.

Badami Sales Oil and Utility Pipelines

Figure 40: Aerial Photograph of the Badami Oil Pipeline

Right-of-Way Lease and Pipeline System Overview

The Badami pipelines connect the North Slope's easternmost oil development, Badami Oil Field, to the Endicott Pipeline. The 12-inch Badami Sales Oil Pipeline begins at the Badami Central Production Facility, where the pig launcher, mainline pumps, and metering equipment are located (see Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines). The pipeline ends approximately 25 miles to the west at the tie-in with the Endicott Pipeline, where their pig receiver is located. Figure 40 was taken by SPCO staff during an aerial surveillance of the Badami Oil Pipeline.

The Badami Sales Oil Pipeline ROW Lease, ADL 415472 and the Badami Utility Pipeline ROW Lease both went into effect on December 15, 1997 (see Appendix D: Acreage, Survey, and Lease Information).

The 6-inch Badami Utility Pipeline begins at the "T" intersection on the Endicott causeway where it ties into the fuel gas line that transports miscible injectant from the Main Production Island (MPI) to the Satellite Drilling Island (SDI) (see Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines). It was designed to transport miscible injectant from MPI to the Badami Central Production Facility, a distance of 31 miles. The pipeline operated intermittently to supply fuel gas for start up of the Badami facility and operated briefly in August 2007 to supply gas to push an ILI tool through the Badami Oil Pipeline. The Badami Utility Pipeline was disconnected from the Endicott Pipeline and is not currently operating. Both the Badami Sales Oil and Badami Utility pipelines share VSMs and are aboveground, except at the major river crossings of the Shaviovik, Kadleroshilik, and Sagavanirktok Rivers.

The Badami Sales Oil Pipeline has a construction width of 300 feet, except at the buried river crossings where the ROW expands to 2,000 feet. The Badami Utility Pipeline has a construction width of five feet, on either side of the centerline, between the Endicott tie-in

and the Badami Central Production Facility and an expanded width of 300 feet between the Endicott tie-in and the MPI (see Appendix E: Pipeline Right-of-Way Lease Appraisal Information). Construction of the Badami Utility Pipeline took place within the ROW of the Sales Oil Pipeline.

The SPCO approved a temporary discountenance of service for the Badami pipelines on September 20, 2007 (SPCO Letter 07-090-TG).

State Pipeline Coordinator's Office Summary of BPTA's CY09 Annual Report for the Badami Pipelines

The *Badami Pipelines Rights-of-Way 2009 Annual ADNR Surveillance and Monitoring Report* was received by the SPCO on January 29, 2010. The report met SPCO expectations, as described on page 7 of this report, as well as the requirements found in stipulation 1.6.2 (Surveillance and Monitoring) of the leases.

The annual report is required by lease stipulation and, in part, is meant to provide a clear picture of the state of the pipeline system. Because of its ties to lease requirements and the importance of the information presented, the SPCO thoroughly reviews the report. Elements of the *Badami Pipelines Rights-of-Way 2009 Annual ADNR Surveillance and Monitoring Report* are summarized or excerpted below. Reported information about programs and systems covering all of the BPXA operated pipelines were presented in the BP Exploration (Alaska) Operated Pipelines section on page 91.

Throughput, Reliability, and Pigging

The Badami pipelines were not operational in 2009; therefore the Badami Sales Oil Pipeline did not transport any oil and no gas was transported through the Badami Utility Pipeline during 2009. The last ILI run for the Badami Sales Oil Pipeline was completed on August 27, 2007, prior to the temporary discontinuance of service. Appendix I: Throughput for SPCO Jurisdictional Pipelines, 2009 provides a listing of throughput for all SPCO jurisdictional pipelines.

Risk Management Programs

Integrity Management, Corrosion, and Quality Assurance Programs

Information related to the Integrity Management, Corrosion, and Quality Assurance Programs can be found on page 91, 93, and 94 of this report.

Safety Programs

In addition to the safety information listed below, information common to all BPXA operated pipelines can be found on page 94 of this report.

Internal Safety Program

Managers and supervisors formally monitor employee and contractor safety through the use of SOCs, with the objective to increase visibility of process safety hazards and risks. During 2009 the number of SOCs totaled 65. There were no OSHA days away from work, no OSHA

recordable incidents, and no major incidents.

Surveillance

The term surveillance is described by BPXA as, "making observations that are primarily qualitative by flying, driving, or walking along the pipeline and related facilities." The SMP is designed to detect and abate situations that endanger health, safety, environment, or pipeline integrity. The program was reviewed and received final approval by the SPCO on April 15, 2009 (SPCO Letter 09-019-CT).

Items noted during aerial or ground surveillance are evaluated to determine if corrective action is required. Preventative maintenance Work Orders are utilized by BPXA to remedy conditions found through surveillance and monitoring.

Aerial Surveillance

Shared Services Aviation (SSA) uses an Otter and a CASA aircraft to perform aerial inspections of the Badami Pipelines. During 2009, SSA conducted 78 aerial visual inspections, of which 73 were conducted by the CASA and 5 were conducted by the Otter. DEC was notified that after January 11 the Otter would be out of the state for regular maintenance and that the CASA which was being retrofitted for FLIR observations was not ready until mid-February. The required FAA certification for the retrofitting took longer than expected. There were no ROW or pipeline integrity issues observed during the aerial inspections performed in 2009.

Ground Surveillance

The Badami Sales Oil and Utility Pipelines and ROWs were visually inspected on March 26, 2009 during the Annual Ground Inspection/Walking Speed Surveys (WSS). A total of 11 reportable conditions were noted on the Badami Sales Oil Pipeline. All of the conditions observed related to pipeline insulation; there were nine areas where the insulation was perforated and two areas where the insulation was unsealed.

The WSS for the Badami Utility Pipeline identified 1,102 reportable conditions. Coating damage was reported in 679 areas. 176 pipeline vibration dampeners were broken or missing, and an additional 242 were misaligned or incorrectly located. Two VSMs experienced frost-jacking and three locations had damaged insulation.

Monitoring

Corrosion

The last ILI pig run of the Badami Sales Oil Pipeline, which was run prior to the pipeline being placed in warm shutdown, did not provide data for the entire pipeline. The next ILI of that line is anticipated prior to restart and is planned for summer 2010.

A cathodic protection survey was conducted in September 2009 covering buried and submerged pipeline segments. Measurements were taken using portable electrodes at above/below ground transitions. Measurements were taken along pipeline centerlines at river crossings. However, no measurements were taken in deep water sections due to safety concerns.

Badami Weir Inspections

The Badami Weir at the Sagavanirktok River crossing is inspected a minimum of three times per summer. Table 14 indicates the key inspection elements evaluated during the inspections.

Table 14: Badami Weir and Sagavanirktok River Crossing Monitoring

Inspection Elements		
Bank Erosion	**Flooding**	**Surface Water**
Bank caving near the pipeline centerline	Conditions that erode the banks or threatening facility/pipeline	Flooding or channel changes or other potential threats to the buried pipe

Badami Weir inspection and inspection implementation procedures, which had been in use, were adapted and formalized as BFOP #94 (Badami Pipeline Sagavanirktok River Weir) and MOC #AMOC-BAD-004 (Administrative Badami Weir Oversight Implementation) in 2009.The 2009 Badami Weir Inspections were conducted on June 17, July 14, and August 2, 2009.

The long-term corrective action approved by the US Army Corps of Engineers was completed in 2009. Weir monitoring will continue as required by the USACE and the ADF&G, until a determination is made that the site has stabilized.

Construction

The Badami weir was extended in accordance with the Long-Term Corrective Action approved by USACE.

Operations

The Badami Pipelines were not operational in 2009. Although the Badami Sales Oil and Utility pipelines were in warm shutdown, both of the pipelines (and related activities) were maintained to meet AS 38.35 lease commitments and standards, as well as, USDOT requirements.

Maintenance

Preventative Maintenance

A computerized maintenance management system is utilized to identify recurring preventative maintenance tasks. Identified tasks are scheduled to meet requirements for inspections and evaluations set by regulators. Maintenance Team Leaders and/or Planner create work orders for those tasks. Some preventative maintenance work orders were generated from reportable conditions noted during the 2008 Walking Speed Survey.

Coating repairs were made at 11 locations on the Badami Utility Pipeline, including coating repairs that were made on the Badami Utility Pipeline at RTU 3. In order to conduct the necessary repairs; the pipeline was lifted in accordance with the Criteria for In-Service Pipeline Lifting.

Deficiencies noted during the 2008 WSS required maintenance of the VSMs and pipeline insulation (jacketing) on the Badami oil pipeline. As a result, VSM 1868 was lowered to the proper height and repairs to the Badami Sales Oil Pipeline's insulation were completed in 2009. In addition, adjustments were made to some pipeline vibration dampeners.

Projects

BPTA issued one letter of Non-Objection on November 10, 2008 for activity in the Badami ROWs in 2009. CGGVeritas was contracted to conduct two seismic surveys during the 2008-2009 winter field seasons; the survey locations overlapped portions of the Badami ROWs.

Oil and Hazardous Substance Discharges

In 2009, there were no discharges of hazardous substances within the Badami ROWs.

2010 Proposed Actions and Plans

The table below (Table 15) lists BPXA planned activities for 2010.

Table 15: Proposed Actions and Plans for 2010, Badami Pipelines

Quarter/Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Aerial Inspections Every Two Weeks	✓	✓	✓	✓
Ground Survey (WSS)	✓			
Formal Risk Assessment (Sales Oil Pipeline)		✓		
Badami Weir Monitoring			✓	
Cathodic Protection Survey			✓	
Corrosion Coupon Installation[22]	✓			
Start-up Activities*			✓	

* Start-up activities, if required, will include ILI and changing out the Remote Terminal Unit propane tanks.

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(*This section provides a summary of SPCO activities in FY10. Information in this section reflects the work of the SPCO and is not taken from the Lessee's annual report. By the nature of the SPCO oversight efforts, there may be some overlap of information.)*

Quarterly Meetings

SPCO and lessee representatives continued to meet quarterly in FY10. The meetings serve to keep both parties up-to-date on important activities, changes in staffing, progress of projects, and other important information. Quarterly meetings for the BPXA operated pipelines under SPCO jurisdiction, including the Badami pipelines, occurred on August 25, 2009,

[22] Cosasco fitting hot tap

December 3, 2009, March 31, 2010, and June 30, 2010. Some of the topics specifically related to the Badami pipelines discussed during the quarterly meetings are listed below:

- Annual Reporting Requirements
  - Proposed changes to the BP annual reports
- Badami Weir
  - Completion of project work
  - As-built Survey
- Badami Surveys
- Badami Utility Pipeline ROW Amendment
- Badami Oil Pipeline Restart
  - Status
  - Activities
- Point Thomson Update (as it relates to the Badami pipeline)
- Badami Utility ROW Relinquishment

Compliance Section FY10 Activities

The purpose of the Compliance Section is to verify that all pipelines administered by the SPCO are operated and maintained in a manner consistent with lease requirements. The following section documents the Compliance Section's efforts to verify Lessee compliance with the Badami Sales Oil and Utility Pipelines Lease Agreements.

Lessee Annual Reporting

The SPCO received the *Badami Pipelines Rights-of-Way 2009 Annual ADNR Surveillance and Monitoring Report on January 29, 2010*. After a thorough review of the 2009 report was completed the SPC found that the report met all SPCO annual reporting requirements as described on page 7 of this report. Two surveillance reports (Appendix G: SPCO Reports Issued in FY10), indicating satisfactory observations, were completed by the Compliance Section (SPCO letter 10-089-AS).

Lessee Local Hire

The Compliance Section reviewed BP Exploration (Alaska) Inc.'s *2009 Alaska Hire Report* and confirmed their efforts to hire, contract and purchase locally, which is encouraged by the leases. BPXA issues a local hire report annually to communicate their ongoing efforts to recruit, and train Alaskans, and purchase Alaskan goods and services.

Although the report did not specify workers dedicated to the Badami Sales Oil or Utility Pipelines, BPXA reported that 81% of their employees in 2008 were Alaskan, which is comparable to last year's report and an increase over the year before that. In addition, the report included the Alaskan employment base information for five of the largest contractors used by BP during the 2006 through 2008 timeframe. The Alaskan employee base for the contractors ranged from 66.8% to 85.7%. The report indicated that in 2008 BP spent two billion dollars on purchases from Alaskan companies, or 82% of their purchases.

Two surveillance reports (see Appendix G) were generated from the review, all reflected satisfactory observations. SPCO found that BPXA's *2009 Alaska Hire Report* clearly demonstrated a high level commitment to hire locally (SPCO letter 10-067-AS).

Badami Weir Inspection

On July 7, 2009, the SPCO issued surveillance reports and a lease compliance report covering an over-flight trip taken in FY09. The SPCO observed the Badami Weir appeared to be maintaining lake levels adequately above the weir site. Surveillance reports 09-SPCO-S-067 through 09-SPCO-S-077 were issued with satisfactory observations. The lease compliance report covering this trip is 09-SPCO-FR-009.

On August 24, 2009, the SPCO issued three surveillance reports and a lease compliance report covering a trip on June 17, 2009, the preceding fiscal year (SPCO letter 09-031-CT). The inspection was completed in order to document BPXA's progress with the Badami Weir Project. The Compliance Section also reviewed reports submitted by BPXA documenting the current status of activities on the Badami Weir and followed up with BPXA on questions related to the conditions at the site. The SPCO will continue to follow up with the lessee on the conditions at the site.

Engineering Section FY10 Activities, Badami Pipelines

During the reporting period, both Badami Pipelines were out of service. The Engineering Section monitored preparations started for a Badami restart to accommodate new finds by Savant and potential oil production from the original Badami oilfield.

A condition for shutting down the pipeline was that BPTA would submit a startup plan prior to restart. BPTA submitted a startup plan and presented it to the SPCO. The Engineering Section reviewed the plan and primarily had comments on the Shaviovik crossing. This area has been a concern to the Compliance Section and to the Engineering Section.

One area of concern for startup is subsidence at the west Shaviovik crossing. This area has displayed a linear depression on the tundra surface directly above the pipeline, in the section from the vertical transition to the riverbank. Although the hole was filled in, it shows further subsidence. Because of remedial efforts, engineering has found it difficult to assess the cumulative or total subsidence.

The Engineering Section has investigated the subsidence. The pipeline is deeply buried at this location, and surface movement may not necessarily indicate ground movement below. The Engineering Section believes that the available evidence shows no apparent indications of movement of the pipeline. The pipe is still centered in the vertical section. The horizontal and vertical spans that are visible near the transition show no bending. However, these are all indirect data. The results of the ILI run, especially the geopigging (spatial) data, should provide evidence of whether the pipeline has moved.

BPTA has committed to performing ILI (smart pig) prior to restart of the Badami Sales Oil Pipeline.(9 p. 21) They have scheduled startup of the pipelines in September or October 2010, with ILI on the oil pipeline about one month ahead of startup. The ILI will include corrosion detection, dent or mechanical damage detection, and spatial geometry detection

(geopigging).

This is the second full summer of operation after BP installed improvements to a weir that was constructed near the banks of the Sagavanirktok River. The main purpose was to stabilize the drainage of the local area. BPTA is required to conduct three summer surveys of the weir until the area is stabilized. The surveys assess bank erosion, flooding conditions, and surface conditions. Their surveillances noted no significant problem, but SPCO surveillance noted minor piping around the downstream apron. Continued monitoring should tell whether this is important to the integrity of the installation.

Right-of-Way Section FY10 Activities, Badami Pipelines

*Badami ROW Survey Corrections***:** The SPCO originally met with BPTA in October 2008 to discuss the Badami Oil and Badami Utility construction ROWs and the status of pipeline ROW surveys. Additional survey work was completed to make corrections and clarifications related to existing and pending survey plats, including EPF 200218, EPF 200806, and EPF 200809. Several meetings occurred between the DNR surveyor and SPCO staff, to discuss survey issues. Several draft survey drawings were submitted to the DNR surveyor for review and the DNR surveyor provided specific comments and edits to the drawings submitted. The Badami Oil ROW survey drawings were approved by DNR during FY10. The Badami Utility ROW Survey has recently been submitted for final review by the DNR surveyor. After the ROW surveys are approved, the information will be used to complete releases of interests of construction ROWs for each pipeline, thus adjusting the ROW size and acreage to amounts specified for pipeline operations and maintenance.

State Fire Marshal's Office Liaison FY10 Activities, Badami Pipelines[23]

The SFMO Liaison conducted the annual inspection of the Badami Pipelines and related facilities on March 4, 2010 a total of 15 facilities were inspected, 8 violations were noted. There were no hazards noted in the process areas. The noted violations occurred in the living quarters and office areas and have since been corrected.

[23] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

Endicott Pipeline

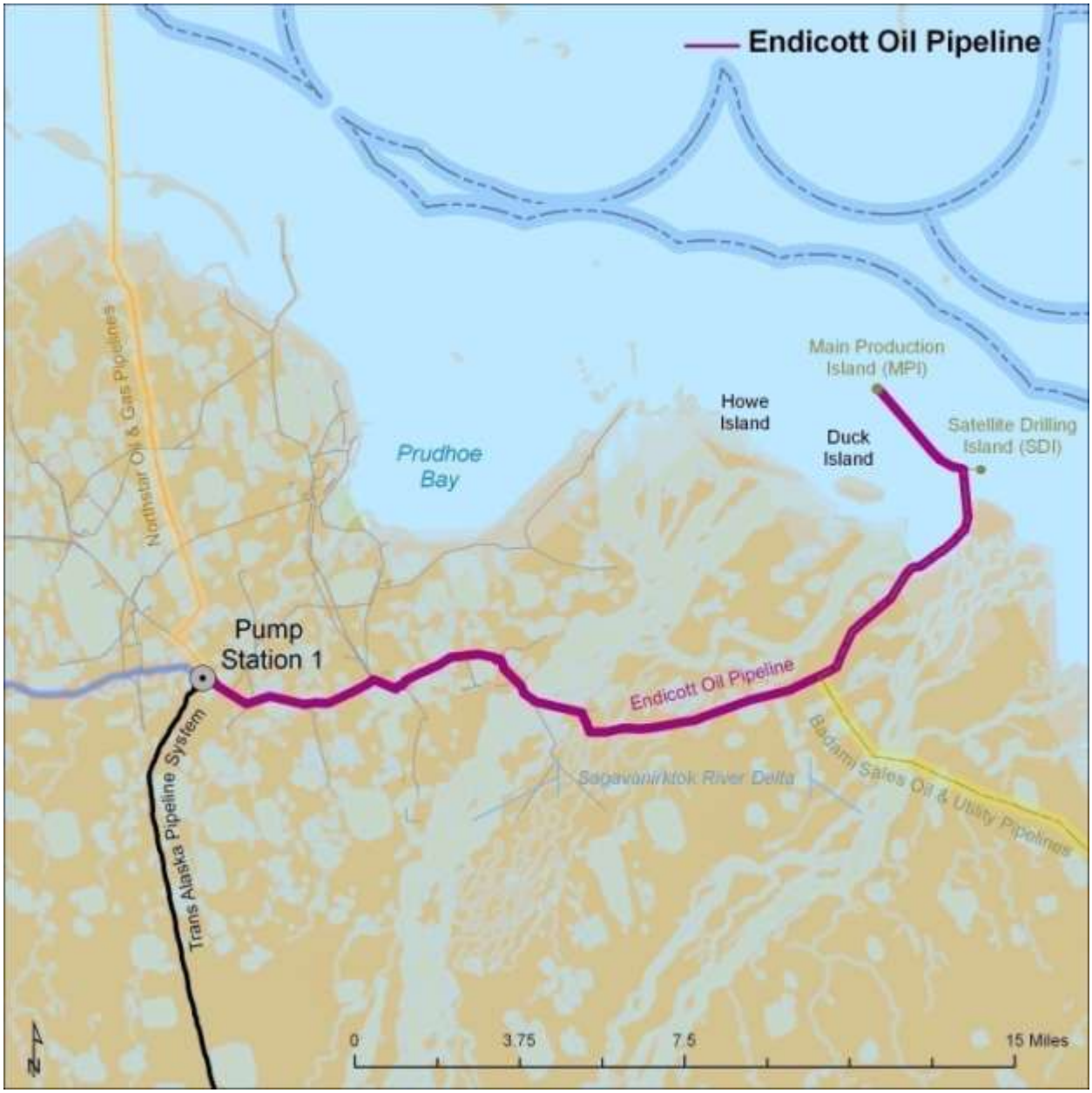


Figure 41: Endicott Pipeline Route Map

Right-of-Way Lease and Pipeline System Overview

The Endicott Development is located offshore in the Beaufort Sea, about 15 miles east of Prudhoe Bay. The facilities are located approximately 2.5 miles seaward of the Sagavanirktok River Delta and shoreward of the barrier islands, in water up to 14 feet deep. The Endicott facility includes the Main Production Island (MPI), the SDI, and Endeavor Island immediately adjacent to the MPI. They are linked to shore by a 1.9-mile long causeway that extends from the Sagavanirktok River delta to the Inter-island causeway that links the MPI and the SDI. Figure 41, above, illustrates the route that the Endicott Pipeline takes from the MPI to TAPS Pump Station 1.

Figure 42, below, is a photograph of the causeway "T"; the Endicott Pipeline is in the foreground. The causeway has three permanent breeches placed to ensure fish passage and maintain water quality. A 1.5-mile gravel approach connects the southern end of the causeway to the Sagavanirktok River Delta uplands where it connects with an eight-mile gravel road tie-in to the Prudhoe Bay road system. This provides year-round access to Endicott facilities and pipelines.

Figure 42: Endicott Causeway "T"

The Endicott Pipeline transports processed crude oil from the Endicott Development approximately 26 miles above ground on VSMs to TAPS PS 1. The 16-inch diameter pipeline begins at Endicott's MPI (Module 303) and is mounted on VSMs along the causeway to shore, where it parallels the road system to PS 1. At PS 1, there is a pig receiver and metering facilities. The Badami Oil Pipeline ties in at approximately the mid-point of the Endicott Pipeline. Additional information regarding the physical features of the Endicott Pipeline can be found in Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines.

The operational ROW width for the Endicott Pipeline is approximately 150 feet wide, except along the causeway, where the ROW is 500 feet wide (see Appendix D: Acreage, Survey, and Lease Information). The pipeline crosses the West Channel of the Sagavanirktok River on a pipe bridge. The as-built for Endicott Pipeline alignment in the area of the new Greater Prudhoe Bay connections was drawn incorrectly. A new survey of the location was completed and a minor lease amendment was executed on January 25, 2010.

State Pipeline Coordinator's Office Summary of Endicott Pipeline Company's CY09 Annual Report for the Endicott Pipeline

The *Endicott Pipeline Rights-of-Way 2009 Annual ADNR Surveillance and Monitoring Report* was received by the SPCO on January 29, 2010. The report met SPCO expectations, as described on page 7 of this report, as well as requirements found in Lease section 4c (Covenants by Lessee), stipulation 1.8.3 (Quality Assurance and Control), and stipulation 1.10.1 (Surveillance and Maintenance).

Elements of the Lessee's *2009 Annual ADNR Surveillance and Monitoring Report* were summarized or excerpted below. Reported information about programs and systems covering all of the BPXA operated pipelines were presented in the BP Exploration (Alaska) Operated Pipelines section on page 91 of this report.

Throughput, Reliability, and Pigging

The Endicott Pipeline transported 5,481,023 net barrels of oil during 2009 and had no unplanned shutdowns. The Endicott Pipeline was 100% reliable based on availability when not in a scheduled shutdown. During 2009, four maintenance pig runs were performed, one per quarter. The maintenance pigs were run on January 18, 2009, May 4, 2009, August 21, 2009, and October 16, 2009. The next ILI run is scheduled to take place in 2011. Table 16 reflects CY09 data for the Endicott Pipeline. Appendix I: Throughput for SPCO Jurisdictional Pipelines, 2009 provides a list of throughput for all SPCO jurisdictional pipelines.

Table 16: Throughput, Reliability, and Pigging Information for Endicott Pipeline, CY09

Pipeline System	2009 Throughput	Reliability	Maintenance Pigging	Last ILI
Endicott	5,481,023 net barrels	100%	Quarterly	2008

Risk Management Programs

Integrity Management and Corrosion Programs

According to the 2009 report, the USDOT performed a standardized field audit for the Endicott Pipeline between, June 22 and 26, 2009 and issued no findings. For more information on Integrity Management and Corrosion Program activities common to all BPXA operated pipelines, refer to page 91 and 93 of this report.

Quality Assurance

Information about Quality Assurance covering all of the BPXA operated pipelines was presented on page 94 of this report.

Safety Programs

In addition to the safety information listed below, information common to all BPXA operated pipelines can be found in the BP Exploration (Alaska) Operated Pipelines section of this report on page 94.

Internal and External Safety Programs

The Endicott Internal Safety Program consists of an employee, behavior-based monitoring program, called ORCA, where employees monitor each other's safety behaviors. Both contractors and BP employees participate in ORCA. In 2009, 778 ORCA observations were made. In addition, there is a management/supervisory monitoring component based on Safety Observations and Conversations. There were 1,111 SOCs during 2009. In 2009, Endicott experienced no OSHA days away from work and no OSHA recordable incidents.

Surveillance

The term surveillance is described by BPXA as, "making observations that are primarily qualitative by flying, driving, or walking along the pipeline and related facilities." The SMP is designed to detect and abate situations that endanger health, safety, environment, or pipeline integrity. The program was reviewed and received final approval by the SPCO on April 15, 2009 (SPCO letter 09-019-CT).

Items noted during aerial or ground surveillance are evaluated to determine if corrective action is required. Preventative Maintenance Work Orders are one tool utilized by BPXA to remedy conditions found through surveillance and monitoring.

Ground Surveillance

Fifty drive-by inspections were made of the Endicott Pipeline. On April 23, 2009 a limited walking speed survey was conducted following blasting operations at the Duck Island Mine Site, 10 locations with damage to insulation/jacketing were identified. The annual walking speed survey was conducted November 17 through December 1, 2009. During that inspection the following 35 observations were documented:

- 1 missing saddle strap
- 3 crushed insulation
- 3 missing foam insulation
- 2 missing jacketing
- 25 perforation of jacketing
- 1 separation between jacketing

In addition, observations not specific to the pipeline components included two VSMs which were experiencing vertical settlement and eight locations with separation between the jacketing and the anchors.

No erosion or wildlife blockage conditions were identified during surveillance activities in 2009.

Monitoring

Corrosion

Ongoing verification of the ILI run of 2008 continued through 2009 and will continue into 2010. The next ILI run is planned for 2011. Until the next ILI inspection, correlation and field confirmation activities will continue based on past and current run information. The Corrosion, Inspection, and Chemical Group did four pipeline lifts in 2009, as a follow up to the 2008 ILI pig run.

Bridges

During 2009, the Endicott Pipeline causeway bridges were inspected by PND Engineers, Inc. The undersides, the top sides, and the underwater sections of the girders for the Resolution Bridge were also inspected. Findings from these inspections will be addressed in the 2010 maintenance program.

Construction

No construction activities were performed on the Endicott Pipeline during 2009.

Operations

Other Activities

BPTA issued letters of non-objection for several activities in the Endicott ROW. These included: blasting at the Liberty Mine Site, Endicott Casing Extension project work, transit requests from ExxonMobil related to their Point Thomson operations, from Savant Alaska related to drilling activities, and for CGGVeritas' seismic survey work during 2009, (letter of non-objection for this activity was issued in 2008).

Maintenance

Preventative Maintenance

USDOT jurisdictional equipment within the Endicott ROW was inspected in July 2009. The inspection found that the scraper enclosure with a chain and needle valve was broken. It was repaired in 2009.

Work was completed on the sealed casing extensions at the 'T', which removed the requirement to have an inspection schedule for the vaults. Pipeline integrity along the casings will continue to be monitored through ILI.

Projects/Repairs

A hole in the pipeline jacket caused by a snow blower near Flow Station (FS) 3 in March of 2009 was repaired.

Oil and Hazardous Substance Discharges

In 2009, there were no reportable discharges, and five non-reportable discharges, related to project work.

Spill Response

If spill response equipment is not available or a significant change has occurred with pipeline leak detection and it no longer meets DEC regulatory requirements *Non-readiness Notifications* are required.

Two Non-readiness Notifications were made during 2009. Endicott Pipeline Company notified DEC of a Human Machine Interface system installation, and the associated impacts to spill response. The Endicott Pipeline was visually inspected twice a day during the installation.

Unplanned Events

On March 3, 2009, a snow blower on FS3 pad struck the Endicott Pipeline. Although the insulation was damaged, no damage occurred to the pipeline and no discharge occurred; as reported above, repair to the jacket was completed in 2009.

On March 23, 2009, blasting at the Duck Island Mine Site resulted in gravel impacts along the Endicott ROW. On April 23, 2009, after the completion of blasting at Duck Island, a "mini" WSS was conducted on the Endicott Pipeline. The insulation and jacketing was found to be damaged in 10 areas. Work Orders were initiated and corrective actions completed.

2010 Proposed Actions and Plans

Table 17 provides BPXA's 2010 schedule for surveillances, audits, self-assessments, and evaluations.

Table 17: Proposed Actions and Plans for CY10, Endicott Pipeline

Quarter/Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Drive-by Inspections Every Two Weeks	✓	✓	✓	✓
Field Verifications of 2008 Smart Pigging (ILI)	✓	✓	✓	✓
Cleaning and Maintenance Pigging	✓	✓	✓	✓
Cosasco Hot Tap Fittings Completed	✓			
Formal Risk Assessment		✓		
Ground Survey (WSS)				✓

During 2010 an ILI expert will evaluate the ROSEN in-line inspection tool which was run in July of 2008 and combined MFL with UT for its fitness for purpose.

As a follow up to the causeway bridge inspections during 2009, the following work will be completed in 2010:

- Big and Little Skookum Bridges
  - Tighten and replace loose and missing bolts
  - Remove debris from girders, and approach ramps and top flanges
- Resolution Bridge
  - Smooth and re-grade approach roadways
  - Replace missing delineators
  - Tighten and replace loose and missing bolts
  - Remove debris from girders, and approach ramps and top flanges

The next formal risk assessment is tentatively scheduled to occur April 13 through 15, 2010.

In 2010, BPTA anticipates submitting an amendment to their QAP. The amendment will reference the new OMS system and remove references to the gHSER.

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(*This section provides a summary of SPCO activities. Information in this section reflects the efforts of the SPCO and is not taken from the Lessee's annual report. By the nature of the SPCO oversight, there may be some overlap of information.)*

Quarterly Meetings

Representatives of the SPCO and the Lessee continued to meet quarterly in FY10. The meetings serve to keep both parties up-to-date on important activities, changes in staffing, progress of projects, and other important information. Quarterly meetings, for the BPXA operated pipelines under SPCO jurisdiction, including the Endicott Pipeline, occurred on August 25, 2009, December 3, 2009, March 31, 2010, and June 30, 2010. Some of the topics specifically related to the Endicott pipeline discussed during the quarterly meetings are listed below:

- Annual Reporting Requirements
    - Proposed changes to the BP annual reports
- Endicott ROW Amendment
- Split Casing letter of non-objection
- Overlapping property interests and pipeline safety
- QAP Changes
- Hot Tap Surveillance Trip Debrief
- SPCO request for information regarding:
    - Flaxman Island
    - Liberty
    - Savant Drilling
    - Point Thomson
- 2010 ILI Schedule
- Alaska Safety Handbook

Compliance Section FY10 Activities

June 17, 2009 Badami Weir and Endicott ROW Surveillance Trip

The Compliance Section issued a surveillance report in FY10 based on a ROW inspection conducted on June 17, 2009. During the inspection, BPXA provided the SPCO with full access to the ROW (SPCO Letter 09-031-CT).

July 20, 2009 Endicott Field Work

A Compliance Section representative made a trip along the Endicott ROW on July 20, 2009. Although no surveillance reports were issued, it provided an opportunity to converse with BPXA staff and observe conditions on the ROW.

November 2009 Endicott Walking Speed Survey

On November 16, 2009 a Compliance Section representative traveled to Endicott Island to observe a contractor, perform a WSS of the Endicott pipeline. The contractor supplies pipeline integrity experts that perform External Corrosion Direct Assessments (ECDA). The

ECDA's are performed as a follow up inspection to ILI, which are normally performed using internal pipeline pig tools.

Figure 43: Endicott Pipeline on the MPI

The SPCO representative observed the contractors as they visually surveyed the Endicott Pipeline for the following conditions:

- lateral or vertical movement of VSMs, outside of norms
- movement of aboveground pipeline; including animal crossings
- narrowing of the gap between the top of insulated pipeline and road crossing casings
- alignment of pipeline vibration dampeners
- missing vibration dampeners
- broken vibration dampeners
- humps, swales or ground cracking
- damage suspected to be caused by vandalism or sabotage
- inadequate support structures of modules and buildings
- any damage that could impact safety, the environment, communications, or pipeline integrity
- odors that indicate a potential gas leak
- gouges, scratches, bulges, and dents on the pipeline

Figure 44: View of the ROW and Endicott Oil Pipeline (3rd from left)

Eight surveillance reports were completed for the trip and all reflected satisfactory observations (SPCO Letter 10-023-AS).

Lessee Annual Reporting

The SPCO received the *Endicott Pipeline Rights-of-Way 2009 Annual ADNR Surveillance and Monitoring Report on January 29, 2010*, and after a thorough review of the 2009 report was completed, the SPC found that the report met all SPCO annual reporting requirements as described on page 7 of this report. Three surveillance reports, with satisfactory observations, were issued (SPCO letter 10-090-AS).

May 26, 2010 Endicott Field Work

The new Natural Resource Manager (NRM) responsible for the ROW the Compliance Sections of the SPCO traveled to Endicott on May 26, 2010. The goal of the trip was to introduce the NRM to the Endicott facilities, personnel, and procedures. BPXA staff from the AK OPS North Regulatory Compliance Team escorted the NRM and coordinated with subject matter experts familiar with each facility (including processing facilities, the pig launcher and receiver, and the pipeline) observed during the trip. A lease compliance report (10-SPCO-R-020) documenting the trip was completed in FY11 and will be counted in the FY11 annual report numbers.

June 2010 Endicott Hot Tapping

The SPCO joined BPXA, BPTA, and contract personnel along the Endicott Pipeline to observe pipeline hot tapping for corrosion coupon and electrical resistance probe set installations over a period of three days in June of 2010. Observations made during three separate hot tapping activities resulted in satisfactory surveillance reports on 10 Lease requirements. Activities observed included a risk assessment meeting and a job hazard tool

box meeting immediately prior to beginning the hot tap processes for all three. The SPCO representative reviewed logs, permits, work orders, procedures, technical drawings and alignment sheets, and spoke with contracting personnel and BPXA employees involved in the activities. A SPCO lease compliance report and the surveillance reports were issued in FY11.

Engineering Section FY10 Activities, Endicott Pipeline

The Engineering Section monitored the operations of the Endicott pipeline during the reporting period. The only major incident was reported in June 2010. It was discovered that a 32-inch produced water flowline and a 24-inch pipeline natural-gas flowline had settled on the Endicott pipeline. The SPCO has not performed an independent evaluation of the situation. However, BP reported that, 'The field mechanical engineers have performed a stress analysis on the Endicott Pipeline using conservative assumptions which shows that the pipeline is not over stressed. Cribbing has been installed to prevent any further settlement of the two crossing lines."(10)

BP plans a permanent repair of the support structure for the 32-inch and 24-inch flowlines for this winter. They anticipate that new VSMs will be required, and plan to install them in the winter to allow better access and faster freeze back. The Engineering Section plans to follow up during the next reporting period to monitor repair and remediation efforts.

Right-of-Way Section FY10 Activities

Survey Correction and Lease Amendment Request: During September 2006, while SPCO reviewed information associated with temporary transit line connections to the Endicott Pipeline, an error was noted indicating that the Endicott pipeline was built outside the surveyed ROW boundaries of ADL 410562 (per ASLS 84-96) within Section 33, T. 11 N., R.15 E., Umiat Meridian, Alaska. Draft survey drawings were submitted and reviewed by the DNR survey section during 2008. The as-built survey, *Record of Survey of the Endicott Right-of-Way*, EPF 20080040, was recommended for approval by the statewide platting officer January 21, 2009, and the plat recorded January 29, 2009, in the Barrow Recording District as Document 2009-000037-0. On January 25, 2010, the Commissioner executed the Amendment to the ROW Lease for Endicott Pipeline to include the additional 1.18 acres.

State Fire Marshal's Office Liaison FY10 Activities[24]

The SFMO Liaison conducted the annual inspection of the Endicott Pipeline and related facilities on November 12 and 13, 2009. A total of 20 facilities were inspected, including the Base Operations Center and process facilities, 13 violations were noted and have been corrected. The SFMO Liaison noted that, "the facility as a whole had few hazards, with minor corrective action."

[24] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

Milne Point Pipelines

Figure 45: Vibration Dampener on the Milne Point (oil) Pipeline

Right-of-Way Lease and Pipeline System Overview

There are two SPCO jurisdictional pipelines associated with Milne Point operations; the Milne Point Pipeline, which is a sales oil pipeline, and the Milne Point Product Pipeline, which is a NGL supply pipeline. The Milne Point Pipeline was built in 1984 and 1985 to transport processed sales oil from the Milne Point Unit to the Kuparuk Pipeline System. The approximately 10-mile Milne Point Pipeline connects the Milne Point Central Facilities Pad (CFP) at Module 58 to the Kuparuk Pipeline at a point that is shortly beyond Module 68, after crossing under Spine Road, just east of Central Processing Facility (CPF)-1. The Milne Point Pipeline is piggable from the Milne CFP to Module 68. A pig receiver, metering equipment, and leak detection equipment are at this location.

The Milne Point Products Pipeline was built in 2000 and placed on the same supports as the Milne Point Pipeline to transport NGL from the Oliktok Pipeline to Milne CFP to be used in enhanced oil recovery. The NGL products pipeline was shutdown in 2002 and has not been operated since. In 2006, the Lessee abandoned the NGL-carrying Milne Point Products Pipeline, per USDOT regulations, and in December 2006, with SPCO authorization, the Milne Point Products Pipeline was purged and physically disconnected from the Oliktok Pipeline. Both of the pipelines have year-round ROW road access.

The 14-inch oil pipeline is piggable, with the exception of a short length between Module 68 and the Kuparuk tie-in. This short section of unpiggable pipeline was replaced in 2007 with corrosion-resistant duplex stainless steel.

The NGL products pipeline is an eight-inch pipeline. Both lines are supported by above-ground VSM support systems. The oil pipeline has vibration dampeners positioned to reduce wind induced vibration (see Figure 45). Specific physical characteristics of the pipelines are provided in Appendix F.

The ROW for the Milne Point Pipeline is in its operational width, approximately 150 feet wide. The ROW for the NGL products pipeline is still in construction width, varying from 185 to 800 feet. An as-built survey was submitted to the State to initiate the Release of Interest process. The ROW will remain in effect until the pipeline lease is formally terminated. Additional lease information can be found in Appendix D: Acreage, Survey, and Lease Information.

State Pipeline Coordinator's Office Summary of Milne Point Pipeline Company's CY09 Annual Report for the Milne Point Pipelines

The *Milne Point Pipelines Rights-of-Way 2009 Annual ADNR Surveillance and Monitoring Report* was received by the SPCO on January 29, 2010. The report met SPCO expectations, as described on page 7 of this report, as well as Milne Point Pipeline Lease section 4c (Covenants by Lessee), stipulation 1.8.3 (Quality Assurance and Control), stipulation 1.10.1 (Surveillance and Maintenance), and Milne Point Products Pipeline Lease stipulation 1.13.1 (Reporting).

The annual report is required by lease stipulation and is intended to provide a clear picture of the state of 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. Elements of the *Milne Point Pipelines 2009 Annual ADNR Surveillance and Monitoring Report* are summarized or excerpted below. Reported information about programs and systems covering all of the BPXA operated pipelines were presented in the BP Exploration (Alaska) Operated Pipelines section on page 91 of this report.

Throughput, Reliability and Pigging

The Milne Point Pipeline transported 10,561,941 net barrels of crude oil during 2009. No unplanned shutdowns occurred during 2009. The Pipeline was 100% reliable in 2009. Maintenance pigging is conducted every quarter; maintenance pigs were run on March 6, June 15, September 25 and December 7, 2009, and the next ILI run is scheduled to take place in 2011. Table 18 reflects CY09 data for the Milne Point Pipeline. Appendix I: Throughput for SPCO Jurisdictional Pipelines, 2009 provides a listing of throughput for all SPCO jurisdictional pipelines. Because the Milne Point Products Pipeline was shutdown in 2002 and disconnected in 2006 it did not transport any product nor have any pigs run through it.

Table 18: Milne Point Pipelines Throughput, Reliability, and Pigging Information, CY09

Pipeline System	2009 Throughput	Reliability	Maintenance Pigging	Last ILI
Milne Point (oil)	10,561,941 net barrels	100%	Quarterly	2008
Milne Point Product	N/A	N/A	N/A	N/A

Risk Management Programs

Integrity Management, Corrosion, and Quality Assurance

For more information on BPXA's Integrity Management Program, Corrosion Program, or QAP refer to page 91, 93, or 94 of this report.

Safety Programs

In addition to the safety information listed below, information common to all BPXA operated pipelines can be found in the BP Exploration (Alaska) Operated Pipelines section of this report on page 94.

Internal Safety Program

The Internal Safety Program for the Milne Point Pipelines consists of an employee, behavior-based monitoring program, called the Behavior Enhanced Safety Techniques (BEST) program. BEST is used by BP employees and contractors. There were a total of 2,224 BEST observations during 2009.

In addition there is a management/supervisory monitoring component based on Safety Observations and Conversations. The goal of the program is to focus on the quality of the safety conversations while minimizing the number of SOC occurrences. Each SOC is tracked in the Tr@ction computerized tracking system. During 2009, there were 1,945 SOCs, no OSHA days away from work, no OSHA recordable incidents, and no major incidents.

Surveillance

The term surveillance is described by BPXA as, "making observations that are primarily qualitative by flying, driving, or walking along the pipeline and related facilities." The SMP is designed to detect and abate situations that endanger health, safety, environment, or pipeline integrity. The program was reviewed and received final approval by the SPCO on April 15, 2009 (SPCO letter 09-019-CT).

Items noted during aerial or ground surveillance are evaluated to determine if corrective action is required. Preventative Maintenance Work Orders are one tool utilized by BPXA to remedy conditions found through surveillance and monitoring.

Ground Surveillance

Milne Point Security conducted 27 drive-by inspections of the Milne Point Pipelines and an additional 138 drive-by inspections at the request of Milne Point Operators. The additional inspections were initiated by unexplained alarms from the leak detection system. Conditions

during each inspection appeared normal.

The Milne Point pipelines and ROWs were also visually inspected during the Annual Ground Inspection/Walking Speed Surveys. The Milne Point (oil) Pipeline inspection was conducted November 10 through November 15, 2009. The WSS did not identify any ROW issues or items of immediate concern; 163 observations were made. No major repairs were recommended as a result of the WSS, however, the following actions were recommended.

- Generate work orders for minor repairs as required, with completion of repairs due April 2010
    - Evaluate twisted horizontal support members (HSM) and bolts (1 HSM and 3 loose bolts)
    - Evaluate non bearing saddles (3 saddles)
    - Repair broken vibration dampeners (52 locations)
    - Repair areas with jacket separation (5 areas)
    - Repair jacket breaks and perforations (16 instances)
    - Repair crushed insulation (3 areas)
    - Replace broken or missing saddle straps (2 saddles)
    - Evaluate jacket discoloration (78 areas)
- Retain records of work orders and repair activities

The Milne Point Product Pipeline inspection was conducted on December 15 and 16, 2009. Four pipeline related observations were made, but no ROW issues were noted. None of the pipeline related observations were of immediate concern. The following actions were recommended as a result of the inspection.

- Generate work orders for minor repairs as required, to be completed by April 2010.
    - Evaluate twisted HSM and bolting (1 location)
    - Evaluate non bearing saddles (1 saddle)
    - Repair areas of jacket separation and replace and seal missing insulation (1 area of separation and 1 area of missing insulation)

Monitoring

Corrosion Monitoring

Follow-up site investigations were completed in 2009 as a result of the findings from a high-resolution MFL/Caliper combination ILI tool that was used on June 3, 2008 to determine if the Milne Point Oil Pipeline had any pipeline wall loss and/or deformations. It was determined that the ILI tool performed within the vendor's specifications and no further follow-up activity was planned from this ILI run, but the pipeline is scheduled for re-inspection in 2011.

Construction

No construction activities occurred on the Milne Point ROW during 2009.

Operations

The Milne Point Unit, which includes the Milne Point Pipeline and the Milne Point Product Pipeline, experienced two unplanned shutdowns in 2009. The first was a full field shutdown on July 18, 2009 that was caused by a power disruption to communication equipment when equipment was plugged into a UPS circuit during construction activities. The second shutdown occurred on October 22, 2010. A ground fault on the F Pad feeder power line caused a complete power and full field shutdown.

Maintenance

The Milne Point Unit schedules preventative maintenance activities to meet regulatory requirements. The required inspection of USDOT jurisdictional equipment was completed in 2009.

In 2009, an annual galvanic isolation test was run on the Milne Point Pipelines which found that conductivity exists.[25] Repairs are planned in 2010. A Cosasco Access Fitting for the coupon at Module 68 was installed including associated all necessary welding and hot tap work.

Repairs identified by the 2008 Walking Speed Survey were completed in April 2009 and included replacing missing insulation jacketing, replacing broken and/or damaged vibration dampeners, and replacing missing straps on saddles and metal jacketing.

To protect the pipeline on the Milne Point Unit side of the Spine Road guard rails were installed by Module 68.

Project Work

The Module 68 communication project was completed in 2009. This project involved installing a secondary (redundant) radio path with new radios and antennas at both ends of the Milne Point Pipelines so that communication between Milne Central Facility and Module 68 were uninterrupted. Ethernet radio is the primary communication link with the Esteem Modem used as the secondary link. If one system fails, communication automatically switches to the other system. In addition, communication continues to be conducted through normal phone traffic, vehicle and hand-held radio equipment (Harmony Radios) and cellular phones.

The Milne Oil Reserve Tank Pipeline Replacement Project (from facility to tank) was completed on November 10, 2009.

Oil and Hazardous Substance Discharges

In 2009, there were no reportable discharges of oil or hazardous waste on the Milne Point ROWs. One non-reportable leak occurred due to mechanical failure on a truck parked at the Milne Point Unit central facility pad.

[25] The *Milne Point Pipelines Rights-of-Way 2009 Annual 2009 Annual ADNR Surveillance and Monitoring Report* references the need to repair the isolation flanges. An SPCO representative followed up with the lessee and was informed of the annual galvanic test.

Unplanned Events

On October 4, 2009 in poor weather conditions, a crew van drove off the CFP access road. No damage was noted. However, the area was located within the pipeline ROWs.

2010 Proposed Actions and Plans

Table 19 highlights BPXA's 2010 schedule for surveillances, audits, self-assessments, and evaluations.

Table 19: Proposed Actions and Plans for 2010, Milne Point Pipelines

Quarter/Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Drive-by Inspections Every Two Weeks	✓	✓	✓	✓
Corrosion Coupon Installation	✓			
Ground Survey (WSS)				✓
Formal Risk Assessment		✓		
Isolation Flange Repairs		✓		

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(*This section provides a summary of SPCO activities during FY10. The Information in this section reflects the work conducted by the SPCO and was not taken from the Lessee's annual report. By the nature of the SPCO oversight efforts, there may be some overlap of information.)*

Quarterly Meetings

Representatives of the SPCO and the Lessee continued to meet quarterly in FY10. The meetings serve to keep both parties up-to-date on important activities, changes in staffing, progress of projects, and other important information. Quarterly meetings, for the BPXA operated pipelines under SPCO jurisdiction, including the Milne Point pipelines, occurred on August 25, 2009, December 3, 2009, March 31, 2010, and June 30, 2010. Some of the topics specifically related to the Milne Point pipelines discussed during the quarterly meetings are listed below:

- Annual Report requirements
  - Separation of the single annual report into separate reports for each pipeline system
- Walking speed survey
  - Possible dates
  - Notification to SPCO
- Pipeline Survey
- Vehicle Incident
- QAP Changes
- ILI Schedule
- Hot Taps Schedule
- Heavy Oil Project (CHOPS)

Compliance Section FY10 Activities, Milne Point Pipelines

Lessee Annual Reporting

The annual report, as prescribed by the State Pipeline Coordinator, was received by the SPCO on January 29, 2010. A thorough review of the 2009 Milne Point Pipelines Annual Report found that the reports met all SPCO annual reporting requirements. Four surveillance reports (Appendix G) indicating satisfactory observations were completed (SPCO letter 10-091-AS).

Lessee Local Hire

The Compliance Section reviewed BPXA's *2009 Alaska Hire Report* and confirmed BP's efforts to hire, contract and purchase locally, which is a requirement of the lease. The BP Exploration (Alaska) Inc.'s *2009 Local Hire Report* highlights the corporate commitment to hire locally. BP Exploration (Alaska) Inc. (BP) issues a local hire report annually to communicate BP's ongoing efforts to recruit, and train Alaskans, and purchase Alaskan goods and services.

Although the report did not specify workers dedicated to the Milne Point Oil or Products Pipelines, BPXA reported that 81% of its employees in 2008 were Alaskan, which is comparable to last year's report for information on 2007 and an increase over the rate in 2006. Based on BP's data for employees, 81.3% are Alaska Residents. In addition the report included Alaskan employment base information for five of the largest contractors used by BP during the 2006 through 2008 timeframe. The Alaskan employee base for the contractors ranged from 66.8% to 85.7%. The report indicated that in 2008 BP spent 2 billion on purchases made from Alaskan Companies, or 82% of their purchases. The report highlighted internships, new hires, and BP's support for the Alaska Native Science and Engineering Program at the University of Alaska Anchorage.

One surveillance report was generated from the review, and reflected a satisfactory observation (SPCO letter 10-067AS). SPCO found that BP Explorations (Alaska) Inc.'s 2009 Alaska Hire Report clearly demonstrated a high level commitment to hire locally.

November 2009 Walking Speed Survey

On November 9-10, 2010 a Compliance Section representative observed processes and reviewed procedures for the annual Milne Point Oil Pipeline WSS activities being performed by BPXA Contractors. The intent of the inspection was to look for breaches in the pipeline's integrity such as leaks or spills, to carefully examine each weld, every VSM, HSM, saddle, crossbeam, pipe hanger, fastener and anchor that was inspected. If there appeared to be substantial lateral and/or vertical movement of a VSM/HSM, greater than 6-inches, it was necessary to document this information on the Corrosion, Inspection, and Chemical Group (CIC) WSS data sheet.

All sides of the pipeline that could be seen by the contractor were inspected for: any gouges, scratches, bulging, or dents in the insulation jacketing. Dents and/or perforations in the insulation jacket along the pipeline, explained the Technician, typically are caused by rocks and/or debris being propelled from the road as vehicles drive by (see Figure 46). Any significant evidence of rust or water drainage from the insulation was also a condition

requiring documentation on the CIC worksheet (see Figure 47).

Figure 46: Perforation of Insulation

Figure 47: Significant Rust

The above conditions are required to be documented on the CIC Data Sheet; which is turned into the CIC Group and maintenance work is set up for the following year (2010).

The surface of the ROW was clear and free from anything that could pose a threat to the integrity of the pipeline (see Figure 48) and/or block wildlife movements. No leaks were identified during the Walking Speed Survey, and there was no sign of vandalism.

Figure 48: Milne Point Pipelines VSM 222 to VSM 432

(The Milne Point lines are one the left)

There were 49 documented conditions noted during the WSS work on November 9-10, 2009. The most frequently documented condition was Data Sheet Code #29, pipeline insulation/jacketing significant deformation, crushed buckled, etc. (see Figure 49 below).

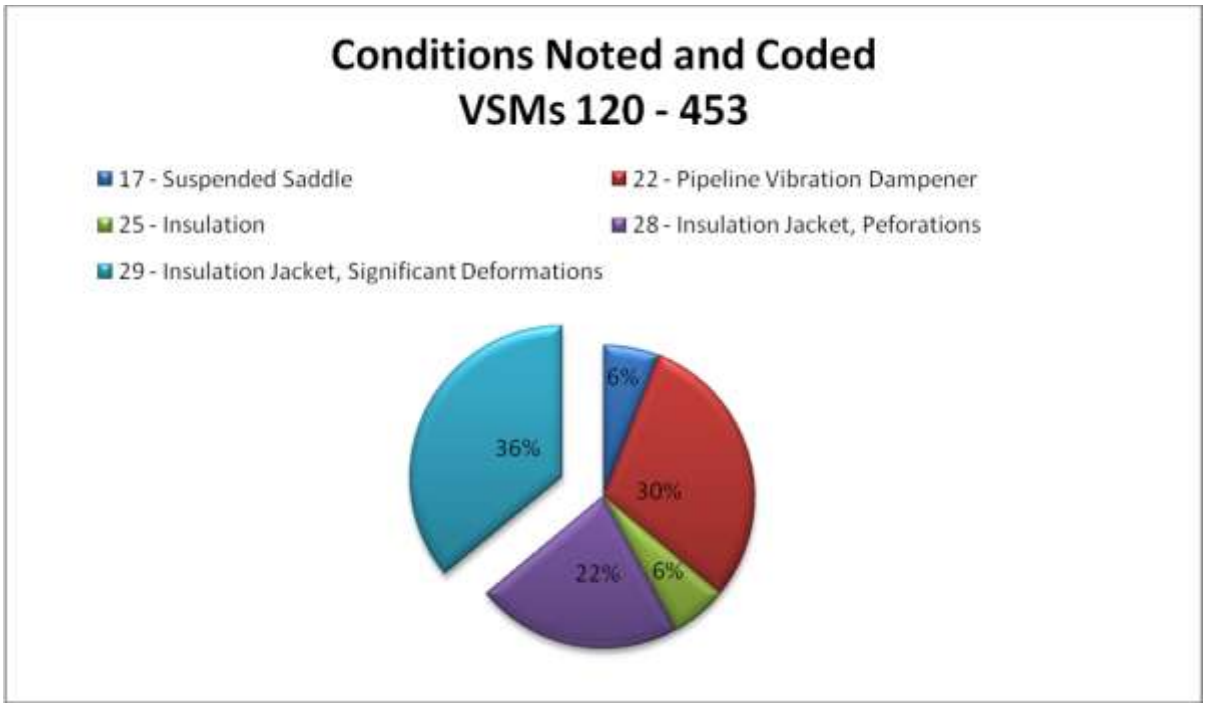


Figure 49: Conditions Noted and Coded from Milne Point Pipelines VSMs 120to 453

WSS supports compliance commitments BPXA/BPTA has set in the approved Milne Point Pipelines Surveillance and Maintenance Program. A lease compliance report and 12 surveillance reports (see Appendix G) were completed and reflected satisfactory observations (SPCO letter 10-021-AS).

May 17, 2010 Milne Point Field Work

The new Natural Resource Manager responsible for the SPCO's ROW and Permits Section and the Compliance Section traveled to Milne Point on May 17, 2010. The goal of the trip was to introduce the manager to the Milne Point facilities, personnel, and procedures. BPXA staff escorted the manager and coordinated with subject matter experts familiar with each facility (including processing facilities, the pig launcher and receiver, and the pipeline) observed during the trip. A lease compliance report (10-SPCO-R-018) documenting the trip was completed in FY11 and will be reported in the FY11 SPCO annual report.

Engineering Section FY10 Activities, Milne Point Pipelines

The Engineering Section monitored major activities on this pipeline. No major incidents were recorded. A walking survey by BP in November 2009 recorded the following minor observations: "One hundred sixty three pipeline-related observations were recorded: four loose bolts, three suspended saddles, fifty-two vibration dampener issues, five jacket separations, sixteen broken/perforated jacketing, three crushed insulation, two saddles with broke or missing straps, and seventy-eight areas of discolored jacketing."(11 p. 22) During the past year, the Milne NGL pipeline remained shut down with a pressurized nitrogen "pack" to mitigate corrosion.

This is the first full year of operation of a section of replacement pipe on the Milne Point pipeline. The Engineering Section followed up on this project because the replacement pipe

was manufactured from an exotic metallurgy: duplex stainless steel. This product has exceptional corrosion resistance. It achieves this by blending two normally incompatible stainless steels and "freezing" them in place during the manufacturing process. This shortens intergranular distances. Corrosion typically progresses in the surfaces between grains of the parent material, so corrosion is dramatically reduced with this type of material. The Engineering Section found that this pipe was operating as expected, with no problems.

State Fire Marshal's Office Liaison FY10 Activities, Milne Point Pipelines[26]

The SFMO Liaison completed the annual inspection of the Milne Point Pipelines and related facilities on January 25 and 26, 2010. The 30 facilities inspected, included the Milne Point Unit living quarters, 19 violations were noted and have since been corrected. The SFMO Liaison noted that, "the number of items is far less than was noted during last year's inspection, indicating a commitment of the part of BP at the Milne Point Facility to strive for a fire safe workplace."

[26] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

Northstar Pipelines

Figure 50: Northstar/Seal Island

Right-of-Way Lease and Pipeline System Overview

The Northstar oilfield is located approximately 6 miles off of the Alaskan Beaufort Sea Coast, and approximately 11 miles northwest of Prudhoe Bay. Oil was originally discovered in the Northstar Unit by Shell in 1983 with exploration wells drilled from Seal Island. This manmade gravel island was built in 1982 in approximately 37-feet of water. It was later abandoned by Amerada Hess in 1994. BP acquired most of the Northstar Unit leases in 1995 and developed the field.

Today, BPXA operates a 10-inch oil pipeline and a 10-inch gas pipeline that extend into the Beaufort Sea to the gravel island, sometimes referred to as Northstar Island or Seal Island (see Figure 50 above).

Produced crude oil is processed on Northstar Island and shipped via a trenched 10-inch oil pipeline to the shore, crossing at Point Storkersen, and then travels an additional 11 miles overland to the TAPS Pump Station 1. Natural gas is transported from the Prudhoe Bay Central Compressor Plant for approximately 16 miles to Northstar Island utilizing a second 10-inch pipeline that shares VSMs and a subsea trench with the oil pipeline.

The trenched pipes are designed and constructed to withstand potential seabed ice gouge and settlement loading conditions of thawed soils. The subsea section of the pipelines employs a leak detection system called LEOS, which is designed to sense hydrocarbon vapors surrounding the pipelines. This equipment is in addition to the oil pipeline's standard leak detection system, which monitors pressure, volume, and temperatures to detect releases. Both pipelines are piggable. Additional information regarding the physical parameters of the pipeline can be found in Appendix F.

The Northstar oil pipeline ROW Lease, ADL 415700, and the Northstar gas pipeline ROW

Lease, ADL 415975, became effective on October 1, 1999, and expires on September 30, 2019 (see Appendix D: Acreage, Survey, and Lease Information). A Release of Interest process for both ROWs was completed during this reporting period. The Release of Interest effectively reduces the original construction ROW width to a smaller operating width.

State Pipeline Coordinator's Office Summary of Northstar Pipeline Company's CY09 Annual Report for the Northstar Pipelines

BPTA submitted the *Northstar Pipelines Rights-of-Way 2009 Annual ADNR Surveillance and Monitoring Report* to the SPCO on January 29, 2010. The report met SPCO expectations, as described on page 7 of this report, as well as requirements found in stipulation 1.14 (Reporting) of the leases.

Elements of the *Northstar Pipelines 2009 Annual ADNR Surveillance and Monitoring Report* are summarized below. Reported information about programs and systems covering all of the BPXA operated pipelines were presented in the BP Exploration (Alaska) Operated Pipelines section on page 91 of this report.

Throughput, Reliability, and Pigging

The Northstar Oil Pipeline transported 7,981,272 net barrels of oil in 2009 and the Northstar Gas Pipeline transported 25,399,627 standard cubic feet of natural gas. Both Northstar Pipelines were 100% reliable during 2009. The pipelines only experienced shutdowns during planned shutdowns associated with field or facility operations or scheduled TAPS shutdowns. Pipeline throughput and reliability information has been summarized in Table 20. Throughput numbers for all SPCO jurisdictional pipelines can be found in Appendix I: Throughput for SPCO Jurisdictional Pipelines, 2009.

Table 20: Throughput, Reliability, and Pigging Information, Northstar Pipeline

Pipeline System	2009 Throughput	Reliability	Maintenance Pigging	Last ILI
Northstar Oil	7,981,272 net barrels	100%	Every 2 weeks	2006
Northstar Gas	25,399,627 Mscf.	100%	2 X calendar year	2006

Risk Management Programs

Integrity Management, Corrosion, and Quality Assurance

For more information on Integrity Management, the Corrosion Program, and Quality Assurance refer to page 91, 93, and 94 of this report.

Safety Programs

In addition to the safety information listed below, information common to all BPXA operated pipelines can be found on page 94 of this report.

Internal Safety Program

The Internal Safety Program for the Northstar Pipelines consists of an employee, behavior-based monitoring program, called STOP. Both contractors and BP employees participate in the STOP program. In 2009, 1,520 safety observations were made.

In addition to STOP, there is a management/supervisory monitoring component based on Safety Observations and Conversations. The goal of the program is to focus on the quality of the safety conversations while minimizing the number of SOC occurrences. Each SOC is tracked in the Tr@ction computerized tracking system. In 2009, 255 SOCs were conducted, a reduction from the number in each of the preceding two years.

There were no OSHA days away from work, and no OSHA recordable incidents. There was one major incident, resulting from pigging activities on an oil transit pipeline, which set off a venting incident at PS 1. It was not triggered by activities related to the Northstar Pipelines, although it had the potential of impacting the ROW.

Surveillance

The Surveillance and Monitoring Program is designed to detect and abate situations that endanger health, safety, environment, or pipeline integrity. The program was reviewed and received final approval by the SPCO on April 15, 2009 (SPCO Letter 09-019-CT). Items noted during aerial or ground surveillance are evaluated to determine if corrective action is required. Preventative Maintenance Work Orders are one tool utilized by BPXA to remedy conditions found through surveillance and monitoring.

Aerial Surveillance

During 2009, 74 aerial surveillances of the Northstar Oil and Gas Pipelines ROWs identified no issues. Three inspections were carried out using FLIR equipment.

Ground Surveillance

In addition to the over flights, the Northstar Oil and Gas Pipeline ROWs were inspected from the ground on April 7, 2009 during the Annual Walking Speed Survey. Some locations were ensconced in snow and were re-inspected in the fall. The Walking Speed Survey identified 10 locations with insulation jacket perforations or separations along the Northstar Natural Gas Pipeline, while a twelve foot area of bare pipe and three locations of jacket perforations were identified on the Northstar Oil Pipeline.

Monitoring

Corrosion

A high-resolution MFL/Caliper combination ILI tool was sent through the Northstar Oil Pipeline on April 7, 2009, and through the Northstar Natural Gas Pipeline on April 3, 2009. All inspections resulting from the ILI runs have been completed, with no additional inspections planned in 2010. Comparative analysis between the data captured during smart pig run and historical data is ongoing. Each of the Northstar Pipelines is scheduled for the next in-line inspection during 2012.

Annual monitoring of the cathodic protection for buried and submerged pipelines in September of 2009 determined that all but one section of pipe at the ground insertion point on Northstar Island was in compliance with regulations. There are future plans to inspect the insertion point on Northstar Island and install an interruptible CP Monitoring Coupon.

Pipeline ROW-Shore Crossing Permafrost

Thermister readings were not taken again in 2009 due to the same wiring fault which precluded readings in 2008. A work order to repair the wiring is scheduled for 2010.

Pipeline ROW-Coastal Stability

Annual monitoring of the coastal transition, *Post-Construction Coastal Stability Monitoring*, was conducted during the summer of calendar year 2009. No erosion mitigation measures are required based on the ten alignments evaluated, which found minimal erosion. The average erosion was 0.5 foot, with a maximum measurement over the pipeline centerline of 1.3 feet. Future bluff monitoring is planned as part of the authorized Annual Monitoring Program.

Pipeline ROW-Landfall Rehabilitation

Rehabilitation Progress Report for the Northstar Pipeline Landfall is a monitoring report that evaluates erosion control measures implemented at the Northstar Pipeline landfall, which consists of a backfill of a trench 79 feet by 39 feet, and a construction gravel remnant. Although monitoring has been going on since construction, vegetation monitoring began in 2003, at which point it was observed that the trench backfill had 36% plant cover, and a gravel remnant had 26% plant cover. Total plant cover[27] on the backfill trench in 2009 was 13% all seeded grass, and 22% on the remnant gravel, consisting of seeded grass (4%) and naturally occurring vegetation (18%). Plant coverage for both the trench and the gravel remnant reflect the lowest coverage measured since measurements have been taken at the site.

Erosion control fabric has also been used along the shore face of the trench. Prior to the 2009 inspection, the erosion control fabric, which had been slated for repairs, had washed away. New erosion control fabric was installed in 2009.

Pipeline ROW-Sea Bottom Conditions

Conditions were evaluated through helicopter reconnaissance combined with multi-beam, single-beam, and side scan sonar along the submerged portion of the pipeline ROW during 2009. The *Northstar Development 2009 Pipeline Route Monitoring Report*, which documents monitoring of the subsea pipeline route, identified one subsidence location where pipeline cover was reduced below the six foot minimum. Gravel was placed in the depression and will be verified during the 2010 annual monitoring program.

The monitoring report found that the bathymetric[28] profile had not changed significantly from 2008. Seven areas suffered subsidence, in one case showing an expansion of

[27] Total plant cover is measured as total live vascular cover measured using a laser assisted point sampling method.
[28] Bathymetric - sea depth measurements

subsidence found in 2008. Four other subsidence locations had been identified during past monitoring, but not the previous year. Six ice gouges, four which were new features, were identified in 2009. Ice gouging detected during 2009 was the lowest recorded since monitoring began. Strudel scouring was also low by historic standards, with 19 drainage sites observed, which created eight new depressions, none resulting in the need for additional fill.

Construction

A letter of non-objection was issued November 30, 2009, for dredging and construction to facilitate the Northstar Southeast Corner Modification and Operations Center Installation. The work is planned to occur between 2009 and 2012. The project is to install a multi-use module on the southeastern corner of the island. Project activities will occur within the pipeline ROWs and include dredging over the pipeline.

Operations

The Northstar Pipelines were 100% available in 2009. There were no unscheduled shutdowns that affected availability.

Maintenance

During 2009, maintenance activities included: running maintenance pigs approximately every two weeks; completing welding associated with the Cosasco Access Fitting of the CP system; and the annual test of the LEOS system which was carried out in July 2009. Results from the new infrared gas analyzer during the LEOS test were excellent.

Jack stands located where the two pipelines come out of the ground at Point Storkerson were removed. 1,000 cubic yards of gravel were placed in the subsidence depression which had reduced pipeline cover to below minimum levels, as reported in the *Northstar Development 2009 Pipeline Route Monitoring Report.* Erosion control fabric was re-installed on the shore crossing land fall in 2009 after the fabric was washed away between the 2008 and 2009 inspections. The purpose of the fabric is to retard erosion along the seaward edge of the backfilled trench, over the pipelines.

Other Activities

There were no pipeline lifts over the Northstar Pipelines during calendar year 2009. However, BPTA issued a letter of non-objection for work within the Northstar Oil and Natural Gas Pipeline ROWs near PS 1 which involved the removal of pipe segments within the ROW. Again in September of 2009, work occurred within the Northstar Oil Pipeline ROW to facilitate the installation of a pig receiver and piping as part of the Skid 50 Pigging Project.

Oil and Hazardous Substance Discharges

There were no reportable oil or hazardous waste discharges in the Northstar ROWs during 2009. However, there was one non-reportable natural gas liquids leak outside of Module 4984.

2010 Proposed Actions and Plans

The planned 2010 BPXA activities are listed below in Table 21.

Table 21: Proposed Actions and Plans for 2010, Northstar Pipelines

Quarter /Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Aerial Inspections Every Two-Weeks	✓	✓	✓	✓
Cleaning/ Maintenance Pig (Sales Oil Line)	✓	✓	✓	✓
Install box to RTU[29] for fuel gas lines/ regulators for standby generators/heaters		✓		
Ground Survey (WSS)		✓		
Bathymetry Survey for Strudel Scour/Ice Gouging			✓	
Thermister readings and repairs			✓	
Annual Corrosion Monitoring in "log cabin" vault				✓
Cathodic Protection Survey			✓	
Formal Risk Assessment (Oil Pipeline)		✓		
Install Interruptible CP Coupon Test Station			✓	

Activities related to the Northstar Southeast Corner Modification and Operations Center Installation project to install a new module on the southeast corner of Northstar Island are anticipated during 2010 and may including dredging within the Northstar ROWs.

During the 2010 pipeline route monitoring activities, the backfill thickness will be verified over the subsidence depression which received 1,000 cubic yards of gravel in 2009.

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(This section provides a summary of SPCO activities during FY10. The information in this section reflects work conducted by the SPCO and was not taken from the Lessee's annual report. By the nature of SPCO oversight efforts there may be some overlap of information.)

Quarterly Meetings

Representatives of the SPCO and the representatives of the Lessee continued to meet quarterly in FY10. The meetings serve to keep both parties up-to-date on important activities, changes in staffing, progress of projects, and other important information. Quarterly meetings, for the BPXA operated pipelines under SPCO jurisdiction, including the Northstar pipelines, occurred on August 25, 2009, December 3, 2009, March 31, 2010, and June 30, 2010. Some of the topics specifically related to the Northstar pipelines discussed during the quarterly meetings are listed below:

- Annual Reporting Requirements

[29] RTU - Remote Terminal Unit

    - Proposed changes to the BP annual reports
- Northstar Lease Transfer
    - Guaranty
- Erosion at Pt. Storkerson
- Appraisal Status
- LEOS Update
- Dredging at Seal (Northstar) Island

Compliance Section FY10 Activities, Northstar Pipelines

Lessee Annual Reporting

The SPCO received the *Northstar Pipelines Rights-of-Way 2009 Annual ADNR Surveillance and Monitoring Report* on January 29, 2010. The report was thoroughly reviewed and found to meet all SPCO annual reporting requirements. Two surveillance reports with satisfactory observations were issued (SPCO letter 10-092-AS).

Lessee Local Hire

Both the Northstar Oil Pipeline and the Northstar Natural Gas Pipeline leases contain language encouraging the lessee to hire local Alaska residents. In 1996, as a part of a development agreement for the Northstar Oil Field between BP and the State of Alaska, BP agreed to actively recruit locally and report those efforts to Alaskans. This resulted in the first BP Alaska Hire Report in 1997. Since then BP Exploration (Alaska) Inc. (BP) has issued a local hire report annually to communicate BP's ongoing efforts to recruit, and train Alaskans, and purchase Alaskan goods and services. The Compliance Section reviewed BP Exploration (Alaska) Inc.'s *2009 Alaska Hire Report* and confirmed BP's efforts to hire, contract and purchase locally.

Although the report did not specify workers dedicated to the Northstar pipelines, BPXA reported that 81% of its employees in 2008 were Alaskan, which is comparable to last year's report for information on 2007 and an increase over the rate in 2006. In addition the report included Alaskan employment base information for five of the largest contractors used by BP during the 2006 through 2008 timeframe. The Alaskan employee base for the contractors ranged from 66.8% to 85.7%. The report indicated that in 2008 BP spent two billion dollars on purchases made from Alaskan Companies, or 82% of their purchases.

Based on the review, two surveillance reports (see Appendix G: SPCO Reports Issued in FY10) were generated on February 12, 2010, and reflected satisfactory observations (SPCO letter 10-067-AS). SPCO found that BP Exploration (Alaska) Inc.'s *2009 Alaska Hire Report* clearly demonstrated a high level of commitment to hire locally.

July 2009 Surveillance of Annual LEOS testing

The SPCO joined BPTA and BPXA staff in the field on July 19 and 20, 2009 to observe the annual LEOS testing. Unfortunately weather conditions precluded conducting the test at that time. Instead, the SPCO representative was provided with detailed information on the LEOS system and the testing that would occur. Representatives from AREVA in Germany performed the test later in the week. On July 22, 2009 the SPCO representative joined lessee and AREVA representatives in a teleconference to discuss the LEOS system and the test. A

field report and three surveillance reports, with satisfactory observations, were completed (SPCO letter 09-037-CT)

May 19, 2010 Northstar Island

The new SPCO Natural Resource Manager responsible for the ROW and Permits and the Lease Compliance Sections traveled to Northstar Island on May 19, 2010. The goal of the trip was to introduce the SPCO representative to the Northstar facilities, personnel, and procedures specific to the Northstar pipeline system; focusing on the unique circumstances that arise from having wells, housing facilities and processing facilities on such a small footprint. BPXA staff from the escorted the SPCO representative and coordinated with subject matter experts familiar with each facility (including processing facilities, the pig launcher and receiver, and the pipeline) observed during the trip. A lease compliance report (10-SPCO-R-019) documenting the trip was completed in FY11 and will be counted in the FY11 annual report numbers.

Right-of-Way Section FY10 Activities

Assignment & Transfer Approved and Acceptance of Guaranty

The SPCO received a request from BPTA to approve an assignment of the Northstar Oil Pipeline (ADL 415700) and Northstar Gas Pipeline (ADL 415975) ROW Leases from BPTA to Northstar Pipeline Company, LLC. BPTA owns 98.5772% and Murphy Exploration (Alaska) Inc. owns 1.4228% of Northstar Pipeline Company, LLC. Before reviewing the transfer requests, the SPCO considered the "Release of Interests" for the construction ROW under Section 29 of the Northstar leases. The SPCO recommended the release of the construction ROW. A release of interests in the construction ROW effectively reduces the ROW to the width necessary for pipeline operation and maintenance. On October 1, 2008, the SPCO sent a letter to BPTA transmitting Executed Release of Certain Interests in Lands for Northstar Oil (ADL 415700) and Gas Pipeline (ADL 415975) ROW Leases documents (SPCO Letter 08-097-TG).

On October 23, 2008, after the Releases of Interests were completed, the SPCO requested additional information regarding the proposed transfers of interest and ROW lease assignments (SPCO Letter 08-097-TG). The SPCO requested completed assignment of ROW lease forms and other information from BPTA on June 10, 2009. On May 10, 2010, the SPCO approved a request from BPTA to assign its interests in the Northstar Oil Pipeline ROW Lease (ADL 415700) and Northstar Gas Pipeline ROW Lease (ADL 415975) to the Northstar Pipeline Company, LLC (SPCO Letter 10-128-AS).

After receipt of the financial guarantees acceptable to the Commissioner, the SPCO approved BPTA's request to transfer its ownership interest in the Northstar Pipelines to the Northstar Pipeline Company, LLC (SPCO Letter 10-129-AS). The assignment and guaranty documents for each pipeline were recorded on May 24, 2010, in the Barrow Recording District as Document Nos. 2010-000234-0, 2010-000235-0, 2010-000236-0, and 2010-000237-0.

Engineering Section FY10 Activities, Northstar Pipelines

A 10-inch oil and a 10-inch gas pipeline T consist of both onshore and offshore portions. They cross over the tundra and under the sea, extending offshore to a barrier island six miles offshore in the Alaska Beaufort Sea. These carry fuel gas from the Prudhoe Bay area, and transport processed oil to PS 1. The gas pipeline provides fuel gas, and the oil pipeline transports oil from the island to TAPS.

The Engineering Section monitored repairs and operations. During CY09 there were no major incidents reported for the Northstar Pipelines. The Engineering Section also evaluated performance testing of a major upgrade of the LEOS leak detection system was completed. The leak detection conduit was not changed, but equipment at both ends was modernized. The Engineering Section found no issues in the testing of the system by the manufacturer and agreed with the conclusions that the changes resulted in improved performance.

It should be noted that the LEOS is a secondary leak detection system that uses a permeable tube buried near the pipelines for detection of minor concentrations of hydrocarbons. It is utilized in addition to the primary oil-leak detection system, which depends upon monitoring fluid pressure, volume and temperature. The primary system is under the jurisdiction of DEC and PHMSA.

Near the landfall of the Northstar pipelines at Point Storkersen the coast line is eroding at rates higher than historical averages. However, increasing shore erosion rates are a feature of the coastline across the Arctic, rather than a specific problem at this site. BP's latest monitoring report states: "At present, the toe of the pipeline shore pad lies about 71 feet landward of the eroding backfill face and the base of the gravel berm that protects the pipeline riser is more than 130 feet from the Mean Lower Low Water shoreline. Given this distance from the coast and the modest historical bluff recession rate, no erosion mitigation measures are required at this time."(12 p. 16) The Engineering Section reviewed their data and concurred with their conclusion.

State Fire Marshal's Office Liaison FY10 Activities[30]

The SFMO Liaison's annual inspection of North Star Pipelines and related facilities was conducted on December 17 and 18 2009. 13 facilities were inspected with 22 violations noted, all have been corrected.

[30] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

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ConocoPhillips Alaska, Inc. Operated Pipelines

This section presents a description of programs and systems that apply to all of the ConocoPhillips Alaska, Inc. (CPAI) operated pipelines covered by CY 2009 annual reporting. Following this overview is a section for each CPAI operated pipeline that includes a brief description of the pipeline system and a summary of highlights from the lessee's CY09 annual report. Following the summary of each lessee's annual report is a section describing SPCO oversight during FY10.

CPAI operates pipelines associated with the following ROW leases:

- ADL 415932, Alpine Diesel Pipeline
- ADL 415701, Alpine Oil Pipeline
- ADL 415857, Alpine Utility Pipeline
- ADL 402294, Kuparuk Pipeline
- ADL 409027, Kuparuk Pipeline Extension
- ADL 411731, 16" Oliktok Pipeline

The pipeline companies that hold the above leases each have a contract with ConocoPhillips Alaska, Inc. to operate their respective pipelines. Each pipeline company, together with CPAI, implement a number of programs that govern their operations and maintenance activities, including those activities associated with the pipeline ROW leases for the respective pipelines. Rather than repeat the description of each program for each pipeline, the programs that apply to all of the CPAI operated pipelines reported on by the lessees in CY 2009 are described below.

Assurance Programs

Health, Safety, and Environmental Management System Standard

The Health, Safety, and Environmental Management System Standard identifies the processes required to assess and manage the operational risk to the business, its stakeholders, and the environment. There are 15 interrelated elements that are essential for successful system implementation:

1. Policy and Leadership
2. Strategic Planning, Goals, and Objectives
3. Structure and Responsibility
4. Asset and Operations Integrity (includes QMS)
5. Risk Assessment
6. Legal Requirements and Operations Standards
7. Measuring, Monitoring, and Review
8. Emergency Preparedness
9. Communication
10. Programs and Procedures
11. Non-Conformance and Investigation
12. Audits
13. Document Control and Records
14. Awareness, Training and Competency
15. Other

Audits are regularly performed on CPAI operated pipelines to assess the effectiveness of its programs. In 2009, CPAI performed an internal health, safety, and environment Compliance Audit. No transportation related findings were identified. A Corporate security audit is scheduled for North Slope facilities in 2010.

Quality Management System

CPAI, as operator for the pipelines, assures compliance, maintains quality, and supports system integrity through the Quality Management System. This system provides a central quality function to ensure that facilities and equipment are designed, built, and operated in compliance with all codes, standards and regulations aimed at assuring system integrity; while meeting the requirements of the Health, Safety, and Environmental Management System Standard (HSEMSS). This program is under the oversight of CPAI and includes criteria that align it with the ISO 2000/9000 philosophies.

The CPAI Quality Assurance Department, in the Capital Projects Group, conducted two assessments in support of the Quality Management System, for all pipelines, in 2009. The Quality Assurance Department rates results from assessments into three levels; *findings*, *concerns*, and *understandings*. In September 2009, over pressure protection was assessed with no findings, concerns, or understandings found. In November and December 2009, the CPAI Cathodic Protection (Rectifiers) was assessed, also with no findings, concerns, or understandings found. A pipeline engineering assessment performed the week of November 3, 2008 has two minor findings which were not closed by the end of the reporting period.

The 2010 assessment plan was under development at the time of the writing of the 2009 annual comprehensive reports. It was anticipated that the plan would be completed and approved during the first quarter of 2010.

Operations Compliance Management System

CPAI uses the Operations Compliance Management System to implement a systematic approach for ensuring pipeline operation in compliance with applicable laws, regulations, and ROW lease and grant covenants and stipulations.

There were four assessments performed in support of the Operations Compliance Management System in 2009. Assessments of Operations and Maintenance Procedures, the Discharge Prevention and Contingency Plan, and the PHMSA Public Awareness Program did not result in any findings. An assessment of Surveillance and Monitoring, which was focused on the timing sequences and steps typically triggered by the initiation of ILI pigging or other means of determining corrosion, resulted in one finding, related to the timing of vendor reporting. The final report was issued on November 13, 2009. The 2010 assessment plan was not completed in time for inclusion in the 2009 annual comprehensive reports.

Risk Management Programs

To ensure effective risk management, CPAI has established a variety of systems for identifying potential hazards and liabilities, assessing risk, evaluating prevention and mitigation measures, and ensuring the implementation of control techniques for the continued management of risk associated with activities such as:

- Acquisition and Divestiture
- Design and Construction
- Operations and Management
- Environmental Management
- Waste Management
- Emergency Planning and Response

Acquisition and Divestiture

CPC's *Due Diligence Standard* and CPAI's *Due Diligence Program* outline requirements to ensure that potential liabilities related to health, safety, environmental, and other social issues are sufficiently identified, understood, documented, and addressed prior to all business transactions pertaining to real property or business ventures.

There were no reported changes to CPC's Due Diligence Standard or CPAI's Due Diligence Program in 2009.

Design and Construction

The *Process Hazard Analysis Standard* establishes the organizations protocols and technical standards to be applied to Process Hazard Analyses and Process Safety Assessments on CPAI facilities.

The Process Hazard Analysis Standard was revised on January 28 and March 26, 2009.

The MOC process ensures changes in facility design and operation do not inadvertently introduce significant new hazards into facility processes. The MOC provides a systematic means for ensuring process safety information and operating procedures are updated; health, safety, and environmental issues are identified and addressed; and training is conducted as necessary, in response to changes. The MOC was revised in 2009.

Operations and Maintenance

CPAI conducts pre-job safety assessments, post job reviews, routine safety meetings, a risk-based evaluation process for maintenance and equipment integrity programs, insurance surveys, and TAP root analysis to minimize operations and maintenance risks.

Integrity Management Program

In accordance with PHMSA Regulations concerning Pipeline Integrity Management in High Consequence Areas, the IMP is designed to enhance and validate pipeline integrity. The program focus is to protect high consequence areas (HCA) from an unintended release of hazardous liquids from the pipeline system. CPAI reviews the IMP annually and revises sections as necessary.

CPAI's annual review of the IMP resulted in revisions to the program. The requirement for the dispersion analysis was clarified and the submission deadline for the National Pipeline Mapping System was changed in the HCA Pipeline Segment Identification requirement, identified risk factors were incorporated into the Inspection Plan requirement, and moderate revisions were made to both the Preventative and Mitigative Measures Evaluation requirement and the Documentation and Communication requirement. Edition 2, Revision 1 of the IMP was issued on June 30, 2009.

The IMP annual Risk Assessment and Preventative and Mitigative Measures screening evaluations were conducted on March 17-18, 2009. No changes resulted from the screenings.

Operator Qualification Program

In addition to internal processes and programs, CPAI also utilizes PHMSA required programs including the Operator Qualification Program. The Operator Qualification Program was significantly revised in 2009. Revisions included an increase in the number of covered tasks and changes in the ratio of non-qualified to qualified individuals.

Public Awareness Program

CPAI implements a Public Awareness Program (PAP) "to enhance the continued safe operations of the North Slope pipelines by promoting safe performance and launching communications networks to help the public understand:

- The North Slope pipelines role in the petroleum products transportation system in Alaska and the United States.
- How these pipelines function (e.g., products transported).
- Their responsibilities to help prevent pipeline damage.

The Public Awareness Program and the Drug and Alcohol (Substance Abuse Policy) were reviewed and revised in 2009.

Environmental Management and Waste Management

No changes were made to the North Slope Environmental Field Handbook, or the Alaska Waste Disposal and Reuse Guide in 2009.

Emergency Planning and Response

The Alpine and the Greater Kuparuk Area Facility/Drillsite Emergency Action Plans were reviewed and had minor revisions in 2009. The Western North Slope Operations Business Recovery Plan was also updated in 2009.

Other Risk Management Processes

There were no changes to the GKA or the Alpine Process Safety Management, Employee Participation Plans in 2009.

The following HSE Policies were revised in 2009: car seal, contractor performance, hazard communication, hearing conservation, hexavalent chromium, HSE legislative, regulatory and standards management process, hydrogen sulfide safety and health, and radiation safety.

Safety Programs

CPAI uses a proactive approach to safety focusing on at-risk behaviors. The Alaska Safety Handbook (ASH) defines standards of conduct and the responsibilities of contractors and CPAI employees that guide their day-to-day efforts on the job. CPAI expects all employees and contractors to understand and use the safety rules defined in the ASH, which was last revised in 2006. The ASH was under review at the time of the production of the 2009 annual reports. It is scheduled to be updated in 2010.

CPAI contractors implement their own plans and programs, which include health, safety, and environmental performance objectives and procedures that fall directly in line with CPAI's culture of safety. Two of CPAI's primary contractors revised their safety related programs in 2009.

ConocoPhillips conducted a corporate audit for compliance with both the Occupational Safety and Health Administration and corporate standards. There were seven minor findings, none of which were directly related to the pipelines. The Alpine and Kuparuk Voluntary Protection Program annual assessments were conducted in 2009 and will be submitted to Alaska Occupational Safety and Health in 2010. There were no lost-time or medical treatment incidents in 2009 for CPAI or contract personnel working on the Alpine or Kuparuk pipelines in 2009.

Pipeline Specific Information

The following sections provide an overview of the pipeline system, highlights from the lessee's CY 2009 annual report, and a description of SPCO activity related to the pipeline system and conducted during FY10.

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Alpine Pipelines

Figure 51: Alpine Diesel, Utility, and Oil Pipelines near CPF-2

Right-of-Way Leases and Pipeline System Overview

Three pipelines, each approximately 34-miles long, connect the North Slope's westernmost development, Alpine, to infrastructure in the Kuparuk River Unit (KRU). The Alpine Oil Pipeline transports processed crude oil from the Alpine Central Facility (ACF) to the KRU Central Processing Facility (CPF)-2, the Alpine Diesel Pipeline transports heating fuel and other petroleum products from CPF-2 to ACF, while the Alpine Utility Pipeline transports treated seawater from CPF-2 to ACF for use in enhanced oil recovery. Figure 51 above shows the three Alpine pipelines just before they cross under a road near CPF-2.

All three pipelines are aboveground for most of their length. Physical characteristics, including pipe diameter and system length, are provided in Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines.

ConocoPhillips Company owns Alpine Pipeline Company and is a general partnership between Alpine Pipeline Company, Anadarko Alaska Pipeline Systems, Arctic Slope Regional Corporation, and Kuukpik Transportation Company. Alpine Transportation Company owns the Alpine Oil Pipeline. CPAI owns the Alpine Utility Pipeline and the Alpine Diesel Pipeline. More information regarding ROW status and lease appraisal information can be found in Appendix E: Pipeline Right-of-Way Lease Appraisal Information. With the execution of the leases and grant on December 31, 2002, CPC became the Lease/Grant holder and is responsible for compliance with the ROW agreement requirements. Appendix D: Acreage, Survey, and Lease Information provides additional lease information.

State Pipeline Coordinator's Office Summary of ConocoPhillips Company's CY09 Annual Report for the Alpine Pipelines

The *2009 Annual Comprehensive Report on Pipeline Activities: Alpine Oil Pipeline ADL 415701, Alpine Utility Pipeline ADL 415857, Alpine Diesel Pipeline ADL 415932* was received by the SPCO on January 29, 2010. The lessee's CY09 report covered numerous topics including throughput, descriptions of the assurance programs, monitoring activities, leak detection, planned maintenance, unplanned events, and upcoming activities. The CY09 report followed guidelines, as described on page 7 of this report, as well as the requirements of Lease and Grant.

The annual report is required by lease/grant stipulation 1.14 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 t reviewed by the SPCO every year. Elements of the Lessee's *2009 Annual Comprehensive Report on Pipeline Activities* are summarized below. Reported information about assurance programs and quality management systems in place to cover all of the CPAI operated pipelines can be found on page 135 of this report.

Throughput, Reliability, and Pigging

The Alpine Oil Pipeline transported 37,432,495 barrels of oil which was down from 2008 numbers by 2,421,118 barrels. Reliability remained consistent with 2008 levels; it was 99.45% reliable in CY09. The Alpine Oil pipeline experienced a greater number of unplanned shutdowns in 2009; there were seven this year, compared to five last year. In addition to the unplanned shut downs there was one planned shutdown. The planned shutdown was the annual maintenance shutdown for the Alpine Central Facility and it affected all three of the Alpine pipelines. The annual maintenance shutdown began on July 18 and ended on July 21, 2009. Unintended valve closures, TAPS proration events, and oil train shut downs caused some operational delays and shut downs. The seven unplanned shut downs/slow downs affecting the Alpine Oil Pipeline were as follows:

3/14/09	unintended valve closure due to an APSC block valve coming off seat
8/9/09	unintended diversion into breakout tank due to replacement of Oliktok Pipeline valve actuator
1/7/09	Alpine Central Facility Oil Train shut down when ramping rates backed up after a proration
5/2/09	Alpine Central Facility shut down during an emergency shut down test
10/9/09	Alpine Central Facility shut down due to a power outage
10/23/09	Alpine Central Facility Oil Train due to a high oil level in the inlet separator
12/18/09	Alpine Central Facility shut down due to a power outage.

There were 14 maintenance pig runs through the Alpine Oil Pipeline in 2009. A MFL/Geometry pig was run on June 12, 2009. The MFL data indicated 88 individual metal loss features, 10 clusters, and 36 dents. The Geometry data indicated that there were four areas of greater than 0.04% differential bending strain. No imminent threats to the integrity

of the pipeline were identified.

The Alpine Utility Pipeline's throughput rose by 4,177,935 barrels in 2009; 46,847,380 barrels of seawater were transported. Reliability remained constant at 98.2% reliability in CY 2009. There was one planned shutdown and there were eight unplanned shut downs/slowdowns. Rates through the utility pipeline were impacted by operations at the Seawater Treatment Plant (STP), maintenance shutdowns, weather problems, and pump maintenance. The Alpine Utility Pipeline was shut down three times in 2009 because of maintenance activities at the STP on April 4, August 16, and September 25, 2009 respectively. The remaining five shut downs/slow downs were as follows:

2/27/09: STP shut down
5/2/09: Alpine Central Facility shut down during an emergency shut down test
10/9/09: Alpine Central Facility shut down due to a power outage
10/22/09: STP shut down
12/18/09: Alpine Central Facility shut down due to a power outage.

The Alpine Utility Pipeline had 35 maintenance pigs run in 2009 and a MFL/Geometry pig run on June 17, 2009. Analysis of the MFL data identified 374 individual metal loss features, and application of 1' x 1'interaction rules to those detected anomalies, identified 66 clusters. The Geometry data indicated that there was one area of movement with greater than 0.04% differential bending strain. There were no imminent threats to the integrity of the pipeline identified.

The Alpine Diesel Pipeline transported 3,679,385 gallons of arctic heating fuel, which was a drop of 1,470,861 barrels from the 2008. There were no mineral oil shipments in 2009. The pipeline was 100% reliable in 2009; there were no shut downs or slowdowns. Arctic heating fuel was the only product transported through the pipeline in 2009; therefore no pigs were run between batches of product. Four maintenance pigs were run in 2009. Table 22 depicts throughput, reliability, and pigging information for each of the Alpine pipelines for CY09.

Table 22: Throughput, Reliability, and Pigging Information for Alpine Pipelines, CY09

Pipeline System	2009 Throughput	Reliability	Maintenance Pigging	Last ILI
Alpine Oil	37,432,495 barrels	99.45%	14 runs	Geometry Pig/MFL 6/12/09
Alpine Diesel	3,679,385 gallons	100%	4 runs	n/a (hydrostatic test in 2008)
Alpine Utility	46,847,380 barrels	98.2%	35 runs	Geometry/MFL 6/17/09

Assurance Programs

The Alpine Pipelines' Quality Program was approved by the SPCO on October 3, 2006. The Quality Program "defines the elements of a quality system necessary to satisfy these (ROW Lease) commitments, identifies what the system intends to accomplish, and provides guidance for the development of contractor quality plans that define how expectations are fulfilled." CPAI, as operator of the pipelines, ensures compliance with the Alpine Pipelines

Quality Program. The Quality Program is one of the assurance programs implemented by the operator; other programs that apply to all CPAI operated pipelines under the jurisdiction of the SPCO were described on page 135 of this report.

Internal Audits

In 2009, a Corporate Health, Safety, and Environment Compliance Audit was performed on the Colville River Unit, which includes the Alpine Pipelines. The audit was intended to evaluate compliance with federal, state, and local laws and regulations, corporate standards, and local policies and procedures. None of the findings were transportation related.

Agency Audits/Inspections

On July 27 through 29, 2009 PHMSA conducted a standard inspection of the Alpine Oil and Diesel Pipelines. All items discussed for revision or improvements were minor in nature and were corrected to the satisfaction of PHMSA prior to closing out the inspection.

ROW Lease/Grant Performance

Performance under the grant and leases is of paramount importance to the SPCO. The Compliance Matrix is one tool that the Lessee uses to correlate Lease and Grant requirements with Lessee activities; those activities completed in 2009 were presented in the 2009 Activities and Results Summary. The Surveillance and Maintenance matrix tracks surveillance and maintenance activities that were performed by the operator (or contractors) during the calendar year and are further discussed in the next section of this report. The Lessee notified the SPCO of a new registered agent and authorized representative in a June 4, 2009 letter, the field representatives were updated in a November 9, 2009 letter; this information is reflected in Appendix J: Lease Required Contact Information. A copy of the Employers' Notice of Insurance, demonstrating compliance with section 10 of the lease, was included in this year's report.

Surveillance and Monitoring

Surveillances cover a number of systems and are completed on different timelines, dependent upon regulatory requirements and other factors. The categories of surveillances are as follows:

- Above ground pipeline
- Communications
- Corrosion control
- Environmental
- HDD river crossing and work pad
- Leak Detection
- Modules/Buildings
- Right-of-Way
- River and floodplain crossings
- Valves

The operator's goal is to conduct an aerial surveillance every 7 to 10 days. Ice and snow accumulation, pipeline movement, leaks or spills, fire or fire hazards, blockage of wildlife movement, presence of bird nests on or near the pipeline, bear den locations, functioning of thermosiphons, damage, situations that may endanger health, safety, environment or the integrity of the pipeline system, unauthorized construction activities, evidence of erosion, and evidence of flooding are some of the things that are looked for during aerial surveillances of the ROW. Aerial surveillance and FLIR results are transmitted by the pilots in a monthly report. In 2009, 104 aerial surveillances of the ROWs were completed, of these, 69 utilized

FLIR technology.

No immediate threats to pipeline integrity were identified in 2009. Ground surveillances identified VSMs that were leaning, migration of intermediate supports, loose saddle bolts, loose and missing U-bolts, damaged insulation, missing and damaged reflective tape, missing pipeline vibration dampeners, locations where saddles are not centered over VSMs, locations where pipelines were in contact with each other, a loose cable clamp, sagging fiber optic line, six monuments that may require repair, and stripped threads on a valve. Preventative maintenance orders were initiated for many items identified during surveillance.

Tangential radiography was completed on all "corrosion under insulation" locations on September 28, 2009 and resulted in the identification of six "heavy wet locations" that will need refurbishment in the future. The next corrosion under insulation inspection is due in 2010. 226 directional changes of piping require visual and UT inspections for corrosion related conditions at a 5 year interval. 20% of the directional changes are completed each year. In 2009, 54 locations were inspected; no corrosion or mechanical damage was noted.

Items noted during surveillances are evaluated to determine if corrective actions are required. Preventative and Corrective Work Orders are created and tracked to remedy conditions found the Surveillance and Monitoring Program. A summary of 2009 Work Orders was included in the annual report for the Alpine pipelines.

Maintenance

Preventative Maintenance

Categories of preventative maintenance activities in 2009 included pig launchers and receivers, the leak detection system, meters and provers, over pressure protection, valves, corrosion control, pipeline, ROW, and river crossings, roads and pads, and wildlife.

As part of the preventative maintenance activities in 2009, 14 maintenance pig runs were conducted on the oil pipeline, 35 on the utility pipeline and four on the diesel pipeline. The oil pipeline had a geometry and MFL pig run on June 12, 2009. The utility pipeline had a geometry pig and a MFL pig run on June 17, 2009. Data from the two pig runs on the utility line were combined for adequate coverage. No imminent threats were identified. The next hydrostatic test for the diesel pipeline is scheduled for 2013.

Corrective Maintenance

A pull point (to make it easier and safer to remove pigs from the trap) for pig receiver smart pig extraction was installed at Alpine for the utility pipeline on August 15, 2009. On June 24, 2009 a prover meter was recertified for the oil pipeline. Reportable conditions identified in 2008 and repaired in 2009 included a survey monument and fiber optic cable.

System Modifications and Improvements

The following activities were some of the reported accomplishments in 2009. Divert tank inspections, associated with the Alpine Oil Pipeline at CPF-2 were completed. Drag Reducing Agent tanks are being de-inventoried; current production rates of the oil pipeline have negated the need for the addition of DRA to the flow. A best available technology review was completed for pipeline leak detection upgrades. Long range planning for low

flow was initiated. Water drop-out prediction, wax deposition modeling, and a viscosity study are included in the planning. In-line inspection of the crude oil pipeline was completed on June 12, 2009, no imminent threats were reported.

A study of wax deposition at different temperatures and different throughputs was completed. Modeling indicated that that the current cleaning pig program is sufficient to manage wax deposition. As throughput declines, the frequency of pigging may be increased, if wax buildup is noted. The study showed that cleaning pigs can address the wax issues through 2034.

In September 2009, two new electric submersible pumps were installed at the Alpine Central Facility to increase water rates, up to 135,000 bpd, through the Alpine Utility Pipeline.

Construction

Construction in the Alpine ROW in 2009 was limited disconnecting and reconnecting the Alpine Oil Pipeline to the Kuparuk Extension and was in support of the Kuparuk Extension upgrades. Details are provided in the Kuparuk, Kuparuk Extension, and Oliktok section of this report.

Oil and Hazardous Substance Discharges

There were no discharges associated with the Alpine pipelines or ROW in 2009. The Alpine Development Area Oil Discharge Prevention and Contingency Plan (ODPCP) provides prevention strategies and response plans to limit the spread of a spill, minimizing potential environmental impacts, and to provide for the safety of personnel. The Alpine ODPCP relies heavily upon information provided in the Alaska Clean Seas Technical Manual. CPAI reviewed and updated information for the Alpine Development Participating Area Oil Discharge Prevention and Contingency Plan (Plan Number 07-CP-4140) in January, March, May, August, October, and December 2009.

The Alpine Incident Management Team participated in a North Slope Exploration Unannounced Qualified Individual Notification Spill Management Team tabletop and equipment deployment exercise on March 31, 2009. The scenario used for the exercise was taken directly from the CPAI North Slope Exploration ODPCP. A total of six rig personnel, 21 Alpine Spill Response Team members, 25 Alpine Incident Management Team members, one technical specialist, 13 drilling and wells Functional Support Team members, one representative of the Crisis Management Team, and four facilitators from the CPAI Emergency Management and Performance Assurance department participated in the tabletop exercise. No real-time safety issues or personnel injuries were reported.

On July 29, 2009 there was a “worst case discharge” tabletop exercise at Alpine. Participants included the CPAI Alpine Incident Management Team, the Anchorage-based Crisis Management Team and Incident Management Team. The exercise was described as Scenario 3 in the Alpine Development ODPCP. All actions were described as being conducted in a safe and efficient manner; no real-time safety issues or personnel injuries were reported.

2010 Plans

Leak detection system upgrade trials were the only activities listed in the plans section of the report.

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the SPCO and is not taken from the Lessee's annual report. By the nature of the SPCO oversight efforts, there may be some overlap of information.)*

Quarterly Meetings

Representatives of the SPCO and the Lessee continued to meet quarterly in FY10. These meetings serve to keep both parties up-to-date on important activities, changes in staffing, progress of projects, and other important information, without the delay of more formal correspondence. Quarterly meetings, for all of the CPAI operated pipelines with ROW leases administered by the SPCO, including the Alpine Pipeline, occurred on July 6, 2009, September 30, 2009, and April 8, 2010. Some of the topics specifically related to the Alpine pipelines discussed during the quarterly meetings are listed below:

- Personnel changes at CPAP, many due to recent reorganization
- U-Bolt retrofits on the Alpine Utility Pipeline
- Results of the last ILI runs at Alpine
- Pending transfer of ownership issues for the Alpine Oil pipeline.
- Alpine appraisal status
- Alpine ROW transfer to ATC
- Finalization of the Alpine survey

Compliance Section FY10 Activities, Alpine Pipelines

The SPCO Compliance Section focused on case file review for the Alpine pipelines during FY10. One of the compliance section research projects centered Lessee notifications to the SPCO. Lease stipulation 2.11 requires the lessee to give notice of any spill, leakage, or discharge of crude oil or other hazardous material in connection with pipeline activities. The initial discharge reports from the lessee, discharges reported by the lessee in the annual reports, and discharges recorded in the DEC Statewide Oil and Hazardous Substance Spills Database were compared and found to be in alignment, resulting in one satisfactory surveillance report (SPCO letter 10-105-AS).

Before a third party is allowed to perform work within the Alpine pipelines ROWs, they are required to request a letter of non-objection (LNO) from the Lessee. The SPCO reviewed two LNOs from the Lessee in FY10, and voiced no objections.

Compliance Section staff planned a surveillance trip to Alpine and Kuparuk to observe work efforts related to erosion, sedimentation and bank migration surveys being performed as part of CPAIs SMP commitments. The survey was to take place at various locations within the active channel and vegetated floodplain of the Kuparuk River as well as at East Creek, Sakonowyak River, East and West Channels of the Putuligquak River and Colville River.

Due to circumstances beyond the SPCO's control the surveillance trip did not occur, however many hours were spent reviewing procedures and requirements related to the application of soil erosion, sedimentation and bank migration control measures and practices currently being administered by CPAI and their contractors. The main objectives for the trip were to observe the contractor performing the mitigation survey to standards set by CPAI, observe how data was collected, the process involved in analyzing the collected data and post analysis efforts.

The *2009 Annual Comprehensive Report on Pipeline Activities: Alpine Oil Pipeline ADL 415701, Alpine Utility Pipeline ADL 415857, Alpine Diesel Pipeline ADL 415932* was received by the SPCO on January 29, 2010. The report contained over 700 pages and was extensively reviewed by Compliance Section staff for compliance with requirements found in the leases and on page 7 of this report.

During the review of the report the SPCO contacted the Lessee with a request to clarify information. The Lessee answered the questions and the responses were added to the SPCO case file. As an example, the report for the Alpine pipelines briefly mentioned an assessment related to Surveillance and Monitoring, but didn't provide any details. The SPCO requested some specifics about the assessment, and was provided a summary of the scope of the assessment, which related to the timing of contractor reporting. The response met SPCO needs. Three surveillance reports, reflecting satisfactory observations were completed as part of the annual report review (SPCO Letter 10-065-AS).

Engineering Section FY10 Activities, Alpine Pipelines

The Alpine Oil Pipeline transports processed crude oil from the ACF to the 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 from CPF-2 to the ACF for use in secondary oil recovery. The engineering section followed developments and major repairs during this period and found that no major incidents of note occurred.

State Fire Marshal's Office Liaison FY10 Activities, Alpine Pipelines[31]

The Annual Fire Prevention and Life Safety Inspection of the Alpine pipelines and related facilities were conducted by the SFMO Liaison on November 23 and 24, 2009. The inspection covered process and production areas, living quarters, and support facilities, 19 violations were noted, three of which were in the process area. The SFMO Liaison noted that time constraints prevented an inspection of all process facilities located at Alpine, and that the remaining facilities would be inspected during the next annual inspection. The inspections were successfully conducted with the cooperation of the ConocoPhillips Fire Marshal Liaison and Alpine operations personnel.

[31] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

Kuparuk, Kuparuk Extension, and Oliktok Pipelines

Figure 52: The Kuparuk Pipeline Enters PS 1 on New Above-ground Pipe

Right-of-Way Lease and Pipeline System Overview

The 9.2-mile Kuparuk Pipeline Extension (KPE) begins at CPF-2 and transports oil from both CPF-2 and the Alpine Oil Pipeline to a connection manifold with the Kuparuk Pipeline (KPL) at CPF-1. The Kuparuk Pipeline then further transports processed crude oil from the KPE and CPF-1, 28 miles eastward to TAPS PS 1. Figure 52 above, shows the new section of pipe for the Kuparuk Pipeline entering PS 1. Additional oil enters the Kuparuk Pipeline approximately six miles downstream from CPF-1 from the Milne Point Pipeline.

The Oliktok Pipeline (OPL) begins adjacent to the BP Operated Skid 50 near PS 1. The OPL transports natural gas liquids from Prudhoe Bay to Kuparuk CPF-1 to support operations. The Kuparuk Pipeline and the Oliktok Pipeline share the same horizontal and vertical supports between CPF-1 and TAPS PS 1.

The road systems in the Kuparuk Unit and Western Prudhoe Bay provide year-round access to the Kuparuk production facilities. Access roads are also located adjacent to the ROW; except for at the river crossings. Figure 53 on the next page shows caribou crossing the access road and passing under the KPL and OPL during a Lease Compliance Section surveillance of the pipelines. The Kuparuk Pipeline and Oliktok Pipeline cross the Kuparuk

River floodplain and various tributaries as well as Central Milne Creek, East Creek, Sakonowyak River, and the Putuligayak River. The Kuparuk Pipeline Extension crosses the Ugnuravik River and a minor unnamed drainage. All three pipelines are located above ground except at caribou and road crossings where they have been placed below grade within casings.

Figure 53: Caribou Crossing Under the KPL and OPL

The "original" 16-inch Kuparuk Pipeline, laid in 1981, carried processed crude oil to PS 1. Later that same year, the Kuparuk Pipeline Extension was constructed from CPF-2 to CPF-1, and was comprised of both 12-inch and 18-inch segments. In 1984, when the new 24-inch Kuparuk Pipeline was laid, the "original" Kuparuk Pipeline was converted to the Oliktok Pipeline, which now carries natural gas liquids from PS 1 (Skid-50) back to CPF-1. The KPE was also placed in service at this time and connected to the 24-inch KPL. In 2009, as part of the "smart pigging project", the 12-inch segment of the Kuparuk Pipeline Extension was replaced with 18-inch pipe, which will make that portion of the pipeline piggable. Physical characteristics of the pipeline, including diameter and product transported, are provided in Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines.

All three of these pipeline rights-of-way are in operational width, typically 150 feet. Although the KPL and OPL share supports, they have separate ROW leases. The KPL Lease was amended in 2004 to place a pig launcher shelter near CPF-1. As part of the ongoing activities related to the KPE smart pigging project, a pig launcher and receiver were installed to provide pigging capabilities along the 18-inch stretch of pipe. (Anticipated completion is in 2010.) Additional lease information can be found in Appendix D: Acreage, Survey, and Lease Information.

The Kuparuk Transportation Company is the Lessee for the KPL and the KPE. Kuparuk Transportation Company is a general partnership between Kuparuk Pipeline Company (owned by CPC), BP Transportations (Alaska), Inc. (BPTA) and Union Kuparuk Pipeline Company (see Appendix J: Lease Required Contact Information). The Lessee for the Oliktok Pipeline is Oliktok Pipeline Company, which is wholly owned by CPC. CPAI is the operator for all three pipelines.

State Pipeline Coordinator's Office Summary of Kuparuk and Oliktok Transportation Company's CY09 Annual Reports for the Kuparuk Pipeline, Kuparuk Pipeline Extension, and Oliktok Pipeline

The *2009 Annual Comprehensive Report on Pipeline Activities: Kuparuk Pipeline ADL 402294, Kuparuk Pipeline Extension ADL 409027* and the *2009 Annual Comprehensive Report on Pipeline Activities: Oliktok Pipeline ADL 411731,* were received by the SPCO on January 29, 2010. The lessee's CY 2009 reports covered numerous topics including throughput, descriptions of the assurance programs, monitoring activities, leak detection, planned maintenance, unplanned events, and upcoming activities. The CY 2009 reports followed guidelines, as described on page 7 of this report, as well as the requirements found in section 4c and stipulations 1.3.3, 1.8.3, and 1.10.1 of the leases.

The annual reports are required by the leases and are intended to provide a clear picture of the state of the pipelines and the pipeline systems. Because of the reports' ties to lease requirements and the importance of the information presented, the reports are thoroughly reviewed by the SPCO every year. Elements of the lessees' 2009 Annual Comprehensive Reports on Pipeline Activities are summarized or excerpted below. Reported information about assurance programs and quality management systems in place to cover all of the CPAI operated pipelines can be found in the overview section of ConocoPhillips Alaska, Inc. Operated Pipelines on page 135.

Throughput, Reliability, and Pigging

The KPL transported an average of 279,800 barrels per day with a total throughput of 102,109,781 barrels of oil transported in CY09. Average daily throughput for the KPL fell an average of 6,800 barrels a day in 2009. The KPE averaged throughput of 171,800 barrels of oil per day with a total throughput of 62,702,971 barrels transported in CY09. The Oliktok Pipeline transported 6,686,650 total barrels of NGLs, averaging 18,320 barrels per day in CY09. See Table 23 on the next page for throughput, reliability, and pigging information for all three pipelines.

The Kuparuk Pipeline experienced two planned shutdowns in 2009; each was due to the scheduled TAPS maintenance shutdowns. In addition to the two scheduled maintenance shutdowns for TAPS, the Kuparuk Pipeline Extension experienced a third shutdown to facilitate start up of the new 18-inch segment of the pipeline. The Oliktok Pipeline experienced two shutdowns in 2009 when Prudhoe Bay temporarily ceased NGL deliveries in May and Aug 2009. All three pipelines were reported to be 100% reliable (or available) in CY09.

There were 12 maintenance pigs run on the KPL 2009. The KPE and the OPL were not piggable in 2009. Changes to the KPE, including the addition of a pig launcher and receiver are scheduled to be completed in 2010. The first pig run through the KPE is scheduled for third or fourth quarter of 2010. CPAI plans to modify the pig launcher and receiver for the Oliktok Pipeline; the engineering was completed in 2009. The modifications are expected to be finished in the third quarter of 2010 with the first ILI scheduled for the fourth quarter.

Table 23: CY09 Throughput, Reliability, and Pigging Information, KPL, KPE, and OPL

Pipeline System	Throughput	Reliability	Maintenance Pigging	Last ILI
Kuparuk	102,109,781 barrels	100%	12 pigs	Geometry/MFL Pig 6/12/09
Kuparuk Extension	62,702,971 barrels	100%	Sections Not piggable	Sections Not piggable
Oliktok	6,686,650 barrels	100% (available)	Not piggable	Not piggable

Assurance Programs

The Kuparuk Pipelines Quality Program, Revision 2, was approved by the SPCO on October 3, 2006, and "defines the elements of a quality system necessary to satisfy these (row lease) commitments, identifies what the system intends to accomplish, and provides guidance for the development of contractor quality plans that define how expectations are fulfilled." CPAI, as operator of the pipelines, ensures compliance with the Kuparuk Pipelines Quality Program through implementation of the HSEMSS. CPAI, as operator of the pipelines, ensures compliance with the Kuparuk Pipelines Quality Program. The Quality Program is one of the assurance programs implemented by the operator; other programs that apply to all CPAI operated pipelines under the jurisdiction of the SPCO were described in the ConocoPhillips Alaska, Inc. Operated Pipelines overview on page 135.

Internal Inspections/Assessments

In 2009, the CPAI Quality Assurance Coordinator conducted assessments related to "PM Observations for DOT Regulatory Audits" for two contractors, and lead to two findings. CPAI reports that, "The overall process was performed safely and in compliance with the involved tasks and deemed adequate according to known procedures." In 2007, ConocoPhillips performed a Corporate HSE Compliance Audit of the KRU pipelines and facilities to evaluate compliance with federal, state and local laws and regulations, corporate standards, and local policies and procedures. The last finding was closed in 2009.

Agency Inspections/Assessments

The US Department of Transportation, PHMSA conducted a standard inspection of the Kuparuk Pipeline from July 29 to July 31, 2009. The operations manual, some reference documents, and select maintenance records were reviewed. Minor items for revision or improvements were addressed and corrected to the satisfaction of the PHMSA inspector before closing out the inspection.

Safety

On August 4, 2006 the Greater Kuparuk Area Process Safety Management Employee Participation Plan and Roadmap was issued, this plan covers the Kuparuk, Kuparuk Extension, and Oliktok Pipelines and includes near miss reporting, the Behavior Eliminates All Risk (BEAR) Process, the ASH revision process, compliance safety audits, monthly incident review meetings, as well as other processes and programs.

Risk Management

Between December 2008 and January 2009, CPAI conducted a process hazard analysis (PHA) of the KPE smart pigging project to identify potential safety and health hazards associated with the project. The PHA Team was comprised of representatives from CPAI, CH2M HILL, and third-party consultants knowledgeable in the methodology used during the review. The Project Team utilized recommendations of the process hazard analysis team to finalize the engineering design and to resolve and mitigate all identified risks and hazards.

ROW Lease Performance

Extensive spreadsheets provided in the CY09 report described surveillance and maintenance activities that were performed and included a reference to the lease requirement that was met by each activity. The Lessee notified the SPCO of a new registered agent, and authorized representative in a June 4, 2009 letter, the field representatives were updated in a November 5, 2009 letter; this information is reflected in Appendix J: Lease Required Contact Information.

Surveillance and Monitoring

Surveillances cover a number of systems and are completed on different timelines, dependent upon regulatory requirements and other factors. The categories of surveillances are as follows:

- Above ground pipeline
- Communications
- Corrosion control
- Environmental
- Leak Detection
- Modules/Buildings/Divert Tank "A"
- Right-of-Way
- River and floodplain crossings
- Valves

Aerial Surveillances

In 2009, 120 aerial surveillances of the KPL and OPL were flown; there were an additional 146 flights utilizing FLIR. In 2009, 136 aerial surveillances and 133 FLIR flights were flown over the KPE. The operator's goal is to conduct an aerial surveillance every 7 to 10 days. Ice and snow accumulation, pipeline movement, leaks or spills, fire or fire hazards, blockage of wildlife movement, presence of bird nests on or near the pipeline, bear den locations, damage, situations that may endanger health, safety, environment or the integrity of the pipeline system, unauthorized construction activities, evidence of erosion, and evidence of flooding are some of the things that are looked for during aerial surveillances of the ROW.

Ground Inspections

Ground inspections cover numerous elements of the operations. Items that are assessed include, but are not limited to, VSMs (tilting, settlement, frost-jacking, saddle movement), pipeline damage (dents, gouges etc.), pipeline insulation and jacketing, pipeline vibration and dampening, systems communication, corrosion control and cathodic protection mechanisms, dead legs, repair sleeves, leaks or spills, vegetation damage or rehabilitation, blockage of fish passage (low-water crossings, culverts), leak detection transmitters, bridge conditions, unauthorized construction, evidence of flooding or erosion, and valve condition (damage,

leaks, indicators of improper functioning). There were no major findings that threatened pipeline integrity in 2009.

Items noted during surveillances are evaluated to determine if corrective actions are required. Preventative and Corrective Work Orders are created and tracked to remedy conditions found the Surveillance and Monitoring Program. A summary of 2009 Work Orders was included in the annual report for the KPL, KPE, and OPL.

Maintenance

Preventative Maintenance

Preventative maintenance activities in 2009 included the following categories and subcategories:

- Components and Systems
  - Leak Detection/Monitoring Instrumentation,
    - KPL Monitoring Instrumentation Check (June 16, 2009)
  - Meters/Provers,
    - Crude Meter Calibration
    - CPF-1 (June 16, 2009)
    - CPF-2 (October 20, 2009)
    - Breakout Tank Crude Flow Meters (December 7, 2009)
  - Over Pressure Protection,
  - Valves,
- Corrosion Control
- Pipeline, ROW, and River Crossings
  - Bridges,
  - Erosion,
  - Fire Protection,
  - Pipeline,
  - River Crossing Generator
  - Roads and Pads

System Modifications and Improvements

New sumps were installed at the pig launcher and receiver for the Kuparuk Pipeline on September 17, 2009. Upgrades to the 24-inch pig launcher and receiver valve actuators, made to enhance safety when performing routine maintenance pigging, were completed on October 30, 2009.

A project to replace the fast loop sampler was in progress at the time the Kuparuk report was being written.

Construction

Construction work on the Kuparuk Pipeline Extension in 2009 involved the KPE pipeline segment replacement/pigging projects. A segment of 12-inch pipe was replaced with 18-inch pipe, resulting in a consistent diameter pipe that will allow for the passage of pigs through the pipeline. The hydrostatic test of the pipe was completed on June 4, 2009 and forward flow through the new section was initiated on July 4, 2009. The KPE pigging project, which

involves installation of a pig launcher and a pig receiver, is scheduled for completion in 2010. Pigging module construction is reported to be scheduled to begin in January, installation between March and June and the tie-in on June 20, 2010.

The Kuparuk Pipeline connection to TAPS is being replaced. In 2009 the IFC package was completed and the VSMs were installed. The new pipe is scheduled to be installed and hydrostatically tested between January and June 2010. The tie-in is scheduled to be completed during the TAPS shutdown on June 19 and 20, 2010. There were no construction activities related to Oliktok Pipeline in 2009.

Oil and Hazardous Substance Discharges

There was one discharge associated with the KPL and OPL, and one associated with the KPE in 2009. The discharges were not from the KPL or KPE and are mentioned here because of the proximity to the ROWs. On January 23, 2009 a hydraulic line on a front end loader leaked hydraulic fluid onto the snow in the KPE ROW. The spill amount was less than one pint, and it was removed from the area. On February 3, 2009 a small split in an injection line caused approximately 6,930 gallons of effluent water to spill onto the tundra on the south side of the CPF-1 pad, inside the KPL ROW; 100% clean-up was reported. The injection line was replaced with high-density polyethylene (HDPE)-lined pipe.

The Kuparuk River Unit ODPCP provides prevention strategies and response plans to limit the spread of a spill, minimizing potential environmental impacts, and to provide for the safety of personnel. The Kuparuk River Unit ODPCP relies heavily upon information provided in the Alaska Clean Seas Technical Manual. CPAI reviewed and updated information for the Kuparuk River Unit Participating Area Oil Discharge Prevention and Contingency Plan in January, March, April, and October 2009. DEC and PHMSA have approved the ODPCP through May 2, 2013 and the EPA has approved the plan through April 24, 2012.

In compliance with the Kuparuk River Unit ODPCP a "Worst Case Discharge" tabletop exercise was conducted on October 14, 2009. The CPAI Kuparuk Emergency Services, Spill Response Team, Incident Management Team (54 individuals), and Crisis Management Team (Seven individuals) participated in the announced qualified individual, equipment deployment, and worst case discharge. No real-time safety issues of personnel injuries were reported.

Events, Incidents, and Issues

2009 was the 25th year of operational status for the Kuparuk pipelines.

Safety Related Condition

The CPAI Corrosion Inspection Crew conducted follow-up inspections to the August 15, 2009 ILI of the Kuparuk Pipeline. The Corrosion Inspection Crew found an area of localized external corrosion near VSM 2525 on December 15, 2009. The corrosion was caused by water gaining entry between the pipe and the insulation. UT measurements found a maximum wall loss of 52%. Calculations determined that the maximum operating pressure (MOP) for this area should not exceed 1,366 psig; the operating pressure at this location is less than 100 psig.

Notification was sent the local PHMSA and SPCO representatives as well as the USDOT National Administrator. On January 15, 2010 a full-rated welded sleeve was fitted at the location of corrosion; this allowed the system to be returned to full operating pressure.

Wax

A study of wax deposition at different temperatures and different throughputs was completed for the KPL and KPE. Modeling indicated that the cleaning pig program currently utilized by CPAI is sufficient to manage wax deposition. In the future, as throughput declines, the frequency of pigging may need to be increased.

VSM Damage

On October 28, 2009 rig mats came off of a truck and struck a VSM for the Kuparuk and Oliktok pipelines. The VSM was moved longitudinally, with the direction of the pipelines, about 1 ½ inches. The saddles were still in the clips, and nothing spilled or leaked. An engineer's evaluation determined that there were no integrity issues.

2010 Plans

CPAI plans to upgrade hardware and software for the Leak Detection System in conjunction with a long term parallel evaluation between the current system and one chosen as a result of their best available technology process.

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the SPCO and is not taken from the Lessee's annual report. By the nature of the SPCO oversight efforts, there may be some overlap of information.)*

Quarterly Meetings

Representatives of the SPCO and the Lessee continued to meet quarterly in FY10. These meetings serve to keep both parties up-to-date on important activities, changes in staffing, progress of projects, and other important information, without the delay of more formal correspondence. Quarterly meetings, for all of the CPAI operated pipelines with ROW leases administered by the SPCO, including the Alpine Pipeline, occurred on July 6, 2009, September 30, 2009, and April 8, 2010. Some of the topics specifically related to the Alpine pipelines discussed during the quarterly meetings are listed below:

- Oliktok Pigging Project
- Bailey Bridge Replacement Project Delay
- Plans to Convert the Oliktok Pipeline from NGL to Fuel Gas
- KPE Pigging Modules
- Plans for KPE Pigging

Compliance Section FY10 Activities

KPE Pigging Module Construction

On January 19, 2010, Kuparuk Pipeline Company representatives, a USDOT/PHMSA representative, contractors, and SPCO representatives met at the fabrication shop of the contractor responsible for constructing the pigging modules for the Kuparuk Pipeline Extension. Agency and industry representative met to examine the new pigging modules as they were being constructed and to view a computer generated movie that illustrated how the new modules would tie in to the existing piping in the field. The new pigging modules will be placed over the existing piping when they reach Prudhoe Bay. Figure 55 shows where the module will tie in to the new piping at CPF-1

The CPF-1 pig receiver module was near completion (see Figure 54). The receiver module features fire and gas detectors, fine water mist fire suppression, the pig receiver, an overhead crane monorail (to facilitate the removal of pigging devices), large heaters, an air exchanger (with a an exchange rate of 30 exchanges per hour), a three hour firewall, and a sump. An eight-hour hydrostatic test was successfully performed on the piping in the CPF-1 module on January 16, 2010.

Construction on the pig launcher module for CPF-2 was not as far along as the pig receiver for CPF-1 (see Figure 56). Before entering the CPF-2 module, observers were required to sign the safety card for the module.

A lease compliance report was completed to document the surveillance trip (SPCO letter 10-035-AS).

Figure 54: CPF-1 Pig Receiver Module

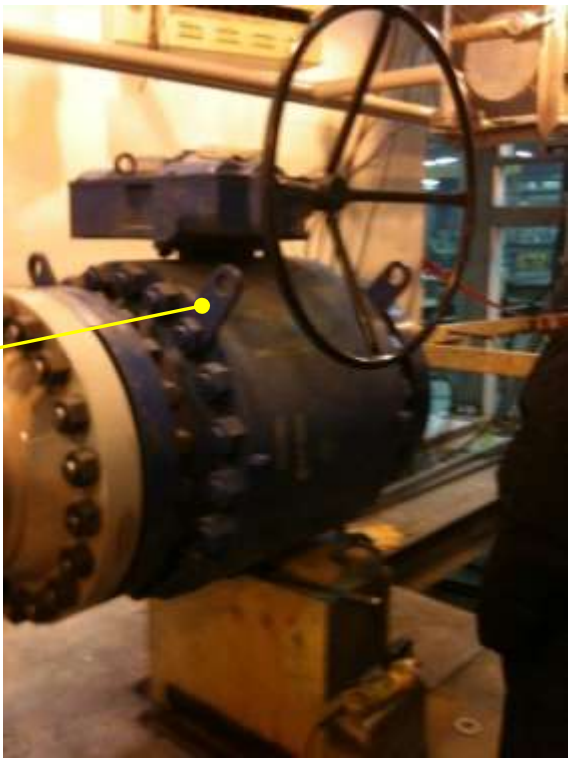

Figure 55: Pig Module Tie-in for New Valve

Figure 56: CPF-2 Pig Launcher Module, January 2010

Documentation

The SPCO Compliance Section focused on case file review for the Kuparuk and Oliktok pipelines during FY10. One of the compliance section research projects focused on Lessee notifications to the SPCO. Stipulation 2.10.1 of the Oliktok, Kuparuk, and Kuparuk Extension leases requires the lessee to give notice of any spill, leakage, or discharge of crude oil or other hazardous material in connection with pipeline activities. The Initial discharge reports from the lessee, discharges reported by the lessee in the annual reports, and discharges recorded in the DEC Statewide Oil and Hazardous Substance Spills Database were compared and found to be in alignment, resulting in three satisfactory surveillance reports (SPCO letter 10-105-AS).

Annual Report Review

The *2009 Annual Comprehensive Report on Pipeline Activities: Kuparuk Pipeline ADL 402294, Kuparuk Pipeline Extension ADL 409027* was received by the SPCO on January 29, 2010. The report contained over 600 pages and was extensively reviewed by Compliance Section staff for compliance with requirements found in the leases and on page 7 of this report.

During the review of the report the SPCO contacted the Lessee with requests to clarify information. All questions were answered by the Lessee and included in the SPCO case file. As an example, the Kuparuk report listed findings from two Quality Management System assessments; however no further information about the assessments or the findings were provided in the report. The SPCO asked the Lessee for some specifics about the assessments, and was provided with a summary of the scope of the assessments, which

related to "Preventative Maintenance for (US) DOT Regulatory Audits", and the use of checklists. The response met SPCO needs. Eight surveillance reports, reflecting satisfactory observations were completed as part of the annual report review (SPCO letter 10-169-AS).

The *2009 Annual Comprehensive Report on Pipeline Activities: Oliktok Pipeline ADL 411731* was received by the SPCO on January 29, 2010. The report contained over 400 pages and was extensively reviewed by Compliance Section staff. Four surveillance reports, reflecting satisfactory observations were completed as part of the annual report review (SPCO letter 10-174-AS).

Engineering Section FY10 Activities

Kuparuk Pipeline and Kuparuk Pipeline Extension

The Engineering Section monitored operation of these pipelines during this reporting period. Neither the KPL nor the KPE had major incidents this year, although there were significant changes on the KPE because of the replacement of a section to make it piggable and the addition of pig launching and receiving facilities.

The 28-mile long KPL starts at the KRU CPF-1 connection manifold to a pig receiver adjacent to PS1. The KPL ends at the flange upstream of an isolation valve inside the PS 1 fence line. Kuparuk Transportation Company continued work on replacing the Kuparuk Pipeline within the PS 1 fenced area. Similar to the BP transit pipeline, it was constructed on VSMs outside of the fence, but changes mode at PS 1, where it is encased in friable concrete. This short section of pipeline was not piggable, because it is downstream of the pig receiver. It also has limited access for external or internal corrosion direct assessment (ECDA or ICDA). Replacement of this section will allow easier inspection.

Approximately six miles downstream of CPF-1, Milne Point crude oil enters the KPL from a 10.4-mile pipeline. Currently, this is the only connector to this common-carrier pipeline. However, two companies are working on new connections.

The Engineering Section has followed plans and made comments on a proposal by Brooks Range Petroleum. That company plans to install a truck receiving facility, storage tanks and processing facility near the pipeline on a gravel pad to receive oil from the North Shore development. The North Shore pad will cover approximately 13 acres. It is proposed for a location approximately 3.5 miles north-northeast of Prudhoe Bay S Pad, one mile west of the Kuparuk River, and two miles inland from the Beaufort Sea coast.[32]

ENI Petroleum is also working on a connection to commingle oil from their new development at Nikaitchuq. It will be located between CPF-1 and CPF-2. The Engineering Section anticipates a review of this connector in the next reporting period. This development is progressing to a planned startup in 2011, but nothing was submitted on this during the past year.

The 9-mile KPE ties the Alpine Oil Pipeline, transporting oil from the Colville River Unit into the KPL. At CPF-2, the pipeline starts as an 18-inch diameter pipe and runs

[32] "North Shore Development Project, Project Summary", Page 1, August 1, 2008.

approximately 9 miles to Module AU-01 at KRU CPF-1. There is a smaller 12-inch diameter section between CPF-2 and Drill Site 2Z Access Road. The smaller section of the KPE was successfully replaced. The Engineering Section reviewed the design basis, Issue-for-Review drawings, and Issue-for-Construction drawings for both the pipeline section and the pigging modules. Engineering also monitored the fabrication and construction progress. The pipeline portion was mechanically complete and hydrostatically tested in June 2009. The new KPE line was filled on July 4, 2009. Two pigging modules were installed in 2010.

KTC made these modifications to make the pipeline piggable by making it the same diameter throughout. This will allow the pipeline operator to meet new PHMSA regulatory requirements by ILI. The first ILI run is scheduled for October 2010, which should meet a regulatory requirement of May 2011(13 p. 283).

Engineering reviewed the Issue-for-Construction drawings of a bridge replacement. KTC completed replacement of a Bailey bridge on Smith Creek(14). The previous bridge had experienced gradual deterioration with age and had load limitations. ConocoPhillips, which would perform cold restart operations for KTC, continued work on cold restart planning of the Kuparuk and Alpine oil pipelines. They plan on injection of a chemical temperature depressant and circulation of the fluid to agitate the depressant and mix it in the pipeline.

Oliktok Pipeline

The OPL transports NGL from Prudhoe Bay westward to the KRU. It has had several lives. It was originally commissioned as the oil transport pipeline from Kuparuk to PS 1 in 1981. It was soon replaced by a larger pipeline, the KPL. It was converted to fuel gas service in 1985 and decommissioned in 1988. It was converted to natural gas liquid transport in December 1995.

The Engineering Section followed the operations and major repairs on the pipeline. There were no major incidents on this pipeline during the reporting period. However, there was one minor incident. October 28, 2009 involving some rig mats coming off a truck, hitting a VSM 1078 supporting both the Kuparuk/Oliktok pipelines. The VSM moved in line (longitudinally) with 1 1/2 inches(13 p. 574). The VSM is still serviceable and the situation is still being evaluated.

Kuparuk Transportation Company informed the SPCO that the OPL would be converted to natural gas service within two or three years. Maturation of the oilfields has resulted in more of a need for natural gas than NGLs in Kuparuk. Because the pipeline has previously been in this service, its conversion is not anticipated to be difficult.

Right-of-Way Section FY10 Activities

*KPE Lease Amendment for Pipe Replacement Project***:** On August 26, 2008, the SPCO received a letter from Kuparuk Transportation Company requesting an amendment to the Kuparuk Pipeline Extension ROW Lease, ADL 409027. The purpose of the lease amendment was to allow both the replacement of the 12-inch portion of the pipeline between CPF-2 and Drill Site 2Z with 18-inch pipe and the inclusion of a pig launcher on the CPF-2 pad and a pig receiver on the CPF-1 pad. The pig receiver area at CPF-1 was located within Section 9, Township 11N, Range 10E, Umiat Meridian, AK. The pig launcher at CPF-2 was

located within Section 21, Township 11N, Range 9E, Umiat Meridian, AK.

On January 8, 2009, the DNR Commissioner signed the lease amendment documents to add the land needed for the pig launcher and receiver areas to the pipeline ROW, encompassing 0.0435 acres, more or less. The lease amendment was later recorded in the Barrow Recording District as Document 2009-000238-0. On February 25, 2010, the DNR Commissioner executed the lease amendment document to amend Section 1.c. of the Lease to reflect that the pipeline replacement was completed and installed with 18-inch diameter pipe. This lease amendment was recorded in the Barrow Recording District as Document 2010-000100-0.

State Fire Marshal's Office Liaison FY10 Activities[33]

The 2009 Annual Fire Prevention and Life Safety Inspection of the Kuparuk Pipeline and related facilities was conducted by the SFMO Liaison on August 11-13, 2009. 14 facilities were inspected including the KOC and KCS Pads. The KIC Pad, the KOC Offices, the A/B Warehouse, and KOC Communications Building had a total of 15 code violations, all were corrected. The SFMO Liaison noted that, "many of the violations noted during the inspection process were minor in nature, and in many cases the hazards were corrected on the spot."

The SFMO Liaison conducted the annual inspection of the Kuparuk Pipeline Extension and related facilities on February 20-22, 2010. During the inspection of 71 modules, nine minor violations were found. The SFMO Liaison noted that, "due to weather conditions the annual inspection of CPF-2 could not be completed, along with other planned inspections for the trip. They may be completed at a later date."

The annual inspection for the Oliktok Pipeline and related facilities, along with further inspection of the Kuparuk Pipeline facilities were conducted on March 17-19, 2010. A total of 49 modules/building were inspected including parts of CPF-2 all of CPF-3 and the Seawater Treatment Plant. 23 code violations were noted, all have been corrected to date.

[33] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

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Nuiqsut Natural Gas Pipeline

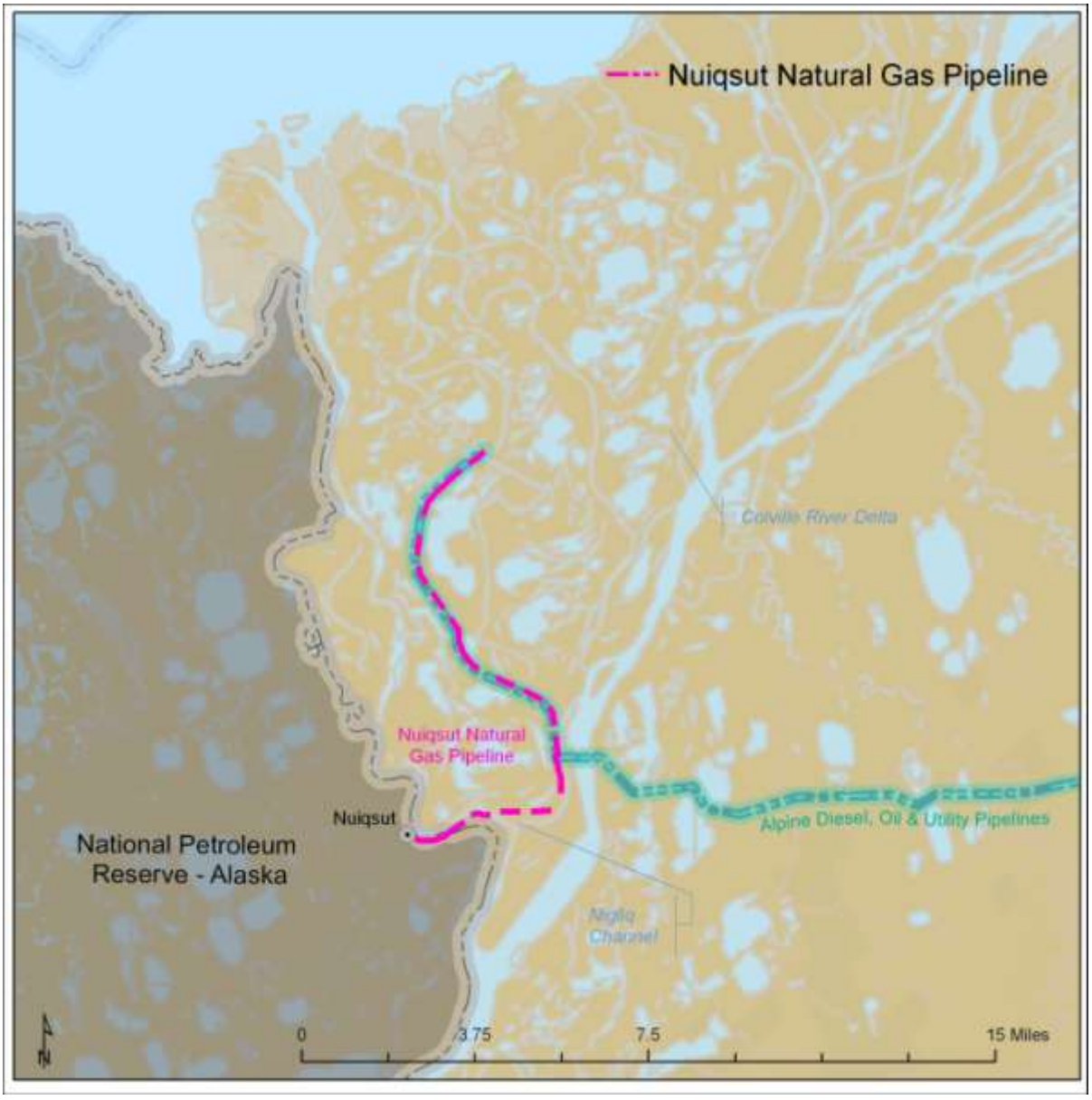

Figure 57: Nuiqsut Natural Gas Pipeline Route Map

Right-of-Way Lease and Pipeline System Overview

The Nuiqsut Natural Gas Pipeline (NNGP) was constructed by the North Slope Borough (NSB) to transport natural gas from the ConocoPhillips Alpine Production pad to the village of Nuiqsut, located within the Colville River Delta. Figure 57 above shows the route of the NNGP. The 14.4-mile NNGP shares horizontal and vertical supports with the Alpine Pipelines from the production pad to the west bank of the Colville River where the NNGP transitions belowground and continues to the village. Approximately 2.4 miles of the 14.4-mile NNGP are located on State of Alaska land. State lands include a section of the aboveground pipeline and the trenched crossing of the Nechelik Channel of the Colville River.

The NNGP is a three and one-half-inch diameter coiled tubing pipeline with a wall thickness of 0.203 inches designed to operate at 1,440 psig. The NNGP was supplied with an external coating applied at the factory. A continuous magnesium strip cathodic protection system was installed on the below ground portion of the NNGP. The pipeline is subject to USDOT/PHMSA jurisdiction and operates under 49 CFR 192 regulatory requirements.

The pipeline project began in 1999 and construction was completed soon after. Operational startup of the pipeline was delayed for eight years. Pipeline operation delivering natural gas for heating and production of electricity to the community of approximately 380 residents began in September 2008. In 2009, service was available to the 122 homes and 30 commercial buildings that had requested service. Nuiqsut is the third North Slope community (after Barrow and Deadhorse) to provide heat and generate electricity from natural gas. 2009 was the first full year of operations for the pipeline system.

The NNGP ROW lease, ADL 416202, was executed on March 15, 1999 and is scheduled to expire on March 14, 2019. The pipeline operational ROW width is 50 feet in the aboveground mode and 200 feet at the river crossing. The ROW as-built survey was approved by DNR on December 17, 2003; it encompasses 17.67 acres of State lands. Additional lease information is available in Appendix D: Acreage, Survey, and Lease Information. The NNGP is due for reappraisal in 2014 (see Appendix E).

State Pipeline Coordinator's Office Summary of North Slope Borough's CY09 Annual Report for the Nuiqsut Natural Gas Pipeline

The NSB submitted their 2009 *Annual Comprehensive Report on Pipeline Activities and the State of the Pipeline System* to the SPCO on February 1, 2009. The CY 2009 report followed guidelines, as described on page 7 of this report, as well as the requirements of Lease stipulation 1.14 (Reporting).

The annual report is required by lease stipulation and is, in part, meant 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. Elements of the Lessee's 2009 *Annual Comprehensive Report on Pipeline Activities* are summarized or excerpted below.

Throughput, Reliability, and Pigging

The NNGP design uses continuous electrical resistance welded coiled pipe which allows for a maximum operating pressure of 1,440 psig. The pipeline is designed to provide a maximum flow rate of 3,500,000 cu ft/day of natural gas from the Alpine Development Project facilities for approximately 14 miles south to the delivery point; the village of Nuiqsut. Natural gas distribution to the portions of the village began with natural gas solely being supplied to the Nuiqsut Power Plant, but the year ended with the majority of residential homes and approximately 30 commercial buildings being supplied with natural gas. Reliability was 99.45% for 2009. There was one shutdown during the year because of the Programmable Logic Controller (PLC) which caused the NNGP System to be down for less than 48 hours. The PLC controls many of the plant operating parameters such as over

pressure protection, metering and recording of gas flow, and the pressure and temperature of gas leaving the pressure reducing valve station for delivery to Nuiqsut residents. The PLC provides for continual communication between the Alpine Control Room and NNGP Operator and any failure in the communications link and/or operating devices will initiate an Emergency Shutdown of the pressure reducing valve station which in turn will discontinue the flow of gas to the distribution system.

A maintenance pig, launched from the pig launcher at the Alpine Production pad, was run through the NNGP in 2008. Next maintenance pigging, upon finalizing contractor services, is slated for November 2010. Current smart-pig technology allows for the NNPG to be in-line inspected, however the NNGP has not been inspected in this manner and there are currently no plans to do so.

Current throughput, reliability, and pigging information are summarized below in Table 24. Appendix I: Throughput for SPCO Jurisdictional Pipelines, 2009 provides a listing of throughput for all SPCO jurisdictional pipelines.

Table 24: Throughput, Reliability, and Pigging Information for NNGP, CY09

Pipeline System	2009 Throughput	Reliability	Maintenance Pigging	Last ILI
NNGP	106,704,228 cf	99.45%	2008	Hydrostatic Test April 2007

Assurance Programs

The North Slope Borough has developed a QAP focusing on operations and maintenance of the NNGP which provide for:

- Risk management,
- Quality assurance,
- Internal safety and
- External safety

Responsibilities for implementing specific sections of the QAP have been assigned to departments within the North Slope Borough (NSB) and are as follows:

Section 1: Statement of Authority – NSB Mayor
Section 2: Program Introduction – NSB Mayor
Section 3: Leadership, Commitment, and Involvement – NSB Mayor
Section 4: Risk Management, Design and Construction Activities – NSB Program Manager, CIPM; Risk Management, O&M activities - Director of Public Works
Section 5: Personnel and Training, Construction Contract and O&M activities - Director of Public Works
Section 6: Design and Construction - NSB Program Manager, CIPM
Section 7: Operations - Director of Public Works
Section 8: Management of Change, O&M activities - Director of Public Works
Section 9: Third Party Services, Design and Construction Contracts - NSB Program

Manager CIPM; Third Party Services, O&M activities - Director of Public Works
Section 10: Incident Investigations - Director of Public Works
Section 11: Emergency Preparedness - Director of Public Works

Safety Programs

Safety programs are currently being developed by the NSB for the safe operations and maintenance of the NNGP System. Currently in place is the *Employee Safety and Accident Prevention Program*, revised by the NSB on February 4, 2010. This program's aim is to provide NSB employees with a workplace that is free from recognized hazards and reduce the likelihood of harm to any NSB employee. The program provides NSB employees with information and training so that they can work safely, it provides directors and supervisors with the tools to manage their facilities, equipment and employees in a safe manner, and facilitates compliance with applicable safety and health regulations required by the OSHA.

Integrity Management

The USDOT/PHMSA audited NNGP documents and records on January 12-15, 2009 to confirm that they met requirements of 49 CFR Part 192. Findings from the audit were that the Operations, Maintenance and Operator Qualifications Manual (OM&OQ) did not contain adequate Public Awareness procedures, or adequate Abnormal Operating procedures.

Corrosion Program

The corrosion program currently in place provides for prevention of internal and external corrosion of the pipeline system. Natural gas is monitored on a monthly basis for corrosive components by a third party. The contractor tests the natural gas being transported from the Alpine Development Project through the NNGP for delivery to residents of Nuiqsut. The contractor reports their findings to the NSB, who in turn will evaluate the results of the test each quarter and report their findings to the SPCO each year. In addition, portions of the NNGP are cathodically protected in order to protect the underground and submerged pipeline from external, internal and atmospheric corrosion.

Surveillance and Monitoring Programs

Audits, Assessments, Inspections and Evaluations

Self Assessments

The Pipeline Operators of the NNGP are responsible for an annual assessment of the OM&OQ. On December 22, 2009 the NNGP Pipeline Operator met with NSBs Project Administrator and LCMF, LLC to review the completed annual assessment and present recommendations for corrections, changes and additions. Findings from the assessment were that the manual lacked procedures for incorporating approved findings from assessments into the OM&OQ.

Assessments and audits that focus on fine tuning the OM&OQ will continue through 2010, and a presentation of recommendations will take place the 4th quarter of 2010 to the SPCO and other parties of interest.

Visual Inspections
Visual inspections took place on December 5, 7, 9, 10, 11 and 12, 2009. These inspections meet the commitments of the NNGP Surveillance and Monitoring Plan and of the OM&OQ manual. Findings from inspections were:

- 3 missing delineators
- 1 missing U-bolt

Evaluations
An internal evaluation of operations, management, administration and regulatory compliance for continuous improvement took place in concurrence with an internal audit that was completed on December 22, 2009. The evaluation results noted that the QAP is inconsistent with realistic systems and plans relating to operation of the NNGP. Inconsistencies were found between the QAP and the OM&OQ Manual. During 2010, changes to each program and manual with the goal of integrating the two will be completed.

2009 Operations and Maintenance Lease Performance

Programs

The current QAP revision, dated March of 2008, reflects the specific changes and additions requested by the SPCO during 2007/2008. The focus of those changes surrounded re-identifying responsibilities and authorities due to the addition of a System Operator for start-up, and the new Operators responsibilities for operating and maintaining the NNGP. The NSB reported that under the revised NSB Quality Assurance Program, the Operator's quality plan is defined as the Nuiqsut Natural Gas OM&OQ, which is consistent with the NSB Quality Assurance Program.

By identifying the Nuiqsut Natural Gas OM&OQ manual as the singular document for carrying out the purpose of the QAP, the NSB believes this is more efficient and can be used as a straightforward tool that provides a means and method now available to the pipeline operator that wasn't there previously. However, during this first year of operations and maintenance the NSB identified a few areas within the QAP that fall outside of the actual conditions related to the gas system as well as areas within the Nuiqsut Natural Gas OM&OQ manual that fail to fully meet the intent of the QAP. Therefore, the NSB is determined to focus CY10 on revising both documents to provide programs that are acceptable by regulatory requirements and standards and that are effective for operating and maintaining the NNGP.

People

Rockford, Inc was the NNGP Operator at start up and when commissioning activities began in 2008. On September 1, 2009, Rockford, Inc was replaced as the Pipeline Operator and the NSB took over operations and maintenance of the pipeline.

Activities

Activities for the year included general operation and maintenance activities in order to ensure the integrity of the NNGP System. No modifications to the Pipeline System or Approved Pipeline Activities were made during CY09.

Other

No spills and/or leaks were reported for 2009. Spill and leak reporting, as required to meet all applicable laws, are current under the Operations, Maintenance and Operator Qualifications Manual.

2010 Proposed Actions and Plans

Table 25 shows the NSBs schedule for surveillances, audits, self-assessments, and evaluations.

Table 25: Proposed actions and plans 2010

Quarter/Activity	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Audit	✓			✓
Self Assessments	✓	✓	✓	✓*
Above Ground Inspections		✓	✓	
Below Ground Inspection		✓		

* Presentation of findings

Additional Proposed Actions and Plans for 2010:

- Replacement of missing delineators along buried pipeline in summer 2010;
- Replacement of U-bolt between VSM 307 and 308;
- Provide missing welding procedures for inclusion into OM&OQ Manual;
- Update the OM&OQ Manual to include Public Awareness Program Procedures;
- Update the OM&OQ Manual to include Abnormal Operations Procedures;
- Incorporate approved findings from the December 12, 2009 assessment of the OM&OQ Manual CY 2010;
- OM&OQ Manual will be amended to include practices and procedures that are consistent with requirements of the NNGP Quality Assurance Program. Amendments will be in place CY 2010.
- Development of Safety programs for the safe operations and maintenance of the NNGP System.

State Pipeline Coordinator's Office Oversight Activities, FY10 Summary

(*This section provides a summary of SPCO activities. Information in this section reflects the work efforts of the SPCO and is not taken from the Lessee's annual report. By the nature of the SPCO oversight efforts, there may be some overlap of information.)*

Compliance Section FY10 Activities

The purpose of the Compliance Section is to verify that all pipelines administered by the SPCO are operated and maintained in a manner consistent with lease requirements. In order to achieve this objective, a lease Compliance Section representative conducted two site visits

and multiple document reviews of NNGP programs and procedures. During the two site visits, the Compliance Section representative conducted field verifications of the Lessee's compliance with lease commitments and produced twenty-one surveillance reports, two lease compliance reports and one assessment. Later in the year, document reviews were completed by various Compliance Section staff resulting in an additional two surveillance reports. Fourteen surveillance reports indicated observations were satisfactory, while seven indicated observations were unsatisfactory. The following section documents the Compliance Section's efforts to establish Lessee compliance with the Nuiqsut Natural Gas Pipeline Lease Agreement.

SPCO Surveillance: August 2009

A general surveillance of portions of the above ground segments of the NNGP was conducted by SPCO Compliance Section staff on August 24-25, 2009. The purpose of the inspection was to observe testing of the Cathodic Protection System, to evaluate the condition of the ROW and assess NNGP compliance with Lease requirements.

The Lessee was unable to meet many requests for documentation that would have verified compliance with components of the Lease agreement. Table 26 below provides a summary of Lease requirements that the Lessee was unable to provide requested documentation for, and received unsatisfactory observations for in the resultant surveillance reports:

Table 26: NNGP Lease Requirements Surveilled August 24-25, 2009

Section/ Stipulation	Description	Observation
Section 8	Covenants of Lease	Unsatisfactory
Section 9	Lessee's Contractors, Agents and Employees	Unsatisfactory
Section 15	Conduct of Operations	Unsatisfactory
Section 40	Compliance	Unsatisfactory
Stipulation 1.4.1	Quality Assurance	Unsatisfactory
Stipulation 1.6.1	Surveillance and Monitoring	Unsatisfactory

The observations made during the August 2009 field inspection were extensive and warranted additional evaluation. An assessment was completed by the Compliance Section staff, which further evaluated the extent of the unsatisfactory observations. The assessment took into consideration the following additional information in order to determine the breadth and depth of the Lessee's noncompliance with the Lease:

- Information from the Lessee's 2008 Annual Report submitted to the SPCO March 2009;
- Verbal communications between the Lessee's Contractor, Operator and SPCO Representatives during the trip to Nuiqsut on August 24-25, 2009;
- All correspondences between the Lessee and the SPCO between August 20, 2009 through October 7, 2009 and;
- All documents submitted by the Lessee to SPCO on September 2, 2009.

The assessment findings indicated that the Lessee was not in compliance with Section 9(d),

Stipulation 1.4.1, and Stipulation 1.6.1. The assessment was formulated from a small sampling of elements from the Lessee's approved QAP and SMP. Findings from the assessment were of concern because they indicated that other aspects of the NNGP operational processes and procedures may not have been fully implemented as required by the Lease. The Lessee was made aware of the compliance issues, and on August 31, 2009, the Lessee replaced their pipeline operator. The SPCO assured the NSB that they were fully committed to working with the North Slope Borough, helping them to meet the requirements of the lease agreement. For more detailed information regarding the assessment and supporting documents please refer to SPCO Letter 09-036-CT.

SPCO Surveillance: February 2010

During February 2010, a Compliance Section representative completed another site visit to observe processes and procedures that the Nuiqsut Natural Gas and Electric Manager (NNGP Operator) uses for their annual valve exercising activity, follow-up on document checks which began during the August 2009 Compliance Section site visit and to verify Lease compliance through the required NSB Surveillance and Monitoring Program. Table 27, below, displays elements of the lease agreement the Compliance Section focused on during the site visit:

Table 27: NNGP Lease Requirements Surveilled in February 2010

Section/Stipulation	Title	Observation
Section 14	Plans and Permitting	Satisfactory
Section 15	Conduct of Operations	Satisfactory
Section 16	Environmental Compliance	Satisfactory
Section 30	Authorized Representatives	Satisfactory
Stipulation 1.2	Communications	Satisfactory
Stipulation 1.4	Quality Assurance	Satisfactory
Stipulation 1.5	Conduct of Operations	Satisfactory
Stipulation 1.6	Surveillance and Monitoring	Satisfactory
Stipulation 1.7	Health and Safety	Satisfactory
Stipulation 1.10	Electronically Operated Devices	Satisfactory
Stipulation 1.11	Regulation of Access	Satisfactory
Stipulation 1.12	Use of Existing Facilities	Satisfactory
Stipulation 1.13	Storage	Satisfactory
Stipulation 2.1	Environmental Briefings	Satisfactory

The February 2010 site visit confirmed that the NSB was making progress toward the goal of Lease compliance. The newly hired (September 1, 2009) NNGP Operator had put much effort towards maintaining high maintenance and operations standards. Improvements with documenting operations and maintenance activities had been made, as well as the Operator having completed winter surveillance and monitoring commitments from the approved SMP. During the this site visit, the Compliance Section representative informed the NSB Operator that summer activities meant to satisfy SMP commitments would be inspected for during the

summer months of 2010.

Although the SPCO Compliance Section representative's observations yielded satisfactory conditions, the SPCO Compliance Section representative had recommendations and follow-up requirements for the NSB Operator due to a deficiency in actively participating in general safety requirements such as the use of personal protective equipment during maintenance and operations activities. The SPCO Compliance Section representative recommended that:

1. The NSB Operator close the gap present between implicit safety awareness and active safety participation,
2. Develop a safety framework and provide the outline in the QAP, and add language to the OM&OQ manual to describe how the safety system will be executed on a daily and project basis.

The goal of the Compliance Section was to promote the NSB Operator's efforts to become more safety conscious and encourage NSB employees who work or will work within the NNGP Right-of-Way to use more safe practices. For more detailed information regarding this report and supporting documents please refer to SPCO Letter 10-097-AS.

Additional Information

Results of the August 2009 and February 2010 field inspection revealed the need to further develop SPCO and NSB communications. Compliance Section representatives have worked closely with the NSB Operator and NSB Project Administrator with the objective of building a solid foundation for open and transparent communication between both groups. The NSB, aware that their QAP and OM&OQ manual needed additional work, began to make changes to both of these programs in an effort to integrate the two. In addition, discussions regarding worker safety have been ongoing, and efforts on behalf of the NSB to provide a system that will ensure NSB employee safety and accident prevention while working within the NNGP right-of-way are in progress.

State Fire Marshal's Office Liaison Activities[34]

The annual SFMO Liaison's inspection of the Nuiqsut Natural Gas Pipeline and related facilities was conducted on August 24 and 25, 2009. Three facilities were inspected; five items were noted for correction and were completed.

[34] Note: This past year the Division of Fire and Life Safety implemented a new automated permit program called Hansen. The Inspection module of the program was utilized to generate several of the SFMO Liaison's reports. There were several issues with the program that are being worked out, letter/report dates may not match actual inspection dates, however all notices to correct were submitted within 2 weeks of inspection to the appropriate liaisons. Responses were received and items were corrected in a timely manner.

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PROPOSED PIPELINE PROJECTS

Before a pipeline ROW lease is issued by DNR, the SPCO conducts a review and decision process as required by AS 38.38, 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. Figure 58 depicts a summary of the ROW leasing process used to authorize oil and gas pipelines on State lands

In FY10, the SPCO was in various stages of the ROW leasing process with several potential applicants and applicants. A brief description of theses pipeline projects follows Figure 58, below.

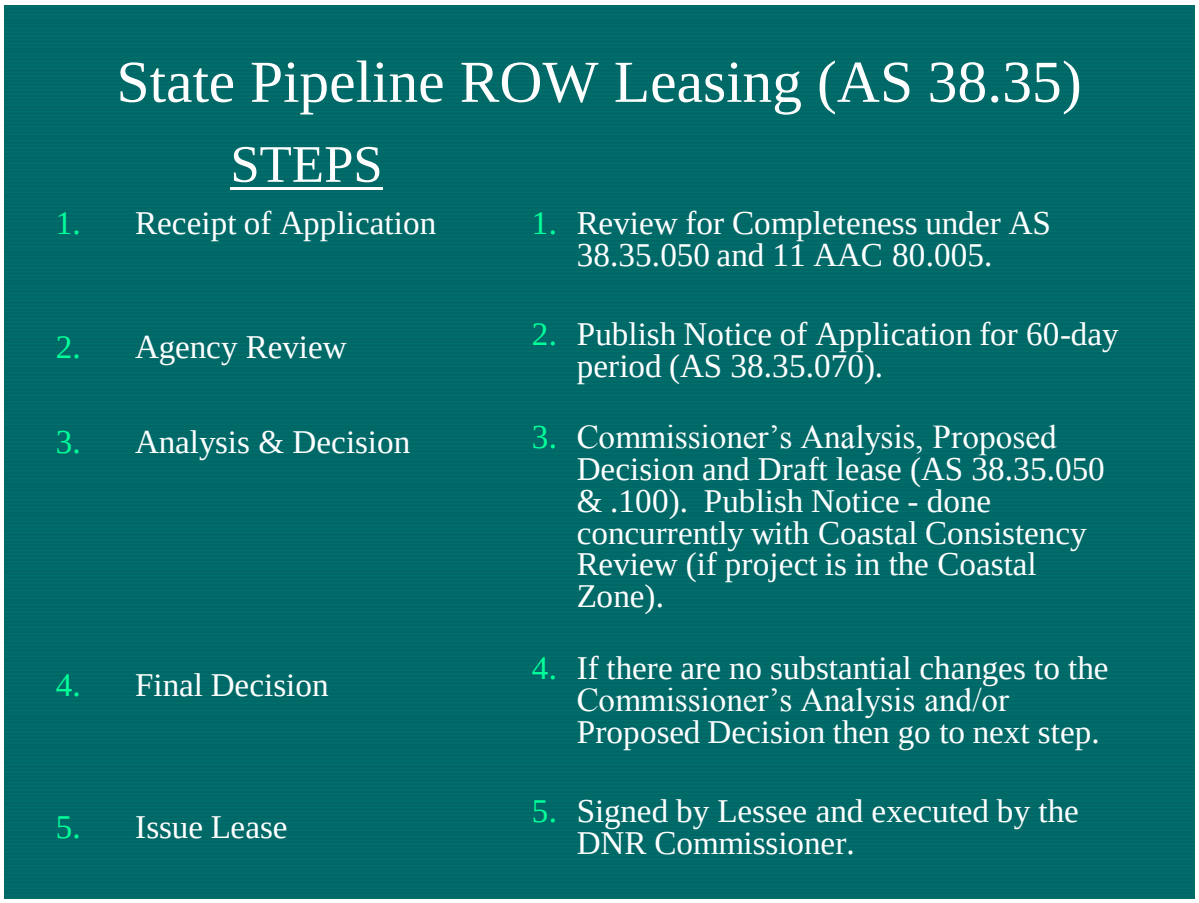

Figure 58: Summary of the State of Alaska Oil and Gas Pipeline ROW Leasing Process

Alaska Natural Gas Development Authority

On April 4, 2005, the Alaska Natural Gas Development Authority (ANGDA) filed an application with the DNR Commissioner for a conditional lease across State lands for a natural gas pipeline. The proposed pipeline would commence near Glennallen on Ahtna, Inc. lands, at Trans-Alaska Pipeline System Milepost 689.5, and terminate south of Palmer near the Glenn Highway and Parks Highway interchange where it would connect to an existing distribution system. The DNR Commissioner signed the conditional ROW lease on July 20,

2006.

A conditional lease does not transfer a real property interest in State lands, and is subject to conditions established by the Commissioner. Issuance of a conditional lease does not prevent the Commissioner from entering into alternative leases, permits or agreements involving all or part of the same lands with others.

In 2008, ANGDA initiated an investigation into the feasibility of extending the conditional ROW lease to include segments from Beluga to Palmer and from Glennallen to Fairbanks (see Figure 59 on the next page). The project was referred to as the Beluga to Fairbanks pipeline (B2F). ANGDA planned to build a 20 to 24-inch steel pipeline from Beluga to Delta Junction and an 8 to 10-inch high density plastic pipeline from Delta Junction to the Fairbanks area. The intent was to initially transport natural gas from Southcentral Alaska to Interior Alaska, but ultimately to bring North Slope natural gas to Alaska markets via a spur line. In addition, during initial operations, the pipeline could provide gas storage for Southcentral use.

The Environmental Impact Statement (EIS) process started in 2008 and scoping meetings were conducted in Glennallen, Delta Junction, Fairbanks, Wasilla, and Anchorage in early 2009. Concurrent to state and federal agency work associated with the B2F project, the Legislature was working on legislation specific to an in-state pipeline project. These efforts culminated in the passage of House Bill 369 which was signed by Governor Parnell on July 9, 2010.

House Bill 369 created the Joint In-State Gasline Development Team and directed the Executive Director of the Alaska Housing Finance Corporation (AHFC) to oversee all aspects of the project. The bill resulted in a consolidation of the two in-state gas pipeline efforts, ANGDA's B2F pipeline project and the Parks Highway Stand Alone Gas Pipeline, under the auspices of the AHFC.

On June 24, 2010, ANGDA formally withdrew the Beluga to Fairbanks EIS and permit applications and transferred their data to the Alaska Housing Finance Corporation subsidiary Alaska Gasline Development Corporation (AGDC).

The SPCO will continue to work with the AHFC/AGDC and participating state and federal agencies as the project moves forward.

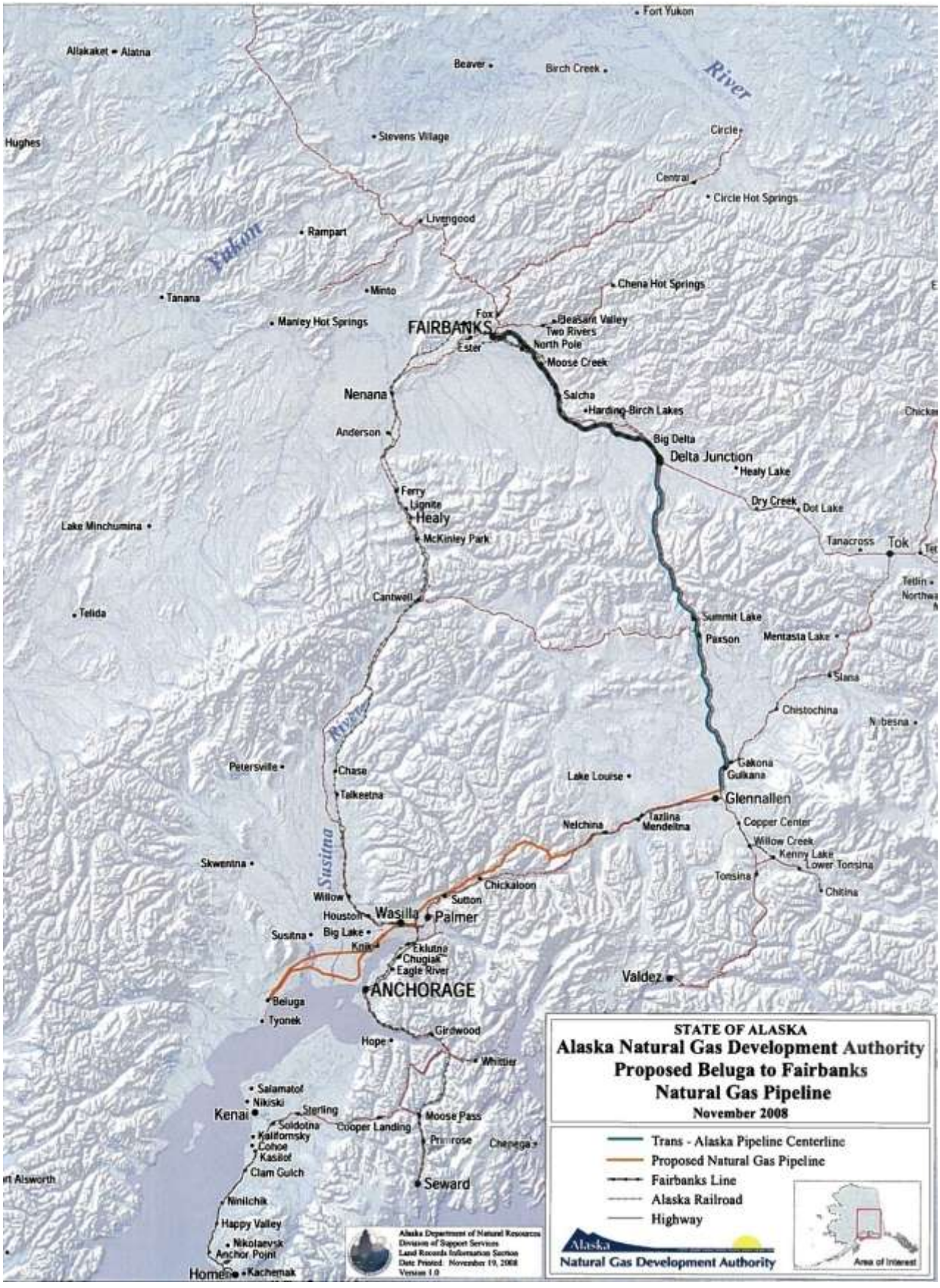

Figure 59: ANGDA Proposed Route B2F

Donlin Creek

Donlin Creek Mine proponents are investigating the practicability of a natural gas pipeline from Cook Inlet to the mine site. The 315 -mile buried pipeline would stretch from Beluga to the future Donlin Creek Mine site, just northwest of Georgetown, which has the potential to be one of the largest gold mines in the world. This pipeline would provide natural gas for Donlin Creek, LLC, to fuel the site which include but are not limited to coal-fired power plant, hydroelectric, nuclear, barging fuel up the Kuskokwim to Birch Tree crossing and trucking the fuel the remainder of the way. Figure 60 below illustrates the proposed transportation routes for the Donlin Creek Mine.

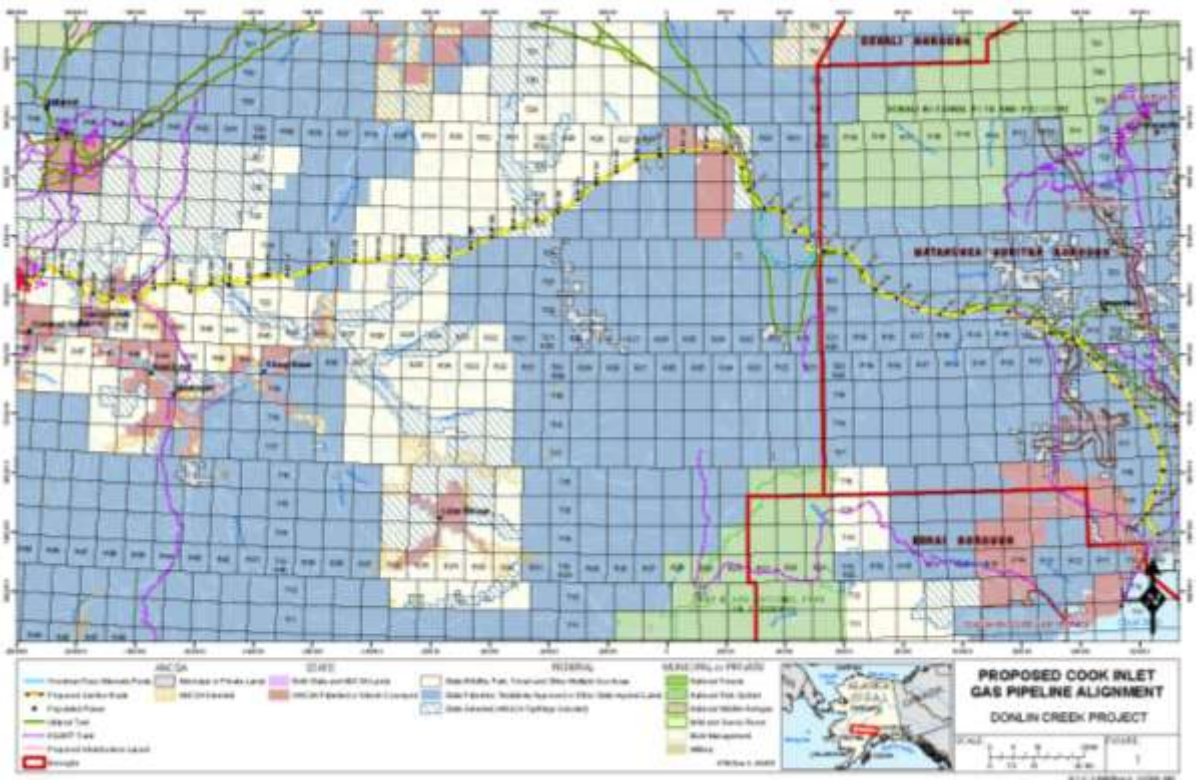

Figure 60: Proposed Donlin Creek Pipeline Route Map

Currently, Donlin Creek is permitted to do preliminary field research to verify the economic feasibility and to gather information necessary to submit a complete pipeline ROW lease application if the pipeline is deemed economically viable. The SPCO has been coordinating with Donlin Creek staff and the DNR Southcentral Regional Office (SCRO) to ensure that activities outside of generally allowed uses are properly permitted. These activities include land use permits for fuel caching, cross-country travel (for heavy machinery), and the digging of test pits.

Portions of the proposed pipeline would impact Alaskan coastal zones and therefore require coastal zone impact analysis, done by ACMP as well as approval from the USACE. Permitting efforts for continued field research and potential development would concurrently be analyzed and processed in a joint effort between SPCO and DNR SCRO.

Donlin Creek, LLC Staff have taken the effort to make contact with the SPCO staff early in their process. This early communication has allowed SPCO to inform Donlin Creek of the SPCO's process for analyzing an AS 38.35 common carrier pipeline ROW for the fit, willing and able analysis, coordinate necessary data, limit duplication of research between state agencies and update interested public with available information.

SPCO has received several questions from the public regarding this project and has given what information is available. This project is in the very early stages and the SPCO has not received an application to date. There currently is no timeline for this project.

North Fork Pipeline

Anchor Point Energy, LLC applied to the DNR for an AS 38.35 ROW Lease for the purpose of constructing dual 7.4-mile long natural gas pipelines, called North Fork Pipeline, with approximately 6.6 miles of the pipeline located on State land. Figure 61 shows satellite imagery of the proposed route for the North Fork Pipeline; the image was provided by the applicant. The proposed North Fork Pipeline will begin at the North Fork Production Pad located within the South East ¼ of Section 26, Township 4 South, Range 14 West, Seward Meridian, approximately 8.6 miles east of Anchor Point and will terminate at the South East ¼ of Section 34, Township 4 South, Range 15 West, Seward Meridian, in Anchor Point, Alaska. The Anchor Point Energy, LLC, North Fork Pipeline will tie directly into Alaska Pipeline Company's proposed Anchor Point Pipeline.

Figure 61: Proposed North Fork Pipeline Route

The SPCO received an application for the pipeline ROW Lease in February 2010; additional information was requested and received. Public notice for the application was posted per AS 38.35.070 for 60 days and received no objection. The SPCO completed the Commissioner's Analysis and Proposed Decision document to determine whether or not the applicant was fit, willing, and able to construct, operate and maintain a pipeline of this nature. Additional Public Notice was conducted for the Proposed Commissioner's Decision, and a public hearing was held in Anchor Point on June 29, 2010. Field inspections were conducted by SPCO staff for the proposed alignment, which included adjudicators, land managers, and the SPCO Engineer. Staff later walked the proposed route with Armstrong

Oil and Gas representatives, which included Armstrong Oil and Gas staff, survey contractors, engineering contractors and the Fiberspar representative (pipeline manufacturer for the project). The project was also reviewed for coastal zone impacts through the ACMP.

The Commissioner's Proposed Decision for the North Fork Pipeline found that the applicant (Anchor Point Energy, LLC) was fit, willing and able to construct, operate, and maintain a pipeline of this nature. The Commissioner's Final Decision was issued in September 2010 (FY11) and a Lease was signed by the applicant and the Commissioner of DNR in late September 2010. Construction is anticipated to be competed by March 2011.

SPCO Engineering Section

The Engineering Section's efforts during the past year were focused on the development of a design basis and an analysis of the technical merits of the pipeline, which used primarily the design basis.

Approximately $1/6^{th}$ of the pipeline's length will be of standard steel construction and $5/6^{th}$ will be of a composite plastic pipe. The composite pipe is dissimilar to other plastic pipes used for gas distribution in Alaska. These are typically single-layer, HDPE pipes used for distribution to homes and businesses at lower pressures. The type of material proposed for the APE pipeline is multi-layer HDPE and/or cross-linked polyethylene (PEX). Although the pipeline will be operating at high pressures, the product has a design pressure well above the operating pressure. If the product is used successfully, it is hoped that its use and lower costs will unlock other gas deposits that currently are considered not economic to develop.

The Engineering Section investigated this product when first proposed for use on the lease. However, PHMSA stated that the use of this composite pipe would require a special permit, so the work has been deferred to their jurisdiction.

Point Thomson Pipeline

In October 2009, ExxonMobil proposed a project to further develop the Point Thomson oil and gas field. Point Thomson, which is located approximately 60 miles east of Deadhorse on the Beaufort Sea coast, and 60 miles west of Kaktovik, just west of the Arctic National Wildlife Refuge, holds an estimated 8 trillion cubic feet of natural gas and 200 million barrels of condensates.

This project requires authorization from the USACE under Section 10 of the Rivers and Harbors Act of 1899 and Section 404 of the Clean Water Act. The project would recover liquid condensate from natural gas, and extract oil. The residual gas would be injected back into the reservoir, conserving it for future use. This project would develop onshore and offshore portions of the Thomson Sand Reservoir using long-reach drilling technology from onshore pads. Extracted condensate and oil would be shipped via a 22 mile export pipeline to connect to the Trans-Alaska Pipeline System to market. Figure 62 below shows the proposed pipeline route.

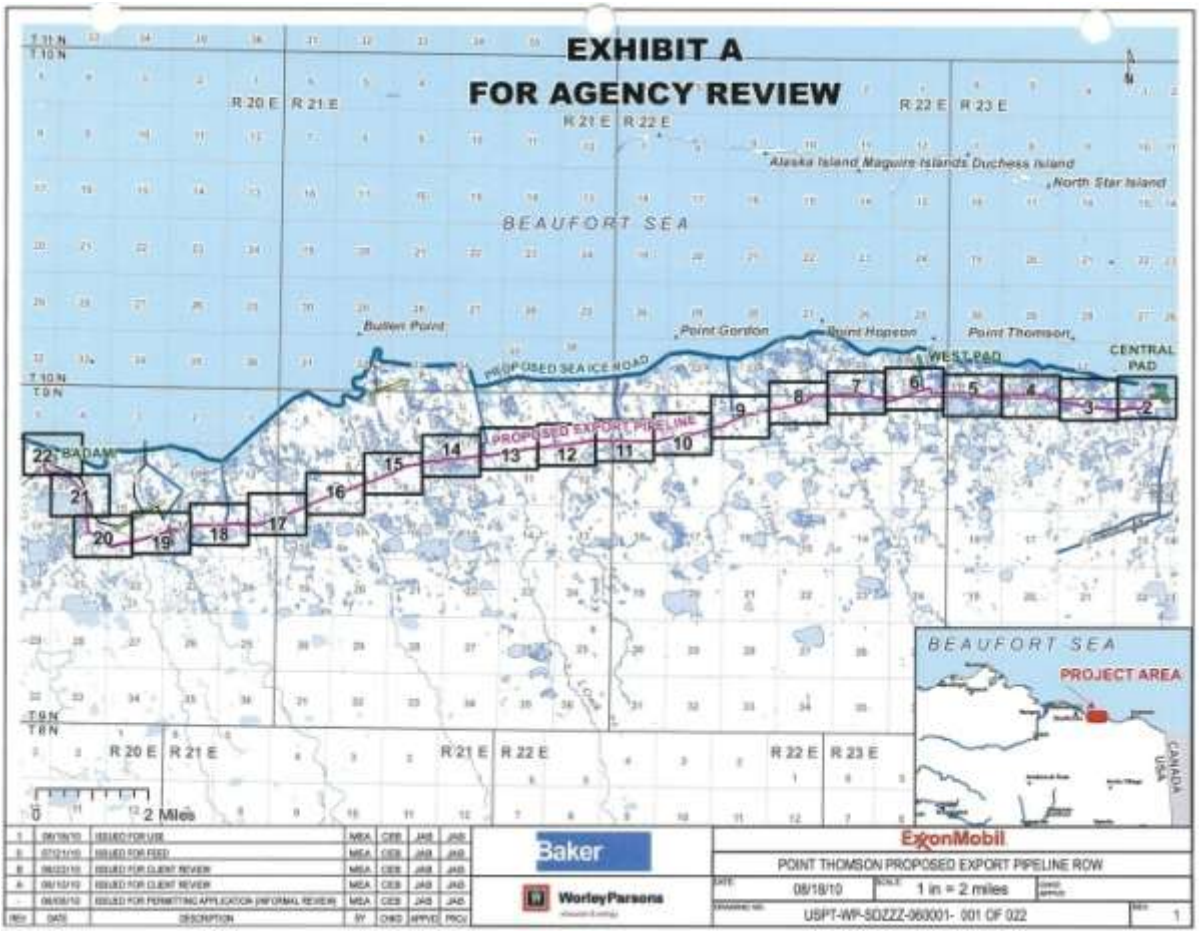

Figure 62: Proposed Point Thomson Pipeline Route Map

The USACE has been designated as the lead Federal Agency on the main Point Thomson project with the State DNR acting as one of the cooperating agencies. The SPCO has been supporting DNR's coordinate efforts during the scoping portion of the Draft Environmental Impact Statement (DEIS).

The SPCO has also been working with ExxonMobil during their preparation to submit an application for an AS 38.35 ROW Lease for the development, construction and operation of an export pipeline. This pipeline is a critical part of the Point Thomson project and ExxonMobil has worked closely with this office to ensure the submission of a complete application.

To date the SPCO has participated in the five DEIS scoping meetings held in January of 2010. These scoping meetings included the entire Point Thomson Project Team from ExxonMobil and its consultants as well as representatives from each of the cooperating agencies. The scoping meetings were held in Kaktovik, Fairbanks, Nuiqsut, Barrow and Anchorage. While the meetings covered the project in its entirety, and was specifically for the purposes of the DEIS, they provided a great opportunity for the SPCO to hear from communities about any issues that may concern the export pipeline.

In early March ExxonMobil Pipeline Company asked the SPCO to participate in a pre-application meeting to discuss the details of the AS 38.35 Application for Pipeline ROW Lease. This meeting was attended by ROW staff as well as our engineer, Director and Deputy Director. ExxonMobil brought a cadre of representation to the meeting including their engineers and consultants. At the meeting specifics about the pipeline ROW, the design and the construction were discussed. The meeting was productive and the SPCO was very satisfied with the effort on ExxonMobil's part to provide a thorough and complete application and to keep communication with this office open throughout the process.

At this time SPCO continues to receive project updates from ExxonMobil regarding the DEIS and the status of the Pipeline ROW Lease application. The USACE timeline for the Point Thomson DEIS process extends past the current projection for SPCO's notice, analysis, and review for the AS 38.35 Lease. The DEIS process includes alternatives that could affect certain aspects of ExxonMobil's Pipeline ROW Lease application. Therefore the final application from ExxonMobil has not yet been received by this office.

SPCO Engineering Section

The Point Thomson Export Pipeline (PTEP) will run from a development on the shore at Point Thomson to the Badami pipeline. The pipeline will cover a route 22 miles long. It will be mounted on VSMs and HSMs on aboveground supports. It will share the supports with infield flowlines for the first five miles. A proposed infield road runs parallel with the PTEP for the first six miles and an airstrip and access road parallel the pipeline for three miles. Both the runway and the road are near the pipeline, but not on the lease(15 p. 23).

Work continued on ExxonMobil's lease application. As part of this work, engineering participated in the development of a design basis for the pipeline. The Engineering Section evaluated the design basis, suggested changes and reviewed the document during its further development. Based upon the design basis, the proposed codes and standards for the pipeline, and other information, engineering recommended approval of a lease, based upon the applicant's demonstration technical, operational and construction capabilities. The lease application with the final SPCO design basis was received after the reporting period, in August 2010.

Parks Highway Stand Alone Gas Pipeline Project

The SPCO received a ROW application from the DOT&PF for the proposed Parks Highway Stand Alone Gas Pipeline on November 27, 2009. The project proposed construction of a 24-inch diameter natural gas pipeline system from the North Slope of Alaska to Cook Inlet in Southcentral Alaska.

The proposed project included a 12-inch diameter lateral pipeline to Fairbanks, up to 11 compressor stations, metering stations, permanent facilities such as regional operations and maintenance centers, roads and temporary facilities for construction such as material sites, roads, workpads, and construction camps. In addition, the proposed project was based on construction of a gas treatment facility in Prudhoe Bay.

Prior to issuing public notice of the application, as required in the Right-of-Way Leasing Act (AS 38.35), the SPCO halted action on the process due to an administrative issue.

The USACE initiated the EIS process with scoping meetings at selected locations along the proposed alignment and in select larger communities. As required by the EIS process, the applicant's preferred alternative was the Parks Highway route and the alternative considered was the Richardson Highway route (see Figure 63 on the next page). Initially, the SPCO participated in the EIS process as a "commenting agency".

In March 2010, the SPCO requested and received "cooperating agency" status which provided more involvement in the EIS process. The ROW process was again delayed due to the confidential nature of information included in the application.

Concurrent to state and federal agency work associated with the Parks Highway Stand Alone Gas Pipeline project, the Legislature was working on legislation specific to an in-state pipeline project. Those efforts culminated in the passage of House Bill 369 which was signed by Governor Parnell on July 9, 2010.

House Bill 369 created the Joint In-State Gasline Development Team and directed the Executive Director of the AHFC to oversee all aspects of the project. The AHFC formed the subsidiary AGDC to administer the in-state gas pipeline project. The bill resulted in a consolidation of two in-state gas pipeline efforts, the Parks Highway Stand Alone Gas Pipeline and the ANGDA B2F pipeline project, under the auspices of the AHFC/AGDC.

The bill also directed the Department of Natural Resources to grant the AHFC/AGDC a ROW lease under AS 38.35 for the gas pipeline transportation corridor if: (1) the corporation submits a complete ROW lease application under As 38.35.050; (2) the lease application is made the subject of notice and other reasonable and appropriate publication requirements under AS 38.35.070; and (3) the corporation agrees to be bound by the ROW lease covenants set out in AS 38.35.120.

The SPCO will continue to work with the AHFC/AGDC and participating state and federal agencies as the project moves forward.

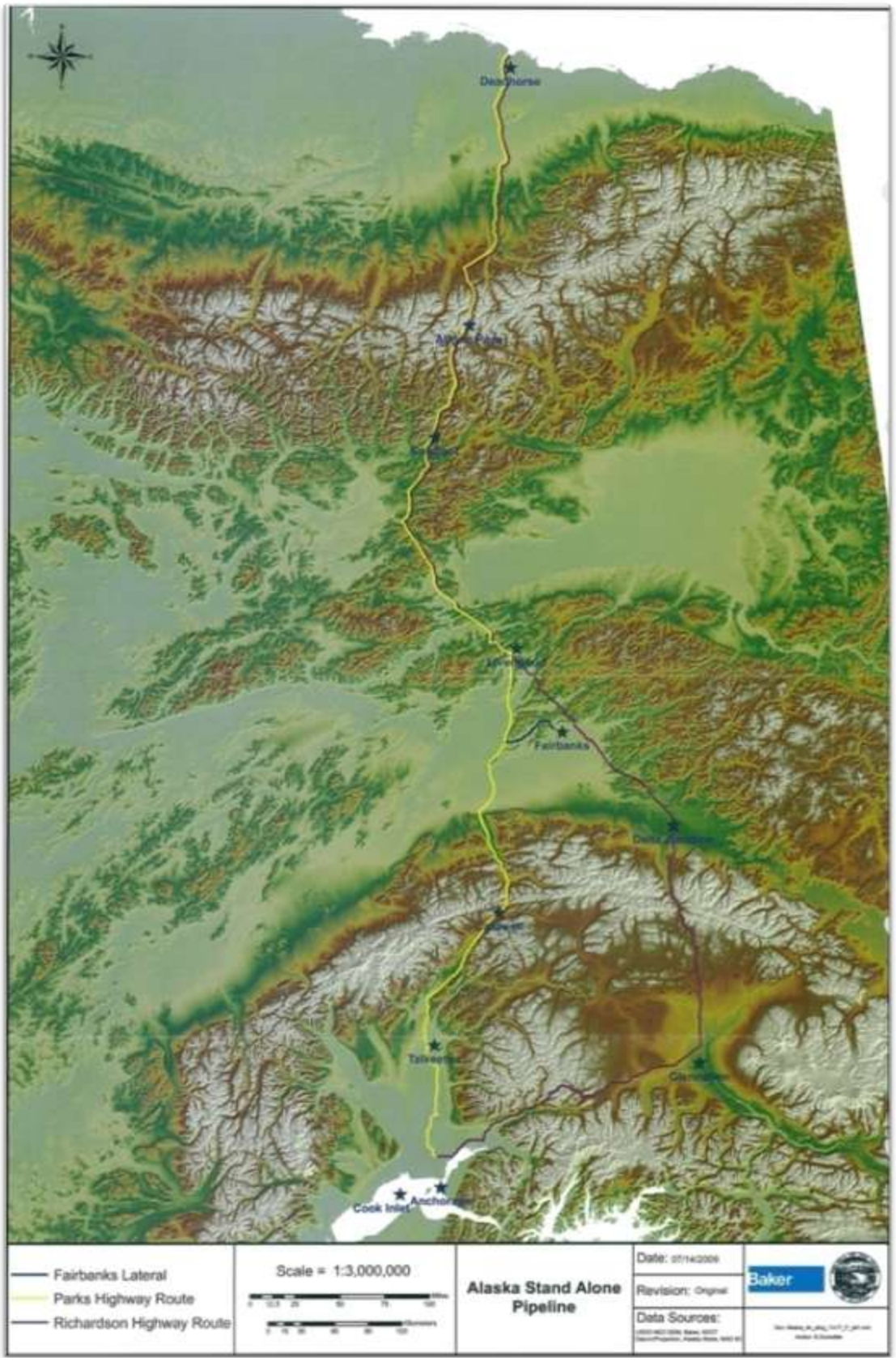

Figure 63: Alaska Stand Alone Gas Pipeline Proposed Routes Map

SPECIAL PROJECTS

ROW Section

LAS Case file Audit

ROW Section staff have been conducting an intensive three-part audit of the LAS case file records for each active pipeline ROW lease or grant case file administered by the State Pipeline Coordinator's Office. The LAS system is used to locate, research, and verify land ownership and land use on State lands. The LAS system is the statewide land records system available to the public on the INTERNET at: http://dnr.alaska.gov/projects/las/lasmenu.cfm

In FY10, there were 17 active case files involving constructed pipelines. Other SPCO case files involving applications, leases, grants, or contracts for non-constructed pipelines have not been included in this audit. The LAS audit was divided into three parts for each case file audited. Part 1 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 2 of the audit involves a quality control check of the Part 1 updates and review and update of LAS Revenue & Billing Subsystem records for that case file. Part 3 of the audit involves a final quality control check of updates made during Parts 1 and 2 for each case file along with any final edits, corrections, and updates to the LAS case file records. During this fiscal year, Part 1 of the audit was completed, except for TAPS, ADL 63574 case file. SPCO-ROW staff will proceed to Part 2 of the audit and continue the data entries for the TAPS case file in the coming fiscal year.

Division of Mining Land and Water Support

During 2010 the ROW Section of SPCO assisted the Division of Mining, Land and Water's (DMLW) Southcentral Region Office in updating the AS 38.05.850 permits, and permitting process, for hydrocarbon pipelines. The DMLW has the authority to authorize permits for pipelines on State land that do not meet the criteria for an AS 38.35 lease. These AS 38.05.850 permitted pipelines are often single source or single carrier lines as opposed to common carriers. The applicant companies work with the DMLW regional offices to obtain permits for obtaining a ROW on State land for the construction of the pipeline. The DMLW Southcentral Office requested SPCO's assistance in reviewing past permits, along with the associated case files of specific pipelines, as well as providing consult on the current permitting and compliance process. The general combined effort is to bring consistency to the methods with which all DNR sections manage hydrocarbon transportation pipelines across State Land. The SPCO has given a considerable amount of attention, time and effort to these collaborative issues and appreciates the opportunity to be involved in such projects of importance.

Engineering Section

BP Connector for the Transit Oil Pipeline

Similar to the Kuparuk Pipeline, the OTL transporting oil from Prudhoe Bay and satellite oilfields to PS 1, changes mode from above ground to below ground. This is identified by APSC as the Sadlerochit connector. The pipeline is not piggable from the Skid 51 to PS 1. The section of the pipeline within the fence is underground and encased in friable concrete.

It is difficult to inspect. During this reporting period, work continued on replacement of this section of pipeline. This work is being performed on APSC property by BP, which performs work for BPTA.

This connector was the conduit for gas to enter PS 1 during a recent incident.

All BP pipelines that have direct connection to PS 1 had their pigging procedures modified. The Engineering Section followed up on improvements made as a result of an incident on January 15, 2009. On January 15, 2009, a serious incident occurred at PS1, a result of pigging and de-oiling of the 34-inch OTL. An investigation by BPTA and BPXA personnel resulted in recommendations for several changes. In addition, APSC also conducted an investigation and made changes in their operations and communications.

It should be noted that this pipeline is not located on an AS38.35 Lease, under the jurisdiction of the SPCO. However, it is a major connector in the TAPS system and part is located within the boundaries of PS 1.

Colville Crossing and the Proposed CD5 Development

The SPCO Engineer assisted the State of Alaska with technical support related to the proposed CD5 development. The Horizontal Directional Drilled (HDD) crossings of these pipelines at the main Colville River came again to prominence. These crossings were completed a decade ago, but remain the only HDD crossings of a major river in a permafrost region. The USACE denied a permit to Kuparuk Transportation Company to build a combination vehicle and pipeline bridge near Nuiqsut at the Natchiq tributary of the Colville River. This would have served an expansion drillsite, CD5. They denied the bridge because of a preference for an HDD crossing. They cited the successful operation of the Alpine oil pipeline HDD crossing as evidence of the efficacy of this type of design.

However, the State of Alaska has supported Kuparuk Transportation Company in its appeal of the USACE decision. The argument said that the Alpine crossing was not a good analogue for the CD5 crossing for several reasons. The primary one is that the CD5 crossing will transport a different type of oil pipeline. It carries a mixture of gas, unprocessed crude oil, water and minor amounts of sediment. The Alpine oil pipeline, in contrast, transports processed oil with very small fractions of water and traces of sediment.

A deeply buried HDD crossing of the type proposed by the USACE at the Natchiq channel appears to be more problematic for a number of reasons. T he accumulation of deposits, wax, flow assurance and maintenance would argue that, in this particular instance, an aboveground crossing might provide fewer risks. In addition, the bridge will assist the village of Nuiqsut in a number of ways. The State of Alaska prepared arguments supporting the appeal to reverse the USACE decision, and the SPCO assisted in the technical support for these efforts(16)(17)

FISCAL YEAR 2011

Pipeline Oversight – Operational Pipelines

The state agencies within the SPCO will continue to provide ROW lease and regulatory oversight of jurisdictional pipelines. APSC is moving forward with EA of PS 1 which will require a higher level of monitoring. APSC provides the JPO with a comprehensive list of projects for each calendar year and the SPCO will focus on several of the proposed projects for compliance with the terms and conditions of the ROW lease and relevant regulations.

The SPCO has identified specific TAPS oversight goals for FY11:

- Complete assessment of PS 1 Incident Investigation follow-up
- Complete assessment of the Status of Technical Drawings and Documents for the PS 3 SR Project
- Track and evaluate the Management Action Plan created from recommendations of the TK 190 Overfill Incident Investigation
- Complete an assessment of Lessee Surveillance and Monitoring Programs,
- Track and evaluate the Management Action Plan created from recommendations of the TK 190 Overfill Incident Investigation
- ROW ground surveillance from PS 1 to VMT

Specific oversight activities for North Slope Pipelines in FY11 include:

- Compare Alpine ROW Storage Inventory to actual ground conditions
- Monitor annual survey of Colville River crossing for Alpine
- Monitor coupon installation at Alpine and Oliktok and track the coupon analysis
- Monitor smart pigging, in support of restart of the Badami Sales Oil Pipeline
- Monitor hot tapping on the Badami and Endicott pipelines
- Monitor restart of the Badami Sales Oil Pipeline
- Monitor coupon testing on the Endicott Pipeline
- Monitor Interim Corrective Action for Flow Station 2 pipeline settlement onto the Endicott Pipeline
- Monitor hot tapping on the Kuparuk Pipeline and Kuparuk Pipeline Extension
- Monitor coupon pulls on the Kuparuk Pipeline and the Kuparuk Pipeline Extension
- On site condition of pigging modules after transport at Kuparuk and Oliktok
- Monitor first In-Line Inspection of the Kuparuk Pipeline Extension
- Conduct Release of Interest inspections at Milne Point and Badami Pipelines
- Monitor coupon installation at Northstar
- Site check of implementation of QAP plans and activities related to the Nuiqsut Natural Gas Pipeline
- Site check of implementation of the Surveillance and Monitoring Program related to the Nuiqsut Natural Gas Pipeline
- Inspect under road crossings, culverts, stream crossings, etc for all North Slope pipelines

Specific oversight activities for Southcentral Pipelines in FY11 include:

- Monitor new construction activities on the North Fork Pipeline ROW
- Conduct Kenai Kachemak Pipeline ROW surveillances and document checks

- Conduct Nikiski Alaska Pipeline ROW surveillances and document checks

Pipeline Permitting – Pre-Application, Application and Construction Phases

The SPCO anticipates increased activity associated with several natural gas pipeline projects. The Denali and Alaska Pipeline projects will continue field data collection efforts in preparation for submittal of a ROW application. The Donlin Creek Mine natural gas pipeline project is performing field studies to facilitate pipeline design and alignment. The Parks Highway Stand Alone Gas Pipeline project, pursuant to HB 369, may be issued a ROW lease in CY11.

The North Fork Pipeline is currently in construction mode, and SPCO compliance staff will coordinate with USDOT/PHMSA on monitoring activities.

Bureau of Land Management, Office of Pipeline Monitoring Move

During FY10, BLM, DNR, DOLWD, DEC, ADF&G and DPS shared office space at 411 West Fourth Avenue, Anchorage Alaska. In FY11, BLM/OPM will move to a new office location, 188 West Northern Lights Boulevard, Anchorage Alaska. This will co-locate the BLM/OPM with other federal agencies including USDOT/PHMSA, the agency with statutory authority for pipeline safety.

State and federal agencies have developed a transition plan to maintain effective communication and coordination following the BLM/OPM move. The JPO electronic Document Tracking System (DTS), JPO website, and a server for shared documents will be maintained through a BLM hosted IT environment (Figure 64). In addition to maintaining past levels of access, other affiliated state and federal agencies such as the Office of the Federal Coordinator (OFC) the DNR Petroleum Systems Integrity Office (PSIO) will have to opportunity to access JPO resources.

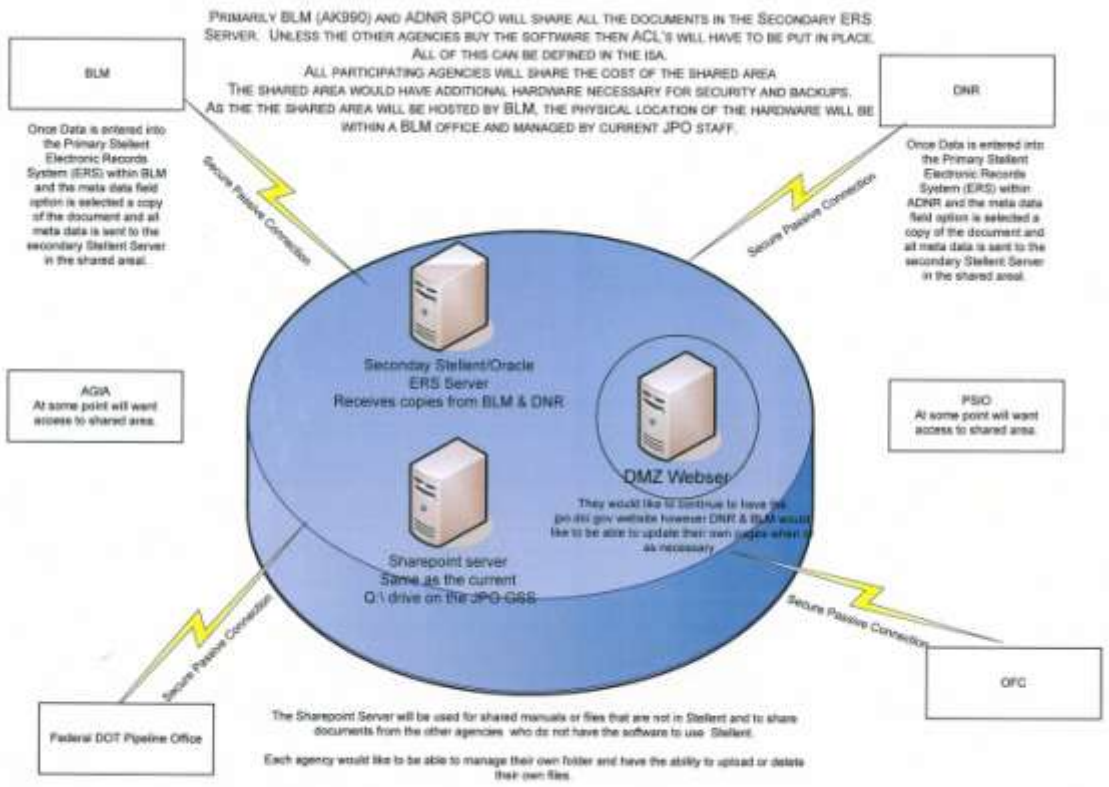

Figure 64: Proposed Shared IT Environment for JPO and Affiliated Agencies

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APPENDICES

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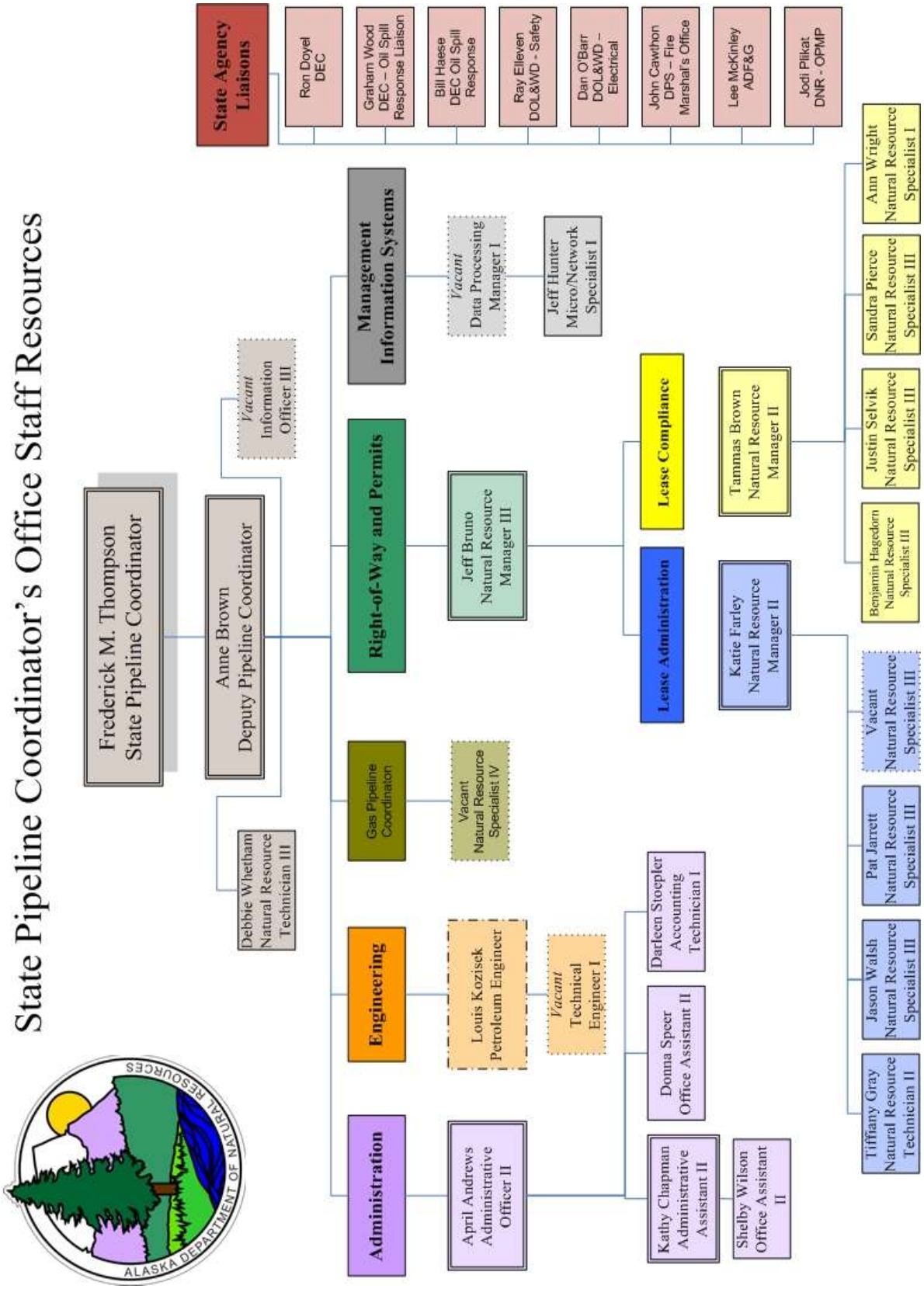
Appendix A: SPCO Staff Resources



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Appendix B: Lease Compliance Monitoring Matrix

Lease Compliance Matrix (Example)													
Lease Section or Stipulation		**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
		Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
Section	**1**	**Grant of Right-of-Way**											
	1.a.	(description)	x										
	1.b.	(subject to State laws)	x										
	1.c.	(purpose)		x	x	x			x	SPCO	CS	x	x
	1.d.(i)	(construction width)		x				x		SPCO	CS	x	x
	1.d.(ii)	(release of interests)		x				x		SPCO	ROW	x	
	1.e.	(As-Built survey)		x				x		SPCO	ROW	x	
	1.f.	(construction zone)		x				x		SPCO	CS		x
Section	**2**	**Duration of Right-of-Way Grant**											
	2.a.	(expiration)	x										
	2.b.	(continuing obligations)					x	x		SPCO	CS	x	
	2.c.	(renewal)					x	x		SPCO	ROW	x	
	2.d.	(conveyance)	x										
Section	**3**	**Rental**											
	3.a.	(annual payment)		x	x	x			x	DNR	ROW	x	
	3.b.	(initial payment/appraisal)		x				x		DNR	ROW	x	
	3.c.	(5 year appraisal)						x		DNR	ROW	x	
	3.d.	(release of interests)	x					x		DNR	ROW	x	
Section	**4**	**Covenants by Lessee**											
	4.a.	(common carrier)			x				x	RCA	CS	x	x
	4.b.	(connections)			x				x	RCA	CS	x	x
	4.c.	(records/reports)		x	x	x	x		x	SPCO	CS	x	x
	4.d.	(access/records)		x	x	x	x		x	SPCO	CS	x	x
	4.e.	(State connections)	x							RCA			
	4.f.	(State connections)	x							RCA			
	4.g.	(lawful operations)		x	x	x			x	RCA	CS	x	x
	4.h.	It will, at its own expense, during the term of this lease:											
	4.h.(1)	(maintain in good repair)		x	x	x	x		x	SPCO	CS	x	x
	4.h.(2)	(repair)		x	x	x	x	x		SPCO	CS	x	x
	4.h.(3)	(compensate for damage)		x	x	x	x	x		SPCO	CS	x	x
	4.i.	(Not transfer)		x	x	x	x	x		SPCO	ROW	x	
	4.j.	(Registered Agent)		x	x	x			x	SPCO	ROW	x	
	4.k.	(State Law)	x										
	4.l.	(State disposal)	x										
	4.m.	(liable to State)		x	x	x	x	x		DNR	Ex	x	
	4.n.	(insurance)		x	x	x	x	x		DNR	ROW	x	
Section	**5**	**Guaranty**											
	5.a.	(May be required by Commissioner)		x	x	x	x	x		DNR	ROW	x	
	5.b.	(Guarantor; description of)	x										
	5.c.	(Commissioner approval)		x	x	x	x	x		DNR	ROW	x	
	5.d.	(Request new Guaranty)		x	x	x	x	x		DNR	ROW	x	

Lease Compliance Matrix (Example)													
Lease Section or Stipulation		**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
		Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
	5.e.	(Certificates/Agent for service of process)		x	x	x	x	x		SPCO	ROW	x	
Section	**6**	**Construction Plans and Quality Assurance**											
	6.a.	(Construction plans and QAP required)		x				x		SPCO	ROW	x	
Section	**7**	**Reservation of Certain Rights to the State**											
	7.a.	(access)		x	x	x	x		x	SPCO	CS		x
	7.b.	(contractors)		x	x	x	x	x		SPCO	Ex		x
	7.c.	(resources)	x										
	7.d.	(additional permits)	x										
Section	**8**	**Reimbursement of State Expenses**											
	8.a.	(Reasonable Reimbursement)		x	x	x	x		x	SPCO	Admin	x	
	8.b	(Quarterly statement)		x	x	x	x		x	SPCO	Admin	x	
	8.c.	(Audits)	x					x		SPCO	Admin	x	
	8.d.	(State records)	x										
	8.e.	(Payment/disputes)	x							SPCO	Admin	x	
	8.f.	(Audit- unnecessary personnel/expenditure)	x										
Section	**9**	**Right of the State to Perform**											
	9.a.	(Reasonable costs paid by Lessee)	x					x					
Section	**10**	**Duty of Lessee to Prevent or Abate**											
	10.a.	(Lessee shall)		x	x	x	x		x	SPCO	CS	x	x
	10.b.	(Agents, employees, contractors)		x	x	x	x		x	SPCO	CS	x	x
Section	**11**	**Compliance with Notices to Proceed**		x				x		SPCO	CS		x
Section	**12**	**Temporary Suspension Orders of the Commissioner or his Designee**											
	12.a.	(Temporary Suspension-any activity phase)	x										
	12.a.(i)	(Immediate threat)	x										
	12.a.(ii)	(Failure to comply with Lease)	x										
	12.b.	(Construction activities)	x	x									
	12.b.(1)	(Stop activity)	x	x									
	12.b.(2)	(Description)	x	x									
	12.b.(3)	(Commissioner's designated field rep.)	x	x									
	12.b.(4)	(Lessee's designated field rep.)	x	x									
	12.b.(5)	(Date and time)	x	x									
	12.c.	(Prior Notice)	x										
	12.d.	(Lessee Promptly comply)		x	x	x	x	x		DNR	CS		x
	12.e.	(Confirmed in writing)	x										
	12.f.	(Resumption)	x										
	12.g.	(Subject to Lease Section 14)	x										
Section	**13**	**Requests to Resume**											
	13.a.	(facts under oath)	x					x					
	13.b.	(Commissioners decision)	x					x					
Section	**14**	**Appeal Procedure**											
	14.a.	(Temp suspension/denial of resumption)	x										
	14.a.(i)	(Lessee statements)		x	x	x	x	x		DNR	Com	x	

Lease Compliance Matrix (Example)													
Lease Section or Stipulation		**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
		Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
	14.a.(ii)	(Commissioners timeline)	x										
	14.a.(ii)	(Final Administrative Decision)	x										
	14.b.	(NTP)	x										
	14.b.(i)	(Commissioners denial)	x										
	14.b.(ii)	(Grounds for appeal)	x										
	14.b.(iii)	(Appeals subject to appeal)	x										
	14.c.	(10 days-Final Administrative Decision)	x										
	14.d.	(30 days- Final Administrative Decision)	x										
Section	**15**	**Liability of the State**	x										
Section	**16**	**Release of Right-of-Way**											
	16.a.	(Instrument of Release)					x	x		SPCO	ROW	x	
	16.b.	(Resolutions-certifications)					x	x		SPCO	ROW	x	
	16.c.	(Not a waiver)	x										
Section	**17**	**Forfeiture of Lease**		x			x	x		SPCO	ROW	x	x
Section	**18**	**Rights of Third Parties**	x										
Section	**19**	**Waiver not Continuing**	x										
Section	**20**	**Remedies Cumulative; Equitable Relief**	x										
Section	**21**	**Section Headings**	x										
Section	**22**	**Authority to Enter Agreement**	x										
Section	**23**	**Exhibits; Incorporation of Certain Documents by Reference; Other Exhibits**											
	23.(i)	Exhibit A (Route)	x										
	23.(ii)	Exhibit B (Related Facilities)	x										
	23.(iii)	Exhibit C (Stipulations)	x										
	23.(iv)	Exhibit D (Typical crossing)	x										
Section	**24**	**Lease not a Waiver of any State Regulatory Power**	x										
Section	**25**	**Binding Effect of Covenants**	x										
Exhibit	**C**	**Stipulations**											
Stipulation	**1**	**General**											
Stipulation	**1.1.**	**Definitions**											
	1.1.1.	(Agency)	x										
	1.1.2.	(Commissioner or his designee)	x										
	1.1.3	(Company)	x										
	1.1.4.	(Construction mode)	x										
	1.1.5.	(Construction segment)	x										
	1.1.6.	(Design criteria)	x										
	1.1.7.	(Final design)	x										
	1.1.8.	(Hazardous substances)	x										
	1.1.9.	(Lessee)	x										
	1.1.10.	(Miscellaneous land use permit)	x										
	1.1.11.	(Notice to proceed)	x										
	1.1.12.	(Oil or crude oil)	x										

Lease Compliance Matrix (Example)													
Lease Section or Stipulation	**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
	Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
1.1.13.	(Pipeline)	x										
1.1.14	(Pipeline coordinator)	x										
1.1.15.	(Pipeline system)	x										
1.1.16.	(Related facilities)	x										
1.1.17	(Revegetation)	x										
1.1.18.	(Roads)	x										
1.1.19.	(State lands)	x										
1.1.20.	(Waste)	x										
1.1.21.	(Wetlands)	x										
Stipulation 1.2	**Applicability**											
1.2.1.	(All phases)		x	x	x	x		x	SPCO	CS	x	x
1.2.1.(1)	(Compliance with Stipulations)		x	x	x	x		x	SPCO	CS	x	x
1.2.1.(2)	(Contractor's failure =Company's failure)	x										
1.2.1.(3)	(Stipulations in Contracts)		x	x	x	x		x	SPCO	CS	x	x
1.2.2.	(Related to pipeline system)	x										
1.2.3.	(No 3rd party rights)	x										
Stipulation 1.3.	**Responsibilities**											
1.3.1.	(Comply with stipulations)		x	x	x	x		x	SPCO	CS	x	x
1.3.2	(Representatives)		x	x	x	x		x	SPCO	ROW	x	
1.3.3.	(Data/Confidentiality)		x	x	x	x	x		SPCO	CS	x	
1.3.4.	(Modification)		x	x	x	x	x		SPCO	Ex	x	
1.3.5.	(Absence of comment)	x										
1.3.6.	(Access)		x	x	x	x		x	SPCO	CS		x
1.3.7.	(Written authority)	x										
1.3.8.	(Supervisor copies)		x	x	x	x		x	SPCO	CS	x	x
Stipulation 1.4.	**Communications**											
1.4.1.	(Ensure transmission of Information)		x	x	x	x		x	SPCO	CS	x	x
1.4.2.	(Preconstruction/construction/initial ops)		x				x		SPCO	CS	x	
1.4.3.	(Written to State)	x										
1.4.4	(Written to company)	x										
1.4.5.	(Emergency)	x										
Stipulation 1.5.	**Summary Network Analysis Diagrams**											
1.5.1.	(Design Criteria)		x				x		SPCO	Eng	x	
1.5.2.	(Updated)			x	x	x	x		SPCO	Eng	x	
Stipulation 1.6.	**Design Criteria, Plans and Programs**											
1.6.1.	(Requirements)		x				x		SPCO	CS	x	x
1.6.1.(1)	(Blasting)		x				x		SPCO	Eng	x	x
1.6.1.(2)	(Corrosion)		x				x		SPCO	Eng	x	x
1.6.1.(3)	(Cultural resources)		x				x		SPCO	ROW	x	x
1.6.1.(4)	(Erosion)		x				x		SPCO	Eng	x	x
1.6.1.(5)	(Materials)		x				x		SPCO	ROW	x	x
1.6.1.(6)	(Oil control/cleanup/disposal)		x				x		SPCO	CS	x	x

Lease Compliance Matrix (Example)												
Lease Section or Stipulation	**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
	Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
1.6.1.(7)	(Overburden)		x				x		SPCO	CS	x	x
1.6.1.(8)	(Contingency)		x				x		SPCO	CS	x	x
1.6.1.(9)	(QAQC)		x				x		SPCO	CS	x	x
1.6.1.(10)	(Restoration)		x				x		SPCO	CS	x	
1.6.1.(11)	(Crossings)		x				x		SPCO	CS	x	
1.6.1.(12)	(SMP)		x				x		SPCO	CS	x	
1.6.1.(13)	(Wetland construction)		x				x		SPCO	CS	x	
1.6.1.	(Timeline)		x				x		SPCO	Ex	x	x
1.6.2.	(Commissioner Approval/Lessee Compliance)		x	x	x	x		x	DNR	Ex	x	x
1.6.3.	(Additional)		x	x	x	x	x		SPCO	Ex	x	
Stipulation 1.7.	**Notice to Proceed (or Construction Authorization)**											
1.7.1	(Written Permission)		x				x		SPCO	ROW	x	x
1.7.2.	(Mark boundaries)		x				x		SPCO	CS		x
1.7.3.	(Supporting documents)		x				x		SPCO	ROW	x	
1.7.3.(1)	(Final design)		x				x		SPCO	Eng	x	
1.7.3.(2)	(Reports and Environmental Studies)		x				x		SPCO	ROW	x	
1.7.3.(3)	(Network design analysis)		x				x		SPCO	Eng	x	
1.7.3.(4)	(Maps)		x				x		SPCO	ROW	x	
1.7.3.(5)	(Required deviation from stipulations)		x				x		SPCO	ROW	x	
1.7.4.	(Schedule for submissions)	x										
1.7.5.	(Review in accordance w/schedule)	x										
1.7.6.	(Issue)	x										
1.7.7.	(Suspend)	x										
Stipulation 1.8.	**Quality Assurance and Control**											
1.8.1.	(Overview)		x	x	x	x		x	SPCO	CS	x	x
1.8.2.	(Minimums)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (1)	(procedures)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (1) (a)	(abatement)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (1) (b)	(reasonable)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (1) (c)	(threats to)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (1) (c) (1)	(health and safety)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (1) (c) (2)	(wildlife)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (1) (c) (3)	(private improvements)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (2)	(Repair/replacement/rehabilitation)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (3)	(quality through design)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (4)	(contractors)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (5)	(records)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (6)	(deviations)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (7)	(subsystems)		x	x	x	x	x		SPCO	CS	x	x
1.8.2. (8)	(field inspections)		x	x	x	x	x		SPCO	CS	x	x
1.8.3	(Compliance and Reporting)		x	x	x	x		x	SPCO	CS	x	x
Stipulation 1.9.	**Conduct of Operations**											

Lease Compliance Matrix (Example)												
Lease Section or Stipulation	**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
	Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
1.9.1.	(Safe and workmanlike manner - notification)		x	x	x	x		x	SPCO	CS	x	x
Stipulation 1.10.	**Surveillance and Maintenance (or Monitoring)**											
1.10.1	(minimums)		x	x	x	x		x	SPCO	CS	x	x
1.10.1 (1)	(public health and safety)		x	x	x	x		x	SPCO	CS	x	x
1.10.1 (2)	(natural resources)		x	x	x	x		x	SPCO	CS	x	x
1.10.1 (3)	(erosion)		x	x	x	x		x	SPCO	CS	x	x
1.10.1 (4)	(pipeline integrity)		x	x	x	x		x	SPCO	CS	x	x
1.10.1 (5)	(property)		x	x	x	x		x	SPCO	CS	x	x
1.10.1	(records)		x	x	x	x		x	SPCO	CS	x	x
Stipulation 1.11.	**Health and Safety**											
1.11.1.	Health and Safety	x	x	x	x	x		x	DOLWD	CS	x	x
Stipulation 1.12.	**Public and Private Improvements**											
1.12.1	Public and Private Improvements		x	x	x	x	x		SPCO	CS	x	x
Stipulation 1.13.	**Survey Monuments**											
1.13.1.	(protect)		x	x	x	x		x	DNR	CS	x	x
1.13.2.	(damaged)		x	x	x	x	x		DNR	CS	x	x
Stipulation 1.14.	**Fire Prevention and Suppression**											
1.14.1	(notification)		x	x	x	x		x	SFMO	SFMO	x	x
Stipulation 1.15.	**Electronically Operated Devices**											
1.15.1.	Electronically Operated Devices		x	x	x	x		x	SPCO	Eng	x	x
Stipulation 1.16.	**Termination of Authorization**											
1.16.1	Termination of Authorization					x	x		SPCO	CS	x	x
Stipulation 1.17.	**Regulation of Access**											
1.17.1	Regulation of Access		x	x	x	x		x	SPCO	ROW	x	x
1.17.2.	(number of crossings)		x				x		SPCO	ROW	x	x
Stipulation 1.18.	**Use of Existing Facilities**											
1.18.1	Use of Existing Facilities		x	x	x	x		x	SPCO	Eng	x	x
Stipulation 1.19	**Reporting**											
1.19.1	(annual reporting requirements)		x	x	x	x		x	SPCO	CS	x	
Stipulation 2	**Environmental**											
Stipulation 2.1	**Environmental Briefings**											
2.1.1	(Supervisory and Field Personnel)		x	x	x	x		x	SPCO	CS	x	x
Stipulation 2.2	**Pollution Control**											
2.2.1	**General**											
2.2.1.1.	General (comply w/laws)		x	x	x	x		x	DEC	CS	x	x
Stipulation 2.2.2.	**Water and Land Pollution**											
2.2.2.1.	(no vehicles in water)		x	x	x	x		x	DEC	CS	x	x
2.2.2.2.	(water temp)		x	x	x	x		x	DEC	CS	x	x
2.2.2.3.	(thermal pollution)		x	x	x	x		x	DEC	CS	x	x
Stipulation 2.2.3.	**Sanitation and Waste Disposal**											
2.2.3.1.	(Disposal in compliance with DEC)		x	x	x	x		x	DEC	CS	x	x

Lease Compliance Matrix (Example)													
Lease Section or Stipulation	**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
	Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
Stipulation 2.2.4.	**Ice Fog**											
2.2.4.1.	Ice Fog		x	x	x			x	DEC	CS	x	x
Stipulation 2.3.	**Erosion and Sedimentation Control**											
Stipulation 2.3.1.	**General**											
2.3.1.1.	(minimize disturbance)		x	x	x	x		x	SPCO	CS	x	x
2.3.1.1.1.	(gravel/spring)		x	x	x	x		x	SPCO	CS	x	x
2.3.1.2.	(design)							x	SPCO	Eng	x	x
2.3.1.3.	(control measures)		x	x	x	x	x		SPCO	Eng	x	x
2.3.1.4.	(restoration/surface materials)		x	x	x	x	x		SPCO	CS	x	x
Stipulation 2.3.2.	**Crossing of Streams, Rivers Floodplains and Wetlands**											
2.3.2.1.	(minimize erosion)		x	x	x	x		x	SPCO	CS	x	x
2.3.2.2.	(fill ramps)		x	x	x	x	x		SPCO	CS	x	x
Stipulation 2.3.3.	**Excavated Material**											
2.3.3.1.	Excavated Material		x				x		SPCO	CS	x	x
Stipulation 2.4	**Fish and Wildlife Protection**											
2.4.1	(fish passage)		x	x	x	x		x	F&G	CS	x	x
2.4.2	(screened intake)		x	x	x	x	x		F&G	CS	x	x
2.4.3.	(abandon diversion structures)		x	x	x	x	x		F&G	CS	x	x
Stipulation 2.4.4.	**Fish Spawning Beds, Fish Rearing Areas, and Overwintering Areas**											
2.4.4.1.	(definitions)	x										
2.4.4.2.	(definitions)	x										
2.4.4.3.	(definitions)	x										
2.4.4.4.	(don't disturb)		x	x	x	x		x	F&G	CS	x	x
2.4.4.5.	(protect)		x					x	F&G	CS	x	x
2.4.4.6.	(Site specific terms		x	x	x	x	x		F&G	CS	x	x
2.4.4.7	(water intake)		x	x	x	x		x	F&G	CS	x	x
Stipulation 2.4.5.	**Zones of Restricted Activity**											
2.4.5.1.	(notify company)		x	x	x	x	x		F&G	CS	x	x
Stipulation 2.4.6.	**Big Game Movements**											
2.4.6.1.	Big Game Movements		x	x	x			x	SPCO	CS		x
Stipulation 2.5.2	**Layout of Material Sites**											
2.5.2.1.	Layout of Material Sites		x		x		x		DNR	CS		x
Stipulation 2.6.	**Disturbance or Use of Natural Waters**											
2.6.1.	(prohibited unless approved)		x	x	x	x		x	SPCO	Eng	x	x
2.6.2.	(wells)		x	x	x	x		x	DNR	CS	x	x
Stipulation 2.7.	**Off Right-of-Way Traffic**											
2.7.1.	(authorization)		x	x	x	x		x	DNR	ROW	x	x
Stipulation 2.8.	**Use of Explosives**											
2.8.1.	(plan, 1.6)		x				x		SPCO	ROW	x	
2.8.2.	(not within ¼ mile of water)		x				x		SPCO	ROW		x
2.8.3.	(Commissioner approval)		x				x		SPCO	ROW	x	
Stipulation 2.9.	**Restoration**											
2.9.1.	(completion of use)					x	x		SPCO	CS	x	x

Lease Compliance Matrix (Example)													
Lease Section or Stipulation	**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
	Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
2.9.2.	(description)					x	x		SPCO	CS	x	x
2.9.3.	(accepted in writing)					x	x		SPCO	CS	x	x
2.9.4.	(earthen material disposal)					x	x		SPCO	CS	x	x
2.9.5.	(stabilization)					x		x	SPCO	CS	x	x
2.9.6.	(remove equipment)					x	x		SPCO	CS	x	x
2.9.7.	(maintain restored areas)		x	x	x	x		x	SPCO	CS	x	x
Stipulation 2.10.	**Reporting, Prevention, Control, Cleanup and Disposal of Oil and Hazardous Substance Discharges**											
2.10.1.	(notification)		x	x	x	x		x	DEC	CS	x	x
2.10.1 (1)	(notification: Commissioner)		x	x	x	x		x	DEC	CS	x	x
2.10.1 (2)	(notification: State officials)		x	x	x	x		x	DEC	CS	x	x
2.10.1.	(notification: oral followed by written)		x	x	x	x	x		DEC	CS	x	x
2.10.2	(description/40 CRF, Part 112)		x	x	x	x		x	DEC	CS	x	x
Stipulation 2.11.	**Pipeline Operating Contingency Plan**											
2.11.1	Pipeline Operating Contingency Plan		x						DNR	Ex	x	
2.11.2.	(changes approved by commissioner)		x	x	x	x	x		SPCO	Ex	x	
Stipulation 2.12	**Cultural Resources**											
2.12.1.	Cultural Resources		x	x	x	x		x	SHPO	CS	x	x
Stipulation 2.13.	**Hunting, Fishing and Trapping**											
2.13.1	Hunting, Fishing and Trapping		x	x	x	x		x	ADF&G	CS	x	x
Stipulation 2.14.	**Small Craft Passage**											
2.14.1	Small Craft Passage		x	x	x	x		x	SPCO	CS	x	x
Stipulation 3	**Technical**											
Stipulation 3.1.	**Pipeline System Standards**											
Stipulation 3.1.1.	**General Standards**											
3.1.1.1.	General Standards		x	x	x	x		x	SPCO	Eng	x	
3.1.1.2.	General Standards	x	x				x		SPCO	Eng	x	
Stipulation 3.1.2.	**Specific Standards**											
3.1.2.1.	(valves)		x				x		SPCO	Eng	x	
3.1.2.2.	(environmentally sensitive areas)		x		x		x		SPCO	Eng	x	x
3.1.2.3.	(organic layer)		x		x		x		SPCO	Eng	x	x
3.1.2.4.	(welder qualification)		x	x	x			x	SPCO	Eng	x	x
3.1.2.5.	(surface modification/ permafrost/integrity)		x	x	x	x		x	SPCO	Eng	x	x
3.1.2.6.	(monitoring program: movement)		x	x	x	x		x	SPCO	Eng	x	x
Stipulation 3.1.3.	**Standards for Roads**											
3.1.3.1	(approved by commissioner)		x				x		SPCO	Eng	x	
3.1.3.2.	(travel speed)		x				x		SPCO	Eng	x	
3.1.3.3.	(permanent/existing/arctic environment))		x				x		SPCO	Eng	x	
3.1.3.4.	(grade)		x				x		SPCO	Eng	x	x
Stipulation 3.2.	**Work Pad**											
Stipulation 3.2.1	**Work Pad Design**											
3.2.1.1.	(3 feet gravel)		x				x		SPCO	Eng	x	
3.2.1.1.1	(otherwise approved by commissioner)		x				x		SPCO	Eng	x	

Lease Compliance Matrix (Example)												
Lease Section or Stipulation	**Requirement**	**Activity Phase**					**Monitoring Required**		**Primary Agency**	**SPCO Section**	Conduct In:	
	Description	Administrative	Construction	Operation	Maintenance	Termination	Conditional	Continuous			Office	Field
3.2.1.1.2	(construction/operations maintenance plan)		x				x		SPCO	Eng	x	
Stipulation 3.2.2.	**Work Pad Construction**											
3.2.2.1.	Work Pad Construction		x				x		SPCO	Eng	x	x
Stipulation 3.3	**Stream and Floodplain Crossing**											
Stipulation 3.3.1.	**General**											
3.3.1.1.	(design)		x				x		SPCO	Eng	x	
3.3.1.2.	(design: hydraulic region)		x				x		SPCO	Eng	x	
3.3.1.2.1.	(specific computer program)		x				x		SPCO	Eng	x	
3.3.1.2.2.	(overhead)		x				x		SPCO	Eng	x	
3.3.1.2.3.	(channelization)		x				x		SPCO	Eng	x	
3.3.1.2.4.	(approval before construction)		x				x		SPCO	Eng	x	
3.3.1.3.	(low water crossings)		x	x	x	x		x	SPCO	Eng	x	
Stipulation 3.3.2.	**Culverts and Bridges**											
3.3.2.1.	Culverts and Bridges		x				x		SPCO	Eng	x	
3.3.2.2.	Culverts and Bridges		x				x		SPCO	Eng	x	
Stipulation 3.4	**Pipeline Corrosion**											
3.4.1.	Pipeline Corrosion		x	x	x		x		USDOT	Eng	x	
3.4.1. (1)	(Material selection)		x	x	x			x	USDOT	Eng	x	x
3.4.1. (2)	(External Pipe Protection)		x	x	x			x	USDOT	Eng	x	x
3.4.1. (3)	(Cathodic Protection)		x	x	x			x	USDOT	Eng	x	x
3.4.1. (4)	(Monitoring CP)		x	x	x			x	USDOT	Eng	x	x
3.4.1. (5)	(Periodic Intensive Surveys)		x	x	x			x	USDOT	Eng	x	x
3.4.1. (6)	(Internal Corrosion)		x	x	x			x	USDOT	Eng	x	

RCA=Regulatory Commission of Alaska
DNR=Department of Natural Resources
SPCO=State Pipeline Coordinator's Office
USDOT=US Department of Transportation
F&G=Alaska Department of Fish and Game
DEC=Alaska Department of Environmental Conservation

ROW=Right-of-Way and Permits Section
Com=DNR Commissioner
CS=Compliance Section
Eng=Engineering Section
Adm=Administrative Section
Ex=State Pipeline Coordinator or Deputy Coordinator

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Appendix C: FY10 Annual Report Major Source Documents

Major Source Documents

1. **Alyeska Pipeline Service Company.** *Trans Alaska Pipeline System (TAPS) 2009 Annual Report: Mainline Aboveground Support System and Bridges Program.* Anchorage : Alyeska Pipeline Service Company, 2010.

2. —. *Trans Alaska Pipeline System (TAPS) 2009 Annual Report: Fuel Gas Line Monitoring Program.* Anchorage : Alyeska Pipeline Service Company, 2010.

3. —. *Trans Alaska Pipeline System (TAPS) 2009 Annual Report: Mainline Integrity Monitoring Program.* Anchorage : Alyeska Pipeline Service Company, 2010.

4. —. *Trans Alaska Pipeline System (TAPS) 2009 Annual Report: Pipeline and Valdez Marine Terminal Corrosion Monitoring Program.* Anchorage : Alyeska Pipeline Service Company, 2010.

5. —. *Trans Alaska Pipeline System (TAPS) 2009 Annual Report: Aboveground Storage and Tank Monitoring Program.* Anchorage : Alyeska Pipeline Service Company, 2010.

6. —. *Trans Alaska Pipeline System (TAPS) 2009 Annual Report: Rivers, Floodplains, and Glacier Monitoring Program.* Anchorage : Alyeska Pipeline Service Company, 2010.

7. —. *Trans Alaska Pipeline System (TAPS) 2009 Annual Report: Right-of-Way and Civil Monitoring Program.* Anchorage : Alyeska Pipeline Service Company, 2010.

8. —. *KYP #10-042 Operations and Maintenance Incident Prevention Board.* ["Keeping You Posted" Email] Anchorage : Alyeksa Pipeline Service Company, 2010.

9. **BP Transportation (Alaska) Inc.** *Badami Pipelines Rights-of-Way: 2009 Annual ADNR Surveillance and Monitoring Report.* Anchorage : BP Transportation (Alaska) Inc., 2010.

10. **BP Transportation (Alaska), Inc.** *Endicott Pipeline - FS2 Water and AGL Pipelines (Notification Update).* [Email chain] Anchorage : BP Transportation (Alaska), Inc., 2010.

11. **BP Transportation (Alaska) Inc.** *Milne Point Pipelines Rights-of-Way: 2009 Annual ADNR Surveillance and Monitoring Report.* Anchorage : BP Transportation (Alaska) Inc., 2010.

12. **Coastal Frontiers Corporation.** *Coastal Stability Monitoring, Northstar Pipeline Shore Crossing: Summer 2009.* Chatsworth : Coastal Frontiers Corporation, 2009.

13. **Kuparuk Transportation Company.** *2009 Annual Comprehensive Report on Pipeline Activities: Kuparuk Pipeline ADL 402294, Kuparuk Pipeline Extension ADL 409027.* Anchorage : Kuparuk Transportation Company, 2010.

14. **Sargent, William A.** Additional Information Requested by SPCO Engineering Concerning the Smith Creek Bridge Replacement: Kuparuk Pipeline ADL 402294, Oliktok Pipeline ADL 411731. Anchorage : Kuparuk Transportation Company, 2010.

15. **Worley Parsons, Resources and Energy and Baker.** *Point Thomson Project: Point Thomson Design Basis for Permitting - Export Pipeline, USPT-WP-YBDES-060001, Revision 1.* Houston : ExxonMobil Development, 2010.

16. **Kozisek, Louis.** *Opinion on Aboveground vs. HDD Waterway Crossings on the North Slope.* Anchorage : State Pipeline Coordinator's Office, 2010.

17. —. *Opinion of Nigliq Channel Pipeline Crossing Scour Report (Rev. 1).* Anchorage : State Pipeline Coordinator's Office, 2010.

18. **BP Transportation (Alaska) Inc.** *Endicott Pipeline Right-of-Way: 2009 Annual ADNR Surveillnace and Monitoring Report.* Anchorage : BP Transportation (Alaska) Inc., 2010.

19. —. *Northstar Pipelines Rights-of-Way: 2009 Annual ADNR Surveillance and Monitoring Report.* Anchorage : BP Transportation (Alaska) Inc., 2010.

20. **ConocoPhillips.** *2009 Annual Comprehensive Report on Pipeline Activities: Alpine Oil Pipeline ADL 414701, Alpine Diesel Pipeline ADL 415932, Alpine Utility Pipeline ADL 415857.* Anchorage : ConocoPhillips, 2010.

21. **Marathon Pipe Line Company, LLC.** *Kenai Kachmak Pipeline 2009 Annual Report.* Kenai : Marahon Pipe Line Company, LLC, 2010.

22. —. *Kenai Kachemak PIpeline 2009 Annual Report: ADDENDUM.* Kenai : Marathon Pipe Line Company, LLC, 2010.

23. **North Slope Borough.** *Nuiqsut Natural Gas Pipeline: Annual Comprehensive Report on Pipeline Activities and the State of the Pipeline System.* Anchorage : North Slope Borough, 2010.

24. **Oliktok Pipeline Company.** *2009 Annual Comprehensive Report on Pipeline Activities: Oliktok Pipeline ADL 411731.* Anchorage : Oliktok Pipeline Company, 2010.

25. **Tesoro Alaska Pipeline Company.** *2009 Annual Comprehensive Report on Pipeline Activities and State of the Pipeline System forTesoro Alaska Pipeline Company (Nikiski) Right-of-Way Lease - ADL 69354.* San Antonio : Tesoro Alaska Pipeline Company, 2010.

26. —. *Amendment for the Tesoro Nikiski ROW (Right-of- Way) Lease ADL 69354 Annual 2009 Report.* San Antonio : Tesoro Alaska Pipeline Company, 2010.

27. **OASIS Environmental, Inc. and BP Exploration (Alaska) Inc., Environmental Studies Group.** *Rehabilitation Progress Rerport for the Badami Weir Site.* Anchorage : BP Exploration (Alaska), Inc., 2009.

Appendix D: Acreage, Survey, and Lease Information

ADL #	Lease Name	Lease Effective Date	Lease Expiration Date	Lessee	Acres on State Land	Survey #
415932	Alpine Diesel Pipeline	12/15/1998	12/14/2018	ConocoPhillips Company	148.51	EPF 2002-40[35]
415701	Alpine Oil Pipeline	12/15/1998	12/14/2018	ConocoPhillips Company	148.66	EPF 2002-40
415857[36]	Alpine Utility Pipeline	1/6/1999	1/5/2019	ConocoPhillips Company	148.65	EPF 2002-40
415472	Badami Sales Oil Pipeline	12/15/1997	12/14/2022	BP Transportation (Alaska) Inc.	1,240[37]	EPF 2002-18; not complete
415965	Badami Utility Pipeline	12/15/1997	12/14/2022	BP Transportation (Alaska, Inc.	352.1[3]	EPF 2002-18; not complete
410562	Endicott Pipeline	8/5/1986	5/2/2034	Endicott Pipeline Company	1,073.816	ASLS 84-96 EPF 20080040
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	8/26/1980	5/2/2034	Kuparuk Transportation Company	485.58	ASLS 87-15
409027	Kuparuk Pipeline Extension	4/18/1983	5/2/2034	Kuparuk Transportation Company	159.09	ASLS 87-15
410221	Milne Point (Oil) Pipeline	1/15/1985	5/2/2034	Milne Point Pipeline, LLC[38]	186.92	ASLS 84-114
416172	Milne Point Products Pipeline	12/5/2000	12/4/2030	Milne Point Pipeline, LLC[4]	258.6 [3]	Not surveyed
69354	Nikiski Alaska Pipeline	1/30/1976	1/29/2031	Tesoro Alaska Pipeline Company	64	ASLS 76-215
415975	Northstar Gas Pipeline	10/1/1999	9/30/2019	Northstar Pipeline Company, LLC	405.51	EPF 2002-17
415700	Northstar Oil Pipeline	10/1/1999	9/30/2019	Northstar Pipeline Company, LLC	419.13	EPF 2002-17
416202	Nuiqsut Natural Gas Pipeline	3/15/1999	3/14/2019	North Slope Borough	17.67	As-built survey approved by DNR 12/17/2003
411731	Oliktok Pipeline	6/1/1986	5/2/2034	Oliktok Pipeline Company	485.58	ASLS 87-15
63574	Trans-Alaska Pipeline System	5/3/1974	5/2/2034	TAPS Owners[39]	6,021.87[40]	Multiple surveys[41]

[35] *A typographical error exists on the survey plat with respect to the acreage of Parcel 4, but the square feet of Parcel 4 is correct; total acreage is 148.51 acres*
[36] *ADL 415857 is a ROW Grant, not a lease*
[37] *Acreage based on construction ROW acreage from lease, not surveyed acreage*
[38] *Wholly owned by BPTA*
[39] *BP Pipelines Alaska Inc. (46.93%), ConocoPhillips Alaska Transportation Inc. (28.29%), Exxon/Mobil Pipeline Co. (20.34%), Unocal Pipeline Company (1.36%), Koch Alaska Pipeline Co. LLC (3.08%)*
[40] *Per Appraisal 3165, DNR Summary of Appraisal dated 7/21/2006, and Memorandum of May 17, 2007 from the Review Appraiser to the SPCO to add fuel gas line acreage*
[41] *Includes the TAPS centerline survey, surveys of pump stations on State land, and as-built surveys for ROW amendments*

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Appendix E: Pipeline Right-of-Way Lease Appraisal Information

Pipeline	ADL #	ROW Status	State Acres	Rental	Next Appraisal Due (Prior to)
Alpine Diesel	415932	Operations	148.51	$77,629*	12/15/2013
Alpine Oil	415701	Operations	148.66	$77,713*	12/15/2013
Alpine Utility	415857	Operations	148.65	$77,703*	1/6/2014
Badami Oil	415472	Construction	1,240.00	$540,144	12/15/2012
Badami Utility	415965	Construction	352.10	$181,122	12/15/2012
Endicott	410562	Operations	1,072.64	$735,627	8/5/2013
Kenai Kachemak	228162	Operations	104.56	$29,709	11/26/2012
Kuparuk	402294	Operations	485.58	$370,347*	8/26/2013
Kuparuk Extension	409027	Operations	159.08	$138,599*	4/18/2013
Milne Point (Oil)	410221	Operations	186.92	$162,845	1/15/2013
Milne Point Products	416172	Construction	258.60	$225,292	12/5/2010
Oliktok	411731	Operations	485.58	$370,347*	1/1/2013
Nikiski Alaska	69354	Operations	64.02	$15,207	1/30/2009**
Northstar Oil	415700	Operations	419.13	$317,456	10/1/2014
Northstar Gas	415975	Operations	405.51	$252,429	10/1/2014
Nuiqsut Natural Gas	416202	Operations	17.67	$11,120	3/15/2014
TAPS	63574	Operations	6,021.87	$220,956	***

** Current Appraisal under appeal*
*** Current Appraisal was due 1/30/2009, but not timely received by DNR*
**** Last Appraisal (No. 3165) was completed in 2002 and is under appeal. SPCO and DNR Appraisal Section agreed a retrospective appraisal is acceptable upon appeal resolution*

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Appendix F: Physical Characteristics of SPCO Jurisdictional Pipelines

Pipeline System	Diameter (inches)	Normal Wall Thickness (inches)	Product	Year Constructed	System Length (miles)
Alpine Diesel Pipeline	2.375	0.156	Diesel Fuel	1998-1999	34.2 (23.7 on state land)
Alpine Oil Pipeline	14	0.312 to 0.438	Crude Oil	1998-1999	34.2 (23.7 on state land)
Alpine Utility Pipeline	12.75	0.330	Seawater	1998-1999	34.2 (23.7 on state land)
Badami Sales Oil Pipeline	12	0.281 aboveground 0.500 belowground	Crude Oil	1998	25 (all on state land)
Badami Utility Pipeline	6	0.375 aboveground 0.432 river crossing	Natural Gas and Product	1998	31 (all on state land)
Endicott Pipeline	16	0.312	Oil	1987	26 (all on state land)
KKPL Mainline and HVE	12.75	0.330 and 0.500	Natural Gas	2003-2004	50 including the HVE (42 on state land)
KKPL, Kasilof Extension	6.63	0.280 and 0.432	Natural Gas	2006	4.2 (all on state land)
Kuparuk Pipeline	24	0.406 (0.750 in Kuparuk Floodplain)	Oil	1984	28 (all on state land)
Kuparuk Pipeline Extension	18	0.375 (original construction); 0.438 (2009 replaced sec.)	Oil	1981 original; 2009 partial replacement	9 (all on state land)
Milne Point (Oil) Pipeline	14	0.312	Oil	1984	10 (all on state land)
Milne Pt. Product Pipeline	8	0.277	Natural Gas Liquids	2000	10 (all on state land)
Nikiski Alaska Pipeline	10.75	0.188 to 0.625	Refined Liquid Petroleum Products	1976	52.8 (20 miles on state land)
Northstar Gas Pipeline	10.15	0.307- (0.594 sub-sea)	Natural Gas	2000-2001	16 (all on state land)
Northstar Oil Pipeline	10.75	0.307 (0.594 sub-sea)	Crude Oil	2000-2001	17 (all on state land)
Nuiqsut Natural Gas Pipeline	3.5	0.203	Natural Gas	1998-1999	14.4 (2.4 miles on state land)
Oliktok Pipeline	16	0.342- (0.750 in Floodplain)	Natural Gas	1981	28 (all on state land)
TAPS	48	0.462 to 0.562	Oil	1975-1977	800

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Appendix G: SPCO Reports Issued in FY10

SPCO/DNR Surveillance Reports, by Pipeline, FY10

Report Number	ADL	Pipeline	Sec/Stip	#	Title	Observation[42]
09-SPCO-S-106	415932	Alpine Diesel Pipeline	Stipulation	2.6.1	Big Game Movement	Satisfactory
10-SPCO-S-025	415932	Alpine Diesel Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
09-SPCO-S-107	415701	Alpine Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-108	415701	Alpine Oil Pipeline	Stipulation	1.13.2	Storage	Satisfactory
09-SPCO-S-109	415701	Alpine Oil Pipeline	Stipulation	2.6.1	Big Game Movement	Satisfactory
09-SPCO-S-110	415701	Alpine Oil Pipeline	Stipulation	2.14.1	Waste Removal	Satisfactory
09-SPCO-S-111	415701	Alpine Oil Pipeline	Stipulation	3.2.1	Pipeline Corrosion	Satisfactory
10-SPCO-S-026	415701	Alpine Oil Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
10-SPCO-S-061	415701	Alpine Oil Pipeline	Stipulation	2.11.1	Reporting, Prevention, Control, Cleanup, and Disposal of Oil and Hazardous Substance Discharges	Satisfactory
09-SPCO-S-112	415857	Alpine Utility Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-113	415857	Alpine Utility Pipeline	Stipulation	1.13.2	Storage	Satisfactory
09-SPCO-S-114	415857	Alpine Utility Pipeline	Stipulation	2.6.1	Big Game Movement	Satisfactory
09-SPCO-S-115	415857	Alpine Utility Pipeline	Stipulation	2.14.1	Waste Removal	Satisfactory
09-SPCO-S-116	415857	Alpine Utility Pipeline	Stipulation	3.2.1	Surveillance and Monitoring	Satisfactory
10-SPCO-S-027	415857	Alpine Utility Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
09-SPCO-S-067	415472	Badami Sales Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-068	415472	Badami Sales Oil Pipeline	Stipulation	2.3	Erosion Control	Satisfactory
09-SPCO-S-069	415472	Badami Sales Oil Pipeline	Stipulation	2.4.4.2	Fish and Wildlife Protection: Fish Spawning Beds, Fish Rearing Areas, and Overwintering Areas	Satisfactory
09-SPCO-S-121	415472	Badami Sales Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-122	415472	Badami Sales Oil Pipeline	Stipulation	2.3	Erosion and Sedimentation Control	Satisfactory
09-SPCO-S-123	415472	Badami Sales Oil Pipeline	Stipulation	2.4.4.2	Fish and Wildlife Protection: Fish Spawning Beds, Fish Rearing Areas, and	Satisfactory

[42] SAT = Satisfactory; COTS = Corrected on the spot (or in a reasonable amount of time); and UNSAT = Unsatisfactory. COTS are not necessarily out of compliance with State Law or the Grant/Lease, but have a deficiency requiring immediate attention to prevent foreseeable problems.

SPCO/DNR Surveillance Reports, by Pipeline, FY10

Report Number	ADL	Pipeline	Sec/Stip	#	Title	Observation[42]
10-SPCO-S-028	415472	Badami Sales Oil Pipeline	Section	28	Local Hire	Satisfactory
10-SPCO-S-036	415472	Badami Sales Oil Pipeline	Stipulation	1.6.2	Surveillance and Monitoring	Satisfactory
09-SPCO-S-075	415965	Badami Utility Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-076	415965	Badami Utility Pipeline	Stipulation	2.3	Erosion and Sedimentation Control	Satisfactory
09-SPCO-S-077	415965	Badami Utility Pipeline	Stipulation	2.4.4.2	Fish and Wildlife Protection: Fish Spawning Beds, Fish Rearing Areas, and Overwintering Areas	Satisfactory
09-SPCO-S-124	415965	Badami Utility Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-125	415965	Badami Utility Pipeline	Stipulation	2.3	Erosion and Sedimentation Control	Satisfactory
09-SPCO-S-126	415965	Badami Utility Pipeline	Stipulation	2.4.4.2	Fish and Wildlife Protection: Fish Spawning Beds, Fish Rearing Areas, and Overwintering Areas	Satisfactory
10-SPCO-S-029	415965	Badami Utility Pipeline	Section	28	Local Hire	Satisfactory
10-SPCO-S-037	415965	Badami Utility Pipeline	Stipulation	1.6.2	Surveillance and Monitoring	Satisfactory
09-SPCO-S-074	410562	Endicott Pipeline	Section	4d	Covenants	Satisfactory
09-SPCO-S-128	410562	Endicott Pipeline	Stipulation	1.17.1	Regulation of Access	Satisfactory
10-SPCO-S-013	410562	Endicott Pipeline	Stipulation	1.3.6	Responsibilities	Satisfactory
10-SPCO-S-014	410562	Endicott Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
10-SPCO-S-015	410562	Endicott Pipeline	Stipulation	1.17.1	Regulation of Access	Satisfactory
10-SPCO-S-016	410562	Endicott Pipeline	Stipulation	2.1.1	Environmental Briefing	Satisfactory
10-SPCO-S-017	410562	Endicott Pipeline	Stipulation	2.4.6.1	Big Game Movements	Satisfactory
10-SPCO-S-018	410562	Endicott Pipeline	Stipulation	3.1.2.6	Specific Standards	Satisfactory
10-SPCO-S-019	410562	Endicott Pipeline	Section	4(d)	Covenants	Satisfactory
10-SPCO-S-020	410562	Endicott Pipeline	Section	7(a)	Reservation of Certain Rights	Satisfactory
10-SPCO-S-042	410562	Endicott Pipeline	Section	4c	Covenants by Lessee	Satisfactory
10-SPCO-S-043	410562	Endicott Pipeline	Stipulation	1.8.3	Quality Assurance and Control	Satisfactory
10-SPCO-S-044	410562	Endicott Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
09-SPCO-S-138	228162	Kenai Kachemak Pipeline	Section	1	Lease of ROW	Satisfactory
09-SPCO-S-139	228162	Kenai Kachemak Pipeline	Section	15	Conduct of Operations	Satisfactory
09-SPCO-S-140	228162	Kenai Kachemak Pipeline	Section	20	Information	Satisfactory
09-SPCO-S-141	228162	Kenai Kachemak Pipeline	Stipulation	1.11.2	Regulation of Access	Satisfactory
09-SPCO-S-142	228162	Kenai Kachemak Pipeline	Stipulation	1.12.1	Storage	Satisfactory

SPCO/DNR Surveillance Reports, by Pipeline, FY10

Report Number	ADL	Pipeline	Sec/Stip	#	Title	Observation[42]
10-SPCO-S-066	228162	Kenai Kachemak Pipeline	Stipulation	1.2.1	Communications	Satisfactory
10-SPCO-S-067	228162	Kenai Kachemak Pipeline	Stipulation	1.4.1	Quality Assurance	Satisfactory
10-SPCO-S-068	228162	Kenai Kachemak Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
10-SPCO-S-069	228162	Kenai Kachemak Pipeline	Stipulation	1.9.1	Fire Prevention and Suppression	Satisfactory
10-SPCO-S-070	228162	Kenai Kachemak Pipeline	Stipulation	1.10.1	Electronically Operated Devices	Satisfactory
10-SPCO-S-088	228162	Kenai Kachemak Pipeline	Section	4(a)	Payment	Satisfactory
10-SPCO-S-089	228162	Kenai Kachemak Pipeline	Section	8(j)	Covenants of Lessee	Satisfactory
10-SPCO-S-090	228162	Kenai Kachemak Pipeline	Section	24(b)	Reimbursement of State Expenses	Satisfactory
10-SPCO-S-091	228162	Kenai Kachemak Pipeline	Section	30	Authorized Representative	Satisfactory
10-SPCO-S-092	228162	Kenai Kachemak Pipeline	Section	34(b)	Correspondence	Satisfactory
10-SPCO-S-062	402294	Kuparuk Pipeline	Stipulation	2.10.1	Reporting, Prevention, Control, Cleanup, and Disposal of Oil and Hazardous Substance Discharges	Satisfactory
10-SPCO-S-080	402294	Kuparuk Pipeline	Section	4c	Covenants of Lessee	Satisfactory
10-SPCO-S-081	402294	Kuparuk Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory
10-SPCO-S-082	402294	Kuparuk Pipeline	Stipulation	1.8.3	Quality Assurance and Control	Satisfactory
10-SPCO-S-083	402294	Kuparuk Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
10-SPCO-S-097	402294	Kuparuk Pipeline	Section	4h	Covenants of Lessee	Satisfactory
09-SPCO-S-117	409027	Kuparuk Pipeline Extension	Stipulation	1.11.1	Health & Safety	Satisfactory
09-SPCO-S-118	409027	Kuparuk Pipeline Extension	Stipulation	1.17.1	Regulation of Access	Satisfactory
09-SPCO-S-119	409027	Kuparuk Pipeline Extension	Stipulation	2.4.6.1	Big Game Movements	Satisfactory
09-SPCO-S-120	409027	Kuparuk Pipeline Extension	Stipulation	3.4.1(5)	Pipeline Corrosion	Satisfactory
10-SPCO-S-063	409027	Kuparuk Pipeline Extension	Stipulation	2.10.1	Reporting, Prevention, Control, Cleanup, and Disposal of Oil and Hazardous Substance Discharges	Satisfactory
10-SPCO-S-084	409027	Kuparuk Pipeline Extension	Section	4c	Covenants of Lessee	Satisfactory
10-SPCO-S-085	409027	Kuparuk Pipeline Extension	Stipulation	1.3.3	Responsibilities	Satisfactory
10-SPCO-S-086	409027	Kuparuk Pipeline Extension	Stipulation	1.8.3	Quality Assurance and Control	Satisfactory
10-SPCO-S-087	409027	Kuparuk Pipeline Extension	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
10-SPCO-S-001	410221	Milne Point Pipeline	Section	10	Duty of Lessee to Prevent or Abate	Satisfactory
10-SPCO-S-002	410221	Milne Point Pipeline	Stipulation	1.4.1	Communications	Satisfactory
10-SPCO-S-003	410221	Milne Point Pipeline	Stipulation	1.8.2,	Quality Assurance and Control	Satisfactory

SPCO/DNR Surveillance Reports, by Pipeline, FY10

Report Number	ADL	Pipeline	Sec/Stip	#	Title	Observation[42]
				1.8.3		
10-SPCO-S-004	410221	Milne Point Pipeline	Stipulation	1.9.1	Conduct of Operations	Satisfactory
10-SPCO-S-005	410221	Milne Point Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
10-SPCO-S-006	410221	Milne Point Pipeline	Stipulation	1.11.1	Health & Safety	Satisfactory
10-SPCO-S-007	410221	Milne Point Pipeline	Stipulation	1.17.1	Regulation of Access	Satisfactory
10-SPCO-S-008	410221	Milne Point Pipeline	Stipulation	2.1.1	Environmental Briefings	Satisfactory
10-SPCO-S-009	410221	Milne Point Pipeline	Stipulation	2.2.1.1	Pollution Control	Satisfactory
10-SPCO-S-010	410221	Milne Point Pipeline	Stipulation	2.4.6.1	Big Game Movements	Satisfactory
10-SPCO-S-011	410221	Milne Point Pipeline	Stipulation	3.1.2.6	Specific Standards	Satisfactory
10-SPCO-S-012	410221	Milne Point Pipeline	Stipulation	3.4.1(5)	Pipeline Corrosion	Satisfactory
10-SPCO-S-038	410221	Milne Point Pipeline	Section	4c	Covenants by Lessee	Satisfactory
10-SPCO-S-039	410221	Milne Point Pipeline	Stipulation	1.8.3	Quality Assurance and Control	Satisfactory
10-SPCO-S-040	410221	Milne Point Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
10-SPCO-S-030	416172	Milne Point Products Pipeline	Section	32	Local Hire	Satisfactory
10-SPCO-S-041	416172	Milne Point Products Pipeline	Stipulation	1.13.1	Reporting	Satisfactory
09-SPCO-S-081	69354	Nikiski Alaska Pipeline	Section	15	Constructions Plans and Quality Assurance	Unsatisfactory
09-SPCO-S-084	69354	Nikiski Alaska Pipeline	Stipulation	1.2.3	Responsibilities	Unsatisfactory
09-SPCO-S-086	69354	Nikiski Alaska Pipeline	Stipulation	1.15	Surveillance and Maintenance	Unsatisfactory
10-SPCO-S-021	69354	Nikiski Alaska Pipeline	Section	19(a)	Duty of Lessee to Prevent or Abate	Satisfactory
10-SPCO-S-022	69354	Nikiski Alaska Pipeline	Stipulation	1.15.2	Surveillance and Maintenance	Satisfactory
10-SPCO-S-023	69354	Nikiski Alaska Pipeline	Stipulation	2.1.1	Water, Air and Land Pollution	Satisfactory
10-SPCO-S-024	69354	Nikiski Alaska Pipeline	Stipulation	2.1.2	Water, Air and Land Pollution	Satisfactory
10-SPCO-S-059	69354	Nikiski Alaska Pipeline	Section	6	Books, Accounts and Reports Access to Property and Records	Satisfactory
10-SPCO-S-060	69354	Nikiski Alaska Pipeline	Stipulation	1.15.3	Surveillance and Maintenance	Satisfactory
10-SPCO-S-071	69354	Nikiski Alaska Pipeline	Section	6	Books, Accounts and Records Access to Property and Records	Satisfactory
10-SPCO-S-072	69354	Nikiski Alaska Pipeline	Section	9	Damage or Destruction of Leasehold or Other Property	Satisfactory
10-SPCO-S-073	69354	Nikiski Alaska Pipeline	Section	15	Construction Plans and Quality Assurance	Satisfactory
10-SPCO-S-074	69354	Nikiski Alaska Pipeline	Section	17	Reservation of Certain Rights to the State	Satisfactory
10-SPCO-S-075	69354	Nikiski Alaska Pipeline	Section	19	Duty of Lessee to Prevent or Abate	Satisfactory

SPCO/DNR Surveillance Reports, by Pipeline, FY10

Report Number	ADL	Pipeline	Sec/Stip	#	Title	Observation[42]
10-SPCO-S-076	69354	Nikiski Alaska Pipeline	Stipulation	1.12.1	Regulation of Public Access	Satisfactory
10-SPCO-S-077	69354	Nikiski Alaska Pipeline	Stipulation	1.15.1	Surveillance and Maintenance	Satisfactory
10-SPCO-S-078	69354	Nikiski Alaska Pipeline	Stipulation	1.15.3	Surveillance and Maintenance	Satisfactory
10-SPCO-S-079	69354	Nikiski Alaska Pipeline	Stipulation	1.16.1	Conduct of Operations	Satisfactory
09-SPCO-S-070	415975	Northstar Gas Pipeline	Stipulation	2.1.1	Environmental Briefing	Satisfactory
09-SPCO-S-071	415975	Northstar Gas Pipeline	Stipulation	3(b)	Rental: O&M Phase	Satisfactory
09-SPCO-S-072	415975	Northstar Gas Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-073	415975	Northstar Gas Pipeline	Stipulation	2.3.2.1	Erosion and Sedimentation Control: Crossing of Streams, Rivers, Flood Plains and Wetlands	Satisfactory
10-SPCO-S-031	415957	Northstar Gas Pipeline	Section	32	Local Hire	Satisfactory
10-SPCO-S-035	415975	Northstar Gas Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
09-SPCO-S-062	415700	Northstar Oil Pipeline	Section	3(b)	Rental: O&M Phase	Satisfactory
09-SPCO-S-063	415700	Northstar Oil Pipeline	Stipulation	2.1.1	Environmental Briefing	Satisfactory
09-SPCO-S-064	415700	Northstar Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-065	415700	Northstar Oil Pipeline	Stipulation	2.3.2.1	Erosion and Sedimentation Control	Satisfactory
09-SPCO-S-066	415700	Northstar Oil Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
09-SPCO-S-127	415700	Northstar Oil Pipeline	Stipulation	2.1.1	Environmental Briefing	Satisfactory
09-SPCO-S-135	415700	Northstar Oil Pipeline	Stipulation	3.2.1	Pipeline Corrosion	Satisfactory
10-SPCO-S-032	415700	Northstar Oil Pipeline	Section	32	Local Hire	Satisfactory
10-SPCO-S-034	415700	Northstar Oil Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
09-SPCO-S-129	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.4.1	Quality Assurance	Unsatisfactory
09-SPCO-S-130	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Unsatisfactory
09-SPCO-S-131	416202	Nuiqsut Natural Gas Pipeline	Section	15(b)	Conduct of Operations	Unsatisfactory
09-SPCO-S-132	416202	Nuiqsut Natural Gas Pipeline	Section	8(c)(d)	Covenants	Unsatisfactory
09-SPCO-S-133	416202	Nuiqsut Natural Gas Pipeline	Section	9(b)	Lessee's Contractors, Agents and Employees	Unsatisfactory
09-SPCO-S-134	416202	Nuiqsut Natural Gas Pipeline	Section	15(b)	Conduct of Operations	Unsatisfactory
09-SPCO-S-137	416202	Nuiqsut Natural Gas Pipeline	Section	40	Compliance	Unsatisfactory
10-SPCO-S-033	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.14.1	Reporting	Satisfactory
10-SPCO-S-045	416202	Nuiqsut Natural Gas Pipeline	Section	14(d)	Plans and Permitting	Satisfactory
10-SPCO-S-046	416202	Nuiqsut Natural Gas Pipeline	Section	15(b)	Conduct of Operations	Satisfactory

SPCO/DNR Surveillance Reports, by Pipeline, FY10

Report Number	ADL	Pipeline	Sec/Stip	#	Title	Observation[42]
10-SPCO-S-047	416202	Nuiqsut Natural Gas Pipeline	Section	16(a)	Environmental Compliance	Satisfactory
10-SPCO-S-048	416202	Nuiqsut Natural Gas Pipeline	Section	30	Authorized Representatives	Satisfactory
10-SPCO-S-049	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.2.1	Communications	Satisfactory
10-SPCO-S-050	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.4.1	Quality Assurance	Satisfactory
10-SPCO-S-051	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.5.1	Conduct of Operations	Satisfactory
10-SPCO-S-052	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.6.1	Surveillance and Monitoring	Satisfactory
10-SPCO-S-053	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.7.1	Health & Safety	Satisfactory
10-SPCO-S-054	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.10.1	Electronically Operated Devices	Satisfactory
10-SPCO-S-055	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.11.2	Regulation of Access	Satisfactory
10-SPCO-S-056	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.12.1	Use of Existing Facilities	Satisfactory
10-SPCO-S-057	416202	Nuiqsut Natural Gas Pipeline	Stipulation	1.13.1, 1.13.2	Storage	Satisfactory
10-SPCO-S-058	416202	Nuiqsut Natural Gas Pipeline	Stipulation	2.1	Environmental Briefing	Satisfactory
10-SPCO-S-064	411731	Oliktok Pipeline	Stipulation	2.10.1	Reporting, Prevention, Control, Cleanup, and Disposal of Oil and Hazardous Substance Discharges	Satisfactory
10-SPCO-S-093	411731	Oliktok Pipeline	Section	4(c)	Covenants of Lessee	Satisfactory
10-SPCO-S-094	411731	Oliktok Pipeline	Stipulation	1.3.3	Responsibilities	Satisfactory
10-SPCO-S-095	411731	Oliktok Pipeline	Stipulation	1.8.3	Quality Assurance and Control	Satisfactory
10-SPCO-S-096	411731	Oliktok Pipeline	Stipulation	1.10.1	Surveillance and Maintenance	Satisfactory
10-SPCO-S-098	411731	Oliktok Pipeline	Section	4h	Covenants of Lessee	Satisfactory
09-TAPS-S-069	63574	TAPS (PS 3)	Stipulation	1.19.1	Housing and Quarters	Satisfactory
09-TAPS-S-070	63574	TAPS (PS 3)	Section	6a	Access to Property and Records	Satisfactory
09-TAPS-S-071	63574	TAPS (PS 3)	Section	10a	Damage or Destruction of Leasehold or Other Property	Satisfactory
09-TAPS-S-072	63574	TAPS (PS 3)	Section	17a	Reservation of Certain Rights to the State	Satisfactory
09-TAPS-S-073	63574	TAPS (PS 3)	Section	22a	Duty of Lessee to Prevent or Abate	Satisfactory
09-TAPS-S-074	63574	TAPS (PS 3)	Stipulation	1.20.1	Health and Safety	Satisfactory
09-TAPS-S-075	63574	TAPS (PS 3)	Stipulation	1.20.1	Health and Safety	Satisfactory
09-TAPS-S-076	63574	TAPS (PS 3)	Stipulation	1.12.1	Conduct of Operations	Satisfactory
09-TAPS-S-077	63574	TAPS (PS 3)	Stipulation	2.2.6.2	Sanitation and Waste Disposal	Satisfactory
09-TAPS-S-087	63574	TAPS (PLMP 792.5)	Section	16c	Construction Plans and Quality Assurance	Satisfactory

SPCO/DNR Surveillance Reports, by Pipeline, FY10

Report Number	ADL	Pipeline	Sec/Stip	#	Title	Observation[42]
09-TAPS-S-088	63574	TAPS (PLMP 792.5)	Section	22a	Duty of Lessee to Prevent or Abate	Satisfactory
09-TAPS-S-089	63574	TAPS (PLMP 792.5)	Stipulation	1.2.3	Compliance with Lease by Contractors	Satisfactory
09-TAPS-S-090	63574	TAPS (PLMP 792.5)	Stipulation	1.2.4	Responsibilities	Satisfactory
09-TAPS-S-091	63574	TAPS (PLMP 792.5)	Stipulation	1.18.1, 1.18.4	Surveillance and Maintenance	Satisfactory
09-TAPS-S-092	63574	TAPS (PLMP 792.5)	Stipulation	1.20.1	Health and Safety	Satisfactory
09-TAPS-S-093	63574	TAPS (PLMP 792.5)	Stipulation	1.21.1	Conduct of Operations	Satisfactory
09-TAPS-S-094	63574	TAPS (PLMP 792.5)	Stimulation	2.9.1	Off ROW Traffic	Satisfactory
09-TAPS-S-116	230710	TAPS (OMS 3-1.1)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-117	230460	TAPS (OMS 3-2)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-118	230047	TAPS (OMS 7-1M)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-119	230711	TAPS (OMS 7-1M)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-120	230398	TAPS (OMS 14-0)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-121	LAS 27192	TAPS (OMS 35-1.2)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-122	418676	TAPS (OMS 41-1R)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-123	418012	TAPS (OMS 41-3)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-124	417721	TAPS (OMS 49-3)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-125	418664	TAPS (OMS 53-2)	Stipulation	2.6	Material Sites	Satisfactory
09-TAPS-S-126	63574	TAPS (RGV 125)	Section	22a	Duty to Prevent or Abate	Satisfactory
09-TAPS-S-127	63574	TAPS (RGV 125)	Stipulation	1.21.1	Conduct of Operations	Satisfactory
10-TAPS-S-001	63574	TAPS (Kimball, Kimball Passive, and Round-top)	Stipulation	1.18.2	Surveillance and Maintenance	Satisfactory
10-TAPS-S-006	63574	TAPS (PS 2-7)	Section	16b, c(i)	Construction Plans and Quality Assurance	Satisfactory
10-TAPS-S-007	63574	TAPS (PS 2-7)	Section	17a	Reservation of Certain Rights to the State	Satisfactory
10-TAPS-S-008	63574	TAPS (PS 2-7)	Section	22a, b	Duty of Lessee to Prevent or Abate	Satisfactory
10-TAPS-S-009	63574	TAPS (PS 2-7)	Stipulation	1.18.1, 1.18.2	Surveillance and Maintenance	Satisfactory
10-TAPS-S-010	63574	TAPS (PS 2-7)	Stipulation	1.20.1	Health and Safety	Satisfactory
10-TAPS-S-011	63574	TAPS (PS 2-7)	Stipulation	1.21.1	Conduct of Operations	Satisfactory
10-TAPS-S-047	63574	TAPS (Fairbanks-Valdez)	Section	17.00	Reservation of Certain Rights to the State	Satisfactory
10-TAPS-S-048	63574	TAPS (Fairbanks-Valdez)	Stipulation	1.18.4	Surveillance and Maintenance	Satisfactory

SPCO/DNR Compliance Reports and Assessments, by Pipeline, FY10

Report/ Assessment Number	Pipeline System	Topic	Report Date	Signed Date
10-SPCO-FR-001	Milne Point	Milne Point Oil Pipeline WSS Inspection	12/30/2009	1/11/2010
10-SPCO-FR-002	Endicott	Endicott WSS Inspection	12/30/2009	1/13/2010
10-SPCO-FR-003	TAPS	TAPS	9/22/2009	1/15/2010
10-SPCO-FR-004	KPE	Kuparuk Extension (Pigging Modules-Anchorage)	1/20/2010	1/27/2010
10-SPCO-FR-005	Nikiski	Nikiski Spill Drill	2/5/2010	2/8/2010
10-SPCO-FR-006	TAPS	TAPS Security FBX-PS 2	3/12/2010	3/25/2010
10-SPCO-FR-007	Nuiqsut	Nuiqsut Gas Pipeline Follow-up	2/21/2010	4/1/2010
10-SPCO-FR-008	KKPL	KKPL Document Check	4/20/2010	4/23/2010
10-SPCO-FR-009	Nikiski	Nikiski Aerial Surveillance	5/11/2010	5/13/2010
10-SPCO-FR-010	TAPS	TAPS over-flight with BLM	6/11/2010	6/25/2010
10-SPCO-FR-011	TAPS	TAPS PS 7 Scheduled Shutdown	8/3/2010	8/6/2010
09-SPCO-FR-014	TAPS	TAPS (PS 1- PS 7)	6/30/2009	7/1/2009
09-SPCO-FR-015	TAPS	TAPS (PS 3)	6/10/2009	7/8/2009
09-SPCO-FR-016	TAPS	TAPS (June Shutdown)	7/21/2009	8/14/2010
09-SPCO-FR-017	Badami/ Endicott	Badami Weir/Endicott	8/17/2009	8/24/2010
09-SPCO-FR-018	Northstar/ Endicott	Northstar Gas/Oil LEOS & Endicott	9/27/2009	9/30/2009
09-SPCO-FR-019	Nikiski	Nikiski document check (QAP)	8/12/2009	10/21/2009
09-SPCO-FR-020	TAPS	TAPS Integrity Dig 792.5	8/25/2009	10/1/2009
09-SPCO-FR-021	Nuiqsut	Nuiqsut Gas Pipeline	9/16/2009	11/12/2009
09-SPCO-FR-022	TAPS	TAPS Integrity Dig RGV 125	10/20/2009	10/23/2009
09-SPCO-FR-023	KKPL	KKPL Aerial Surveillance/Document Check	11/23/2009	11/24/2009
09-SPCO-FR-009 (2)	Northstar/ Badami	Northstar and Badami (Aerial Inspection)	5/10/2009	7/7/2009
09-SPCO-FR-011	Alpine/KPE	Alpine/Kuparuk Extension	7/22/2009	9/24/2009
09-SPCO-A-001	Nuiqsut	Nuiqsut	11/6/2009	11/12/2009
10-SPCO-A-001	TAPS	TAPS	5/14/2010	5/18/2010

SPCO/ADF&G TAPS Surveillance Reports, FY10

Report Number	ADL	TAPS PLMP	Stipulation	Title	Observation
09-TAPS-S-078	63574	PLMP 437.36	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	COTS
09-TAPS-S-079	63574	PLMP 408.35	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-080	63574	PLMP 412.47	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-081	63574	PLMP 378.54	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Unsatisfactory
09-TAPS-S-082	FF012505	PLMP 344.96	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-083	FF012505	PLMP 271.5	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-084	FF012505	PLMP 217.45	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-085	FF012505	PLMP 197.86	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-086	FF012505	PLMP 186	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Unsatisfactory
09-TAPS-S-095	63574	PLMP 24.91	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-096	63574	PLMP 25.50	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	COTS
09-TAPS-S-097	63574	PLMP 40.68	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	COTS
09-TAPS-S-098	63574	FGL MP 82	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-099	63574	PLMP 95.79	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-100	63574	PLMP 96.12	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory

SPCO/ADF&G TAPS Surveillance Reports, FY10

Report Number	ADL	TAPS PLMP	Stipulation	Title	Observation
09-TAPS-S-101	FF012505	PLMP 127.04	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-102	FF012505	PLMP 127.17	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-103	FF012505	PLMP 128.62	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-104	FF012505	PLMP 134.85	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-105	FF012505	PLMP 135.11	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-106	FF012505	PLMP 145.76	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-107	FF012505	PLMP 153.25	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-108	FF012505	PLMP 160	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-109	FF012505	PLMP 169	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	COTS
09-TAPS-S-110	FF012505	PLMP 202.14	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-111	FF012505	PLMP 202.99	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-112	FF012505	PLMP 312.13	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-113	FF012505	PLMP 312.99	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-114	FF012505	PLMP 314.81	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory
09-TAPS-S-115	FF012505	PLMP 317.6	2.4, 2.5.1.1, 2.12.1	Crossing of Streams, River or Flood Plains, Seeding & Planting & Passage of Fish & Restoration	Satisfactory

SPCO/DOLWD TAPS Safety Surveillance Reports, FY10

Report Number	TAPS Location	Stip	Title	Observation
09-TAPS-S-128	PS 7	1.20	Health and Safety	Satisfactory
09-TAPS-S-129	PS 6	1.20	Health and Safety	Satisfactory
09-TAPS-S-130	PS 5	1.20	Health and Safety	Satisfactory
10-TAPS-S-002	PS 1	1.20	Health and Safety	Satisfactory
10-TAPS-S-003	PS 2	1.20	Health and Safety	COTS
10-TAPS-S-004	PS 4	1.20	Health and Safety	COTS
10-TAPS-S-005	PS 3	1.20	Health and Safety	Satisfactory
10-TAPS-S-012	North Pole Metering	1.20	Health and Safety	COTS
10-TAPS-S-013	PS 10	1.20	Health and Safety	Satisfactory
10-TAPS-S-014	PS 9	1.20	Health and Safety	Satisfactory
10-TAPS-S-015	PS 8	1.20	Health and Safety	Satisfactory
10-TAPS-S-016	Nordale Yard	1.20	Health and Safety	COTS
10-TAPS-S-017	Rotating Equipment Shop	1.20	Health and Safety	Satisfactory
10-TAPS-S-018	Fabrication Shop	1.20	Health and Safety	Satisfactory
10-TAPS-S-019	Linewide Shop	1.20	Health and Safety	COTS
10-TAPS-S-020	Equipment Shop	1.20	Health and Safety	COTS
10-TAPS-S-021	Materials Warehouse	1.20	Health and Safety	Satisfactory
10-TAPS-S-022	PLMP 490.8	1.20	Health and Safety	Satisfactory
10-TAPS-S-023	PLMP 653.06	1.20	Health and Safety	Satisfactory
10-TAPS-S-024	MLR 1	1.20	Health and Safety	Satisfactory
10-TAPS-S-025	MLR 2	1.20	Health and Safety	Satisfactory
10-TAPS-S-026	GRB/PS 11	1.20	Health and Safety	COTS
10-TAPS-S-027	MLR 7	1.20	Health and Safety	COTS
10-TAPS-S-028	PS 12	1.20	Health and Safety	COTS
10-TAPS-S-029	VMT Power Vapor	1.20	Health and Safety	COTS
10-TAPS-S-030	VMT Maintenance	1.20	Health and Safety	Satisfactory
10-TAPS-S-031	VMT Materials Warehouse	1.20	Health and Safety	COTS
10-TAPS-S-032	VMT Equipment Shop	1.20	Health and Safety	Satisfactory
10-TAPS-S-033	VMT BWT	1.20	Health and Safety	COTS
10-TAPS-S-034	VMT OMS Marine	1.20	Health and Safety	COTS
10-TAPS-S-035	VMT Laboratory	1.20	Health and Safety	COTS
10-TAPS-S-036	Valdez Terminal Office	1.20	Health and Safety	Satisfactory
10-TAPS-S-037	Lower Area 19	1.20	Health and Safety	Satisfactory
10-TAPS-S-038	Upper Area 19	1.20	Health and Safety	COTS
10-TAPS-S-039	Man Camp 3	1.20	Health and Safety	COTS
10-TAPS-S-040	TCC	1.20	Health and Safety	Satisfactory
10-TAPS-S-041	SERVS	1.20	Health and Safety	COTS
10-TAPS-S-042	PS 7	1.20	Health and Safety	Satisfactory
10-TAPS-S-043	PLMP 400	1.20	Health and Safety	Satisfactory
10-TAPS-S-044	Jim River Boat Launch	1.20	Health and Safety	Satisfactory
10-TAPS-S-045	PS 4	1.20	Health and Safety	Satisfactory
10-TAPS-S-046	PLMP 172	1.20	Health and Safety	Satisfactory
10-TAPS-S-049	PS 9	1.20	Health and Safety	Satisfactory
10-TAPS-S-050	PS 7	1.20	Health and Safety	Satisfactory
10-TAPS-S-051	PS 4	1.20	Health and Safety	Satisfactory
10-TAPS-S-052	PS 1	1.20	Health and Safety	Satisfactory

SPCO/DOLWD TAPS Electrical Inspection Reports, FY10

Inspection Report #	TAPS Location and Inspection Description	Inspection Date
DO072809-1	YRB (Yukon Response Base - Old PS 6), Security Upgrades	7/28/2009
DO072809-2	PS 5, Post SR Projects	7/28/2009
DO072809-3	PLMP 246.18, Talked to Surveyor for upcoming dig	7/28/2009
DO072809-4	PLMP 238-DRA (Drag Reducing Agent) facility, Courtesy Inspection	7/28/2009
DO072909-1	PS 4, Post SR Projects	7/29/2009
DO072909-2	PS 3 F-730 Project	7/29/2009
DO073009-1	Courtesy Inspection	7/30/2009
DO081709-1	PS 8 F788 project	8/17/2009
DO081709-2	PS 8 COF card check (Electrical License)	8/17/2009
DO081809-1	GRB (Glennallen Response Base - Old PS 11), Security Upgrades	8/18/2009
DO081909-1	PS 12, Courtesy Inspection	8/19/2009
DO081909-2	Petro Star Metering, Project Z458	8/19/2009
DO081909-3	Petro Star Metering, COF card check (Electrical License)	8/19/2009
DO082009-1	PS 10, Courtesy Inspection	8/20/2009
DO082009-2	DRB (Delta Response Base - Old PS-9), Security Upgrades and Post SR	8/20/2009
DO100509-1	NPMS (North Pole Metering Station), Courtesy Inspection	10/5/2009
DO100509-2	PS 8, F788 project	10/5/2009
DO100609-1	DRB, Electrical Panels Thermal Survey	10/6/2009
DO100609-2	DRB, COF Check	10/6/2009
DO100709-1	Petro Star Metering, Project Z458 *NOV (Notice Of Violation)	10/7/2009
DO100809-1	GRB, Security Upgrade	10/8/2009
DO100809-2	GRB (PS 9), Pump Module catwalks and stairs lighting *NOV	10/8/2009
DO111709-1	PS 2, F-782 Project	11/17/2009
DO111709-2	PS 2, COF card check (Electrical License)	11/17/2009
DO111709-3	PS 3, F-734 Project	11/17/2009
DO111709-4	PS 4, SR Project	11/17/2009
DO111809-1	PS 1, Fire and gas upgrades	11/18/2009
DO111809-2	PS 1, COF card check (Electrical License)	11/18/2009
DO120809-1	DRB (PS 9), Post SR Project	12/8/2009
DO120809-2	DRB (PS 9), Electrical Substation	12/8/2009
DO120809-3	GRB, Security Upgrade	12/8/2009
DO120909-1	Petro Star Metering, Project Z458	12/9/2009
DO121009-1	PS 8, F788 project	12/10/2009
DO020910-1	YRB (Old PS 6), PLQ electrical panels	2/9/2010
DO020910-2	YRB (Old PS 6), Electrical cords *2 NOVs	2/9/2010
DO020910-3	PS 7, PLQ electrical panels	2/9/2010
DO030910-1	DRB PS 9, Security upgrades	3/9/2010

SPCO/DOLWD TAPS Electrical Inspection Reports, FY10

Inspection Report #	TAPS Location and Inspection Description	Inspection Date
DO030910-2	DRB PS 9, Pump Module catwalks and stairs light upgrade	3/9/2010
DO030910-3	GRB PS 11, Security upgrades	3/9/2010
DO031010-1	VMT, Reuse of existing Rockbestos Cable	3/10/2010
DO031110-1	NPMS, Ongoing migration of metering and control to new buildings	3/11/2010
DO042010-1	PS 1 Electrification and Automation Project	4/20/2010
DO042010-2	PS 1 New alarms in tank farm and gas refrigeration-compression restart	4/20/2010
DO042110-1	PS 2 Security System	4/21/2010
DO042110-2	PS 3 Post SR Project and security system upgrades	4/21/2010
DO042110-3	PS 3 COF card check (Electrical License)	4/21/2010
DO042110-4	PS 4 Post SR Project and security system upgrades	4/21/2010
DO050310-1	PS 8 Courtesy Inspection	5/3/2010
DO050410-1	DRB (PS 9) Security and communications upgrades	5/4/2010
DO050410-2	DRB (PS 9) Pump module's catwalks and stairs	5/4/2010
DO050410-3	PS 10 Courtesy Inspection	5/4/2010
DO050410-4	GRB Security and communications upgrades	5/4/2010
DO050510-1	VMT courtesy inspection	5/5/2010
DO050510-2	Petro Star Metering courtesy inspection	5/5/2010
DO050510-3	PS 12 courtesy inspection	5/5/2010
DO051810-1	YRB (PS 6) PLQ kitchen remodel	5/18/2010
DO051810-2	PS 5 kitchen remodel	5/18/2010
DO051810-3	PS 5 kitchen remodel project COF card check (Electrical License)	5/18/2010
DO051810-4	DRA, PLMP 238, courtesy inspection	5/18/2010
DO051910-1	PS 4 projects F522, M162, and W/Y048	5/19/2010
DO052010-1	PS 7 courtesy inspection	5/20/2010
DO060710-1	PS 8 Courtesy Inspection	6/7/2010
DO060810-1	DRB (PS 9) Security and communications upgrades	6/8/2010
DO060810-2	PS 10 Courtesy Inspection	6/8/2010
DO060810-3	GRB Security and communications upgrades	6/8/2010
DO060910-1	VMT courtesy inspection	6/9/2010
DO060910-2	PS 12 courtesy inspection	6/9/2010
DO062210-1	PS 1 Electrification and Automation Project	6/22/2010
DO062210-2	PS 1 storage area know as the Taj Mahal	6/22/2010
DO062310-1	PS 2 Courtesy Inspection	6/23/2010
DO062310-2	PS 3 Post SR Projects	6/23/2010
DO062310-3	PS 4 Post SR Projects	6/23/2010

SPCO/SFMO Fire and Life Safety Inspection Reports, by Pipeline, FY 2010

Pipeline System	Description	Inspection Date(s)	Letter Date
Alpine	Annual Inspection of Alpine Pipeline Facilities	12/8/2009	12/8/2009
Badami	Annual Inspection of Badami Facilities	11/10/2010	3/10/2010
Endicott	Annual Inspection of Endicott Facilities	11/19/2009	11/19/2009
KKPL	Annual Inspection of Kenai Kachemak Pipeline Facilities	9/14/2010	9/14/2009
Kuparuk	Annual Inspection of Kuparuk Pipeline Facilities	8/26/2009	11/10/2009
Kuparuk/ KPE	Annual Inspection of Kuparuk and KPE Facilities	11/10/2009	8/26/2009
Milne Point	Annual Inspection of Milne Point Pipelines Facilities	1/28/2010	1/28/2010
Northstar	Annual Inspection of Northstar Pipelines Facilities	12/30/2009	12/30/2009
Nuiqsut	Annual Inspection of Nuiqsut Natural Gas Pipeline Facilities	8/31/2009	8/31/2009
Oliktok	Annual Inspection of Oliktok Pipeline Facilities	4/5/2010	4/5/2010
TAPS	Notification of Fire Hazard and Order to Correct: Annual Fire and Life Safety Inspection: TAPS Fairbanks Area Facilities	4/28-30/2010	6/9/10
TAPS	Notification of Fire Hazard and Order to Correct: Annual Fire and Life Safety Inspection: TAPS GRB, PS 12, VMT, and SERVS	5/3-5/2010	6/3/2010
TAPS	Notification of Fire Hazard and Order to Correct: Annual Fire and Life Safety Inspection: TAPS PS 1	5/25/2010	6/2/10
TAPS	Notification of Fire Hazard and Order to Correct: Annual Fire and Life Safety Inspection: TAPS PS 2 - PS 7	6/22-25/2010	6/28/2010
TAPS	Annual Inspections of Fairbanks Area Facilities (10-187-AS)	4/28/2010	6/9/2010
TAPS	Annual Inspection of PS 1 Area Facilities (10-165-AS)	5/25/2010	6/2/2010
TAPS	Annual Inspection of GRB, PS 12, VMT, and SERVS (10-170-AS)	5/3/2010	6/3/2010
TAPS	Annual Inspections PS 2 to PS7 (10-229-AS)	6/22/2010	6/28/2010

Appendix H: Authorizations, Rights-of-Way, and Permits Issued by SPCO, by Quarter

First Quarter FY10: July 1, 2009 – September 30, 2009

Permit / ADL Number	Date	Description
LAS 27300	7/6/2009	LUP was issued for installing up to three riffle grade-control structures in Milky Creek located downstream of the Dalton Highway (DH) culvert and FGL crossing of the creek located at FGL MP 82 and DH MP 335.5.
ADL 418676	7/21/2009	Material Sale Contract for 10,000 cy of sandy gravel with interbedded sand lenses was issued to APSC for 28 acres. The area is identified as OMS 41-1R.
TWUP P2007-9 Amendment No. 1	7/25/2009	Emergency amendment to TWUP P2007-9 to increase the authorized amount of water from 40,000 gpd from Avalanche Diversion Pond at the VMT to a total of 400,000 gpd. Water is needed for vapor scrubbers and to cool equipment used in the X009 tank bottoms cleaning project.
ADL 63574	7/27/2009	An Off R/W Access letter was issued under Stipulation 2.9.1 to APSC to enter public land outside the permanent ROW and access road boundaries related to this project to retrieve the culvert parts on the high water drainage at Dome Creek of Access Road 63 APL/AMS-2.
ADL 230710	8/5/2009	Material Sale Contract for 9,000 cy of sandy gravel with cobbles and boulders was issued to APSC for 60 acres. The area is identified as OMS 3-1.1.
ADL 230711	8/5/2009	Material Sale Contract for 40,000 cy of sandy gravel and reject was issued to APSC for 60 acres; identified as OM S 7-1M.
ADL 418664	8/5/2009	Material Sale Contract for 10,000 cy of sandy silty gravel was issued to APSC for 13 acres. The area is identified as OMS 53-2.
ADL 418665	8/5/2009	Material Sale Contract for 2,500 cy of highly fractured; deeply weathered bedrock was issued to APSC for 26 acres. The area is identified as OMS 65-1M.
ADL 418666	8/5/2009	Material Sale Contract for 5,000 cy of gravel, sandy gravel and fractured rock was issued to APSC for 17 acres. The area is identified as OMS 66-1R.
ADL 418667	8/5/2009	Material Sale Contract for 5,000 cy of weathered bedrock was issued to APSC for 11 acres. The area is identified as OMS 71-0.
ADL 418668	8/5/2009	Material Sale Contract for 4,000 cy of gravel was issued to APSC for 5.7 acres. The area is identified as OMS 71-8.
ADL 418669	8/5/2009	Material Sale Contract for 15,000 cy of weathered, metamorphic bedrock was issued to APSC for 13 acres. The area is identified as OMS 76-2.1.
ADL 63574, PLMP 200.8	9/8/2009	Amendment of the Right-of-Way Lease for the Trans-Alaska Pipeline System, ADL 63574, Dietrich River Guidebank Extension, PLMP 200.8
LAS 27417	9/16/2009	LUP was issued supporting an oil spill response exercise in October, 2009 near PLMP 779.
LAS 27357	9/17/09	LUP was issued to occupy a previously-used laydown area for staging equipment and materials in support of the repair of TAPS vehicle bridge across the Little Salcha River near PLMP 490.8.
LAS 27370	9/17/09	LUP issued for permanently restoring fish passage and retrieving outwash gravel on a seasonal side flow channel of the Sagavanirktok River at TAPS Access Road 131 APL-1 near PLMP 40, continuing as far as 300 ft. downstream.

Second Quarter FY10: October 1, 2009 – December 31, 2009

Permit / ADL Number	Date	Description
ADL 418713	10/12/09	Executed ROW, Jim River Boat Launch to establish reliable access to the Jim River for oil spill response and oil spill training. Project will install a boat launch upstream on Jim River on a former material site.
ADL 63574	12/1/09	An Off ROW Access letter was issued under Stipulation 2.9.1 to APSC to take low impact vehicles such as, but not limited to, snow machines, four-wheelers, tucker, nodwells, and bombardiers off the TAPS ROW during the 2009/2010 winter.

Third Quarter FY10: January 1, 2010 - March 31, 2010

Permit / ADL Number	Date	Description
410562	1/25/10	Amendment issued to amend the existing ROW lease for Endicott Pipeline to add apprx. 1.18 acres, more or less, of state land. The acreage adds two areas to the existing pipeline row. The add'l acres of land are located northeast of Deadhorse, AK in the Prudhoe Bay Oil and Gas Unit near Flow Station 2. Record of Survey EPF 20080040, recorded in the Barrow Recording District as Document Number 2009-000037, Plat 2009-2 on 1/29/09.
LAS 27513	2/12/10	LUP issued to the excavating of 4 sections of buried pipe to investigate the integrity of the pipe, repair the pipe if needed, and re-coat the pipe as part of APSC's Project X510-2010 Mainline Integrity Investigations.
409027	2/18/10	Amendment issued to replace pipeline and install 18-inch diameter pipe within the existing Kuparuk Pipeline Extension Right-of-Way for approximately 4.15 miles. Recorded 3/2/10, 2010-000100-0.

Fourth Quarter FY10: April 1, 2010 - June 30, 2010

Permit / ADL Number	Date	Description
TWUP P2010-1	5/1/2010	A TWUP was issued to withdraw up to 20,000 gallons of water per day from the SW4NW4 of a Seasonal Pond at OMS 7-1M at PLMP 769.1 and the NW4NW4 of Ptarmigan Creek at PLMP 768.5 for dust control, soil compaction, sand-cement slurry, and water-filled traffic barriers in support of the Y027 Shorted Pipeline Road Casing Removal Project from PLMP 758.9 – 765.2.
ADL 415700	5/5/10	Assignment and Transfer of Right-of-Way Lease was approved. BPTA assigns, for good and valuable consideration, and subject to all rents, covenants, and conditions, all right, title, and interest to Northstar Pipeline Co., LLC and successors. (Doc No.: 1999-003566-0, 2003-000085-0 & 2008-000906-0)
ADL 415975	5/5/10	Assignment and Transfer of Right-of-Way Lease was approved. BPTA assigns, for good and valuable consideration, and subject to all rents, covenants, and conditions, all right, title, and interest to Northstar Pipeline Co., LLC and successors. (Doc No.: 1999-003566-0, 2003-000085-0 & 2008-000906-0)
TWUP P2010-2	5/19/10	TWUP was issued to withdraw 5,000 gallons per day for domestic and industrial uses from existing water well at PS 7.
TWUP P2010-3	5/19/10	TWUP was issued to withdraw 20,000 gallons per day from the NW4NW4 of the Chatanika River at PLMP 438.1 for oil spill source control training activities.
LAS 27611	5/26/10	LUP was issued for the purpose of fish passage will be reestablished by constricting a let-down structure on a rock base filled with imported gravel to prevent French draining. Within the base, a channel will be formed for fish passage including boulder clusters to provide diverse flows to dampen high velocities and small pools w/in the channel for fish resting areas.
LAS 27592	5/27/10	LUP was issued for placing two storage conexes w/in a cleared and previously mined area of OMS 74-2HR in support of activities at Oil Spill Containment Site CS 6-11A, Unnamed Creek/Hess Creek.
LAS 27593	5/27/10	LUP was issued for placing two storage conexes w/in a cleared and previously mined area of OMS 72-1 in support of activities at Oil Spill Containment Site CS 6-24, Erickson Creek.
LAS 27597	5/27/10	LUP was issued for placing two storage conexes w/in a cleared and previously mined area of OMS 76-2.1 in support of activities at Oil Spill Containment Site CS 6-4, Unnamed Creek/Isom Creek.
LAS 27605	6/4/10	LUP was issued for staging area to support the TAPS Mainline Shorted Road Crossing Casing Removal Project at PLMP 765.2 and Richardson Hwy Milepost 35.
TWUP P2010-5	6/22/10	TWUP was issued to withdraw 35,000 gallons per day from the Tatalina River at PLMP 412.5 to support the 2010 PS7 Tank 170 Inspection Project and for long term use for row and pump station pad maintenance & dust control in and around PS7 between PLMP 400 and 430.
TWUP P2010-4	6/22/10	TWUP was issued to divert 75,000 gallons per day from the north and south banks of the Tazlina River located between PLMP 686.8 and RHMP 110.6. The water will be used to support the Rivers and Flood Plains Project as well as general workpad and road maintenance activities along the TAPS row.

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Appendix I: Throughput for SPCO Jurisdictional Pipelines, 2009

Alpine Diesel Pipeline	3,679,385 gallons
Alpine Oil Pipeline	37,432,495 barrels
Alpine Utility Pipeline	46,847,380 barrels
Badami Sales Oil	Not in service
Badami Utility	Not in service
Endicott (Oil)	5,481,023 net barrels
Kenai Kachemak Pipeline (Natural Gas)	19,982 MMcf
Kuparuk Pipeline	102,109,781 barrels
Kuparuk Pipeline Extension	62,702,971 barrels
Milne Point Pipeline (Oil)	10,561,941 net barrels
Milne Point Product Pipeline (NGL)	Not in service
Nikiski Alaska (Refined Products)	11,406,712 barrels
Northstar Oil	7,981,272 net barrels
Northstar Gas	25,399,627 Mscf.
Nuiqsut Natural Gas Pipeline	106,704,228 cf
Oliktok Pipeline	6,686,650
Trans-Alaska Pipeline System (Oil)	245,290,143 bbl.

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Appendix J: Lease Required Contact Information

Pipeline	Lease Sec/Stip	Registered Agent	Lease Sec/Stip	Authorized Representative	Lease Sec/Stip	Field Representative
Alpine Pipelines	Sec. 30	Mr. William Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Sec. 30	Mr. William Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Sec. 30	David Todd / Larry Baker CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105, NSK 22 Anchorage, AK 99519-6105
Badami Pipelines	Sec. 8(j)	CT Corporation, Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Sec. 26	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Sec. 26	Bruce W. Robinson / T.J. Barnes Mail Stop END 900 E. Benson Blvd. Anchorage, AK 99508
Endicott	Sec. 4(j)	CT Corporation, Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Stip. 1.3.2	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Stip. 1.3.2	Bruce W. Robinson / T.J. Barnes Mail Stop END 900 E. Benson Blvd. Anchorage, AK 99508
KKPL	Sec. 8(j)	Ms. Jaci Stasak Marathon Pipe Line, LLC P.O. Box 2399 Kenai, AK 99611	Sec. 30	Mr. Daniel Riemer, President Kenai Kachemak Pipeline, LLC 5555 San Felipe Road Houston, TX 77056	Sec. 30	Marathon Pipe Line, LLC Attn: Ms. Pamela J. Locke Kenai Area Manager P.O Box 2399 Kenai, AK 99611
Kuparuk and Kuparuk Extension	Sec. 4(j)	Mr. William Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Stip. 1.3.2	Mr. William Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Stip. 1.3.2	David Todd / Larry Baker CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105, NSK 22 Anchorage, AK 99519-6105
Milne Point Pipelines	Sec. 4(j)	CT Corporation, Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Stip. 1.3.2 Sec. 30	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Stip. 1.3.2 Sec. 30	Jeff Michels / Kenton Schoch Mail Stop MPU 900 E. Benson Blvd. Anchorage, AK 99508

Pipeline	Lease Sec/Stip	Registered Agent	Lease Sec/Stip	Authorized Representative	Lease Sec/Stip	Field Representative
Nikiski Alaska Pipeline	Sec. 11	Tesoro Alaska Pipeline Co. Attn: Shawn Brown Manager Pipeline & Terminals P.O. Box 3369 Kenai, AK 99611	Stip. 1.4.2			Tesoro Alaska Pipeline Co Attn: Shawn Brown Manager Pipelines & Terminals P.O. Box 3369 Kenai, AK 99611
Northstar Pipelines	Sec. 8(j)	CT Corporation Re: BPTA Suite 202 9360 Glacier Highway Juneau, AK 99801	Sec. 30	Mr. Don Turner Vice President, BPTA, Inc. P.O. Box 190848 Anchorage, AK 99519-0848	Sec. 30	Wayne Kuykendall / Gary Herring Mail Stop Northstar 900 E. Benson Blvd. Anchorage, AK 99508
Nuiqsut Natural Gas Pipeline	Sec. 8(j)	Mr. Marvin Olson Director, Department of Public Works North Slope Borough PO Box 350 Barrow, AK 99723	Sec. 30	Mayor Edward Itta North Slope Borough PO Box 69 Barrow, Alaska 99732	Sec. 30	Mr. Marvin Olson Director, Dept. of Public Works North Slope Borough PO Box 350 Barrow, Alaska 99723
Oliktok Pipeline	Sec. 4(j)	Mr. William Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Stip. 1.3.2	Mr. William Sargent Engineering & Operations Manager Alpine Transportation Company P.O. Box 100360 ATO 908 Anchorage, AK 99510-0360	Stip. 1.3.2	David Todd / Larry Baker CPF-3 Operations Superintendent ConocoPhillips Alaska, Inc. P.O. Box 196105, NSK 22 Anchorage, AK 99519-6105
TAPS	Sec. 12	Alyeska Pipeline Service Company Attn: Mr. Kevin Hostler, President P.O. Box 196660 Anchorage, AK 99519-6660	Stip. 1.5.3	Mr. Joseph Robertson JPO/DOT Liaison Director, APSC P.O. Box 196660, MS 502 Anchorage, AK 99519-6660	N/A	N/A

Appendix K: Strategic Reconfiguration Related Shutdowns of TAPS

[*Note that the calendar range begins before the fiscal year covered by this report*.]

Table 28: PS 3 Unscheduled Slowdowns/Shutdowns Related to SR Installed Equipment*

Date	Stop (H:M)	Start (H:M)	Duration (H:M)	Cause(s)
5-Jan-08	0:42	0:45	0:03	MLU1 and MLU3 shutdown during pig passage.
6-Jan-08	16:51	17:00	0:09	TG trip during testing of TG2.
1-Mar-08	2:40	3:03	0:23	Loss of Station Control Panel permissives during pig passage.
26-Mar-08	18:02	18:30	0:28	Frequency control on TG1
29-Mar-08	13:48	13:54	0:06	Under frequency load shed
29-Mar-08	18:39	19:58	1:19	Under frequency load shed
6-May-08	14:02	14:53	0:51	MLU reverse rotation indication. MLU went to idle.
22-May-08	18:47	19:44	0:57	TG1 tripped. High lube oil temp.
22-May-08	7:37	8:10	0:33	TG2 tripped. Local I/O error in ControlNet.
30-May-08	7:57	8:31	0:34	TG1 Control Net I/O card failure
6-Jun-08	15:43	16:00	0:17	Accidental ESD trip. Loose connection to ESD button
22-Jun-08	1:18	2:59	1:41	TG1 tripped. Cause unknown.
24-Jun-08	15:00	15:08	0:08	TG1 and TG2 tripped under frequency load shed
27-Jun-08	9:03	9:25	0:22	Pilot Gas Valve Position Indicator
9-Jul-08	4:31	4:40	0:09	MLU2 trip on low lube oil in accumulator tank.
9-Jul-08	12:19	13:06	0:47	TG2 tripped on high fluid level in wash tank
10-Jul-08	15:45	17:17	1:32	TG1 trip. Cause unknown.
13-Aug-08	14:16	14:39	0:23	Turbine Generator tripped. No cause or specific generator provided.
20-Aug-08	12:55	13:50	0:55	TG1 and TG2 tripped while running parallel. Cause unknown.
20-Aug-08	15:01	15:25	0:24	TG1 and TG2 tripped 2nd time while running parallel. Cause unknown.
11-Sep-08	14:29	15:07	0:38	MLU2 S/D on False High Sump Alarm & ATT Radio Comm trip
23-Sep-08	5:02	8:03	3:01	TG1 trip. Cause unknown.
17-Sep-08	14:24	14:32	0:08	MLU1 Shut Down on Low Oil Pressure
23-Sep-08	5:02	8:03	3:01	MLU1 Shut Down Because of Air Compressor Problem
20-Oct-08	7:42	8:53	1:11	Sequence of Failures Starting w/ MLU1 Hi Winding Temp
2-Nov-08	12:32	13:00	0:28	TG1 primary generator tripped off-line. All MLUs S/D
17-Nov-08	13:37	13:43	0:06	Valve opening sequence problem initiated MLU shutdown.
9-Dec-08	5:57	6:45	0:48	TG2 tripped. Suspected voltage control problem.
14-Dec-08	21:18	21:42	0:24	TG1 tripped. Cause: high lube oil pressure.
15-Dec-08	6:40	7:03	0:23	TG2 tripped. Cause: high lube oil pressure.
15-Dec-08	18:30	19:00	0:30	TG1 trip caused by low ventilation air flow.
28-Feb-09	15:11	16:12	1:01	Maintenance on inverter caused accidental trip

Table 28: PS 3 Unscheduled Slowdowns/Shutdowns Related to SR Installed Equipment*

Date	Stop (H:M)	Start (H:M)	Duration (H:M)	Cause(s)
28-Feb-09	19:32	19:56	0:24	Maintenance inadvertently closed fuel valve to TG2
7-Mar-09	14:45	14:51	0:06	Uncommanded shutdown S1 signal. Source unknown.
11-Apr-09	17:14	17:54	0:40	False Hi-Level signal on sump at PS3 pump.
18-Apr-09	17:20	18:01	0:41	TG2 shutdown because of interruption in fuel gas supply.
19-Apr-09	18:52	18:53	0:01	TG1&TG2 in parallel. Transients caused TG2 to also trip.
24-May-09	14:04	14:31	0:27	TG-2 tripped. Unknown reason. TG-1 used for restart.
12-Jun-09	7:21	7:28	0:07	MLU run permissive lost during network troubleshooting.
17-Jun-09	14:16	15:03	0:47	Valves S1, S2 and D1 began transit. Running MLU stopped.
18-Jun-09	9:35	10:35	1:00	TG-2 tripped. No stated reason on incident report.
15-Jul-09	9:03	9:30	0:27	TG2 shutdown. No stated reason on incident report.
9-Aug-09	17:32	18:09	0:37	TG1 shutdown. No stated reason on incident report.
18-Aug-09	13:28	14:27	0:59	Breaker feed on TG2 opened.
20-Aug-09	7:27	7:45	0:18	MLU3 S/D on load shed.
31-Aug-09	1:56	2:26	0:30	TG1 auto shutdown initiated. Cause unknown.
25-Sep-09	11:50	12:27	0:37	TG1 tripped. Cause unknown.
26-Sep-09	20:49	21:21	0:32	TG1 tripped. Cause unknown.
9-Oct-09	6:18	8:41	2:23	Breakers 1-52-7 & 2-52-8 tripped, causing TG2 to trip.
11-Oct-09	16:21	18:41	2:20	Breaker 2-52-8 tripped, causing MLU 2 & 3 to go offline.
12-Oct-09	20:05	20:22	0:17	VFD fault caused MLU 1 trip &TG2 trip. Low spinning reserve.
19-Oct-09	6:13	6:41	0:28	Primary enclosure vent fan trip caused TG2 trip.
20-Oct-09	2:27	2:57	0:30	Primary enclosure vent fan trip caused TG2 trip.
5-Dec-09	20:14	1:46	5:32	TG2 tripped. Cause not established.
11-Jan-10	15:08	17:56	2:48	TG2 tripped on high diff pressure in the fuel gas system.
13-Jan-10	13:43	14:38	0:55	TG2 tripped. Cause not established. TG1 was offline.
14-Jan-10	8:38	9:35	0:57	PS3 pressure transmitter problem idled North End.
15-Jan-10	12:52	13:00	0:08	Undervoltage caused TG2 trip during load sharing with TG1.
19-Jan-10	20:23	20:28	0:05	MLU2 shut down. Cause not given.
20-Jan-10	14:32	14:37	0:05	MLU1 auto load shed. Possibly cause: TG2 maintenance.
23-Jan-10	11:31	12:12	0:41	TG2 tripped, causing black plant. Cause not established.
4-Mar-10	14:24	15:03	0:39	TG2 tripped upon loading MLU3. Cause unknown.
26-Apr-10	14:18	15:12	0:54	TG1 tripped on fuel gas valve position error.
30-Apr-10	7:57	8:18	0:21	TG1 tripped. Cause unknown.
8-May-10	8:15	14:29	6:14	SIPPS failure. Comm failure with Turin network. Production lost.
8-Jun-10	4:09	4:23	0.01	TG2 Trip. Cause unknown.

** January 1, 2008 to the Last Data Date (Not Including CY08 Quarter 1 Cold Temp Modifications)*

Table 29: PS 4 Unscheduled Slowdowns/Shutdowns Related to SR Installed Equipment*

Date	Stop (H:M)	Start (H:M)	Duration (H:M)	Cause(s)
6-Jun-09	13:19	14:15	0:56	PS4 PLC Primary and Secondary PLCs Stopped
12-Jun-09	19:02	19:39	0:37	False High High Sump Level Signal in Manifold Bldg
15-Jul-09	8:00	8:23	0:23	Turbine Reset Probably Caused Communications Failure
22-Jul-09	9:36	10:17	0:41	Switchgear tripped open. Power loss to MLU1 and MLU3.
8-Oct-09	17:46	18:17	0:31	Wind restricted cooling air flow to lube oil, resulting in TG2 hi-temp shutdown.
22-Nov-09	23:49	0:12	0:23	TG1 auto shut down. Cause unknown.
3-Dec-09	13:49	15:17	1:28	SPC PLC switched to PROGRAM. Cause unknown. MLUs lost run permissives.
2-Mar-10	16:42	19:19	2:37	Loss of instrument air caused TG2 shutdown.
27-Mar-10	12:53	13:38	0:45	TG1 trip on low enclosure ventilation rate. Fan shut down after a Power Controller (PCP) reset.
6-Apr-10	9:45	10:30	0:45	Manifold building sump high level shutdown initiated a station isolate command.
3-May-10	16:05	16:21	0:16	PS4 shutdown during fire PMs.
5-May-10	1:23	2:30	1:07	TG1 tripped. Cause unknown.
31-May-10	13:32	14:06	0:34	TG1 trip on loss of aux power. Breaker opened when trying to reset a PCP Remote I/O rack fault.
14-Jul-10	6:11	6:37	0:26	TG2 trip caused a black plant. Cause unknown.
3-Aug-10	3:33	3:50	0:17	TG2 tripped. Cause unknown.

** May 21, 2009 to Last Data Date*