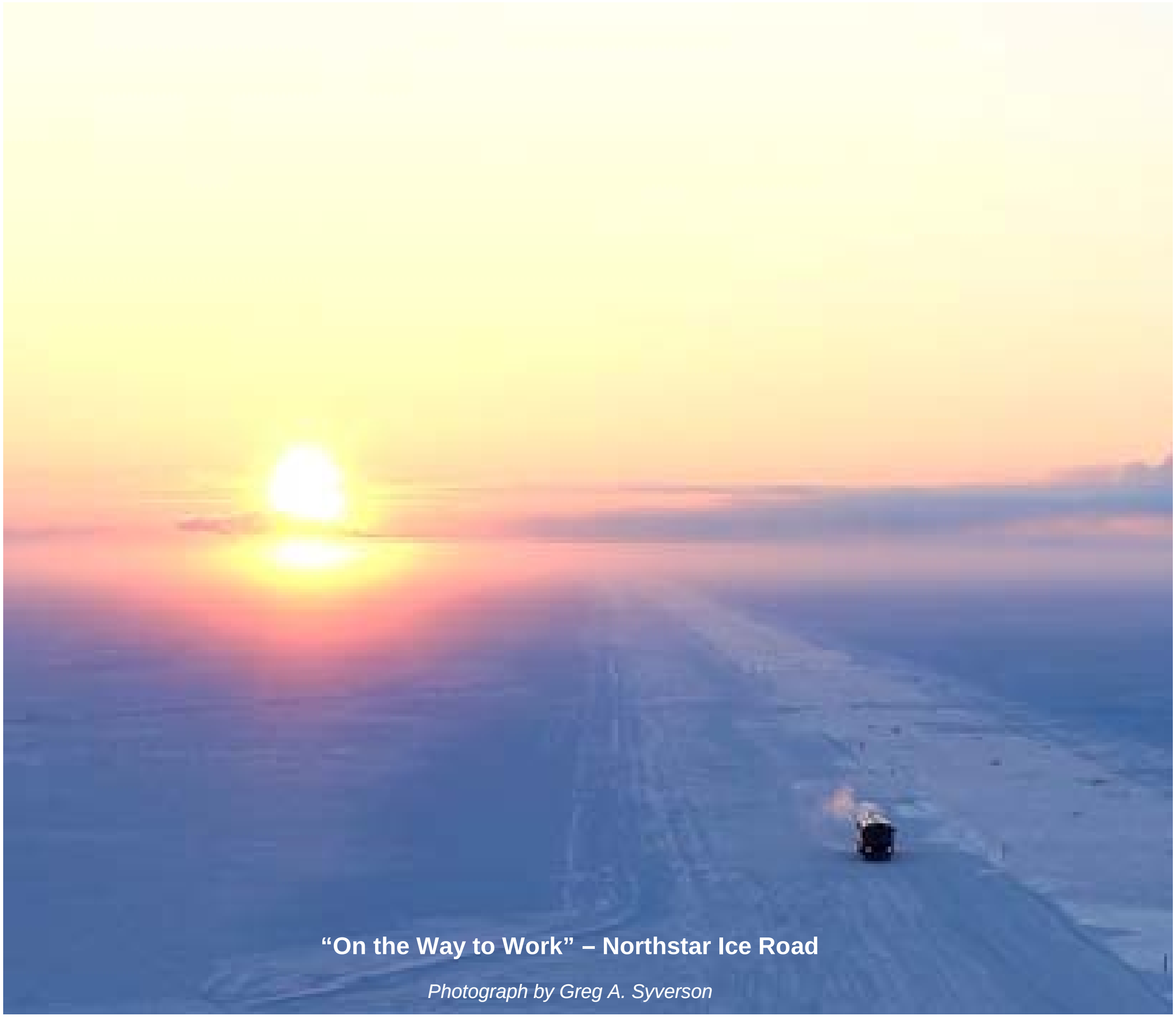
2013

Annual ADNR Surveillance and Monitoring Report



"On the Way to Work" – Northstar Ice Road

Photograph by Greg A. Syverson

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ACRONYMS

AC	alternating current
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADL	Alaska Division of Land
ADNR	Alaska Department of Natural Resources
AOC	Abnormal Operating Condition
ANSI/ASME	American National Standard Institute/American Society of Mechanical Engineers
ASRC	Arctic Slope Regional Corporation
ATP	Authority to Proceed
BEST	Behavior Enhanced Safety Techniques
BPTA	BP Transportation (Alaska) Inc.
BPXA	BP Exploration (Alaska) Inc.
BS&W	Bottom Sediment & Water
CCP	Central Compressor Plant
CFP	Central Facility Pad
CFR	Code of Federal Regulations
CGF	Central Gas Facility
CIC	Corrosion, Inspection, and Chemical Group
CIP	Comprehensive Integrity Program
COTU	Crude Oil Topping Unit
CoW	Control of Work
CP	Cathodic Protection
CPAI	ConocoPhillips Alaska, Inc.
CRM	Corrosion Rate Monitoring
CSP	Corrosion Strategy and Planning
CTM	Compliance Task Manager
CUI	Corrosion Under Insulation
DAFW	Days Away From Work
DCS	Digital Control System
DOT	Department of Transportation
EOC	Eastern Offtake Center
EPC	Endicott Pipeline Company
ER	Electrical Resistance
ESDV	Emergency Shutdown Valve
F	Fahrenheit
FCO	Functional Check Out
FIP	Frequent Inspection Program
FLIR	Forward Looking Infrared
FRA	Formal Risk Assessment
FS	Flow Station
G&I	Grind and Inject
GIS	Geographic Information System

GPB	Greater Prudhoe Bay
HMI	Human Machine Interface
HSE	Health, Safety, and Environment
HSM	Horizontal Support Member
HV	Hand Valve
ILI	In-line Inspection
IMP	Integrity Management Program
IMU	Inertial Measurement Unit
LEOS	Leck Erkennungs und Ortungs System (Translation: Leak Detection and Location System)
MFL	Magnetic Flux Leakage
MISTRAS	MISTRAS Group, Inc.
MPU	Milne Point Unit
mpy	milli-inches per year
Mscf	thousand standard cubic feet
NACE	NACE® International Corrosion Society
NGL	Natural Gas Liquid
NOA	Notice of Amendment
NOPV	Notice of Probable Violation
NOV	Notice of Violation
NRC	National Response Center
NTSB	National Transportation Safety Board
Nutaaq	Nutaaq Pipeline, LLC
OASIS	OASIS Environmental, Inc.
ODPCP	Oil Discharge Prevention and Contingency Plan
OMER	Operation, Maintenance, and Emergency Response
OMS	Operating Management System
OQ	Operator Qualification
ORCA	Observing Risks, Changes, and Attitudes
PBOC	Prudhoe Bay Operations Center
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Pipeline Inspection Protection Enforcement and Safety
PLC	Programmable Logic Controller
PMG	Pipeline Management Group
PS	Pump Station
psig	pounds/square inch [gauge]
RCA	Regulatory Commission of Alaska
ROW	Right-of-Way
RTU	Remote Terminal Unit
Savant	Savant Alaska, LLC
SCADA	Supervisory Control and Data Acquisition
SDV	Shutdown Valve
SOC	Safety Observations and Conversations
SORA	Safety and Operational Risk Assessment

S&OR	Safety & Operational Risk
SPCO	State Pipeline Coordinator's Office
SSPC-VIS	Society for Protective Coatings (formerly Steel Structures Painting Council) – Visual depictions
STOP	Safety Training Observation Program
SWI/AL	Salt Water Injection/Artificial Lift
TAPS	Trans Alaska Pipeline System
UPS	Uninterruptible Power Supply
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
VSM	Vertical Support Member
VTA	Virtual Training Assistant
WLC	Weight Loss Coupons
WSS	Walking Speed Survey

SPCO'S REQUEST

In accordance with an SPCO information request (SPCO letter Nos. 99-164-GS and 99-165-GS) and the SPCO Lease Compliance Monitoring Report Fiscal Year 2013, this report contains the following information.

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, Quality Assurance Program, 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.

EXECUTIVE SUMMARY

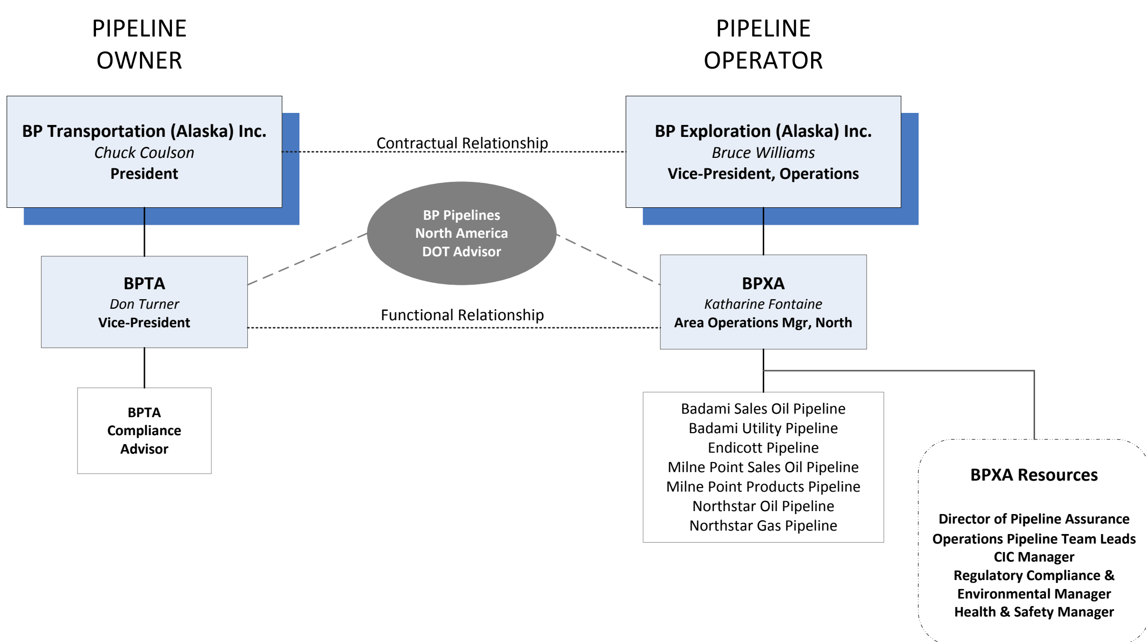
The submittal of this annual report to the SPCO meets the requirements of the ADNR ROW leases. The ROWs leased to BPTA, or its subsidiaries and affiliates are:

- Badami Sales Oil Pipeline ROW Lease (ADL 415472)[1]
- Badami Utility Pipeline ROW Lease (ADL 415965)[1]
- Endicott Pipeline ROW Lease (ADL 410562)
- Milne Point Pipeline ROW Lease (ADL 410221)
- Milne Point Products Pipeline ROW Lease (ADL 416172)
- Northstar Oil Pipeline ROW Lease (ADL 415700)
- Northstar Gas Pipeline ROW Lease (ADL 415975)

BPTA owns wholly or in part the pipeline systems located on the State of Alaska ROWs. The pipelines located within these ROWs are collectively referred to as “BPTA Pipelines.”

BPTA contracts BPXA to operate the BPTA Pipelines. The organization chart below in Figure 1 outlines the contractual and functional relationships between BPTA and BPXA. It also shows the role of BP Pipelines (North America) Inc. This report describes BPTA’s and its agents’ compliance with the terms of the ROW leases.

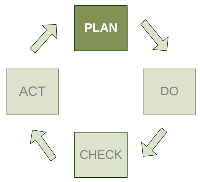
Figure 1 - Organization Chart



[1] The Badami Pipelines were conveyed to Nutaaq effective February 1, 2014. BPTA owned and BPXA operated the Badami pipelines throughout calendar year 2013. The portions of this 2013 that speak to 2014 plans refer to the conveyance to Nutaaq.

During the 2013 FRA, the BPTA Pipelines were determined to be fit for continued operation by the BPXA Director of Pipeline Assurance in accordance with CRT-AK-43-49, “Criteria for Pipeline Integrity Management System” and the BP Integrity Management Standards.

“PLAN” – ACTIVITIES AND RISK MANAGEMENT



The “PLAN” portion of the management cycle involves recognizing the scope of work and providing risk management. The primary activity in the State ROWs is the operation and maintenance of the crude oil and gas pipelines. This section provides an overview of the ROWs and pipelines and then describes the programs in place to manage the work in a safe and environmentally sound manner.

PIPELINE OVERVIEWS

Although the seven pipelines each have their own lease, the overviews and descriptions are grouped by the associated facility. The pipelines’ schematics and equipment tag numbers are shown in Appendix A.

Badami Pipelines

The Badami Sales Oil Pipeline and Badami Utility Pipeline are wholly owned by BPTA. The Badami Sales Oil Pipeline is a 12-inch diameter pipeline that runs approximately 25 miles and delivers crude oil from the Badami Central Production Facility to the Endicott Pipeline.

Aerial Photo – Badami Sales Oil Pipeline

The Badami Utility Pipeline is a 6-inch diameter pipeline that runs approximately 31 miles. The Utility Pipeline delivers fuel gas from the Endicott field to the Badami field. Both pipelines are aboveground except for crossings at the Shaviovik, Kadleroshilik, and Sagavanirktok Rivers.

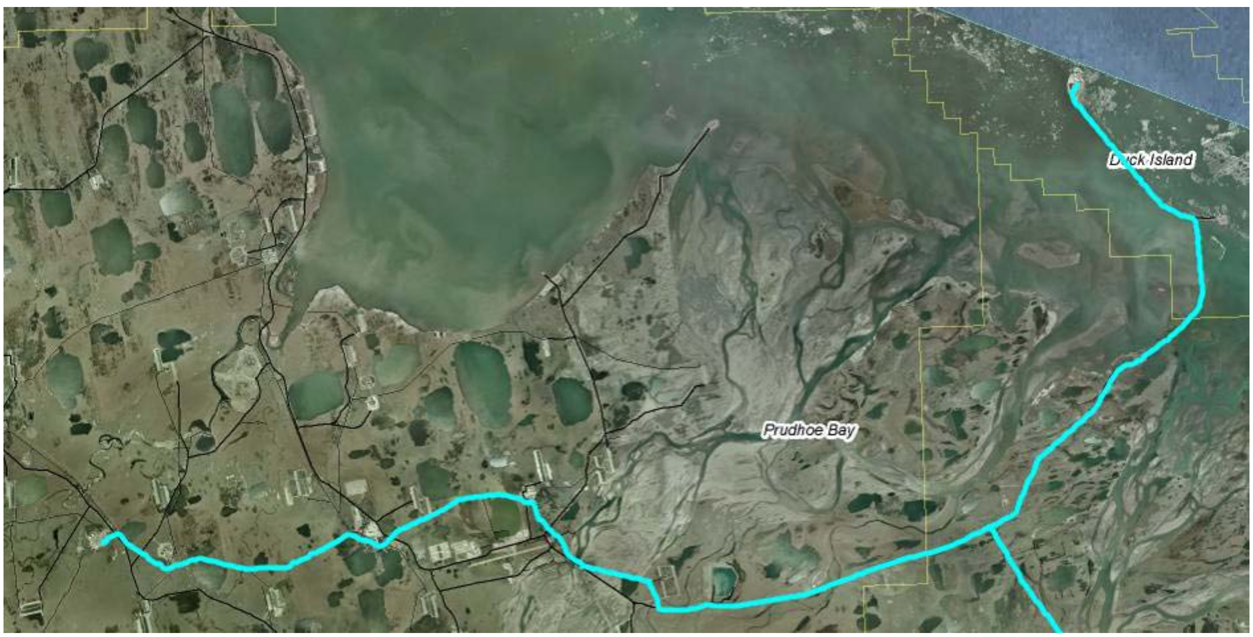
Badami production began in August of 1998. When the conditions became technically challenging, BPTA put the field in warm shutdown to allow the reservoir to recharge. It was restarted in 2005, but production was temporarily discontinued in 2007 to again allow for recharge. In 2008, BPTA entered into a farm-out agreement with Savant and its local partner, ASRC. The pipeline was restarted November 5, 2010. In 2011, the ADNR approved Savant as the new operator of the Badami plant and associated surface facilities. The Badami Pipelines remain under BPXA operations until the ADNR approves the transfer of the ROWs and the RCA approves the transfer of the certificate of public convenience and necessity. There were no significant changes to the Badami Pipelines during 2013.

Aerial Photos – Badami Utility Pipeline

Endicott Pipeline

The Endicott Pipeline is a 16-inch diameter pipeline that runs aboveground for approximately 26 miles and is owned by the EPC, a general partnership. BPTA is the Managing Partner of EPC. This oil pipeline transports crude oil from Endicott's Module 303 to TAPS PS 1. There is a pig receiver and metering facility at PS 1.

The Badami tie-in is approximately at the midpoint of the Endicott Pipeline and the Badami pig receiver is located at this point. Installation of Endicott oil heater tubes on the Northstar heater was completed in August of 2013, to enable delivery of 105°F crude oil to TAPS, throughout the year.



Aerial Photo – Endicott Sales Oil Pipeline

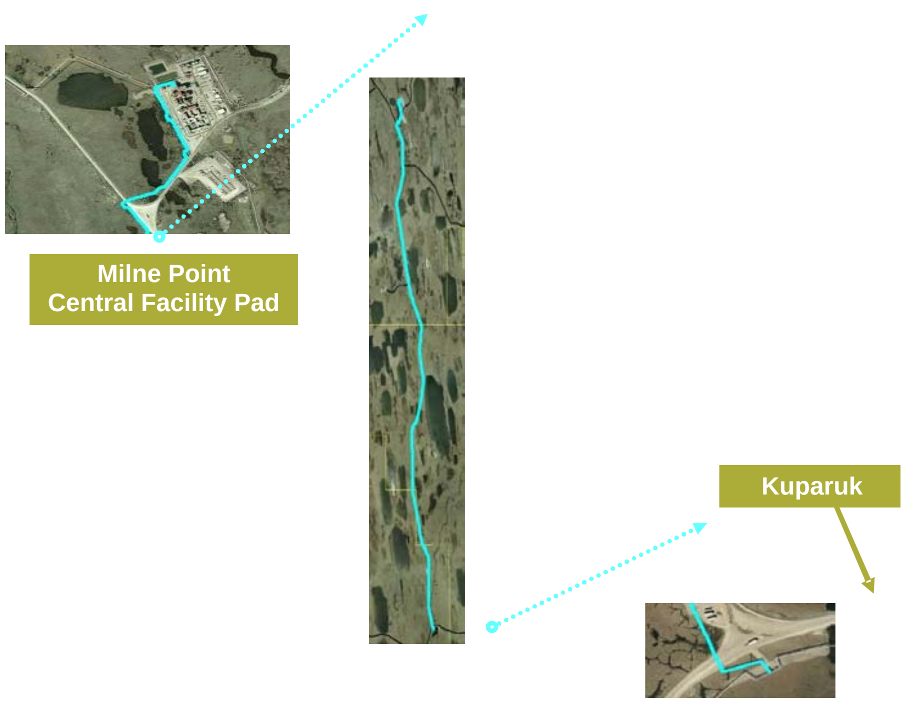
Milne Point Pipelines

Milne Point Pipelines, LLC owns the Milne Point Pipeline and the Milne Point Products Pipeline. Milne Point Pipelines, LLC is wholly owned by BPTA, and BPTA is the Managing Member of the LLC.

The Milne Point Pipeline is a 14-inch diameter pipeline that runs aboveground for approximately 10 miles. It transports crude oil from Milne Point Unit's CFP Module 58 to the Kuparuk Pipeline System at Module 68. Module 58 houses a sampling system, a custody transfer metering system, a mainline pump, and a pig launcher. Module 68 contains a pig receiver and turbine meters that support leak detection. Piping downstream of the pig receiver to the Kuparuk tie-in is duplex stainless steel.

The Milne Point Products Pipeline is an aboveground, eight-inch diameter pipeline that was designed to transport natural gas liquids from a tie-in point on the Oliktok Pipeline to Milne Point Unit's CFP. The Milne Point Products Pipeline was idled and put into warm shutdown during December 2002. In December 2006, the SPCO authorized the temporary discontinuance of service of this pipeline. The Products Pipeline was purged, physically disconnected from the Oliktok Pipeline, and taken out-of-service.

Both the Milne Point Pipeline and the Milne Point Products Pipeline are situated on the same VSMs. There were no significant changes to the Milne Point Pipelines' facilities or operations during 2013.



Aerial Photos – Milne Pipelines

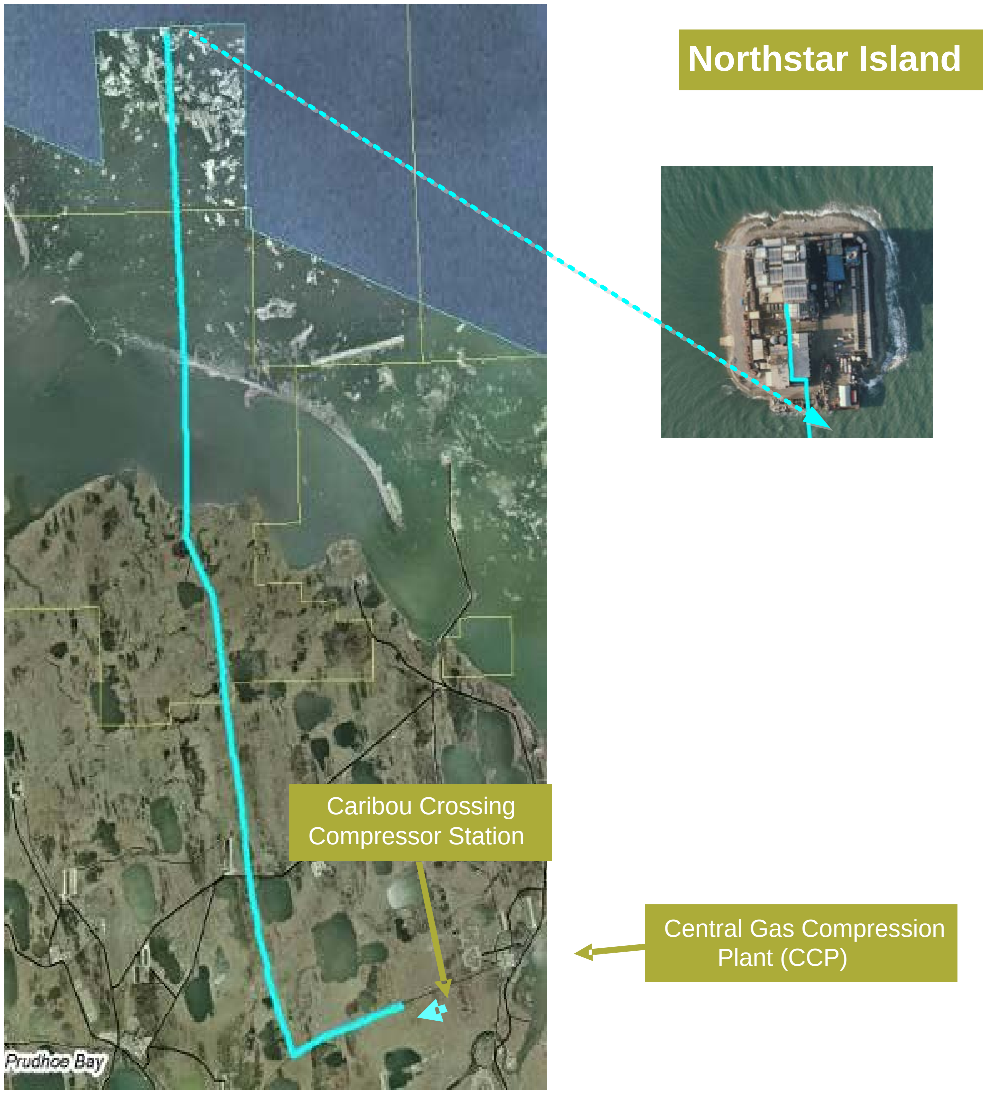
Northstar Pipelines

The Northstar Oil Pipeline is a 10-inch diameter pipeline that runs approximately 17 miles. It originates at the Northstar Production facility located approximately six miles offshore on Northstar Island in the Beaufort Sea and terminates at Pump Station 1. The tie-in facilities at Pump Station 1 include a pig receiver, a crude oil heater, and custody transfer meters.

The Northstar Gas Pipeline is a 10-inch diameter, high-pressure pipeline that runs approximately 16 miles. The Northstar Gas Pipeline originates at the Prudhoe Bay CCP and terminates at Northstar Island. The pipeline resides in a Class 1 Location per 49 CFR 192.5.

Both pipelines are bundled together for approximately six miles in a common offshore trench and occupy the same VSMs for approximately six miles from the shore transition point to a point where the Northstar Gas Pipeline turns east to the CCP and the Northstar Oil Pipeline continues to PS 1. The Northstar shore crossing RTU valve separates the overland portion of the Northstar Oil Pipeline from the offshore portion. The tube bundle of the Northstar heater was modified in August of 2013, to include heating tubes for Endicott oil.

Aerial Photos – Northstar Oil Pipeline



Aerial Photos – Northstar Gas Pipeline

ROW STATUS

Badami Pipelines

The Badami Sales Oil Pipeline and the Badami Utility Pipeline run within their leases' operation and maintenance boundaries. Both leases were executed on December 15, 1997 and expire on December 14, 2022. In April of 2013, BPTA requested the ADNR Commissioner to transfer the lease ownership of both the Badami Sales Oil Pipeline and Badami Utility Pipeline to Nutaaq. This transfer occurred effective February 1, 2014. The pipelines' transfer to Nutaaq will not change the use of the ROWs.

Endicott Pipeline

The Endicott Pipeline operates within the lease's operation and maintenance boundary. In January 2010, a lease amendment became effective that added 1.18 acres to the ROW. The original ROW lease was effective August 5, 1986 and expires May 2, 2034.

Milne Point Pipelines

The Milne Point Pipeline operates within the lease's operation and maintenance boundary. This pipeline lease was executed January 15, 1985 and expires May 2, 2034. The Milne Point Products Pipeline is within the lease's operation and maintenance boundary. The lease was executed December 5, 2000 and expires on December 4, 2030.

Northstar Pipelines

The Northstar Oil Pipeline and the Northstar Gas Pipeline operate within their leases' operation and maintenance boundaries. The leases were effective as of December 15, 1997 and expire on December 14, 2022. The next lease rental appraisals for both Northstar Pipelines are due October 1, 2014.

RISK MANAGEMENT PROGRAMS

Multiple Programs collectively serve to address and manage HSE and pipeline integrity risks. These Programs include the DOT IMP FRAs, the DOT OQ Program, the DOT Public Awareness/Damage Prevention Program, BPXA's Corrosion Programs, Quality Assurance Program/OMS, BPXA's Personal Safety Program, and the ADEC-approved ODPCPs. These Programs align work practices and give consistent directions to employees and contractors who work on both DOT jurisdictional and non-jurisdictional assets.

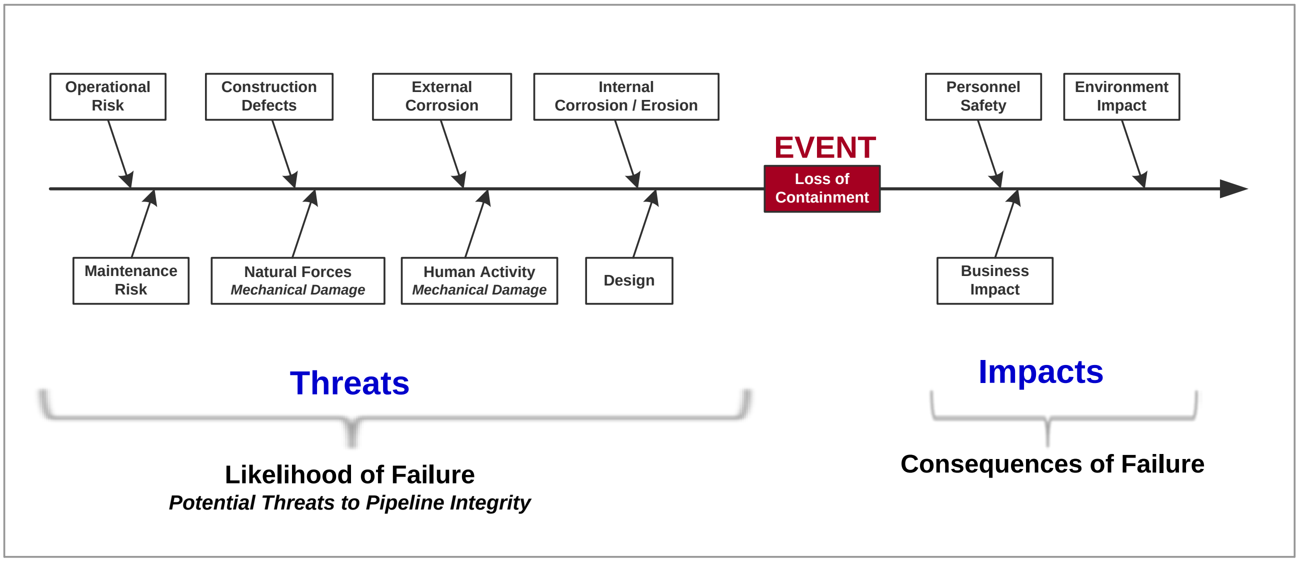
DOT IMP

In accordance with BPXA's DOT Pipeline IMP, FRAs are conducted periodically for each DOT-regulated oil pipeline that meets the requirements of 49 CFR 195.452. The FRA process identifies pipeline integrity risks and then evaluates and manages those risks.

The FRA process and the IMP program are regularly audited by DOT and no findings have been identified in the past several audits.

The annual FRA was held on December 11, 2013. The FRA reviewed information collected from Operations, CIC, and the Pipeline Slope Team. Pipeline Integrity Risk is the combination of the "Likelihood of Failure" caused by a specific threat and the resulting "Consequence of Failure" of a specific event, such as a loss of containment. The risk assessment process reviewed potential pipeline threats, the effectiveness of the "Preventive Measures" (barriers), and opportunities to strengthen those barriers. The effectiveness of the "Mitigative Measures" (barriers to limit the impact of a loss of containment) and opportunities to strengthen those barriers were assessed. Figure 2 depicts the threat categories and the consequence types reviewed during the FRA.

Figure 2 - Threats and Impacts



In general, the key integrity management related programs (inspections, operations, maintenance, and testing) are functioning as expected. The next annual FRA is tentatively set for December 2014.

DOT OQ Program

In accordance with Subpart G of 49 CFR 195 and Subpart N of 49 CFR 192, the BPXA OQ Program is designed to ensure individuals working on BPXA DOT-regulated facilities are qualified to perform specific covered tasks and to reduce the probability and consequences of incidents/accidents.

This Program ensures that personnel have the necessary knowledge, skills, and ability to perform covered tasks and are able to recognize and respond appropriately to abnormal operations. OQ records of BPXA employees are retained within VTA, BPXA's Learning Management Database. Contractors who perform "covered tasks" on DOT

Pipelines are required to post their OQ training in ISNetworld, which is a secure, Internet-based records repository and reporting database.

DOT Public Awareness/Damage Prevention Program

BPXA complies with the DOT Public Awareness/Damage Prevention Program outlined in 49 CFR 195.440. This Program targets the affected public, excavators, emergency officials, and public officials and provides meaningful information about the pipelines' operations and products.

The Program was designed to establish long-standing and mutually beneficial relationships with those who live or work near DOT-regulated pipelines. This Program is continually evaluated and refined to ensure that the information meets the needs of stakeholder audiences.

The following are this Program's objectives:

- Increase public awareness and understanding of pipeline operations,
- Identify the affected public, general businesses, excavators, emergency officials, and public officials,
- Determine the public outreach messages, methods, and frequency, and
- Measure and evaluate the Program.

The Public Awareness/Damage Prevention Program includes mailed brochures, agency facility tours, North Slope Training Cooperative training, BP employee training, and HSE Fairs.

Arctic Swans

DOT Drug and Alcohol Program

BPXA complies with the DOT Drug and Alcohol Program established in 49 CFR 199. The "BPXA Drug and Alcohol Policy Statement" and the "BPXA DOT PHMSA Drug Testing and Alcohol Misuse Prevention Procedure" are designed to eliminate substance use and abuse in the workplace and preserve a safe, healthful and productive work environment for employees.

DOT Control Room Management Rule

The Control Room Management Rule under PHMSA became fully enforceable on August 1, 2012 per 49 CFR 195.446 and 192.631. This rule was established in response to the 2006 PIPES Act and a 2005 NTSB Study. The Act and Study identified the need of sustainable risk mitigation measures among DOT operators in addressing controller human factors that, if left unchecked, could adversely impact the remote operation and monitoring of pipelines.

Resulting from the issuance of the rule, BPXA has reaffirmed through policy and procedures that for North Area facilities, the DOT Controller under the rule is that of the EOC, located at the PBOC base camp of GPB. The EOC Pipeline controller is a qualified individual who remotely monitors and controls the safety-related operation of a pipeline system via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline system outside the facility boundary. Although the respective North Area board room operators are not under the Rule, they are responsible for ensuring the EOC is adequately informed of facility and situational statuses that impact the DOT jurisdictional pipelines. The North Area board operators adhere to and administer EOC directives.

BPXA underwent a four-day PHMSA audit in October 2012 that was solely focused on this Rule. As an outcome of the audit, there were no NOVs, NOPVs, or NOAs identified by the PHMSA auditor.

BPXA's Corrosion Management Programs

This section provides an overview of BPXA's corrosion management programs. A summary of the 2013 results for the DOT pipelines on the ROWs is in the "CHECK – 2013 OVERSIGHT" section of this report.

The corrosion management programs incorporate a number of processes and procedures including:

- Identification of corrosion threats and determination of susceptibility,
- Inspection and monitoring to assess corrosivity, potential changes, the necessary level of control, and appropriate mitigation activity,
- Mitigation (including design and materials selection) to provide a level of corrosion control over a particular system,
- Operational requirements that can affect a system's integrity level,
- The effect of changes, both short- and long-term (creeping change), that can significantly alter the equipment's life cycle, and
- Periodic tactical, strategic, and peer reviews as a means of conveying experiences and lessons learned.

The Anchorage CSP Team is responsible for development of strategic programs, establishment of performance targets, tracking performance, and regulatory reporting related to chemical inhibition, corrosion monitoring, and equipment inspection. Part of CSP's function is to provide an independent evaluation of the operating organization's activities and identify organizational constraints that may interfere with corrosion management.

The North Slope CIC Team is responsible for executing the various corrosion management programs and interfaces daily with operations in order to accomplish work activities. The team is staffed with certified inspection personnel, production chemists, pigging operators, and technical/administrative personnel.

CMP

The Corrosion Monitoring Program consists of ER probes and WLCs which provide a measure of the corrosivity of transported fluids and the effectiveness of the chemical injection mitigation process. Both WLCs and ER probes are considered leading indicators of corrosion activity. ER readings are collected by a remote data collector and provide a short term (days to weeks) view into the system's corrosivity. WLCs are installed and removed at prescribed intervals and provide a medium term (i.e. months) view into the system's corrosivity. Coupons are field graded and then sent to a laboratory for analysis.

The WLC program at BPXA is consistent with NACE International Standard Practice RP0775 "Standard Recommended Practice - Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations" and industry best practices. General guidelines for the use of WLCs in corrosion monitoring are also provided in BPXA CRT-AK-06-70, "Criteria for Corrosion Monitoring."

CIP

This is an annual inspection program that is aimed at detecting new corrosion mechanisms and new corrosion locations, as well as monitoring damage at known locations. The CIP provides an assessment of the extent of degradation and the fitness-for-service. All equipment is covered by the CIP, although not all equipment is inspected annually.

CRM

The CRM is an inspection program established to supplement corrosion monitoring data and evaluate the effectiveness of corrosion mitigation programs. Since it is inspection-based, it is a lagging indicator, meaning corrosion will have had to occur for confirmation of corrosion activity.

As the primary aim is to determine corrosion activity (initiation and rate), this program consists of a fixed scope at fixed inspection intervals. For a typical cross-country pipeline, the CRM program includes a representative sampling of locations deemed susceptible to corrosion (e.g., elbows, girth welds, long seam welds, and bottom of line sections) distributed along the length of the pipeline**.**

FIP

This inspection program monitors mechanical integrity at locations where significant corrosion damage is detected. Locations are added to the FIP if they are approaching repair, derate criteria, or unusually high corrosion or erosion rates are detected. Inspections are performed frequently until the item meets criteria for repair, replacement, derate, taken out of service, or until corrosion rates are reduced to an acceptable level. The inspection intervals vary, depending on how close the location is to the repair/derate threshold, but do not exceed one year. Currently, this program is not necessary for Badami, Northstar, Endicott, and Milne Point DOT pipelines.

ILI Program

ILI tools or intelligent/instrumented pigs are utilized to assess, record, and report mechanical damage and internal and external metal loss anomalies. MFL tools are the most common technology used by BPXA. The ILI program provides feedback to Corrosion Engineers on the condition of the equipment and the effectiveness of mitigation programs. ILI data may also help determine when corrosivity or corrosion mechanisms are changing based on comparison with historical data.

MFL ILI Tool

Below Grade Piping Program

The Below Grade Piping Program employs the best inspection technology available for below grade piping segments where the main threat is external corrosion. Types of below grade piping include: 1) cased piping, 2) direct buried piping, 3) piping in vaults, and 4) piping in utiliways. Excavation of below grade piping may be performed if visual/instrument inspections and/or ILI runs are not feasible. Exposure also allows mitigation of active corrosion and assures the piping is fit-for-service and safe to operate.

CUI Program

The purpose of the CUI Program is to monitor and control external corrosion on insulated piping that is susceptible to moisture ingress. Inspection activities evaluate the condition of piping and insulation, fitness for service, and mechanical integrity under prevailing operating conditions. Insulated pipe locations are examined at established recurring frequencies.

Cathodic Protection Program

Northstar's offshore and Badami's river crossing segments have buried/submerged pipelines that do not have thermal insulation. External corrosion is mitigated through external coatings and supplemented by galvanic anode CP systems. The post-mounted CP test stations are inspected annually to ensure proper operation and effectiveness.

Pipe-to-soil potential measurements are performed in accordance with BP GP 06-36, “Guidance on Practice for Cathodic Protection-Maintenance and Monitoring.” Pipe-to-soil measurements are performed on both sides of the road and water crossings where the pipeline is buried/submerged and at isolation flanges.

Isolation flanges on the Milne Point Pipeline are inspected and tested to ensure electrical isolation between the stainless steel segment and the carbon steel segments. The flanges were installed to assure corrosion control in accordance with DOT requirements, but do not affect cathodic protection systems. They are located on a short section of aboveground pipe near the tie-in point at the Kuparuk Oil Sales pipeline.

Atmospheric Corrosion Monitoring

Atmospheric Corrosion Monitoring addresses bare or un-insulated aboveground piping which is exposed to the atmosphere. This piping is visually inspected in accordance with DOT requirements.

If the pipeline is located onshore, the inspection frequency is at least once every three calendar years, but with intervals not exceeding 39 months. If the pipeline is located offshore, the inspection frequency is at least once each calendar year, but with intervals not exceeding 15 months.

BPXA uses a pass/fail grading system to monitor and assess atmospheric corrosion. Atmospheric corrosion protection is assessed as either adequate or inadequate. Adequate atmospheric corrosion protection is defined as:

- Coated pipe has the approved coating system intact with visible evidence of rusting occurring on no more than 10% of the exposed surface (Visual comparison of an acceptable coating condition is given by degree of rusting Rust Grade 4 or greater under SSPC VIS-2), or
- Non-coated pipe has corrosion present consisting of a light surface oxide that will not affect safe operation prior to the next inspection.

Quality Assurance Program

On May 8, 2013 (SPCO Letter No. 13-157-AS), BPTA’s updated Quality Assurance Manual was approved by the SPCO. The Quality Assurance Program is based on BP’s OMS. The OMS ensures commitments are met and documented through planned and systematic actions, providing evidence that ROW lease stipulations and DOT requirements are satisfied. The comprehensive program establishes continuity and consistency across the seven BPTA ROW leases. For the past decade, BPXA has maintained external certification of its environmental management system through annual audits by Det Norske Veritas, an ISO 14001 Registered Firm. Environmental risks are identified during the OMS Gap Assessments and managed through the various Annual Operating Plans.

BPXA's Personal Safety Program

The CoW Group-defined Practice is a cornerstone to BPXA's Personal Safety Program. CoW provides a means of safely controlling construction, maintenance, demolition, remediation, operating tasks, and similar work activities carried out by the workforce at BPXA premises. This practice emphasizes accountabilities, training, competence, planning and scheduling, task-based risk assessments, and a Permit to Work process.

Shared Services Aircraft

Permits to Work are for Breaking Containment, Confined Space Entry, Energized Electrical Work, Ground Disturbance, Hot Work, Lifting Operations, and Unit Work. These permits add structure to work authorization, increase communication, monitor work, and ensure completion and close-out. Other elements of CoW are auditing, lessons learned, and stopping unsafe work. The intent of the Stop Work element is to halt unsafe work at the earliest stage possible by making every member of the workforce responsible for accident prevention.

Internal Safety Program

At the large facilities, employees formally monitor each other's safety with behavior-based techniques. The employees have taken ownership of the program and given them site-specific names: Endicott - ORCA, Milne Point - BEST, and Northstar - STOP programs. The facilities' statistics in Table 1 demonstrate these programs are well-established.

Table 1 - Behavior-Based Observations

	Behavior-Based Observations		
Year	Badami/Endicott's ORCA	Milne Point's BEST	Northstar's STOP
2011	1,510	1,138	1,008
2012	872	1,256	841
2013	356	813	303

Managers and supervisors formally monitor employee safety through SOCs. The SOC focus is personal impact and intelligently addressing risk. This Program is also intended to increase visibility of process safety hazards and risk mitigation. SOCs are tracked by location in Tr@ction, the BP worldwide-computerized tracking system. The SOC statistics listed below in Table 2 represent the observations completed at each facility.

Table 2 - Management's SOCs

	Management's SOCs		
Year	**Badami/Endicott**	**Milne Point**	**Northstar**
2011	# SOCs - 179 # SOC Lites - 1,402	# SOCs - 739 # SOC Lites - 1,006	# SOCs - 927 # SOC Lites - 192
2012	# SOCs - 389 # SOC Lites - 1,012	# SOCs - 890 # SOC Lites - 770	# SOCs - 133 # SOC Lites - 388
2013	#SOCs - 366 #SOC Lites - 905	#SOCs - 946 #SOC Lites - 663	#SOCs - 76 #SOC Lites - 555

The effectiveness of BPXA's Personal Safety Program is demonstrated by the ROWs' safety statistics shown in Table 3. These ROW statistics cover both BPXA and contractor work.

Table 3 - ROW Safety Records

	Badami/Endicott ROW		Milne ROWs		Northstar ROWs	
Year	**DAFW**	**Recordables**	**DAFW**	**Recordables**	**DAFW**	**Recordables**
2011	None	None	None	None	None	None
2012	None	None	None	None	None	None
2013	None	None	None	None	None	None

<u>Contractor Safety Oversight</u>

Contractor safety is managed by BPXA's Internal Safety Program. The contractors actively participate in the site's behavior-based program and are observed by BPXA supervisors through the SOCs. See the Internal Safety Programs section above for these statistics. Contractor work is covered by BP's CoW Group-Defined Practice. Contractors are required to conform to the CoW requirements.

For non-routine work, two other controls are in place, the ATP and Task Hazard Analyses.

The ATP process ensures adequate controls are in place prior to construction, project, or major maintenance work. As applicable, the ATP is signed off by the BPXA Operations Supervisor, BPXA HSE Representative, Contract Project Lead, Project Manager, and Job Supervisor.

Task Hazard Analyses are routinely conducted to gather information for employee protection prior to start of work. The scope of work is analyzed and the means and methods to protect employees and the environment are determined. The Task Hazard Analyses Database serves as a repository for frequent tasks.

The primary contractors working on BPTA's ROWs and the service they provide are summarized in Table 4.

Table 4 - Primary ROW Contractors

Primary ROW Contractors	Service Provided
Acuren	Corrosion Inspection
AES Alaska Inc	Maintenance Activities
Alaska Clean Seas	Spill Response and Cleanup
Alaska Frontier Constructors	Ice Road Construction
Alutiiq Oilfield Services	Coating
ASRC	Milne Point Roads and Pads
ASRC Energy Services	Labor for Operations & Maintenance – Endicott, Badami, and Milne Point
Bay Valve Services & Engineering	Valve PM/Maintenance
BJ Services	Endicott Equipment Inspections
CCI Industrial Services	CUI & Anchor Chop/Asbestos Abatement
Century Inspection, Inc.	NDE Work on Northstar/Endicott Heater Project
CH2M Hill	Engineering, Construction, Campaign Maintenance, Valve Inspections
Coastal Frontiers	Coastal Remediation
Conam	Construction
Conoco Phillips	Pilots/Aerial surveillance
Crowley All Terrain Corporation	Badami Tundra Travel
Cruz Construction / Peak Construction	Badami Ice Road Construction
ERA Helicopters	Transportation
F. Robert Bell and Associates	Surveying
Mears Group	Cathodic Protection
Mistras Group	Corrosion Monitoring and Inspection (WSSs)
NANA/Purcell Services	Security
PND Engineers	Endicott Bridge Inspection
TD Williams	Stopples: Northstar/Endicott Heater Project
Udelhoven Oilfield System Services / Savant	Project Management, Functional Check Out and Quality Assurance

ADEC-Approved ODPCPs

Spill Drill – Booming a River

BPXA maintains comprehensive ADEC-approved ODPCPs. The scenario-driven plans are based on rigorous response planning standards. They describe preventive measures and the strategies that would be employed to respond to an oil spill along the pipeline ROW. Through ADEC's plan approval process, the State of Alaska evaluates BPXA's controls to assure environmental protection. The North Slope ODPCPs were also approved by the DOT Office of Public Safety on December 17, 2008 as meeting the requirements for Facility Response Plans under the Oil Pollution Act of 1990.

COMPLIANCE MANAGEMENT TOOLS

CTM

The CTM is a software tool used to monitor and report on routine regulatory compliance tasks. Regulatory compliance requirements, responsible parties, and operational controls are identified and documented. The database provides a systematic approach for ensuring operational compliance with applicable laws, regulations, and ROW lease requirements.

Field Handbooks

The following standardized field handbooks help ensure regulatory compliance on the North Slope.

- The 2010 Alaska Safety Handbook is a set of uniform safety procedures for application across BPXA's leases and ROWs. This handbook identifies and manages risk by incorporating the CoW standard and other processes and procedures.
- The 2011 North Slope Environmental Field Handbook provides a general overview of environmental regulations applicable to North Slope oil fields. This tool summarizes procedures developed by BPXA and CPAI to comply with the environmental regulations.
- The Alaska Waste Disposal and Reuse Guide is a joint BPXA and CPAI environmental guide that provides a single set of "best" waste management practices for employees and contractors. Revision 9 of this guide was published in February 2013.

Communications

The pipelines are monitored by personnel twenty-four hours a day, seven days a week. BPXA, as operator on behalf of BPTA, has redundant communication systems that provide for the transmission of information needed for safe operation of the pipeline systems. Day-to-day communication is conducted through normal phone traffic, vehicle and hand-held radio equipment, and cell phones. This equipment is compatible with Alaska Clean Seas and Anchorage BPXA communication equipment. Repeaters are installed across the North Slope providing coverage from Alpine to Badami. Badami satellite phones provide an alternative means of communication following any upset of their communication systems.

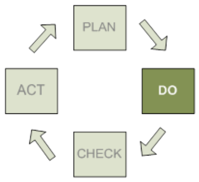
Emergency communication systems are outlined in each facility's ODPCP. These plans are reviewed by the ADEC to ensure there is a means of communicating with fire, police, and other appropriate public officials during emergency conditions and natural disasters. The North Slope communication systems enable two-way vocal communication systems between control centers and the scene of abnormal operations and emergencies.

The Harmony Radios used by BPXA facilities provide field-wide connectivity and a consolidated communication platform for BPXA-operated areas on the North Slope, fire, police, and other emergency responders. These various communication systems are used in BPXA's day-to-day operations and by the first responders during emergency response and weekly training.

GIS System

BPXA's Atlas Enterprise GIS provides user friendly access to aerial photography, maps, and geographically-referenced information. The GIS provides coverage for the BP-operated assets and facilities on the North Slope. The extensive content, mapping layers, and features are available both in Anchorage and the North Slope via the BPXA intranet and they are widely utilized by a number of functional groups within the organization. This system has proved to be a valuable analytical and communication tool.

“DO” – 2013 FIELD ACTIVITIES



The “DO” portion of the management cycle involves construction, operations, maintenance, and project activities. This section describes the day-to-day activities of operation and maintenance as well as the projects that had impact on the ROW.

CONSTRUCTION / PROJECTS

Badami

BPTA issued three Letters of Non-Objection for third-party activities within the Badami ROWs.

- On January 24, 2013, a Letter of Non-Objection was issued to PTE Pipeline LLC for construction of the Point Thomson Export Pipeline in overlapping rights-of-way in the Badami Unit. BPTA listed 10 conditions for the activities associated with construction.
- On September 3, 2013, a Letter of Non-Objection was issued to BPXA for a portion of the 2013 Archaeological Field Study that would take place in the Badami ROWs. BPTA listed eight conditions for this study.
- On September 12, 2013, a Letter of Non-Objection was issued to Exxon Mobil Development Company for ice road construction that crosses the Badami Pipeline ROWs. BPTA issued 10 conditions for this activity.

Endicott

BPTA issued five Letters of Non-Objection for third-party activities within the Endicott ROW.

- On January 15, 2013, a Letter of Non-Objection was issued to BPXA for repairs on the FS-2 SIP/IMF2 and ALGASTL pipelines. BPTA listed three conditions for the portion of the work in the Endicott ROW.
- On January 15, 2013, a Letter of Non-Objection was issued to BPXA for VSM work between Drill Site 9 and Flow Station 2 that was to occur in the Endicott ROW. BPTA listed seven conditions.
- On June 24, 2013, a Letter of Non-Objection was issued to BPXA for road repairs from FS1 to FS2 and FS1 to DS6. BPTA listed eight conditions for this work.
- On September 3, 2013, a Letter of Non-Objection was issued to BPXA for a portion of the 2013 Archaeological Field Study that would take place in the Endicott ROW. BPTA listed eight conditions for this study.

- On September 19, 2013, a Letter of Non-Objection was issued to Exxon Mobil Development Company for ice road construction that crosses the Endicott Pipeline ROW. BPTA issued 10 conditions for this activity.

Milne Point

BPTA issued five Letters of Non-Objection for third-party activities within the Milne Point ROWs.

- On January 16, 2013, a Letter of Non-Objection was issued to BPXA for the portion of work in the ROW during the Produced Water Injection Pipeline replacement from CFP to MPU C Pad. BPTA listed seven conditions for the replacement project.
- On February 7, 2013, a Letter of Non-Objection was issued to CPAI for the installation, operation, and maintenance of a pipeline fiber optic cable within the ROWs. BPTA listed 7 conditions for the gravel expansion.
- On April 26, 2013, a Letter of Non-Objection was issued to BPXA for the placement of gravel within the pipeline ROWs. The purpose was to increase the size of the intersection at Milne Point Road and the access road to MPU S Pad to allow vehicle egress from S Pad during rig moves. BPTA listed 10 conditions for the fiber optic cable installation.
- On July 18, 2013, a Letter of Non-Objection was issued to CPAI for the East Creek culvert battery replacement at the Milne Point Access Road associated with setting up spill containment and equipment staging areas. BPTA listed 10 conditions for this project.
- On November 8, 2013, a Letter of Non-Objection was issued to BPXA for the nitrogen line extension on the CFP. BPTA listed seven conditions for the extension project.

Northstar

During 2013, BPTA did not issue any Letters of Non-Objection for third-party activities within the Northstar ROWs.

OPERATIONS

Badami

The number of crude oil barrels transported in the Badami Sales Oil Pipeline during 2013 was:

457,504	Gross Barrels, and
456,508	Net Barrels (without water and sediment).

The amount of gas transported in the Badami Utility Pipeline during 2013 was 89,722 Mscf.

Endicott

The number of crude oil barrels transported in the Endicott Pipeline during 2013 was:

3,066,433	Gross Barrels, and
3,065,481	Net Barrels (without water and sediment).

Milne Point

The number of crude oil barrels transported in the Milne Point Pipeline to the Kuparuk Pipeline during 2013 was:

6,831,957	Gross Barrels, and
6,814,722	Net Barrels (without water and sediment).

No Natural Gas Liquids were transported in the Milne Point Products Pipeline during 2013.

Northstar

The number of crude oil barrels transported in the Northstar Oil Pipeline during 2013 was:

3,389,436	Gross Barrels, and
3,389,396	Net Barrels (without water and sediment).

The amount of gas transported in the Northstar Gas Pipeline during 2013 was 7,659,326 Mscf.

MAINTENANCE

Each facility has a computerized maintenance management system that identifies recurring preventive maintenance tasks and manages non-routine work. The maintenance schedules are designed to meet DOT required inspections, such as valve maintenance and maintenance pigging. Work orders and status reports are generated by Maintenance Team Leaders and/or Planners.

DOT Equipment Requirements

Pipeline schematics are shown in Appendix A. The schematics are a graphic representation of DOT components and indicate the equipment-specific tag numbers. The DOT equipment and their general locations are listed in Tables 5 through 10 below. The BPXA equipment tag numbers provide traceability in each field's computerized maintenance management system, accountability, and continuity during field inspections. Maintenance activities may be performed under ongoing campaign and/or addressed by local maintenance personnel.

Regulatory preventive maintenance frequencies are referenced in the BPXA DOT OMER Tier 2 Manuals and listed by equipment tag number in the facility-specific OMER Tier 4 Manuals. PHMSA frequently audits to ensure procedures and inspections are properly performed.

Entrance to Northstar Ice Road

BPXA DOT jurisdictional pipeline equipment identified in the tables below was maintained and inspected on schedule during 2013. In addition to DOT-required maintenance, cleaning pigs were run based on the crude stream BS&W and other operational factors.

Table 5 - Badami Sales Oil Pipeline

Tag No.	Description	Location Details
HV-1299	Pig Launcher Inlet	Badami - launcher
HV-1301	Pig Launcher Outlet Isolation	Badami - launcher
HV-1305	Launcher By-pass Valve	launcher by-pass
ESDV-1305	Remote Operated Emergency Shutdown Valve	At Badami, downstream of Pig Launcher
ESDV-1317	Emergency Shutdown Valve	On east side of No-Name River
HV-1319	12" Manual Block Valve	On west side of No-Name River
HV-1321	12" Manual Block Valve	On east side of Shaviovik River
HV-1323	12" Manual Block Valve	On west side of Shaviovik River
HV-1325	12" Manual Block Valve	On east side of Kadleroshilik River
HV-1327	12" Manual Block Valve	On west side of Kadleroshilik River
ESDV-1331	Remote Operated Emergency Shutdown Valve	On east side of Sagavanirktok River
HV-1333	12" Manual Block Valve	On west side of Sagavanirktok River
HV-1337	Pig Receiver Inlet Isolation	At inlet of Pig Receiver
HV-1335	Lateral to Endicott Tie-in	Endicott Tie-in
HV-1341	Pig Receiver Outlet By-pass	Endicott Tie-in
HV-1343	Receiver Lateral Return Line	Endicott Tie-in
ESDV-1339	Remote Operated Emergency Shutdown Valve	Endicott Tie-in

Table 6 - Badami Utility Pipeline

Tag No.	Description	Location Details
HV-1350	2" temporary Endicott tie-in	Endicott MI tie-in
HV-1352	Future tie-in block valve (blind flanged)	Endicott MI tie-in
HV-1348	Manual block valve	Adjacent to Endicott HV 5006
HV-1340	Manual block valve	West side of Sagavanirktok River
HV-1338	Manual block valve	East side of Sagavanirktok River
HV-1336	Manual block valve	West side of Kadleroshilik River
HV-1332	Manual block valve	East side of Kadleroshilik River
HV-1330	Manual block valve	West side of Shaviovik River
HV-1322	Manual block valve	East side of Shaviovik River
HV-1320	Manual block valve	West side of No Name River
HV-1310	Manual block valve	East side of No Name River
ESDV-1308	Remotely Operated Emergency Shutdown Valve	Badami
HV-1302	Bypass valve to Badami	Badami
HV-1306	Pig Receiver Inlet isolation	Badami
HV-1304	Pig Receiver return line valve	Badami

Table 7 - Endicott Pipeline

Tag No.	Description	Location Details
HV-E3-1392*	Pig launcher kicker actuated valve	Endicott
HV-E3-1393	Lateral to Sales actuated valve	Endicott
HV-E3-1391 *	Pig launcher outlet isolation valve	Endicott
HV-E9-5006	16" Manual Block Valve	Causeway Breach South
HV-E9-5007	16" Manual Block Valve	Causeway Breach South
HV-E9-5001	16" Manual Block Valve	Across Beaufort Shoreline
HV-E9-5008	8" Manual Gate Valve	Badami/Endicott Tie-In
HV-E9-5002	16" Block Valve	East side of Sagavanirktok River
HV-E9-5003	16" Block Valve	West side of Sagavanirktok River
HV-E9-5004	16" Manual Block Valve	APS PS1 Battery Limits
HV-E9-5005	Pig receiver inlet isolation valve	APS PS1 Battery Limits
HV-E9-5054	Crude heater inlet block valve	Crude Heater at PS1
HV-E9-5060	Crude heater outlet block valve	Crude Heater at PS1
PSV-1165	Crude heater inlet pressure safety valve	END Pipeline PSV U/S of crude heater
HV-E9-1397 *	Pig receiver bypass (506CF-8")	APS PS1 Battery Limits
HV-E9-1396 *	Pig receiver bypass lateral (506CF-8")	APS PS1 Battery Limits
PSH-E9-1395 **	Pipeline Pressure Switch (High)	PS #1 Pig Receiver Skid 409
PSHH-E9-1393	Pipeline Pressure Switch (High High)	PS #1 Pig Receiver Skid 409
*CC 5176	Corrosion Coupon	Between Endicott Island and the “T”.
*CC 5178	Corrosion Coupon	Between Badami Tie-in / Sagavanirktok River
*CC 5180	Corrosion Coupon	Near PS1

Table 8 - Milne Point Pipeline

Tag No.	Description	Location Details
PSV-5869A *	Shipping pump overpressure relief valves	CPF module 58
PSV-5869B *	Shipping pump overpressure relief valves	CPF module 58
HCV-5804	Lateral to Sales manual valve	CPF module 58
HCV-5810 *	Pig launcher kicker manual valve	CPF module 58
HCV-5805 *	Pig launcher outlet isolation valve	CPF module 58
XV-5814	Shutdown Valve	CPF module 58
HCV-6801	Pig receiver inlet isolation valve	Module 68
HCV-6802	Manual block valve	Upstream of Module 68
HCV-6807 *	Pig receiver bypass isolation valve	Module 68
XV-6850	Shutdown Valve	At Kuparuk tie-in
PSHH-5886*	Shipping pump discharge high-high shutdown	CPF Module 58
NE6801	Corrosion Coupon	Module 68
NE5807	Corrosion Coupon and Corrosion Probe	CPF Module 58

Table 9 - Northstar Oil Pipeline

Tag No.	Description	Location Details
PSHH-1130 A	Shipping pump high pressure shut down @ 1200 psig	Northstar
PSHH-1130 B	Shipping pump high pressure shut down @ 1200 psig	Northstar
HV-1140F	6” Pig launcher kicker manual valve	Northstar
HV-1140C	10” Lateral to Sales manual valve	Northstar
HV-1140B	10” Pig launcher outlet isolation valve	Northstar
HV-1140A	10” Manual block valve	Northstar
HV-1140D	10” SDV isolation valve	Northstar
HV-1140H	1” thermal relief isolation valve	Northstar
PSV-1140	1” Pig launcher thermal relief valve set @ 1480 psig	Northstar
SDV-1130	10” Remote operated shutdown valve	Northstar
SDV-0011	10” Remote operated shutdown valve	Pt. Storkersen
HV-0012A	10” Manual block valve	West side of Putuligayuk river
HV-0012B	10” Manual block valve	East side of Putuligayuk river
HV-9221A	10” Pig receiver bypass lateral	TAPS PS1
HV-9221B	10” Manual block valve	TAPS PS1
HV-9221C	10” Pig receiver inlet isolation valve	TAPS PS1
HV-9221G	6” Pig receiver bypass	TAPS PS1
HV-9221H	1” thermal relief isolation valve	TAPS PS1
PSV-9221	1” Pig launcher thermal relief set @ 1480 psig	TAPS PS1
PSV-9231	1” Pressure safety valve set @ 1332 psig	TAPS PS1
SDV-9221	10” Remote operated shutdown valve	TAPS PS1
CP 9212	Corrosion Coupon	TAPS PS1
CP1144	Corrosion Coupon	Northstar

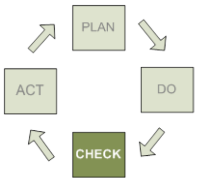
Table 10 – Northstar Gas Pipeline

Tag No.	Description	Location Details
HV-9405G	4" Pig launcher kicker manual valve	Caribou Crossing
HV-9405A	10" Lateral to Sales manual valve	Caribou Crossing
HV-9405C	10" Pig launcher outlet isolation valve	Caribou Crossing
HV-9405B	10" Manual block valve	Caribou Crossing
HV-9405E	1" Thermal relief isolation valve	Caribou Crossing
PSV-9405	1" x 1" Pig launcher thermal relief valve set @ 1350 psig	Caribou Crossing
SDV-0001	10" Remote operated shutdown valve	Pt Storkersen
HV-2500A	10" Manual block valve	Northstar
HV-2500B	10" Manual block valve	Northstar
HV-2500C	6" Fuel gas lateral manual block valve	Northstar
HV-2500L	2" Fuel gas SDV bypass manual block valve	Northstar
SDV-2500	10" Remote operated shutdown valve	Northstar
HV-2500D	10" Pig receiver bypass lateral	Northstar
HV-2500E	10" Manual block valve	Northstar
HV-2500F	10" Pig inlet isolation valve	Northstar
HV-2500H	6" Pig receiver bypass	Northstar
HV-2500J	1" Thermal relief isolation valve	Northstar
PSV-2500	1" x 1" Pig receiver thermal relief valve set @ 1350 psig	Northstar

LEASE TERMINATIONS

During 2013, the seven BPTA ROW leases were maintained in force.

"CHECK" – 2013 OVERSIGHT



The "CHECK" portion of the management cycle involves monitoring and measurement of critical components of the ROWs and related pipelines. A summary of events, issues, and incidents is included in this section.

The state ROW leases require the development and submittal of a Surveillance and Monitoring Program to detect and abate situations that may endanger health, safety, environment, or the integrity of a pipeline. The ADNR Commissioner approved the current Program on April 15, 2009.

SURVEILLANCE

General Information

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 Surveillance and Monitoring Program states, "The scope of the Program is to prevent, detect, and abate situations that may endanger public health and safety, environment or pipeline integrity and public or private property damage." This is accomplished, in part, through DOT-required inspections and ground surveys, called Walking Speed Surveys. Appendix B outlines the specific components of the SPCO-approved Surveillance and Monitoring Program.

Pedicularis Kanei

<u>DOT-required Inspections</u>

49 CFR 195.412(a) requires the surface conditions on or adjacent to each hazardous liquid pipeline ROW to be inspected at intervals not exceeding three weeks, but at least 26 times each calendar year. 49 CFR 192.703 requires a patrol program for natural gas pipeline ROWs to observe surface conditions on and adjacent to the ROW for indications of leaks, construction activity, and other factors affecting the safety and operation of the pipeline.

Endicott and Milne Point meet the DOT requirements with visual drive-by inspections, Badami utilizes visual aerial inspections, and Northstar utilizes both driving and aerial inspections. On the North Slope, natural gas pipelines typically share ROWs with hazardous liquid pipelines. Those pipelines that share ROWs are inspected at the same time.

Shared Services Aviation conducts the aerial inspections. Facility Security conducts the drive-by inspections. Occasionally the overflights include FLIR observations. Table 11 summarizes the 2013 DOT inspections.

Table 11 - DOT Pipeline Inspection Methods

Pipeline(s)	Inspection Method	Inspection Group	# of 2013 Inspections
Badami Pipelines	Aerial	Shared Services Aviation	41
Endicott Pipeline	Driving	Security	46
Milne Point Pipelines	Driving	Security	42
Northstar Pipelines	Aerial and Driving	Shared Services Aviation and/or Security	53

Walking Speed Surveys

WSSs consist of a visual examination of process equipment and system components to identify mechanical integrity deficiencies. Anomalies are noted and evaluated for appropriate action. The WSSs are conducted by MISTRAS on behalf of CIC's Operations Integrity Support. These inspections are completed utilizing track vehicles and walking the pipeline ROWs.

Tuned Vibration Absorber

These surveys are focused on, but are not limited to piping and insulation, structural components, electrical equipment, instrumentation equipment, communication equipment, chemical injection tubing, pipeline road and animal crossings. Additionally, each of the below-grade cased crossings is visually inspected to ensure that debris and water are not accumulating in the casing and immersing the pipeline. Snow-covered pipeline segments are re-inspected during other seasons.

The annual and cumulative changes associated with WSSs are summarized in Appendix C. Anomalies identified during these inspections are addressed through the facilities' work order systems. Depending on the specific issue and facility, action items may be addressed by creating new work orders or by using existing/standing work orders.

Badami Surveillance Results

Shared Services Aviation conducted 41 aerial visual inspections in 2013. These inspections fulfilled DOT inspection and patrol requirements. Thirty-five of these overflights included FLIR assessments. No ROW or pipeline issues were identified during the Badami DOT inspections.

The Badami Sales Oil Pipeline WSS was conducted between March 13 and 20, 2013. The scope of this Phase I survey was from the Badami Pad to the Endicott tie-in at RTU3. Areas which were inaccessible and snow-covered during March were re-inspected during the July 2013 Phase II survey. No significant problems of immediate concern were observed in these inspections. A summary of the results is in Appendix C.

The Badami Utility Pipeline Phase I WSS was conducted between March 9 and 20, 2013. The areas inspected were from the Endicott Causeway Tie-in to RTU3 and on to the Badami Gas Receiver. The snow-covered sections were re-inspected during the Phase II WSS during July 2013 Phase II survey. No significant problems of immediate concern were observed in these inspections. A summary of the results is in Appendix C.

Endicott Surveillance Results

During 2013, 46 routine drive-by inspections of the Endicott Pipeline were conducted in compliance with DOT requirements. The minor issues observed during the Endicott DOT surveillances were evaluated and repairs were completed as necessary.

The 2013 Endicott Pipeline WSS was conducted in two phases. Phase I was conducted March 29 through April 9, 2013 and covered the section of pipeline from the pig launcher inside of Mod 303 at MPI to PS 1. The snow-covered segments were surveilled during Phase II in June 2013. No significant problems of immediate concern were observed in these inspections. A summary of the results is in Appendix C.

Milne Point Surveillance Results

Milne Point Security conducted 42 routine drive-by inspections during 2013. These inspections fulfilled DOT requirements. The minor issues observed during the Milne Point DOT surveillances were mitigated through the standing work order for the CIC Core Inspection Program.

In 2013, Milne Point operators also requested additional drive-by inspections in response to unexplained leak detection alarms. Alarms are considered unexplained when the Mass Pack alarm does not clear within ten minutes.

The Milne Point Phase I WSS for the Sales Oil Pipeline was conducted between May 22 and 26, 2013. The remaining six partially snow covered areas of the Sales Oil Pipeline were reviewed during the Phase II WSS on July 7, 2013. The Milne Point Products Pipeline WSS was conducted between December 12 and 14, 2013. The areas that were partially snow covered will be inspected at a later date. No significant problems of immediate concern were observed in these inspections. A summary of the results is in Appendix C.

The minor issues observed during the Milne Point DOT inspections are mitigated through the standing work order for the CIC Core Inspection Program.

Northstar Surveillance Results

Shared Services Aviation conducted 53 DOT aerial visual inspections of the Northstar ROWs in 2013. These inspections fulfilled the DOT surveillance and patrol requirements. No ROW or pipeline issues were identified during the Northstar DOT surveillances.

The Northstar Oil and the Northstar Gas Pipelines' Phase I WSSs were completed March 27, 2013. The inspected portions of the Northstar Oil Pipeline were the above ground sections from Northstar Island to PS 1. The Northstar Gas Pipeline was inspected from Northstar Island to the Northstar Gas Pipeline pig launcher. The snow-covered sections of both pipelines were re-inspected during the Phase II WSS conducted on September 7, 2013. No significant problems of immediate concern were observed in these inspections. A summary of the results is in Appendix C.

MONITORING

General Information

The term monitoring is described by BPXA as the acquisition, storage, and evaluation of quantitative data using specific instrumentation. Monitoring information is gathered and used to recognize trends, detect unknown and unexpected problems, and plan and prioritize repairs.

BPXA's corrosion programs ensure the mechanical integrity of the pipelines through regularly scheduled internal and external corrosion evaluations. High-level annual and cumulative changes are summarized in Appendix D, the Monitoring Program Summary.

In addition to the Surveillance and Monitoring Program, other oversight activities are conducted, such as the DOT pipeline mainline valve inspection and maintenance, and various shoreline and subsea monitoring.

2013 Corrosion Programs' Results

Corrosion data are stored electronically and key performance indicators are tracked. Specific mitigation timelines are in place for actionable issues and recorded in the Asset Specific Corrosion Control Plans. The fitness-for-service criterion used by BPXA is SPC-PP-00090, "Evaluation and Repair of Corroded Piping Systems," which includes ANSI/ASME B31G, PRC 3-805, and additional BPXA-specific requirements.

CIP Results

In 2013, 36 CIP inspections were performed. The B Grade location that experienced a 20 mil wall loss was converted to a CRM location for monitoring, and had no change in the recurring inspection.

CRM Results

The DOT pipelines carry products that meet sales quality specifications. Even though they are not in corrosive service, BPXA has included DOT pipelines in the

CRM Program as a proactive measure. There were 226 inspections performed at 177 locations during 2013. All of the 2013 inspections resulted in no change from previous inspection results.

FIP Status

Currently, Badami, Northstar, Milne, and Endicott Pipelines do not have locations of significant corrosion damage or have levels of corrosion that mandate their inclusion in this Program.

Below Grade Piping Results

Piggable segments of below grade pipe are monitored for internal and external corrosion with ILI. During 2013, no integrity concerns or significant corrosion concerns were identified in below grade segments.

Badami

Four non-piggable segments of the Badami Utility Pipeline were inspected with a Guided Wave Ultrasonic inspection during 2012. No integrity or significant corrosion concerns were identified.

Northstar

The two non-piggable segments of Northstar Gas Pipeline from the CGF to the Caribou Crossing were inspected in 2010 with Guided Wave Ultrasonics and no corrosion damage was noted. The next Guided Wave Ultrasonic inspection for the Northstar Gas Pipeline is scheduled for 2015.

CUI Program Results

Badami

It was determined external corrosion surveys were not necessary on the Badami Oil and Badami Gas Pipelines during 2013.

Endicott

In 2013, 10 external corrosion surveys were conducted on the Endicott Pipeline. Six A grade and four C grade conditions were found. The C grade areas of external corrosion were mitigated.

Milne Point

There was not an external corrosion survey conducted on the Milne Point Products Pipeline during 2013. Forty-nine inspections were conducted on the Milne Point Pipeline during 2013. Twenty-two A grade and 24 B, C, and D grade conditions were found. The 24 B, C, and D grades areas of external corrosion were mitigated.

Northstar

It was determined external corrosion surveys were not necessary on the Northstar Oil and Northstar Gas Pipelines during 2013.

CMP Results

During 2013 Corrosion Monitoring, pulled coupons did not exceed the corrosion limit of 2 mpy general or 20 mpy pitting. Laboratory analyses showed no notable corrosion or pitting rates for any of the Sales Oil Pipelines located on the ROWs.

ILI Results

BPXA continues to correlate historic and current investigation data. Future scopes of work will be chosen to mitigate potential integrity threats due to internal and external corrosion and complete ILI performance specification verification. The ILI Schedule for applicable pipelines is outlined in Table 12.

Table 12 - ILI Schedule

Pipeline	Last Smart Pig Run	Next ILI Run
Badami Sales	10/7/2010: MFL and caliper tool	2015
Endicott Sales	8/27/2011: MFL run by Rosen Inspection	2014
Milne Oil	6/27/2011: MFL run by Baker Hughes	2014
Northstar Sales	7/26/2012: MFL and caliper tool run by Baker Hughes 9/28/2012: Geopig ILI tool run by Baker Hughes	2017
Northstar Gas	7/22/2012: MFL and caliper tool run by Baker Hughes 9/26/2012: Geopig ILI tool run by Baker Hughes	2017

Badami

The Badami Sales Oil Pipeline was inspected by a high-resolution MFL/caliper combination ILI tool on October 7, 2010. Field verification activities were completed in 2011. Post the development and the March 2013 approval, of a new BPXA criteria that governs the setting of in-line inspection frequencies, the inspection frequency of this line was changed from 3 years to 5 years. The next in-line inspection is scheduled for 2015.

Endicott

The Endicott Sales Pipeline was inspected by a Rosen Inspection Services high-resolution MFL/caliper combination ILI tool on August 27, 2011. Field inspections that were generated as a result of the 2011 run have been completed. Field verification results continue to show that the tool performed within acceptable performance specifications. A high resolution magnetic flux leakage and a high resolution caliper tool with IMU, supplied by Pii Pipeline Solutions, are scheduled to be run in the summer of 2014.

Milne Point

The Milne Point Pipeline was inspected by Baker Hughes PMG Inspection Services using a high-resolution MFL/caliper combination tool on June 27,

2011. Field inspections that were generated as a result of the 2011 run have been completed. Field verification results continue to show that the tool performed within acceptable performance specifications. A high resolution magnetic flux leakage and a high resolution caliper tool with IMU, supplied by Baker Hughes, are scheduled to be run in the summer of 2014.

Northstar

Results from the previous ILI runs and associated field follow-up indicated no work was necessary for the Northstar Pipelines during 2013. Post the development and the March 2013 approval, of a new BPXA criteria that governs the setting of in-line inspection frequencies, the inspection frequency of this line was changed from 3 years to 5 years. The next in-line inspection is scheduled for 2017.

Cathodic Protection Results

Badami

In July 2013, an inspection and system performance analysis was performed on the CP systems installed on the Badami Sales Oil Pipeline and Badami Utility Pipeline. This inspection included systems to control external corrosion on the buried sections of the Badami Sales Oil Pipeline at Sagavanirktok, Kadleroshilik, and Shaviovik river crossings and the road crossing at the Badami production facility. The half-cell potentials at the three buried river crossings indicate the pipelines are meeting the CP industry acceptable criteria of the -850 mV polarized standard. The buried section of the Badami Utility Pipeline at the road crossing meets the accepted CP criteria of the 100 mV polarization standard.

The isolation flange kits were providing electrical isolation, with the exception of the two at the Badami Pad in the fuel gas pipeline. Those two isolation kits were functional, but the conduit and grounding for this motor-operated valve provided a by-pass short through the conduit, making the installation ineffective. This was addressed on August 23, 2013 by installing an isolation kit on the upstream side of the valve. With this work complete, the tests confirm the cathodic protection systems meet industry acceptance criteria.

Electrical isolation flange installations at these locations and the tie-in into the Endicott Pipeline were also inspected. During isolation flange inspections, continuity was detected across four flanges. This deficiency has no effect on the functionality of the cathodic protection system; however, this issue will be addressed within a reasonable time to ensure anode life. The installation of a valve isolation kit was completed in 2013 and will be validated in the 2014 survey.

Milne Point

In July of 2013, the electrical isolation flanges between the stainless steel and carbon steel sections on the Milne Point Pipeline were inspected to confirm their operating condition and effectiveness. The isolation flanges were found to be functioning as designed and were 100 percent isolated.

Northstar

Annual cathodic protection inspections have been conducted by testing at the facility and shoreline ends. In addition to these routine inspections, the Mears Group, Inc. completed a 50-foot interval pipe-to-soil potential survey, through the ice, over the length of both subsea pipelines between April 18 and 22, 2012. Subsequent annual test results at each end can be compared against the 2012 results.

The annual test on April 25, 2013 performed by the Mears Group, Inc. reaffirmed results from the 2012 survey, which concluded both pipelines have adequate cathodic protection over the length of the crossing, the isolation flanges at each end of the crossing are providing electrical isolation as designed, the estimated life of the anodes is at least an additional 15 to 20 years, and the damage to the monitoring system mountings and/or test leads at Point Storkersen do not impact the cathodic protection system or limit the ability to perform the required annual testing.

It is recommended that 50' interval surveys over the length of the pipeline be conducted on a 5 year basis.

<u>Atmospheric Corrosion Inspection Results</u>

Badami

During March 2013, the Badami Gas Pipeline was visually inspected for atmospheric corrosion from the Causeway T Intersection to the first onshore VSM. Light surface, non measurable corrosion was noted. No action was required for the non measurable corrosion since it will not affect the safe operation of the pipeline prior to the next inspection.

Tundra Travel Configuration

Endicott

During late March and early April of 2013, the Endicott Pipeline was visually inspected for atmospheric corrosion from Northstar Island to Pump Station 1 to satisfy the offshore pipeline requirements of 49 CFR 195.583. No atmospheric corrosion conditions were observed or reported during this survey. Annual atmospheric monitoring of the pipeline will continue.

Milne Point

During January 2013, a visual atmospheric corrosion inspection was completed for Milne Point's Module 58 launcher, Module 68 receiver, and associated launcher/receiver piping. The barrels and doors were free of external corrosion, valves and bolting were free of corrosion and fluid leakage, and no mechanical damage was noted on the equipment or piping.

Northstar

During March 2013, both Northstar Pipelines were visually inspected for atmospheric corrosion from their launcher barrels to the Log Cabin to satisfy the offshore pipeline requirements of 49 CFR 195.583. Light corrosion and varying degrees of coating failure were noted. No action was required for the non measurable corrosion since it will not affect the safe operation of the pipeline prior to the next inspection. However, consideration to coat the 2" bypass loop was requested prior to any measurable pitting occurring.

Badami Pipelines' Weir Monitoring

Badami is required by the USACE and the ADF&G to inspect the weir at the Sagavanirktok River three times each summer for bank erosion, flooding, channel changes, and gullying that could threaten the pipeline. These required inspections were conducted on June 15, July 26, and August 26, 2013. During these inspections the weir was functioning as designed and water was flowing within the established channel. No leaks were noted. In July, new growths of indigenous sedges were abundant around the mat and were growing through it. In August, vegetation was observed to be even taller and more robust. Numerous caribou and ground squirrel tracks were seen and waterfowl droppings were observed in the matted area.

Rehabilitation Report for the Badami Pipeline East Shaviovik River Crossing

The east side of the Shaviovik River Crossing was reevaluated during 2013 and ABR, Inc. prepared the "Summary Rehabilitation Report for the Badami Pipeline East Shaviovik River Crossing." This is the fourth report submitted for this site and focuses on environmental conditions, primarily vegetation, surface stability, and hydrology, as part of an overall assessment of site recovery and integration with the surrounding ecological communities. There was no standing water or evidence of seasonal channels or signs of erosion on the face of the backfilled trench, where it meets the river bank. A productive, species-rich cover of vascular plants was found established on the backfilled trench. The site will be

Northstar Hovercraft

inspected again in 2016 to confirm the trench remains stable and the vegetation cover is sustained. The 2013 report is in Appendix E.

Annual Northstar LEOS Leak Detection System Test

In addition to the standard leak detection systems that monitor pressure, volume, and temperature in the pipeline, the Northstar subsea pipeline segment employs a leak detection system which is designed to sense hydrocarbon vapors surrounding the pipeline. The annual preventive maintenance and a functional leak test of the LEOS detection system was conducted in September 2013. The test simulated leakage at the far end of the LEOS monitoring line. The LEOS system performed well.

Coastal Stability Monitoring – Northstar Pipeline Shore Crossing

Coastal Frontiers conducted the annual coastal stability monitoring on August 10, 2013 and reported their findings in the "2013 Coastal Stability Monitoring of the Northstar Shore Crossing Report." This monitoring has been performed annually since 2000 in accordance with the USACE-approved plan.

North Slope Shoreline

The objective is to determine annual coastal changes and report measurable bluff recession. Ten shore-perpendicular profiles are surveyed annually at intervals of 250 feet and atop the pipeline crossing from the backshore to wading depth.

At present, the toe of the pipeline shore pad lies about 70 feet landward of the eroding backfill face, and the base of the gravel berm that protects the pipeline riser is more than 125 feet from the Mean Lower Low Water shoreline. No erosion mitigation measures are required at this time due to the modest historical bluff recession rate.

Future bluff monitoring will be performed in order to monitor the bluff position in accordance with the authorized Coastal Stability Monitoring Program. The full report can be found in Appendix F.

Rehabilitation Report for the Northstar Pipeline Landfall

The location of this shore crossing is west of West Dock in the Western Operating Area of Prudhoe Bay. Access to the site is either by helicopter or by shallow draft boat. Since the pipeline was constructed in the winters of 1999 and 2000, the focus of this rehabilitation effort has been to control erosion and maintain the stability of the trench backfill. This was the tenth year the annual inspection and evaluation has been conducted.

ABR, Inc. reported their findings in the "Rehabilitation Report for the Northstar Pipeline Landfall" dated November 15, 2013 (see Appendix G). The remnant gravel area appeared stable and vegetated with a productive cover of predominantly indigenous vascular plants. Erosion of the trench side slope has been minimal since 2009, due primarily to the protection provided by the erosion control fabric. To prevent the erosion gully that has developed beneath the fabric from deepening and expanding, cocomat tubes full of soil will be installed in the gullied area and sprigged with *Leymus mollis* (American dunegrass) in 2014.

Northstar Pipeline Route Monitoring

The 2013 Pipeline Route Monitoring Program represents the fourteenth annual post-construction investigation of the pipelines' subsea route from Northstar Production Island to the Shore Crossing. It is designed to accomplish four specific tasks:

- Obtain detailed bathymetric data;
- Determine the locations and characteristics of ice gouges in the sea bottom;
- Determine the locations of strudel drainage features in the ice within a 5,000 foot wide corridor centered on the pipeline alignment; and
- Determine the locations and characteristics of strudel scour depressions in the sea bottom and at selected additional sites within the 5,000 foot monitoring corridor where strudel drainage features had been observed.

Coastal Frontiers conducted fieldwork in two phases, a helicopter-based reconnaissance of strudel drainage features in early June and a vessel-based survey program in late July. The "Northstar Development 2013 Pipeline Route Monitoring Program" report was submitted to BPTA in January 2014 and can be found in Appendix H. The principle 2013 findings follow. Annual monitoring and reporting will be continued.

- The bathymetric profile on the pipeline alignment bore a close resemblance to that recorded in 2012. Between Northstar Production Island and Stump Island the most significant changes consisted of a general reduction in bathymetric relief, in-filling of two relict strudel scour depressions, and sediment accumulation in an inactive subsidence area immediately north of Stump Island. Between Stump Island and the shore crossing, the profile was virtually identical to that in 2012 and similar to the pre-construction profile obtained in 1996.
- For the first time since oil began flowing in the fall of 2001, no areas of active subsidence were detected on the pipeline alignment in 2013.
- One modest deficiency in the backfill thickness relative to the six foot minimum value stipulated in the pipeline permit was detected off Stump Island in an inactive subsidence area immediately north of Stump Island. Shortfalls had been noted at this location in each of the past four years.

- Nine ice gouges were detected on the pipeline route during the 2013 survey. Five represented newly-discovered features. The number of new gouges was extremely low by historical standards, while the severity was consistent with historical precedent. Although one gouge crossed the pipeline alignment, it did not cause the backfill thickness to violate the six foot minimum acceptable value.
- No new ice wallows were identified during the 2013 survey, but two of the 18 wallows discovered in 2011 were found again.
- The 2013 Kuparuk River overflood was vigorous by historical standards but remained within the footprint established by pervious flood boundaries. Sixty seven drainage features were detected in the 5,000-ft wide monitoring corridor. Sixty-five were located to the north of Stump Island, while two were located to the south of Gwydyr Bay.
- A sonar search for strudel scours was conducted over the pipeline route and at the 67 drainage sites observed during the overflood period. Seventy new depressions were discovered in the sea bottom. Sixty-three of the scours were circular in plan form, while seven were linear. The numbers of circular and linear scours were high by historical standards, but the severity of the scouring was relatively low. None of the scours impinged on the backfill over the pipelines.

BPXA ENVIRONMENTAL STUDIES

BPXA and other organizations conduct various scientific fauna and flora studies across the North Slope. There have been substantial collaborative projects with the Alaska SeaGrant, National Fish and Wildlife Foundation, Polar Bears International, Wildlife Conservation Society, and others. The BPXA Environmental Department takes the lead on the permitting and reporting required by agencies such as ADF&G, USFWS, and National Marine Fisheries Service.

Various environmental studies and reports demonstrate how the pipeline ROW requirements are satisfied. Three examples of these reports can be found in Appendices E, and F, and G.

AUDITS / ASSESSMENTS

SPCO Surveillances

SPCO Surveillance involved interactions between SPCO, BPTA, and BPXA and included office and field interviews, inspections, and record reviews. The 2013 surveillance reports, SPCO observations, and BPTA follow-up status are summarized in Appendix I. The dates indicate SPCO's internal approval and issuance of the surveillance reports. A description is given below.

Badami Pipelines

On February 25, 2013, the SPCO issued two surveillance reports accepting BPTA's updated Quality Assurance Manual for the Badami Oil and Badami Utility Pipelines.

On March 10, 2013, one SPCO representative observed BPXA contractors performing a Walking Speed Survey of the Badami Utility Pipeline from the "T" adjacent to the Endicott Satellite Drilling Island and walking south along the Endicott road causeway. Ten satisfactory surveillance reports resulted from this North Slope visit.

On May 15, 2013, the SPCO reviewed BPTA's 2012 Annual Report and found the "Conduct of Operations," "Surveillance and Monitoring," "Orders by the Commissioner," and "Covenants of the Lessee" requirements of the Badami Oil Pipeline and Badami Utility Pipeline leases were met.

Endicott Pipeline

On January 7, 2013, the SPCO issued eight surveillance reports that were the outcome of a September 2012 field visit of the Endicott ROW. The eight reports reflected satisfactory conditions.

On February 25, 2013, the SPCO issued a surveillance report accepting BPTA's updated Quality Assurance Manual for the Endicott Pipeline.

On May 15, 2013, the SPCO reviewed BPTA's 2012 Annual Report and found the "Covenant of Lessee," "Responsibilities," "Surveillance and Maintenance" and "Duty of Lessee to Prevent or Abate" requirements were met.

On July 29, 2013 two SPCO representatives visited the Northstar/Endicott heater and then traveled the Endicott Pipeline ROW. Debris was noted in the Endicott ROW.

On September 16, 2013, two SPCO representatives inspected the Endicott Pipeline ROW. They confirmed the debris noted in the July visit was removed.

Milne Point Pipelines

On January 7, 2013, the SPCO issued eleven surveillance reports that were the outcome of a September 2012 field visit of the Milne Point ROWs. The eleven reports reflected satisfactory conditions.

On February 25, 2013, the SPCO issued two surveillance reports accepting BPTA's updated Quality Assurance Manual for the Milne Point Pipeline and Milne Point Products Pipeline.

On May 15, 2013, the SPCO reviewed BPTA's 2012 Annual Report and found the "Covenants of Lessee," "Duty of Lessee to Prevent or Abate," "Responsibilities," and "Surveillance and Monitoring" requirements of the Milne Point Pipeline lease were met. The review also found the requirements of

"Covenants of Lessee," "Information," and "Reporting" of the Milne Point Products Pipeline lease were met.

Northstar Pipelines

On January 7, 2013, the SPCO issued eight surveillance reports that were the outcome of a September 2012 field visit of the Northstar ROWs. The eight reports reflected satisfactory conditions.

On February 25, 2013, the SPCO issued two surveillance reports accepting BPTA's updated Quality Assurance Manual for the Northstar Oil and Northstar Gas Pipelines.

On March 26, 2013, one SPCO representative observed BPXA contractors performing a Walking Speed Survey of the Northstar Oil Pipeline. Nine satisfactory reports resulted from this North Slope visit.

On May 15, 2013, the SPCO reviewed BPTA's 2012 Annual Report and found the "Conduct of Operations," "Covenants of Lessee," "Information," "Surveillance and Monitoring," and "Reporting" requirements of the Northstar Oil Pipeline and Northstar Gas Pipeline leases were met.

On July 29, 2013, two SPCO representatives inspected the Northstar/Endicott heater. BPXA personnel escorted them to the site. No heater issues were reported.

On September 16, 2013, two SPCO representatives visited the Northstar Pipelines shore crossing at Pt. Storkersen. Coastal Frontier personnel explained to the SPCO their annual inspection which documents any measurable bluff recession. No concerns were noted during the field visit.

State Fire Marshal

During May 2013, the State Fire Marshal inspected the production facilities at Endicott, Milne Point, and Northstar. There were no findings related to the pipeline ROWs.

ROW EVENTS / INCIDENTS / ISSUES

DOT Incident/Accident/Safety Reports

There were no DOT Reportable Incident, Accident, or Safety Reports during 2013.

DOT NOPV

None of the pipelines within the ROWs received a NOPV during 2013. A NOPV is a letter alleging the existence of one or more DOT violations. It states the evidence upon which each allegation is passed and proposes a civil penalty and/or compliance order for at least one of the probable violations.

DOT Warning Letters

None of the pipelines within the ROWs received DOT Warning Letters during 2013. A Warning Letter is written when a probable violation is identified, but the circumstances do not warrant a proposed civil penalty or compliance order. These probable violations involve less risk than those addressed in NOPVs.

DOT NOA

None of the pipelines within the ROWs received DOT NOAs during 2013. A NOA is a letter alleging inadequate plans or procedures. NOAs advise the operator to correct the inadequate plans or procedures. NOTE: Per a visit to the PHMSA office, there are no open letters or issues. All DOT requests to date are closed.

DOT AOCs

AOCs are unexplainable or unintended events caused by the failure of operating equipment that potentially result in exceedances of the design limits of a pipeline system, but are not immediately identified as emergencies. Explainable events caused by an upset condition on the pipeline system that do not exceed design limits are not identified as AOCs. In most cases, the control room operator can clear these explainable events. DOT specifically defines the following events as AOCs:

- Unintended shutdowns or valve closures;
- Increased or decreased pressure or flow rate outside normal operating limits;
- Loss of communications;
- Operation of any safety device; or
- Any other malfunction, component deviation from normal operation, or personnel error that could cause hazards to persons or property.

After an AOC has ended, the operators check the operating parameters at sufficient critical locations in the system to determine continued pipeline integrity and safe operation. The following list summarizes AOCs that occurred during 2013.

Badami Sales Oil Pipeline

On February 10, 2013, there was an unintended valve closure of SDV 1339. The Badami control room operator notified the EOC and Endicott control rooms. A technician responded and the valve was re-opened.

On February 22, 2013, communication was lost with the Badami oil rate indicator. The Leak Detection System Administrator trouble shot and the system issue was corrected. The “RICI” was reset at Badami and no further problems were experienced.

On April 11, 2013, a portable generator supplying power to RTU-3 became unplugged causing the RTU-3 batteries to lose voltage and produce a low voltage alarm. An operator was sent to RTU-3 and the pipeline valve was found to be off seat. The problem was resolved by reconnecting the generator.

On April 19, 2013, there was an unintended closure of the tie-in valve 1339. The operator responded, found the generator down, and was unable restart the generator. The operator hand jacked the valve open and gagged it. The generator was replaced with power from a Tioga heater.

On August 26, 2013, the Badami Oil Pipeline had a momentary shutdown due to high suction pressure on the dehydrator pumps which caused the shipping pump to shutdown. The pipeline was returned to normal operations.

On December 3, 2013 there were unintended valve closures, one on the oil pipeline, and one on the gas line caused when the production facility experienced an electrical power failure. When electrical power was restored the valves opened.

On December 23, 2013, communication was lost with the Badami Oil Pipeline. The portable generator, responsible for charging the RTU-3 batteries, shut down due to a low battery voltage. The generator was replaced and communication was restored.

<u>Milne Point Pipeline</u>

On October 26, 2013, a loss of leak detection between MPU to Kuparuk and EOC occurred during a new microwave cutover. The Milne board operator had communication with pressure and flow rate on the Milne Point Pipeline. This was communicated to Kuparuk and EOC by phone.

On October 27, 2013, there was a malfunction of a component. An actuated valve did not close upon command. Corrective action was taken and a failed solenoid on the valve actuator was replaced.

<u>Northstar Pipelines</u>

On July 8, 2013, the Northstar Sales Oil Pipeline shut down when an emergency shutdown valve in the plan was activated due to fire and gas testing. Normal startup procedures were followed and no further problems were experienced.

On July 30, 2013, a shutdown valve on the Northstar Sales Oil Pipeline went closed. This was due to a momentary interruption in the PLC power supply during a FCO of the Heater upgrade at PS 1. The shore operator and instrumentation tech reset the PLC, the valve was reopened, and the facility began shipping oil without further issues.

On September 22, 2013, the Northstar Sales Oil Pipeline and the Gas Pipeline experienced a loss of HMI communications. The weather had interrupted the microwave signal. Communications were restored within minutes.

On December 1, 2013, there was an unintended closure of a valve during maintenance of a temperature control valve. The closed valve was quickly reset and there were no associated safety concerns or production loss.

Occupied Grizzly Bear Dens

(Badami and Northstar Stips 2.5.2)

No occupied grizzly bear dens were encountered on the ROWs during 2013. If an occupied den is encountered, it is reported to the ADF&G Division of Wildlife Conservation.

New Polar Bear Dens

(Badami and Northstar Stips 2.5.3)

No new polar bear dens were encountered on the ROWs during 2013. If a new den is encountered, it is immediately reported to that agency.

Survey Marker Conditions

No damage to the survey monuments or accessories was reported in 2013.

Oil / Hazardous Substance Discharges

The following two reportable spills occurred in the BPTA ROWs during 2013. Notifications were made to appropriate agencies.

Badami ROW

On March 12, 2013, one of the two tuckers being used to conduct the annual Badami Walking speed Survey threw a track causing one of the axle seals to break. The break resulted in approximately a two pint gear oil spill to the surface snow. The equipment operators stopped the leaking gear oil from the axle seal and recovered the contaminated snow. The contaminated snow was placed in a Class 1 regulated storage pit for future recycle in the plant.

Endicott ROW

On August 17, 2013, security found an active leak on the DS9A common line, a pipeline that is within the Endicott ROW. The line was shut-in and all the contaminated fluid was recovered by flushing the area with water, vacuuming it up, and sending it to the Grind and Injection facility for Class 2 disposal.

Milne Point ROWs

Cleanup and rehabilitation activities associated with the October 2012 spill at the mile 6.5 “Y” were complete on August 26, 2013. The ADEC-approved Cleanup and Waste Disposal Plan was followed and the NSB inspected the site and was satisfied with the cleanup and rehabilitation.

The following two non-reportable leaks occurred in the BPTA ROWs during 2013. Released materials were cleaned up and disposed of appropriately.

Endicott ROW

On April 25, 2013, a very small leak on HV-1393 pipeline valve flange was found coming from the flex gasket flange area on the pipeline side of the valve. The flange bolt was tightened and re-inspected.

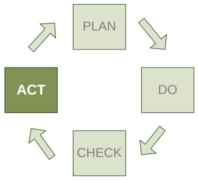
Other

One vehicle incident occurred in the BPTA ROWs during 2013.

Milne Point ROWs

On November 18, 2013 a MPU truck went off the road into the ROW. Due to blowing snow, the driver couldn't see the delineators marking the right side of the roadway and drove off the road at 10-15 mph. The vehicle was removed and there were no spills, leaks, or damage to the tundra.

"ACT" – MANAGEMENT REVIEWS AND 2014 PLANS



The "ACT" portion of the management cycle involves management reviews and activity planning. The BPTA Authorized Representatives and BPXA Field Representatives are identified below. BPTA, BPXA, and SPCO representatives communicate through meetings, North Slope visits, e-mail, and other correspondence.

AUTHORIZED REPRESENTATIVES

Identification of BPTA Authorized Representatives and the BPXA Field Representatives are required by the ROW leases. BPTA designates the following as Authorized Representatives who are empowered by BPTA to communicate with, and receive the communications and orders from, the Commissioner for the purpose of administrating the leases:

- President, BPTA – Charles Coulson
- Vice President, BPTA – Don Turner

The Authorized Representatives' mailing address is:

BP Pipelines (Alaska) Inc.
P.O. Box 190848
Anchorage, AK 99519-0848

BPXA Field Representatives must be available in the immediate area of the leasehold. The Field Representative is typically the Offshore Installation Manager, Onshore Area Manager, Facility/Field Operations and Maintenance Team Leader, or their delegate. The Field Representatives are listed by oil field.

- Endicott/Badami: Gary D. Herring and Ricardo Rodriguez
- Northstar: Joanne Johnson and Dwight Warner
- Milne Point: Wayne Hauger and Kenton Schoch

BPTA's Registered Agent for the North Slope pipeline ROW leases is:

CT Corporation System
Re: BP Transportation (Alaska) Inc.
Suite 2002
9360 Glacier Highway
Juneau, AK 99801

SPCO-LESSEE INTERACTIONS

BPTA leadership and the SPCO periodically met in Anchorage to review pipeline activities and lease-related issues. Meeting dates were January 16th, April 24th, August 6th, and November 5th, 2013. Minutes were kept from each meeting with action items reviewed at subsequent meetings.

Fox

In addition to the Anchorage meetings, members of the SPCO's Lease Compliance Section interacted with the Field Representatives during surveillances on the North Slope. Appendix J contains a synopsis of 2013 correspondence between BP entities and the SPCO.

2014 PROPOSED ACTIONS AND PLANS

The 2014 proposed actions and plans are listed below by facility and quarter.

Badami Pipelines

Effective February 1, 2014, the Badami Sales Oil and Badami Utility Pipelines were transferred to Nutaaq. Nutaaq's operator, Savant, has now assumed all operational and regulatory responsibility for these pipelines.

Endicott Pipeline

1st Quarter:

- DOT Drive-by Inspections, approximately every two weeks
- WSS

2nd Quarter:

- DOT Drive-by Inspections, approximately every two weeks
- DOT Preventive Maintenance
- Corrosion Monitoring Programs
- Repairs recommended per 2013 WSS

3rd Quarter:

- DOT Drive-by Inspections, approximately every two weeks
- DOT Preventive Maintenance
- ILI Run

4th Quarter:

- DOT Drive-by Inspections, approximately every two weeks

- 2014 DOT IMP FRA

Milne Point Pipelines

1st Quarter:

- DOT Drive-by Inspections, approximately every two weeks

2nd Quarter:

- DOT Drive-by Inspections, approximately every two weeks
- DOT Preventive Maintenance
- Verify stainless steel pipe’s isolation from carbon steel pipe
- Repairs recommended per 2013 WSS
- WSS
- Corrosion Monitoring Programs

3rd Quarter:

- DOT Drive-by Inspections, approximately every two weeks
- ILI Run

4th Quarter:

- DOT Drive-by Inspections, approximately every two weeks
- DOT Preventive Maintenance
- 2014 DOT IMP FRA

Northstar Pipelines

1st Quarter:

- DOT Aerial Inspections, approximately every two weeks

2nd Quarter:

- DOT Aerial Inspections, approximately every two weeks
- DOT Preventive Maintenance
- WSS I
- Cathodic Protection Survey
- Repairs recommended per 2013 WSS
- Corrosion Monitoring Programs

3rd Quarter:

- DOT Aerial Inspections, approximately every two weeks
- WSS II

- Submit formal appraisal for Northstar ROW Leases to the Alaska Appraisal Unit of ADNR
- In gullied area at the Landfall Shore Crossing, install cocomat tubes full of soil, sprigged with *Leymus mollis*
- Annual Northstar LEOS Leak Detection Test
- Rehabilitation Report for Northstar Pipeline Landfall
- Northstar Development Pipeline Route Monitoring
- Northstar Coastal Stability Monitoring

4th Quarter:

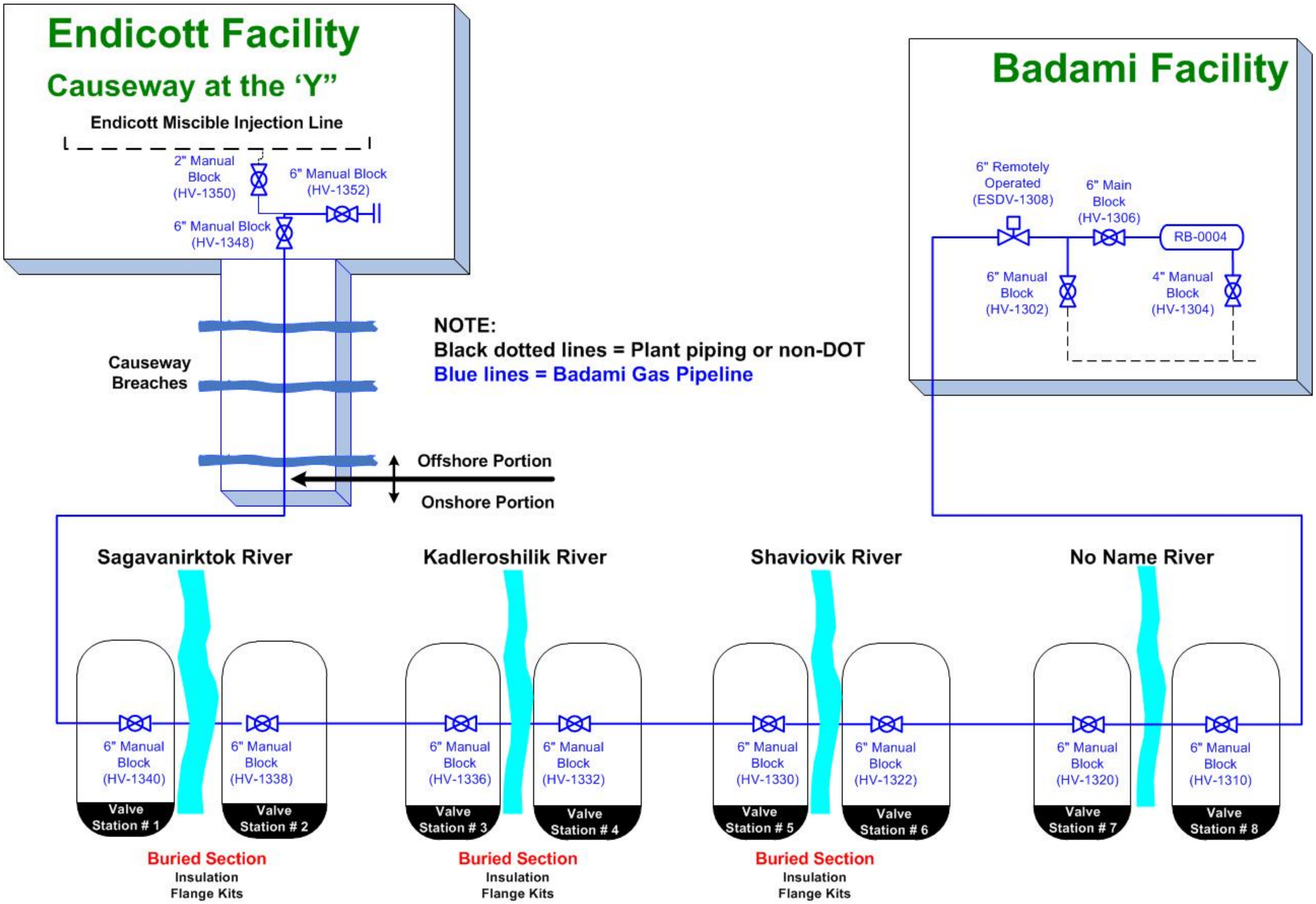
- DOT Aerial Inspections, approximately every two weeks
- DOT Preventive Maintenance
- 2014 DOT IMP FRA

Appendix A

Pipeline Schematics

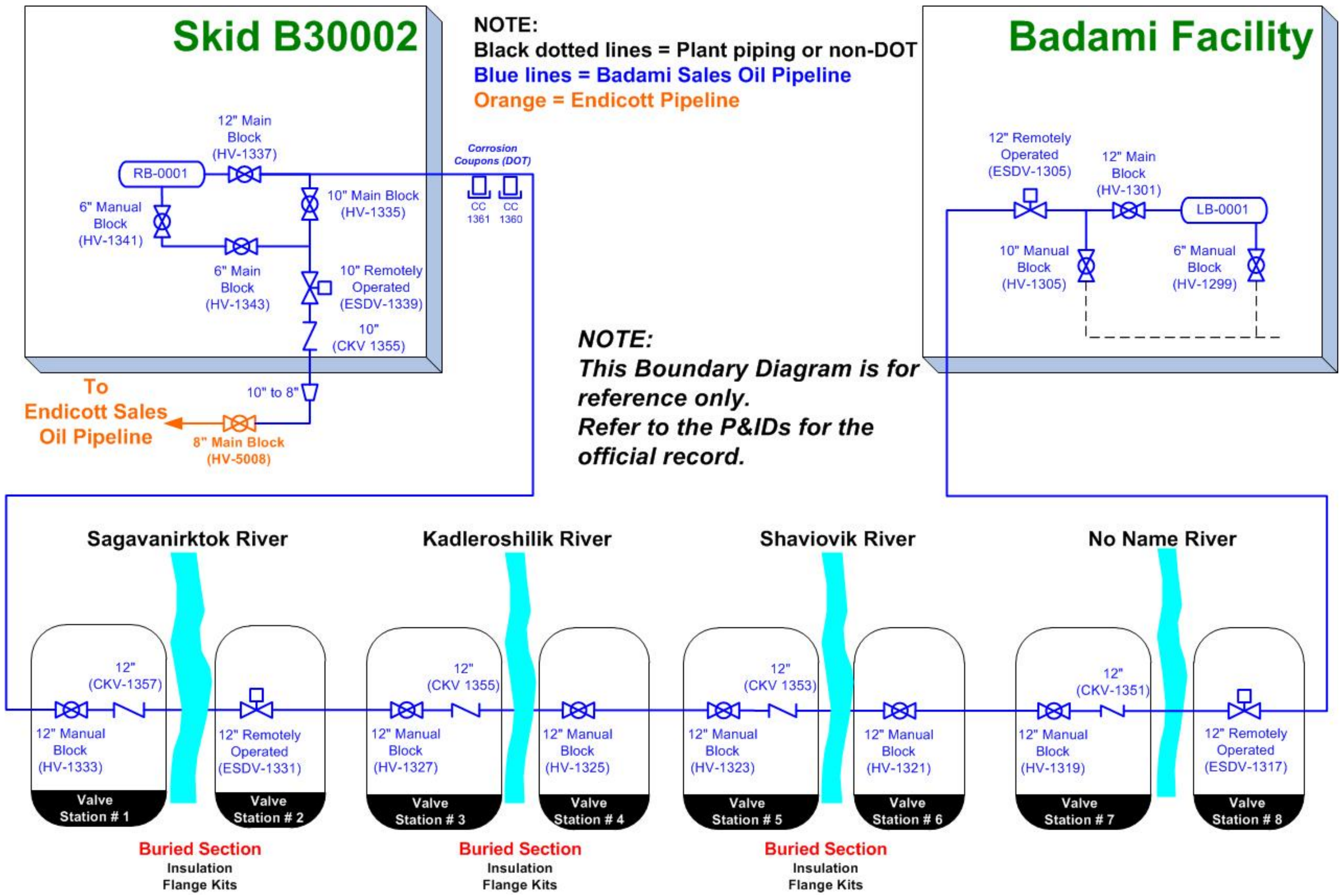
Appendix A – Pipeline Schematics

Badami Utility Pipeline

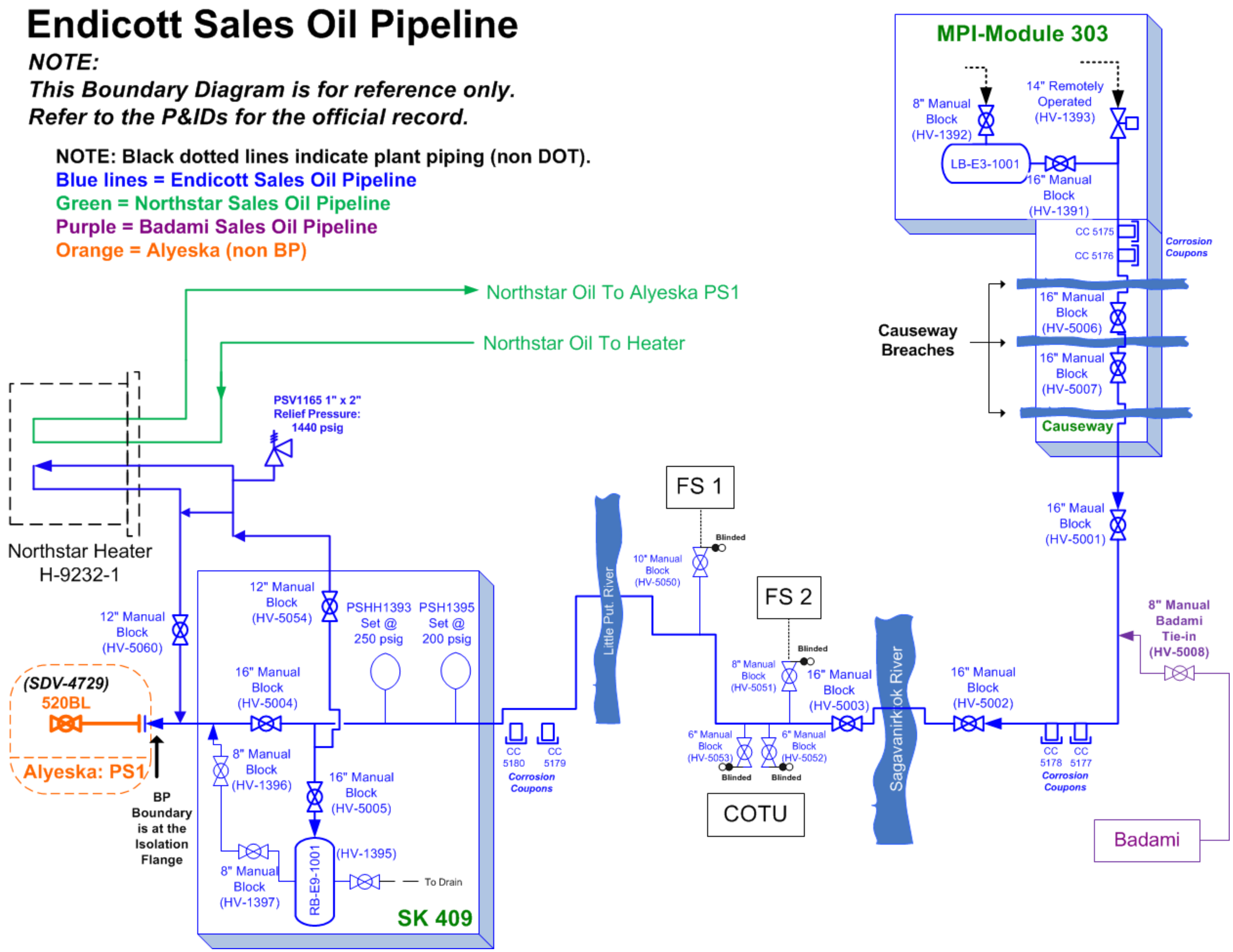


Appendix A – Pipeline Schematics

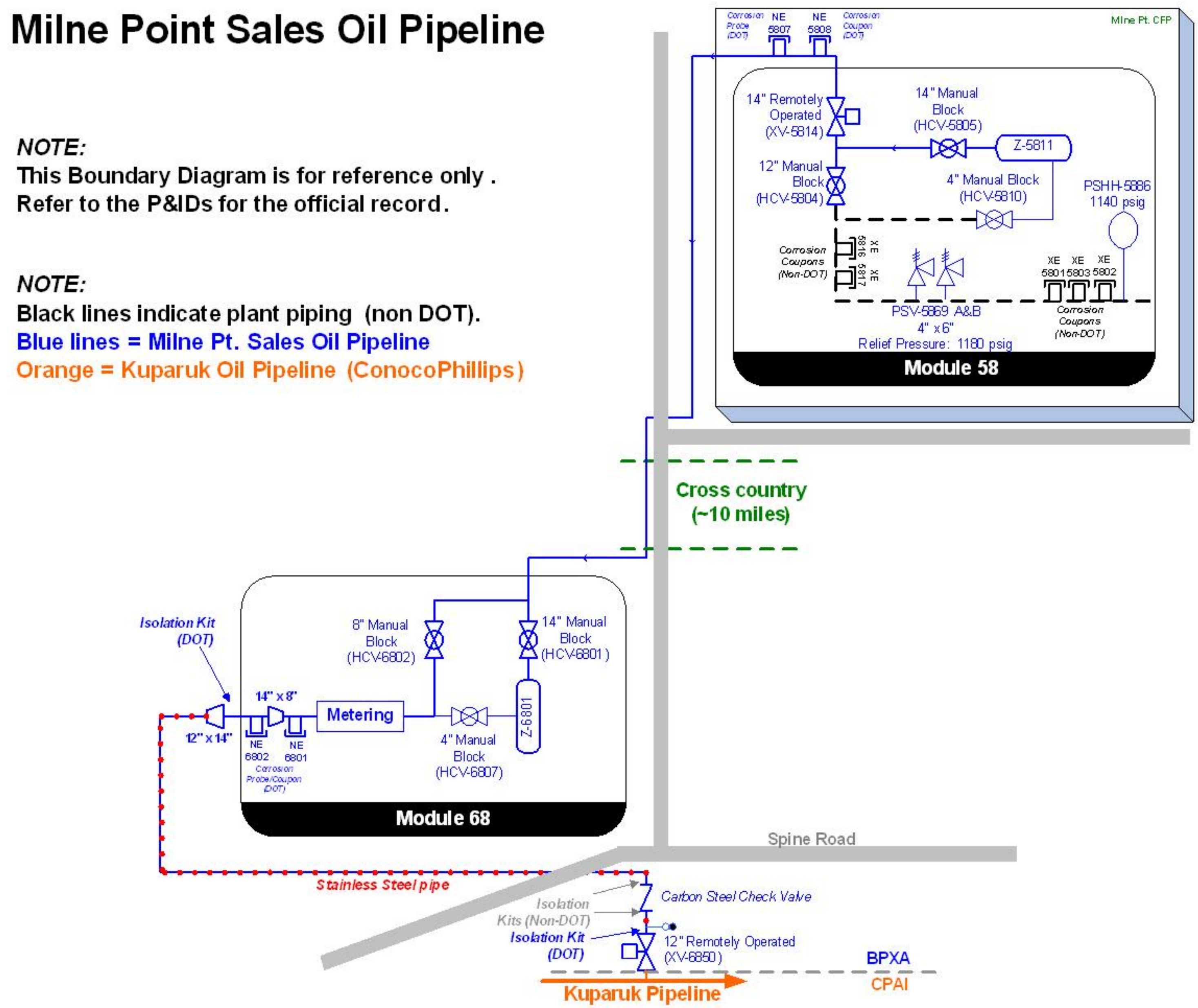
Badami Sales Oil Pipeline



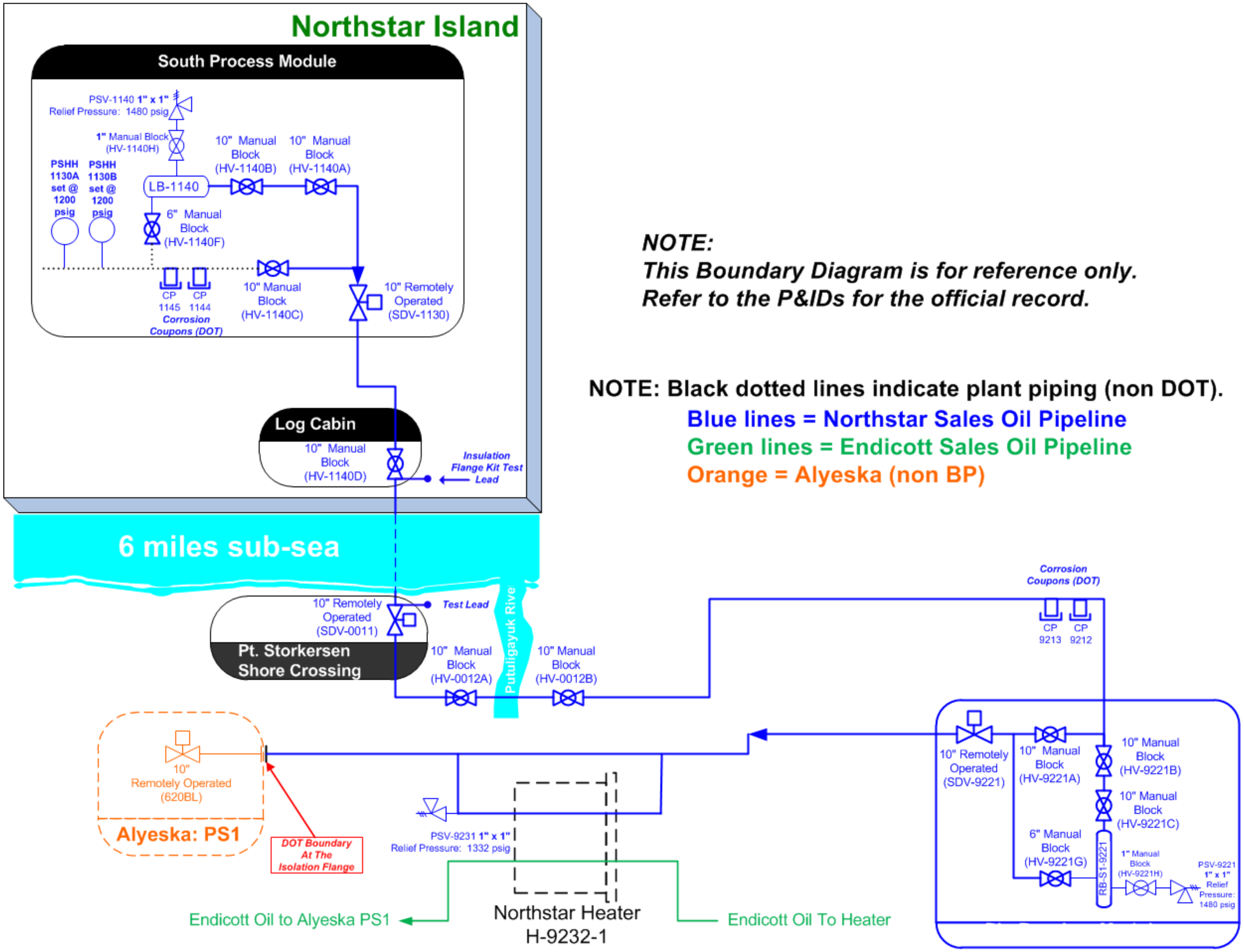
Appendix A – Pipeline Schematics



Appendix A – Pipeline Schematics



Northstar Oil Pipeline



NOTE:
This Boundary Diagram is for reference only.
Refer to the P&IDs for the official record.

NOTE: Black dotted lines indicate plant piping (non DOT).
Blue lines = Northstar Sales Oil Pipeline
Green lines = Endicott Sales Oil Pipeline
Orange = Alyeska (non BP)

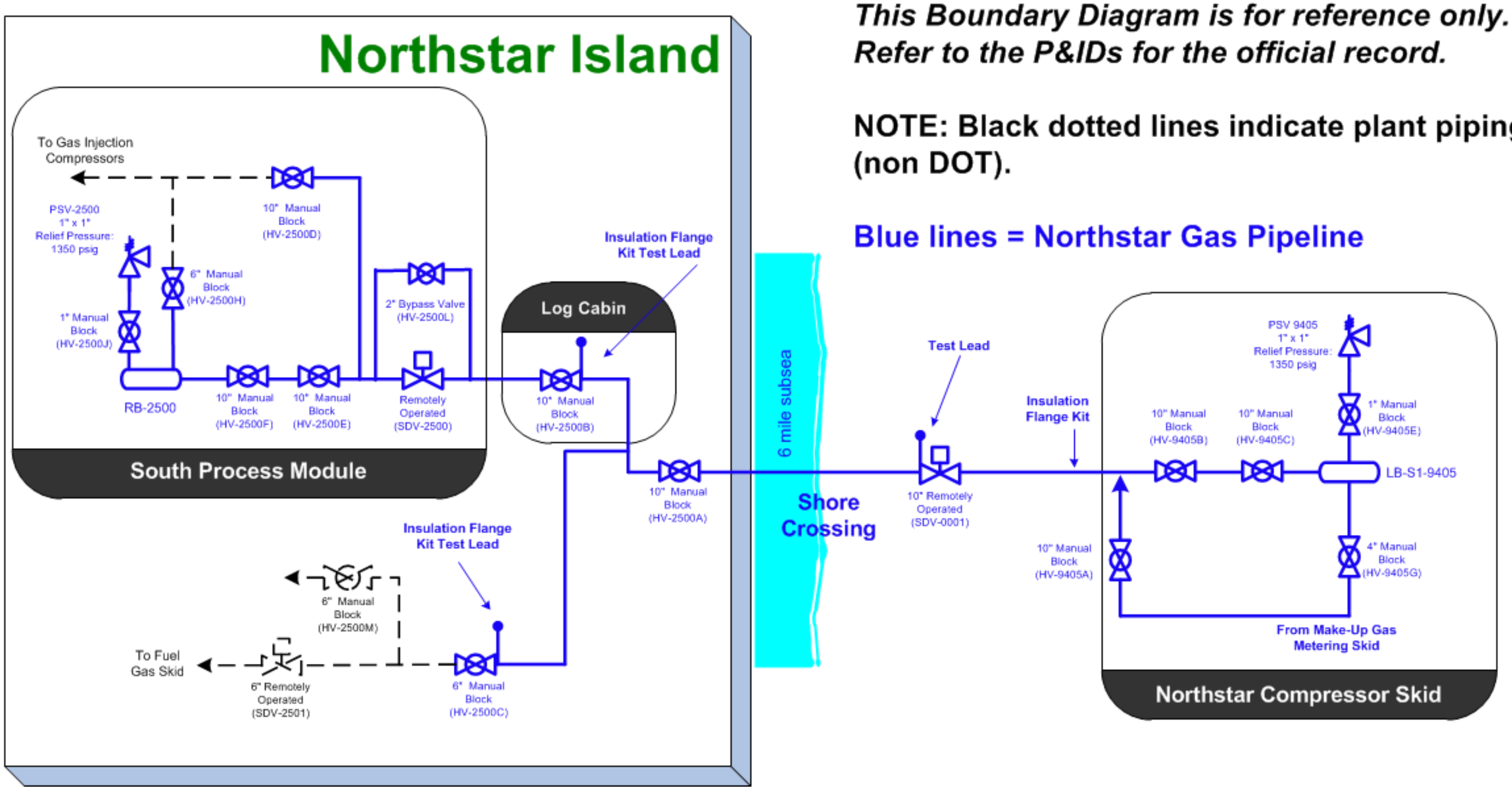
Appendix A – Pipeline Schematics

Northstar Gas Pipeline

NOTE:
This Boundary Diagram is for reference only.
Refer to the P&IDs for the official record.

NOTE: Black dotted lines indicate plant piping (non DOT).

Blue lines = Northstar Gas Pipeline



Appendix B

Components of SPCO-Approved

Surveillance and Monitoring Program

Appendix B - Components of the SPCO-approved Surveillance and Monitoring Program

ROW Surveillance

ENVIRONMENTAL

	ROW REPORTING CONDITION	RATIONALE/CONCERN	BPXA SURVEILLANCE	Aerial		Driving		Ground
Oil Spills or Leaks	▫ Any spill or leak; report via BPXA Spill Reporting System	▫ Potential breach of pipeline integrity	▫ During routine DOT ROW inspection ▫ During annual ground inspection	X	or	X	and	X
Erosion	▫ Bank erosion causing increased water turbidity ▫ Thermal erosion causing formation of additional open water areas or ground depressions ▫ Erosion of gravel pad(s), including valve pads	▫ Detect during or immediately after break-up and during maximum thaw rate to prevent potential consequences of erosion	▫ Between break-up to freeze-up during routine DOT ROW inspections ▫ During annual ground inspection	X	or	X	and	X
Wildlife Blockage	▫ Evidence that wildlife movement are blocked	▫ Detect blockage of caribou insect relieve movement or musk ox feeding movements.	▫ During routine DOT ROW inspections ▫ During annual ground inspections	X	or	X	and	X

PIPELINES / MAINLINE VALVES

	ROW REPORTING CONDITION	RATIONALE/CONCERN	BPXA SURVEILLANCE	Aerial		Driving		Ground
Public Access	▫ Unauthorized Entry ▫ Vandalism ▫ Sabotage ▫ Restricted access along shoreline	▫ Provide for public health and safety ▫ Ensure security of pipeline ▫ Assure public access along shoreline	▫ During routine DOT ROW inspections ▫ During annual ground inspection	X	or	X	and	X
VSM	▫ Evidence of any tilting, settlement or jacking ▫ Scouring that could affect integrity of VMS	▫ Potential overstress of pipeline	▫ During routine DOT ROW inspections ▫ During annual ground inspection	X	or	X	and	X
Sloping Crossbeam	▫ Visible sloping ▫ Visible tilting	▫ Potential overstress of pipeline	▫ During annual ground inspection					X
Tilted Saddle	▫ Out-of-level conditions that result in an edge between any part of the saddle and any part of the crossbeam or pipe	▫ Potential overstress of pipeline	▫ During annual ground inspection					X
Saddle suspended above crossbeam	▫ Anywhere the saddle is not in contact with the crossbeam	▫ Potential overstress of pipeline	▫ During annual ground inspection					X

Appendix B - Components of the SPCO-approved Surveillance and Monitoring Program

ROW Surveillance (cont'd)

PIPELINES / MAINLINE VALVES

	ROW REPORTING CONDITION	RATIONALE/CONCERN	BPXA SURVEILLANCE	Aerial		Driving		Ground
Failed Anchor	▫ Anchors which have visibly moved, are out of level, or with broken welds	▫ Potential overstress of pipeline	▫ During annual ground inspection					X
Gap between pipe and saddle	▫ Any gap	▫ Potential overstress of pipeline	▫ During annual ground inspection					X
Pipeline Vibration	▫ Amplitudes above 0.5 inches	▫ Potential for wind induced vibration high cycle fatigue failure	▫ During annual ground inspection					X
Pipeline Vibration Dampeners	▫ Missing or broken parts ▫ Out-of-location or misalignment Note: Misalignment greater than 45° requires immediate reporting.	▫ Potential for failure of WIV prevention system	▫ During annual ground inspection					X
Damaged piping insulation at risers	▫ Significant indentations, cracks, missing foam insulation.	▫ Potential for reduced thermal protection and external corrosion	▫ During annual ground inspection					X
Damaged piping or components at risers	▫ Any significant damage, including - Pipeline dents, - VSM dents greater than 3/4" deep and 9" long - VSM gouges deeper than 1/8 " - VSM cracks, - Structural damage such as cracks or broken parts on clamps, saddle assembly, crossbeam, brackets, weld packs, or any assembly components - Saddle base deformed over crossbeams - Bullet holes, - Damaged sheet metal, insulation or FBE coating, - Any damage to valves, supporting structures.	▫ Potential breach of pipeline integrity	▫ During annual ground inspection					X
Putuligayuk River Pile Scouring	Northstar-specific ▫ Depth of scour shall not exceed four (4) feet from zero mark on pile.	▫ Potential for pile loss and subsequent overstress of pipeline	▫ During annual ground inspection					X

Appendix B - Components of the SPCO-approved Surveillance and Monitoring Program

ROW Surveillance (cont'd)

PIPELINES / MAINLINE VALVES

	ROW REPORTING CONDITION	RATIONALE/CONCERN	BPXA SURVEILLANCE	Aerial		Driving		Ground
Hump or Swales	▫ Pressure ridges develop parallel to pipe axis and exceed 1 ft in height and 60 ft in length ▫ Accompanied by ground cracking.	▫ Potential for structural support change on pipeline	▫ During annual ground inspection					**X**
Ground Cracking	▫ Cracks w/in 10 ft of pipeline centerline having one of following characteristics: - At least 10 ft long with vertical displacement exceeding 6" - Wider than 2", parallel to pipe axis and longer than 60 feet.	▫ Potential for structural support change on pipeline	▫ During routine DOT ROW inspections ▫ During annual ground inspection	**X**	or		and	**X**
Cased pipe	▫ Debris, water, or blockage between casing and pipe.	▫ Potential water retention in casing resulting in corrosion	▫ During annual ground inspection					**X**

MODULES / BUILDINGS

	ROW REPORTING CONDITION	RATIONALE/CONCERN	BPXA SURVEILLANCE	Aerial		Driving		Ground
Damage	▫ Leaks around fuel storage containers. ▫ Any damage to communication sites and/or support structures. ▫ Debris or corrosion around building sumps.	▫ Personnel safety and environmental impacts ▫ Loss of communications ▫ Inadequate support structures ▫ Potential leaks	▫ During routine DOT ROW inspections ▫ During annual ground inspection	**X**	or		and	**X**
Foundation Movement	▫ Any settlement or jacking or communication sites and/or support structures.	▫ Potential breach of module integrity ▫ Inadequate support structures	▫ During annual ground inspection					**X**
Fuel/Gas Leak	▫ Any odor or monitor detection.	▫ Personnel safety and environmental impacts ▫ Potential breach of pipeline integrity.	▫ During annual ground inspection					**X**

Appendix B - Components of the SPCO-approved Surveillance and Monitoring Program

ROW Surveillance (cont'd)

BADAMI AND NORTHSTAR : River, Shoreline, Floodplain Crossings, and Offshore Pipelines								
	ROW REPORTING CONDITION	RATIONALE/CONCERN	BPXA SURVEILLANCE	Aerial		Driving		Ground
Exposed Pipe	▫ Any evidence of exposed pipe at shore crossing. ▫ Any evidence of exposed pipe between the risers.	▫ Pipe more susceptible to damage. ▫ Pipe could be subject to aggressive corrosion.	▫ Between break-up to freeze-up during the routine DOT ROW inspections. ▫ During annual ground inspection.	**X**			and	**X**
Bank Erosion	▫ Banks at shore crossing are caving within 25 feet of the riser. ▫ Bank erosion causing increased water turbidity.	▫ Detection allows prevention and/or mitigation of erosion consequences. ▫ Ensure public access and alter animal movement available at shoreline.	▫ Between break-up to freeze-up during the routine DOT ROW inspections. ▫ During annual ground inspection.	**X**			and	**X**
Flooding	▫ Conditions which reduce the setback by eroding the banks or threaten a facility or pipeline.	▫ Detection allows prevention and/or mitigation of flooding consequences.	▫ Between break-up to freeze-up during the routine DOT ROW inspections. ▫ During annual ground inspection.	**X**			and	**X**
Channel Obstruction	▫ Threatens to cause erosion or flooding of the setback or pipeline facilities.	▫ Detection allows for prevention and/or mitigating actions.	▫ Between break-up to freeze-up during the routine DOT ROW inspections. ▫ During annual ground inspection.	**X**			and	**X**
Channel Change	▫ Change in the river channel flow at the river crossings.	▫ Detection allows for prevention and/or mitigating actions.	▫ During the routine DOT ROW inspections. ▫ During annual ground inspection.	**X**			and	**X**
Depressions	▫ Occur longitudinally over pipe axis, are deeper than 1 foot, and more than 100 feet long.	▫ Potential indication of pipeline settlement.	▫ During annual ground inspection.					**X**
Ponding	▫ Extend over the pipe axis, deeper than 1 foot, and more than 100 feet long.	▫ Continued deepening of depression through freeze/thaw cycle.	▫ During the routine DOT ROW inspections. ▫ During annual ground inspection.	**X**			and	**X**
Surface Water	▫ Flooding or channel changes where water cannot be diverted and: - Concentrated longitudinal flow on or along the pipeline centerline. - gulling threatening the buried pipe.	▫ Loss of pipe cover or potential loss of pipe ground support.	▫ During the routine DOT ROW inspections. ▫ During annual ground inspection.	**X**			and	**X**
Erosion of Riser Pad	▫ Deterioration of the gravel riser pad more than 12" from the original crown/toe profiles.	▫ Detection during or immediately after break-up and during time of maximum thaw rate allows for prevention and/or mitigation of erosion consequences.	▫ During the routine DOT ROW inspections. ▫ During annual ground inspection.	**X**			and	**X**
Damage at Risers	▫ Significant indentations, cracks, missing foam insulation.	▫ Potential loss of structural support	▫ During annual ground inspection.					**X**

Appendix B - Components of the SPCO-approved Surveillance and Monitoring Program

ROW Surveillance (cont'd)

During Construction / Projects / Rehabilitation								
	ROW REPORTING CONDITION	RATIONALE/CONCERN	BPXA SURVEILLANCE	Aerial		Driving		Ground
Fish	▫ Insure no blockage of fish passage (e.g. cables hanging below the pipe) ▫ Fish Exclusion Screen (if required) on water intake not functioning properly.	▫ Check trench fill until stable to ensure fish habitat is not adversely disturbed. ▫ Fish Exclusion Screens prevent fish from being sucked into pumps during dewatering, etc.	▫ Ongoing.					**X**
Vegetation Rehabilitation	▫ Check rehabilitation sites for expected results.	▫ Detect need for additional treatment early in growing season and evaluate growth at end of growing season.	▫ Study program to be developed and re-evaluation as required.					**X**
Brown Bears	▫ Coordinate with ADF&G on bear den locations along the ROW ▫ Notify security if bear observations and/or human interactions occur. Security will complete the appropriate form, forward the information to BPXA Wildlife Studies in Anchorage, and notify ADF&G of any occupied dens encountered.	▫ Identify den locations and prevent human/ bear interaction. ▫ ADF&G permit is needed to conduct activities within 1/2 mile of any known grizzly bear dens.	▫ Ongoing.	Phone calls, as necessary.				
Polar Bears	▫ Coordinate with USF&WS on bear den locations along the ROW. ▫ Notify security if bear observations and/or human interactions occur. Security will complete the appropriate form, forward the information to BPXA Wildlife Studies in Anchorage, and notify USF&WS of any occupied dens encountered.	▫ Identify den locations and prevent human/ bear interactions ▫ USFWS permit is needed to conduct activities within 1 mile of known polar bear dens.	▫ Ongoing.	Phone calls, as necessary.				
Endangered or Threatened Species	▫ Check for presence of bird nests on or near pipeline ROW. ▫ Determine if the Commissioner has declared any Zones of Restricted Activities on or near the pipeline ROW. ▫ Document the presence of any species specified by the Commissioner.	▫ Detect nesting - a USFWS permit may be required if a bird nest is to be disturbed. ▫ Detect the presence of threatened or endangered species. Dead or alive - agency notification may be necessary. Contact your Environmental Advisor.	▫ Between break-up to freeze-up during the routine DOT ROW inspections ▫ During annual ground inspection.			**X**	and	**X**

Appendix B - Components of the SPCO-approved Surveillance and Monitoring Program

Monitoring

	DOT Communications	Smart Pigging – Mapping (Geometry)	Smart Pigging – Metal Loss	Cathodic Protection	Monitor Pressure of Nitrogen/Natural Gas Blanket	Test for Galvanic Isolation between Duplex and Carbon Steel Pipe	Ice Gouge / Strudel Scour	Shoreline / River Bank Erosion
Badami Sales Oil *In-Service*	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Citation:*** 49 CFR 195.452 ***Frequency:*** Baseline pigging conducted, then only on as needed basis.	***Citation:*** 49 CFR 195.452 ***Frequency:*** Not to exceed 5 years.	***Citation:*** 49 CFR 195.571 and .573 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Not applicable*** while pipeline is in service	***Not applicable.***	***Not Applicable.*** This is an onshore facility.	***Drivers:*** U.S. Army Corps of Engineers and AK Dept. of Fish and Game ***Frequency:*** 3 inspections / summer
ADNR Out-of-Service / DOT Abandoned	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Not Applicable.*** Idled; in Warm Shutdown	***Not Applicable.*** Idled; in Warm Shutdown	***Citation:*** 49 CFR 195.465 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Applicable.*** Frequency determined during shutdown's Management of Change.	***Not applicable.***	***Not Applicable.*** This is an onshore facility.	***Drivers:*** U.S. Army Corps of Engineers and AK Dept. of Fish and Game ***Frequency:*** 3 inspections / summer
Badami Gas Utility *In-Service*	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Not Applicable.*** Only required for underground sales oil pipeline.	***Not Applicable.*** This is a gas pipeline.	***Citation:*** 49 CFR 195.465 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Not applicable*** while pipeline is in service.	***Not applicable.***	***Not Applicable.*** This is an onshore facility.	***Drivers:*** U.S. Army Corps of Engineers and AK Dept. of Fish and Game ***Frequency:*** 3 inspections/summer
ADNR Out-of-Service / DOT Abandoned	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Not Applicable.*** Only required for underground sales oil pipeline.	***Not Applicable.*** This is a gas pipeline.	***Citation:*** 49 CFR 195.465 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Applicable.*** Frequency determined during shutdown's Management of Change.	***Not applicable.***	***Not Applicable.*** This is an onshore facility.	***Drivers:*** U.S. Army Corps of Engineers and AK Dept. of Fish and Game ***Frequency:*** 3 inspections / summer
Endicott *In-Service*	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Not Applicable.*** Endicott pipeline is 100% aboveground.	***Citation:*** 49 CFR 195.452 ***Frequency:*** Not to exceed 5 years.	***Not Applicable.*** Endicott pipeline is 100% aboveground.	***Not applicable*** while pipeline is in service.	***Not applicable.***	***Not Applicable.*** This is an onshore facility.	***Not Applicable.*** This is an onshore facility.

Appendix B - Components of the SPCO-approved Surveillance and Monitoring Program

Monitoring (cont'd)

	DOT Communications	Smart Pigging – Mapping (Geometry)	Smart Pigging – Metal Loss	Cathodic Protection	Monitor Pressure of Nitrogen/Natural Gas Blanket	Test for Galvanic Isolation between Duplex and Carbon Steel Pipe	Ice Gouge / Strudel Scour	Shoreline / River Bank Erosion
Milne Sales Oil *In-Service*	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Not Applicable.*** Milne pipeline is 100% aboveground.	***Citation:*** 49 CFR 195.452 ***Frequency:*** Not to exceed 5 years.	***Not Applicable.*** Milne pipeline is 100% aboveground.	***Not applicable*** while pipeline is in service.	***Applicable:*** Annually	***Not Applicable.*** This is an onshore facility.	***Not Applicable.*** This is an onshore facility.
Milne Product *In-Service*	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Not Applicable.*** Milne pipeline is 100% aboveground.	***Citation:*** 49 CFR 195.452 ***Frequency:*** Not to exceed 5 years.	***Not Applicable.*** Milne pipeline is 100% aboveground.	***Not applicable*** while pipeline is in service.	***Not applicable.***	***Not Applicable.*** This is an onshore facility.	***Not Applicable.*** This is an onshore facility.
ADNR Out-of-Service / DOT Abandoned	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Not Applicable.*** Milne pipeline is 100% aboveground.	***Not Applicable.*** Idled; in Warm Shutdown	***Not Applicable.*** Milne pipeline is 100% aboveground.	***Applicable.*** Frequency determined during shutdown's Management of Change.	***Not applicable.***	***Not Applicable.*** This is an onshore facility.	***Not Applicable.*** This is an onshore facility.
Northstar Sales Oil *In-Service*	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Citation:*** 49 CFR 195.452 ***Frequency:*** Minimum of 2 runs were made prior to reaching 85°F; 1x/yr for next 2 years following date that 85°F is achieved.	***Citation:*** 49 CFR 195.452 ***Frequency:*** Not to exceed 5 years.	***Citation:*** 49 CFR 195.571 and .573 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Not applicable*** while pipeline is in service.	***Not applicable.***	***Frequency:*** Evaluate annually until SPCO determines longer intervals will provide adequate monitoring.	***Driver:*** U.S. Army COE Plan ***Frequency:*** Annual ***Driver:*** USACE Permit 950372 ***Frequency:*** Annual
Northstar Gas *In-Service*	***Citation:*** 49 CFR 195.408 ***Frequency:*** The 24/7 on-site operation ensures DOT communication requirements are met.	***Not required by DOT*** for gas pipelines.	***Citation:*** 49 CFR 195.911 ***Frequency:*** Not to exceed 5 years.	***Citation:*** 49 CFR 195.465 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Not applicable*** while pipeline is in service.	***Not applicable.***		

Appendix B - Components of the SPCO-approved Surveillance and Monitoring Program

Maintenance

	MAINTENANCE ACTIVITIES		
	DOT Mainline Valve Inspections and Maintenance	*DOT* Mainline Relief Valves on Liquid Pipelines	Maintenance Pigging Frequency
Badami Sales Oil *In-Service*	***Citation:*** 49 CFR 195.420 ***Frequency:*** 2x/calendar year (interval not to exceed 7.5 months)	***Not Applicable.*** Over pressurizing devices not installed because the maximum pump pressure is < the pipeline's Maximum Allowable Operating Pressure.	Frequency adjusted based on crude stream, BS&W, and other factors.
Out-of-Service	***Citation:*** 49 CFR 195.420 ***Frequency:*** 2x/calendar year (interval not to exceed 7.5 months)	***Not Applicable.***	***Not Applicable.***
Badami Gas Utility *In-Service*	***Citation:*** 49 CFR 192.745 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Not Applicable.***	***Not Applicable.***
Out-of-Service	***Citation:*** 49 CFR 192.745 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Not Applicable.***	***Not Applicable.***
Endicott *In-Service*	***Citation:*** 49 CFR 195.420 ***Frequency:*** 2x/calendar year (interval not to exceed 7.5 months)	***Not Applicable.*** Over pressurizing devices not installed because the maximum pump pressure is < the pipeline's Maximum Allowable Operating Pressure.	Frequency adjusted based on crude stream, BS&W, and other factors.
Milne Sales Oil *In-Service*	***Citation:*** 49 CFR 195.420 ***Frequency:*** 2x/calendar year (interval not to exceed 7.5 months)	***Citation:*** 49 CFR 195.428 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	Frequency adjusted based on crude stream, BS&W, and other factors.

Maintenance (cont'd)

	MAINTENANCE ACTIVITIES		
	DOT **Mainline Valve Inspection and Maintenance**	***DOT*** **Mainline Relief Valves on Liquid Pipelines**	**Maintenance Pigging Frequency**
Milne Product *In-Service*	***Citation:*** 49 CFR 195.420 ***Frequency:*** 2x/calendar year (interval not to exceed 7.5 months)	***Citation:*** 49 CFR 195.428 ***Frequency:*** 2x/calendar year (interval not to exceed 7.5 months)	Frequency adjusted based on crude stream, BS&W, and other factors.
Out-of-Service	***Citation:*** 49 CFR 195.420 ***Frequency:*** 2x/calendar year (interval not to exceed 7.5 months)	***Not Applicable.***	***Not Applicable.***
Northstar Sales Oil *In-Service*	***Citation:*** 49 CFR 195.420 ***Frequency:*** 2x/calendar year (interval not to exceed 7.5 months)	***Not Applicable.*** Over pressurizing devices not installed because the maximum pump pressure is < the pipeline's Maximum Allowable Operating Pressure.	Frequency adjusted based on crude stream, BS&W, and other factors.
Northstar Gas *In-Service*	***Citation:*** 49 CFR 192.745 ***Frequency:*** 1x/calendar year (interval not to exceed 15 months)	***Not Applicable.***	***Not Applicable.***

Appendix C

Walking Speed Surveys Summary

APPENDIX C - 2013 Walking Speed Surveys Summary

	ROW REPORTING CONDITION	Badami Sales Oil	Badami Utility	Endicott Pipeline	Milne (Sales Oil)	Milne Product	Northstar Oil	Northstar Gas
ENVIRONMENTAL								
Oil Spills or Leaks	• Any spill or leak; report via BPXA Spill Reporting System	**2013:** 1 spill **2012:** 1 spill **2011:** 2 spills,1 leak (non-reportable release)	**2013:** None reported **2012:** 1 leak (non-reportable release) **2011:** 2 spills, 1 leak (non-reportable release)	**2013:** 1 spill, 1 leak (non-reportable release) **2012:** 1 spill, 2 leaks (non-reportable releases) **2011:** 1 leak (non-reportable release)	**2013:** 1 spill, 1 leak (non-reportable release) **2012:** 1 spill, 1 leak (non-reportable release) **2011:** 4 leaks (non-reportable releases)	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** 1 spill, 1 leak (non-reportable release)	**2013:** None reported **2012:** 2 leaks, (non-reportable releases) **2011:** None reported
Erosion	• Bank erosion causing increased water turbidity • Thermal erosion causing the formation of additional open water areas or ground depressions • Erosion of the gravel pad(s), including valve pads	**2013:** 1 inadequate grade coverage over road crossing casing **2012:** 1 inadequate coverage on road crossing **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** Slight erosion on west side of gravel pad, not affecting casing depth of cover **2012:** None reported **2011:** None reported	**2013:** Slight erosion on west side of gravel pad, not affecting casing depth of cover **2012:** None reported **2011:** None reported	**2013:** 2 areas of inadequate grade coverage **2012:** 2 inadequate grades above road crossing casings **2011:** 2009 matting is still preventing erosion	**2013:** 2 areas of inadequate grade coverage **2012:** 2 inadequate grades above road crossing casings **2011:** 2009 matting is still preventing erosion
Wildlife Blockage	• Evidence that wildlife movements are blocked	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** 1 area gravel was removed over caribou crossing casing **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
PIPELINES / MAINLINE VALVES								
Public Access	• Unauthorized Entry • Vandalism • Sabotage • Restricted access along shoreline	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
VSM	• Evidence of tilting, settlement, or jacking • Scouring that could affect integrity of VSM	**2013:** None reported **2012:** 1 VSM jacked, 1 settlement of VSM support **2011:** 1 VSM jacked	**2013:** 2 VSMs jacking **2012:** 4 VSMs jacked, 3 VSM pipe support settlement **2011:** 2 VSM settlements, 3 VSM alignments	**2013:** 3 locations w/ VSM jacking **2012:** 4 VSMs jacked, 1 VSM subsidence **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** 3 VSM horizontal misalignments	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** 1 VSM jacked **2011:** None reported	**2013:** None reported **2012:** 1 VSM jacked **2011:** 1 VSM settlement
Sloping crossbeam	• Visible sloping • Visible tilting	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Tilted Saddle	• Out-of-level conditions that result in an edge between any part of the saddle and any part of the crossbeam or pipe	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** 1 slipped saddle	**2013:** None reported **2012:** None reported **2011:** 159 tilted saddles, 1 saddle cradle bent	**2013:** None reported **2012:** None reported **2011:** 1 saddle misaligned	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** 1 saddle suspended above crossbeam
Saddle suspended above crossbeam	• Anywhere the saddle is not in contact with the crossbeam	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** 1 location where pipeline is in contact w/ adjacent pipeline saddle **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None **2011:** 1 saddle not bearing weight	**2013:** 1 saddle not bearing weight **2012:** None **2011:** 1 saddle not bearing weight	**2013:** None reported **2012:** 1 slipped saddle **2011:** 1 saddle not bearing weight	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported

APPENDIX C - 2013 Walking Speed Surveys Summary

	ROW REPORTING CONDITION	Badami Sales Oil	Badami Utility	Endicott Pipeline	Milne (Sales Oil)	Milne Product	Northstar Oil	Northstar Gas
Failed anchor	• Anchors that have visibly moved, are out of level, or with broken welds	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** 18 anchors need sealing, some end caps needed	**2013:** None reported **2012:** 12 anchors need seals, 1 anchor lifted off of HSM **2011:** 15 anchors need seals	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
PIPELINES / MAINLINE VALVES (CONTINUED)								
Gap between the pipe and saddle	• Any gap	**2013:** None reported **2012:** None reported **2011:** Flange on HSM bent	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** 1 gap between saddle and pipe	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Pipeline Vibration	• Amplitudes above 0.5 inches	**2013:** None reported **2012:** None **2011:** Flange on HSM bent	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** Flange on HSM bent	**2013:** None reported **2012:** None **2011:** Flange on HSM bent	**2013:** 2 locations where wind induced vibration of 1 inch **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Pipeline Vibration Dampeners	• Missing or broken parts • Out-of-location or misalignment NOTE: Misalignment greater than 45° requires immediate reporting.	**2013:** 1 TVA tilting **2012:** None **2011:** 1 loose TVA weight, 3 TVA missing or intermittent installation, 54 TVAs misaligned or snubbers resting on insulation	**2013:** 64 vibration dampeners with broken or missing parts, 2 TVAs tilted out of position **2012:** 114 vibration dampeners missing/broken parts, 80 PVDs misaligned, 8 TVAs tilting > 45° **2011:** 157 Vibration dampeners with missing or broken parts, 23 misaligned PVDs, 2 PVDs missing, 127 misaligned TVAs, 151 TVAs with missing or broken parts, 4 TVAs rotated 180 degrees, 1 TVA resting at 45 degrees	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** 106 vibration dampener grommets broken or missing **2012:** 18 vibration dampeners broken or missing **2011:** 57 dampener issues	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** 1 TVA tilted **2012:** 3 missing snubbers on TVAs, 1 vibration absorber tilted 40° **2011:** 10 TVAs missing snubbers, 2 TVAs out of alignment	**2013:** None reported **2012:** 2 missing snubbers on TVAs **2011:** 2 TVAs out of alignment; 1 missing snubber on TVA, 3 missing nylon EPDM liners
Damaged piping insulation at risers	• Significant indentations, cracks, missing foam insulation	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	Not Applicable	Not Applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported

APPENDIX C - 2013 Walking Speed Surveys Summary

	ROW REPORTING CONDITION	Badami Sales Oil	Badami Utility	Endicott Pipeline	Milne (Sales Oil)	Milne Product	Northstar Oil	Northstar Gas
PIPELINES / MAINLINE VALVES (CONTINUED)								
Damaged Piping or Components	Any significant damage, including: ✓ Pipeline dents ✓ VSM dents greater than ¾ inch in depth and 9 inches in length ✓ VSM gouges deeper than 1/8 inch ✓ VSM cracks ✓ Structural damage such as cracks or broken parts on the clamps, saddle assembly, crossbeam, brackets, weld packs, or anchor assembly components ✓ Saddle base deformed over the crossbeam ✓ Bullet holes ✓ Damaged sheet metal or insulation or FBE coating ✓ Any damage to valves, supporting structures	**2013:** 2 PIDs w/o calibration dates, 1 missing insulation end cap, 1 torn insulation blanket,40 coating failures on valve bodies, 1 broken banding strap, 1 missing clamp liner, 2 insulation separations w/ caulking failure, 2 jacketing discolorations, 26 crushed insulation, 2 dented VSMs. **2012:** 40 coating failures of valve bodies, 2 broken banding straps, 1 tubing damage, 3 areas interference w/ Badami Gas P/L, 1 HSM flange bent, 1 jacket discoloration, 1 jacket separation, 3 sheet metal perforations, 1 East Kad jacketing perforation, 104 crushed insulation, 1 West Sag marker broken, **2011:** 5 saddles slipped, 2 saddles need metal straps, 2 guides bent, 1 valve missing insulation, 1 area of broken sheet metal banding straps, 1 small fastener on saddle cushion missing, 1 perforation on snow shelter	**2013:** 441 findings of coating damage, 4 sheet areas of metal exposing pipe wrapping, 9 slipped saddle plates, 1 DOT Line Marker missing, 2 PIDs w/ no calibration stickers, 2 coating failures on piping, 10 findings of mastic missing or sealant failure on anchor caps, 2 findings of insulation missing, 4 torn blankets **2012:** 714 various coating damage, 1 coating failure, 2 HSM flanges bent, 1 U-bolt bent, 16 missing sheet metal, 1 damaged insulation jacketing, 5 areas of exposed insulation, 2 pipeline markers broken, 1 pressure device issue, 1 valve insulation damaged. **2011:** 242 coating damage, 3 bent flanges on HSMs, 1 torn insulation blanket, 2 rubber type boots separated, 1 threaded connection on process side of pig launcher, 1 shallow gouge near weld	**2013:** 210 locations with sheet metal separations at well packs, 62 locations with sheet metal perforations, 13 locations with crushed insulation jacketing, 4 broken signs **2012:** 1 coating failure on valve, 79 sheet metal separations, 14 surface corrosion of jacketing, 7 sheet metal perforations, 9 crushed insulation jacketing, 3 line markers broken and/or illegible, 1 Pressure Indicator w/ no calibration date **2011:** 98 sheet metal issues, 25 insulation issues, 1 web damage, 2 flanges bent, 1 corrosometer hanging,1 Teflon slide missing, 1 HSM issue, FS2 GTL in contact w/ Endicott P/L	**2013:** 112 areas of insulation banding missing, 98 areas of insulation discolored, 21 sheet metal perforations, 51 insulation jacketing crushed, 4 saddles missing banding straps. **2012:** 57 saddle and insulation banding straps missing or broken, 35 insulation separation and caulking failure, 56 discolored insulation jacketing, 1 missing insulation, 11 sheet metal perforations, 102 insulation jacketing crushed **2011:** 8 broken/missing straps, 2 twisted HSMs, 5 bent or sheared guides, 1 saddle cradle bent; 48 areas insulation separation missing straps at weld packs, 4 crushed insulation, 5 perforated insulations	**2013:** 1 saddle with broken and missing bands, 4 sheet metal perforations **2012:** 5 coating failures, 6 insulation separation and caulking failures, 15 sheet metal perforations, 51 insulation jacketing crushed **2011:** 5 sheet metal perforations, 2 insulation issues, 2 insulation issues	**2013:** 16 coating failures, 1 broken insulation band, 3 valves w/ holes in bonnets, 5 insulation separations or failures, 13 insulation jacketing discolored/stained, 4 locations of missing sheet metal,8 locations of punctured insulation or jacketing, 25 locations of insulation jacketing crushed/dented, 2 PID calibration issues, 1 marker missing **2012:** 16 coating failures, 1 missing sheet metal screw, 5 insulation separations, 1 insulation crushed/separation, 3 rusted insulation jacketing, 1 missing insulation jacketing, 2 insulation punctures, 2 sheet metal perforations, 3 crushed insulation jacketing, 22 crushed and dented insulation jacketing, 2 pressure indicator devices w/ expired calibration, 1 pipeline sag **2011:** 1 missing support under saddle, 11 insulation perforations, 1 crushed insulation.	**2013:** 20 coating failures including a bent saddle, 3 insulation separations, 14 insulation jacketing discoloration, 2 locations of punctured insulations, 13 locations of insulation jacketing crushed, 4 PID calibration issues, 2 missing markers **2012:** 13 coating failures, 4 crushed/separated insulation, 4 rusted insulation jacketing, 2 insulation punctures, 52 crushed insulation jacketing, 2 missing pipeline markers, 3 pressure devices w/expired calibration **2011:** 1 missing saddle support, 20 insulation perforations and separations, 1 broken saddle strap, 2 HSM's with damage, 1 deformed saddle, 2 dents in insulation
Putuligayuk River Pile Scouring	<u>Northstar-specific</u> • Depth of scour shall not exceed 4 ft. from zero mark on pile	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Hump or Swales	• Pressure ridges develop parallel to the pipe axis and exceed 1 ft. in height and 60 ft. in length • Accompanied by ground cracking	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Ground Cracking	• Cracks within 10 ft. of pipeline centerline with one of the following characteristics: - At least 10 ft. long with vertical displacement exceeding 6 inches - Wider than 2 inches, parallel to the pipe axis, and longer than 60 ft.	**2013:** None reported by ABR, Inc. **2012:** None reported by ABR, Inc. **2011:** OASIS 2011 Report stated corrective actions are not warranted	**2013:** None reported by ABR, Inc. **2012:** None reported by ABR, Inc. **2011:** OASIS 2011 Report stated corrective actions are not warranted	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported

APPENDIX C - 2013 Walking Speed Surveys Summary

	ROW REPORTING CONDITION	Badami Sales Oil	Badami Utility	Endicott Pipeline	Milne (Sales Oil)	Milne Product	Northstar Oil	Northstar Gas
Cased Pipe	▪ Debris, water, or blockage between casing and pipe	**2013:** 1 casing misalignment, seasonal drainage at various locations **2012:** Seasonal drainage at various locations **2011:** Seasonal drainage at various locations	**2013:** 1 casing misalignment, seasonal drainage at various locations **2012:** Seasonal drainage at various locations **2011:** Seasonal drainage at various locations	**2013:** Seasonal drainage at various locations **2012:** Seasonal drainage at various locations **2011:** Seasonal drainage at various locations	**2013:** Seasonal drainage at various locations **2012:** 1 casing centralizer broken, Seasonal drainage at various locations **2011:** Seasonal drainage at various locations	**2013:** None reported **2012:** 4 casing spacer/ centralizers broken, Seasonal drainage at various locations **2011:** Seasonal drainage at various locations	**2013:** 1 location where pipeline is in contact w/casing, seasonal drainage at various locations **2012:** Seasonal drainage at various locations **2011:** Seasonal drainage at various locations	**2013**: Seasonal drainage at various locations **2012:** Seasonal drainage at various locations **2011:** Seasonal drainage at various locations
MODULES / BUILDINGS								
Damage	• Leaks around fuel storage containers • Any damage to communication sites and/or support structures • Debris or corrosion around building sumps	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None **2011:** 3 communication issues, ladder repair needed	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Foundation Movement	• Any settlement or jacking at communication sites and/or support structures	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Fuel/Gas Leak	• Any odor or monitor detection	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported

APPENDIX C - 2013 Walking Speed Surveys Summary

	ROW REPORTING CONDITION	Badami Sales Oil	Badami Utility	Endicott Pipeline	Milne (Sales Oil)	Milne Product	Northstar Oil	Northstar Gas
During Construction / Projects / Rehabilitation (Continued)								
Fish	• Insure no blockage of fish passage (e.g., cables hanging below the pipe) • *Fish Exclusion Screen* (if required) on water intake not functioning properly	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Vegetation Rehabilitation	• Check rehabilitation sites for expected results	**2013:** In July, new growth of indigenous sedges was abundant around the mat and was growing through it. In August, vegetation was observed to be even taller and more robust. **2012:** During June inspection dormant grasses appeared to be well established. New vegetative growth seen in subsequent inspections. **2011:** Seeded areas are established and growing through erosion fabric, as intended		Not applicable	Not applicable	Not applicable	**2013:** 2009 matting is minimizing erosion of trench side slope. An erosion gully beneath the fabric has developed. In 20214, Cocomat tubes full of soil will be installed and sprigged with *Leymus mollis*. **2012:** 2009 matting is still preventing erosion **2011:** 2009 matting is still preventing erosion	
Brown Bears	• Coordinate with ADF&G on bear den locations along the ROW • Notify security if bear observations and/or human interactions occur. Security will complete the appropriate form, forward the information to BPXA Wildlife Studies in Anchorage, and notify ADF&G of any occupied dens encountered.	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Polar Bears	• Coordinate with USF&WS on bear den locations along the ROW • Notify security if bear observations and/or human interactions occur. Security will complete the appropriate form, forward the information to BPXA Wildlife Studies in Anchorage, and notify USF&WS of any occupied dens encountered.	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Endangered or Threatened Species	• Check for presence of bird nests on or near pipeline ROW • Determine if the Commissioner has declared any Zones of Restricted Activities on or near pipeline ROW. • Document the presence of any species specified by the Commissioner.	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported

APPENDIX C - 2013 Walking Speed Surveys Summary

	ROW REPORTING CONDITION	Badami Sales Oil	Badami Utility	Endicott Pipeline	Milne (Sales Oil)	Milne Product	Northstar Oil	Northstar Gas
Badami and Northstar: River, Shoreline, Floodplain Crossings, and Offshore Pipelines								
Exposed Pipe	• Any evidence of exposed pipe at shore crossing • Any evidence of exposed pipe between the risers	**2013:** None reported **2012:** 1 area of bare pipe **2011:** None	**2013:** None reported **2012:** None reported **2011:** None reported	Not applicable	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** 2 areas of bare pipe **2011:** None
Bank Erosion	• Banks at shore crossing are caving within 25 ft. of the riser • Bank erosion causing increased water turbidity	**2013:** Weir remains stabilized and functioning as designed, grasses and sedges appear to be well established. **2012:** Weir remains stabilized and functioning as designed, new vegetative growth seen in July inspection **2011:** Weir remains stabilized, Seeded areas are established and growing through erosion fabric, as intended	**2013:** Weir remains stabilized and functioning as designed, grasses and sedges appear to be well established. **2012:** Weir remains stabilized and functioning as designed, new vegetative growth seen in July inspection **2011:** Weir remains stabilized, Seeded areas are established and growing through erosion fabric, as intended	Not applicable	Not applicable	Not applicable	**2013:** See Coastal Frontier's 2013 Stability Analysis **2012:** See Coastal Frontier's 2012 Stability Analysis **2011:** See Coastal Frontier's 2011 Stability Analysis	
Erosion of Riser Pad	• Deterioration of the gravel riser pad more than 12 inches from the original crown/toe profile	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	Not applicable	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Damage at Risers	• Significant indentations, cracks, missing foam insulation	**2013:** 1 insulation missing in riser **2012:** 1 area of jacketing perforation at east Kadleroshilik River **2011:** 6 areas of Ethafoam and/or deteriorated jacketing	**2013:** 2 findings of damaged insulation inside river crossing vaults. **2012:** Valve insulation damaged at East Kadleroshilik River **2011:** 6 areas of deteriorated Ethafoam and/or jacketing	Not applicable	Not applicable	Not applicable	**2013:** 1 sediment build-up in vault, 1 finding of piping submerged underwater **2012:** None reported **2011:** None reported	**2013:** 1 sediment built-up in vault, 1 finding of piping submerged underwater **2012:** None reported **2011:** None reported
Flooding	• Conditions which reduce the setback by eroding the banks or threaten a facility or pipeline	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	Not applicable	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Channel Obstruction	• Threatens to cause erosion or flooding of the setback or pipeline facilities	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	Not applicable	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Channel Change	• Change in the river channel flow at the river crossings	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	Not applicable	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Depressions	• Occur longitudinally over pipe axis, are deeper than 1 foot, and are more than 100 ft. long	**2013:** 1 finding of ground depression **2012:** Same as last year **2011:** Same as last year	**2013:** 1 finding of ground depression **2012:** Same as last year **2011:** Same as last year	Not applicable .0ble	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported

APPENDIX C - 2013 Walking Speed Surveys Summary

	ROW REPORTING CONDITION	Badami Sales Oil	Badami Utility	Endicott Pipeline	Milne (Sales Oil)	Milne Product	Northstar Oil	Northstar Gas
Ponding	• Extend over the pipe axis, deeper than 1 foot, and more than 100 ft. long	**2013:** None reported by ABR, Inc. **2012:** None reported by ABR, Inc. **2011:** OASIS 2011 Report stated corrective actions are not warranted	**2013:** None reported by ABR, Inc. **2012:** None reported by ABR, Inc. **2011:** OASIS 2011 Report stated corrective actions are not warranted	Not applicable	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported
Surface Water	• Flooding or channel changes where water cannot be diverted and: - Concentrated longitudinal flow on or along the pipeline centerline - Gullying threatening the buried pipe	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported	Not applicable	Not applicable	Not applicable	**2013:** None reported **2012:** None reported **2011:** None reported	**2013:** None reported **2012:** None reported **2011:** None reported

Appendix D

2013 Monitoring Program Summary

Appendix D - 2013 Monitoring Program Summary

	DOT Communications	Smart Pigging - Mapping (Geometry)	Smart Pigging - Metal Loss	Cathodic Protection	Monitor Nitrogen/ Natural Gas Blanket	Test for Electrical Isolation	Ice Gouge and Strudel Scour	Shoreline / River Bank Erosion
Badami Sales Oil *In-Service*	**Citation:** **49 CFR 195.408** **Frequency:** The 24/7 on-site operation ensures DOT communication requirements are met. **2013 Changes:** None	**Citation:** 49 CFR 195.452 **Frequency:** Not to exceed 5 years. **2013 Changes:** Inspection frequency was changed from 3 to 5 years per the new BPXA criteria. **Proposed Action:** Next ILI run scheduled for 2015.	**Citation:** 49 CFR 195.452 **Frequency:** Not to exceed 5 years. **2013 Changes:** Inspection frequency was changed from 3 to 5 years per the new BPXA criteria. **Proposed Action:** Next ILI run scheduled for 2015.	**Citation:** 49 CFR 195.571 and .573 **Frequency:** 1x/calendar year (interval not to exceed 15 months). **2013 Changes:** None **Proposed Action:** Continue inspections.	**Not Applicable.** This pipeline is in service.	**Citation:** 49 CFR 195.575 **Frequency:** 1x/calendar year (interval not to exceed 15 months). **2013 Changes:** A valve isolation kit was installed in 2013. **Proposed Action:** Validate the isolation in 2014.	**Not Applicable.** This is an onshore facility.	**Sag River Inspections Drivers:** U.S. Army Corp of Engineers (USACE) and AK Dept. of Fish and Game **Frequency:** 3 inspections/summer **2013 Changes:** Grasses and sedges appear to be well established. **Proposed Action:** Continue summer inspections. Continue to monitor small erosional rills and welding crack on weir. --- **Additional Shav River Rehabilitation Report Driver:** SPCO **2013 Changes:** During site visit, productive, species-rich cover of vascular plants was found established on the backfilled trench. **Proposed Action:** Follow up ground Monitoring in 2016 and 2021.
Badami Utility *In Service*	**Frequency:** The 24/7 on-site operation ensures DOT communication requirements are met. **2013 Changes:** None	**Not Applicable.** The Utility (gas) Pipeline is not in a High Consequence Area, as defined by DOT.	**Not Applicable.** The Utility (gas) Pipeline is not in a High Consequence Area, as defined by DOT.	**Citation:** 49 CFR 192.465 **Frequency:** 1x/calendar year (interval not to exceed 15 months). **2013 Changes:** None **Proposed Action:** Continue inspections.	**Not Applicable.** This pipeline is in service.	**Citation:** 49 CFR 192.467 **Frequency:** 1x/calendar year (interval not to exceed 15 months). **2013 Changes:** A valve isolation kit was installed in 2013. **Proposed Action:** Validate the isolation in 2014.	**Not Applicable.** This is an onshore facility.	
Endicott *In-Service*	**Citation:** **49 CFR 195.408** **Frequency:** The 24/7 on-site operation ensures DOT communication requirements are met. **2013 Changes:** None	**Not Applicable.** Endicott Pipeline is 100% aboveground.	**Citation:** 49 CFR 195.452 **Frequency:** Not to exceed 5 years. **2013 Changes:** Inspection frequency was changed from 3 to 5 years per the new BPXA criteria. **Proposed Action:** Next ILI run scheduled for 2014.	**Not Applicable.** Endicott Pipeline is 100% aboveground.	**Not Applicable.** This pipeline is in service.	**Not Applicable.**	**Not Applicable.** This is an onshore facility.	**Not Applicable.** This is an onshore facility.

Appendix D - 2013 Monitoring Program Summary

	DOT Communications	Smart Pigging - Mapping (Geometry)	Smart Pigging - Metal Loss	Cathodic Protection	Monitor Nitrogen/ Natural Gas Blanket	Test for Electrical Isolation	Ice Gouge and Strudel Scour	Shoreline / River Bank Erosion
Milne Sales Oil *In-Service*	**Citation:** **49 CFR 195.408** **Frequency:** The 24/7 on-site operation ensures DOT communication requirements are met. **2013 Changes:** None	**Not Applicable.** Milne pipeline is 100% aboveground.	**Citation:** 49 CFR 195.452 **Frequency:** Not to exceed 5 years. **2013 Changes:** Inspection frequency was changed from 3 to 5 years per the new BPXA criteria. **Proposed Action:** Next ILI run scheduled for 2014.	**Not Applicable.** Milne pipeline is 100% aboveground.	**Not Applicable.** This pipeline is in service.	**Required for:** Isolation flanges between the stainless steel and carbon steel sections. **Frequency:** Annually **2013 Changes:** None – electrical isolation is effective. **Proposed Action:** Continue Annual Inspection.	**Not Applicable.** This is an onshore facility.	**Not Applicable.** This is an onshore facility.
Milne Products *ADNR Out-of-Service / DOT Abandoned*	**Citation:** **49 CFR 195.408** **Frequency:** The 24/7 on-site operation ensures DOT communication requirements are met. **2013 Changes:** None	**Not Applicable.** Milne pipeline is 100% aboveground.	**Not Applicable.** Idled; in Warm Shutdown.	**Not Applicable.** Milne pipeline is 100% aboveground.	**Applicable.** Frequency determined during shutdown's Management of Change.	**Not Applicable.**	**Not Applicable.** This is an onshore facility.	**Not Applicable.** This is an onshore facility.

Appendix D - 2013 Monitoring Program Summary

<table>
<tr><th></th><th>DOT Communications</th><th>Smart Pigging - Mapping (Geometry)</th><th>Smart Pigging - Metal Loss</th><th>Cathodic Protection</th><th>Monitor Nitrogen/ Natural Gas Blanket</th><th>Test for Electrical Isolation</th><th>Ice Gouge and Strudel Scour</th><th>Shoreline / River Bank Erosion</th></tr>
<tr>
<td>Northstar Sales Oil
In-Service</td>
<td>Citation:
49 CFR 195.408
Frequency:
The 24/7 on-site operation ensures DOT communication requirements are met.
2013 Changes:
None</td>
<td>Citation:
49 CFR 195.452
Frequency:
Not to exceed 5 yrs.
2013 Changes:
Inspection frequency was changed from 3 to 5 years per the new BPXA criteria.
Proposed Action:
Next run scheduled for 2017.</td>
<td>Citation:
49 CFR 195.452
Frequency:
Not to exceed 5 yrs.
2013 Changes:
Inspection frequency was changed from 3 to 5 years per the new BPXA criteria.
Proposed Action:
Next run scheduled for 2017.</td>
<td>Citation:
49 CFR 195.571 and.573
Frequency:
1x/calendar year (interval not to exceed 15 months).
2013 Changes:
None
Proposed Action:
Continue inspections.</td>
<td>Not Applicable.
This pipeline is in service.</td>
<td>Citation:
49 CFR 195.575
Frequency:
1x/calendar year (interval not to exceed 15 months).
2013 Changes:
None
Proposed Action:
Continue inspections.</td>
<td rowspan="2">Frequency:
Annual evaluation until SPCO determines longer intervals will provide adequate monitoring.
2013 Changes:
<u>Bathymetric profile</u>
No areas of active subsidence were detected on the pipeline alignment.
<u>Ice Gouging</u>
Nine ice gouges were detected. Five represented newly discovered features.
<u>Ice Wallows</u>
No new wallows were identified during 2013. Two of the 18 wallows discovered in 2011 were found again.
<u>Scouring</u>
Seventy new depressions were discovered. None of the depressions impinged on the backfill
Effects of Changes:
One modest deficiencies of trench backfill thickness was detected off Stump Island.
Although one ice gouge crossed the pipeline alignment, it did not cause the backfill thickness to violate the six foot minimum acceptable value.
The numbers of circular and linear scours were high by historical standards, but the severity of the scouring was relatively low.
Proposed Action:
Continue summer monitoring.</td>
<td rowspan="2">Coastal Stability Analysis:
Required by USACE Plan.
Frequency:
Annual
2013 Changes:
Coastal Frontier's "2013 Coastal Stability Monitoring Report": No erosion mitigation measures are required.
Proposed Action:
Continue annual monitoring.
Rehabilitation Progress Report:
Required by USACE Permit #950372.
Frequency:
Annual
2013 Changes:
ABR, Inc.'s "2013 Rehabilitation Progress Report": Erosion control matting placed on the site in 2009 remains intact. Erosion gulley still exists beneath the netting.
Proposed Action:
In 2014, install cocomat tubes full of soil in the gullied area and sprigged with Leymus mollis.
Continue annual monitoring and reporting.</td>
</tr>
<tr>
<td>Northstar Gas
In-Service</td>
<td>Citation:
49 CFR 195.408
Frequency:
The 24/7 on-site operation ensures DOT communication requirements are met.
2013 Changes:
None</td>
<td>Not Applicable.
Not required by DOT for gas pipelines.</td>
<td>Citation:
49 CFR 192.911
Frequency:
Not to exceed 5 years
2013 Changes:
Inspection frequency was changed from 3 to 5 years per the new BPXA criteria.
Proposed Action:
Next run scheduled for 2017.</td>
<td>Citation:
49 CFR 192.465
Frequency:
1x/calendar year (interval not to exceed 15 months).
2013 Changes:
None
Proposed Action:
Continue inspections.</td>
<td>Not Applicable.
This pipeline is in service.</td>
<td>Citation:
49 CFR 192.467
Frequency:
1x/calendar year (interval not to exceed 15 months).
2013 Changes:
None
Proposed Action:
Continue inspections.</td>
</tr>
</table>

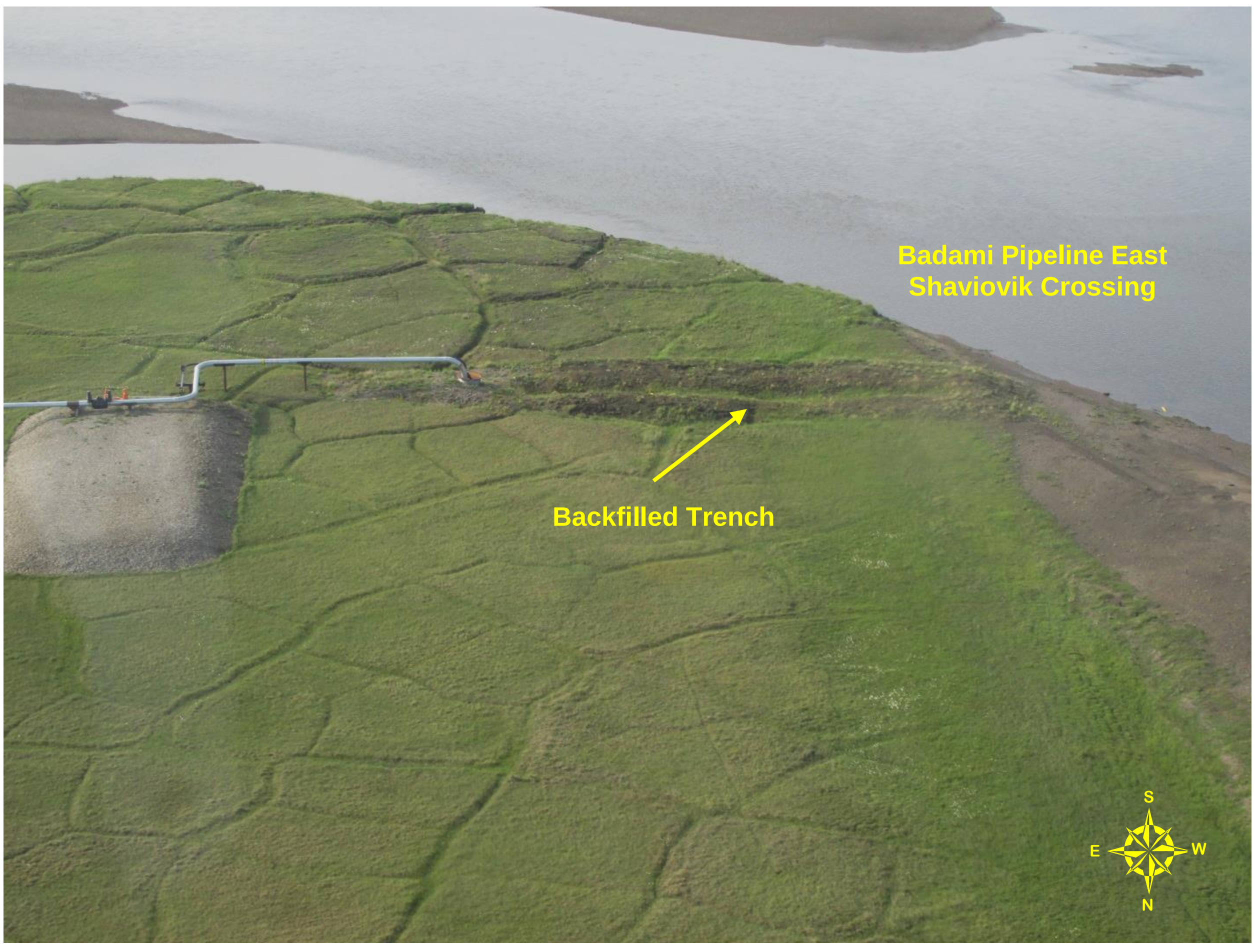
Appendix E

Rehabilitation Report for the Badami Pipeline
East Shaviovik River Crossing

REHABILITATION REPORT FOR THE
BADAMI PIPELINE EAST SHAVIOVIK RIVER CROSSING
PRUDHOE BAY OILFIELD, ALASKA

Prepared by
Janet Kidd / ABR, Inc.—Environmental Research & Services, Fairbanks, AK
and
BP Environmental Studies Group, Anchorage, AK

31 December 2013



Oblique aerial view of the Badami Pipeline East Shaviovik Crossing,
Prudhoe Bay Oilfield, 3 August 2013. Photograph taken by ABR, Inc.

INTRODUCTION

This report was prepared to provide information through 2013 on the Badami Pipeline crossing site located on the east side of the Shaviovik River. This report follows BP Exploration (Alaska), Inc.'s (BPXA) standard format for rehabilitation reports and is the fourth report submitted for this site. The pipeline is routinely monitored to detect leaks or other maintenance issues. The monitoring described here focused on environmental conditions, primarily vegetation, surface stability, and hydrology, as part of an overall assessment of site recovery and integration with the surrounding ecological communities.

LOCATION: The site is located on the east side of the Shaviovik River, approximately 46 km east of Prudhoe Bay (Figure 1). Location coordinates are: 70.146° N and 147.251° W. Access to the site is by helicopter or by shallow-draft boat. The site was accessed by helicopter in 2013.

HISTORY: The Badami Pipeline was constructed in winter 1997–1998, and is mainly aboveground. Buried sections were installed at three river crossings, where spring ice movement could potentially damage an aboveground pipe. Trenches were excavated on both sides of each channel crossing. After installation of the pipe, the trenches were backfilled with gravel and topdressed with overburden. The lengths of the backfilled areas varied from 30–76 m, and the material was mounded approximately 1.5 m above grade to allow for settling.

When the Badami river crossings were inspected in August 1998, no significant subsidence was observed on the east side of the Shaviovik River. During an inspection of the East Shaviovik crossing in 1999 (McKendrick 2000), subsidence was noted along the centerline of the backfilled trench, extending almost its entire length. Site inspections in 2007 and 2011 found good vegetation recovery on the backfilled trench, with no signs of significant additional subsidence or erosion. Comparisons between historic and recent aerial photography also supported the assessment that the area had remained generally stable, with no indications of continued subsidence.

Previous reports were prepared by Lazy Mountain Research (2000), LGL Alaska Research and BPXA (2007), and OASIS Environmental, Inc. and BPXA (2011).

SITE SIZE: The backfilled trench is approximately 40 m long and 14 m wide (0.14 acre).

SITE DESCRIPTION: Vegetation on the surface of the backfilled trench was productive and supported a variety of tundra plant species, predominantly graminoids and forbs (Figure 2). The surrounding vegetation consists mainly of Moist Sedge Meadow Tundra.

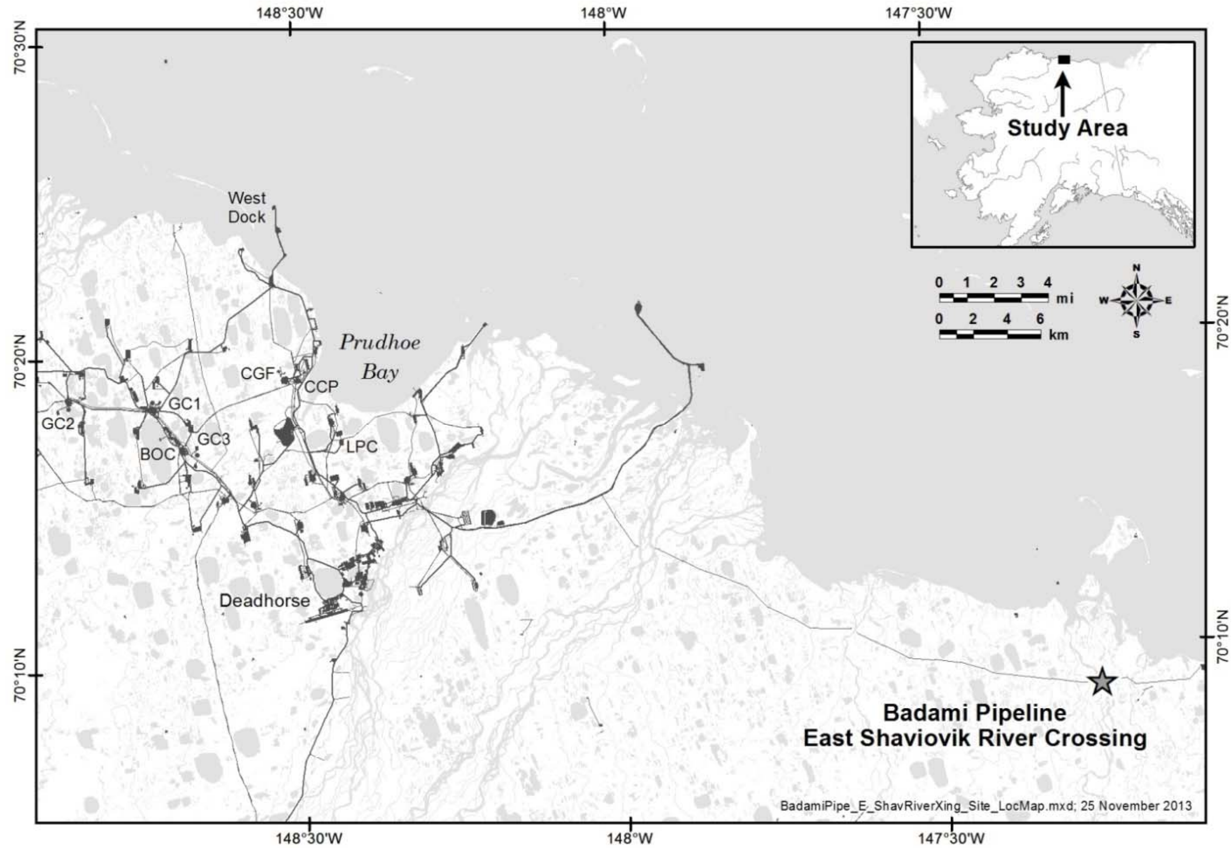


Figure 1. Location of Badami Pipeline East Shaviovik Crossing, Prudhoe Bay Oilfield, Alaska.

Figure 2. Views (facing east) of backfilled trench, Badami Pipeline East Shaviovik Crossing, 13 September 2007 and 3 August 2013.

REHABILITATION GOALS, OBJECTIVES, AND PERFORMANCE STANDARDS: The rehabilitation approach and schedule are summarized in Table 1. No specific performance standards were established for this site.

Table 1. Schedule of rehabilitation treatments applied and monitoring conducted 1998–2013 and planned through 2021, at the Badami Pipeline East Shaviovik Crossing.

1998 (completed)	1999[a] (completed)	2007 & 2011 (completed)	2013 (completed)	2016 and 2021 (planned)
Site Preparation: • Backfill with gravel and topdress with overburden Monitoring: • Qualitative site assessment	Monitoring: • Qualitative site assessment • Repeat photography Summary rehabilitation report	Monitoring: • Qualitative site assessment • Repeat photography Summary rehabilitation report	Monitoring: • Qualitative site assessment • Repeat photography Progress report describing findings	Monitoring: • Qualitative site assessment • Repeat photography Progress reports describing findings

[a] Summary was part of an inspection report of all Badami River crossings (McKendrick 2000).

MONITORING

PLANT MONITORING: Vegetation recovery at the Badami Pipeline East Shaviovik Crossing was qualitatively assessed on 3 August 2013. Plant species were identified by Janet Kidd. Taxonomic nomenclature follows *Flora of Alaska and Neighboring Territories* (Hultén 1968) except for shrubs, which follows *Alaska Trees and Shrubs* (Viereck and Little 2007).

A productive cover of vascular plants has established on the backfilled trench (Figures 2 and 3). No seeding of the site was described in previous reports, but the native-grass cultivars *Puccinellia borealis* (arctic alkaligrass) and *Poa alpina* (alpine bluegrass) were the dominant species present. An additional 25 indigenous species have colonized the site (Table 2), including grasses, forbs, sedges, and shrubs. The central portion of the trench included species commonly associated with moist-to-wet habitats, including *Eriophorum* (cottongrass) spp., *Dupontia fischeri* (Fisher's tundragrass), and *Parnassia kotzebui* (Kotzebue's grass of Parnassus). The margins of the backfilled trench, which are slightly above tundra grade, supported several species commonly associated with riparian habitats such as *Artemisia tilesii* (Tilesius' wormwood), *Epilobium latifolium* (river beauty), *Salix alaxensis* (feltleaf willow), and *Oxytropis borealis* var. *viscida* (viscid locoweed).

ELEVATION MONITORING: The backfilled trench appeared mostly stable in 2013; the topography appeared similar to conditions in 2007 (Figures 2 and 3). Although wetland plant species such as *Carex aquatilis* (water sedge), *Eriophorum angustifolium* (tall cottongrass), and *E. scheuchzeri* (white cottongrass) were colonizing the central portion of the trench, no standing water or evidence of seasonal channels were observed. Similarly, no signs of erosion were noted on the face of the backfilled trench, where it meets the river bank (Figure 4).

Table 2. List of vascular plant species found at the Badami Pipeline East Shaviovik Crossing, 3 August 2013.

Lifeform / Species	Backfilled Trench	Side Slope of Trench
Native Grass Cultivars		
Puccinellia borealis	×	
Poa alpina	×	×
Indigenous Species		
Grasses		
Alopecurus alpinus	×	×
Arctagrostis latifolia	×	×
Dupontia fischeri	×	
Festuca baffinensis	×	×
F. brachyphylla	×	
Poa arctica		×
Trisetum spicatum		×
Sedges and Rushes		
Carex aquatilis	×	×
C. saxatilis	×	
Eriophorum angustifolium	×	
E. scheuchzeri	×	
Juncus arcticus	×	
Forbs		
Artemisia arctica		×
A. tilesii		×
Astragalus alpinus		×
Braya sp.	×	×
Cerastium beeringianum		×
C. jenisejense		×
Chrysanthemum integrifolium	×	×
Cochlearia officinalis	×	
Draba sp.	×	
Equisetum arvense	×	×
Epilobium latifolium		×
Melandrium apetalum		×
Oxytropis borealis		×
Oxyria digyna		×
Papaver Hulténii		×
Parnassia Kotzebuei	×	
Pedicularis sp.		×
Polygonum bistorta	×	×
Saxifraga caespitosa	×	×

Table 2. Continued.

Lifeform / Species	Backfilled Trench	Side slope of Trench
S. cernua	×	×
S. hieracifolia		×
S. hirculus	×	×
S. oppositifolia		×
Senecio atropurpureus	×	×
Silene acaulis		×
Stellaria longipes		×
Valeriana capitata		×
Shrubs		
Dryas integrifolia		×
Salix alaxensis		×
S. arctica	×	×
S. ovalifolia	×	×
S. rotundifolia	×	×

Figure 3. Views (facing west) of backfilled trench, Badami Pipeline East Shaviovik Crossing, 13 September 2007 and 3 August 2013.

Figure 4. Views (facing east) of the face of the backfilled trench where it meets the river bank, Badami Pipeline East Shaviovik Crossing, 13 September 2007 and 3 August 2013.

SOIL MONITORING: No soil monitoring was conducted for the period covered in this report.

WILDLIFE USE OF AREA: No observations of use of the site by wildlife were noted.

PROGRESS TOWARD PERFORMANCE STANDARDS AND RECOMMENDED REMEDIAL ACTION

No specific performance standards have been established for this site. Monitoring in 2013 found that a productive, species-rich cover of vascular plants has established on the backfilled trench. The site will be inspected again in 2016 to confirm that the surface of the backfilled trench remains stable and vegetation cover is sustained.

REPORTING

This report will be distributed to the following agency by 31 December 2013:

1. Alaska State Pipeline Coordinator's Office

Report contact information: Bill Streever, Senior Environmental Studies Advisor, 900 East Benson Blvd., PO Box 196612, Anchorage, AK 99519-6612. This report was prepared by Janet Kidd, ABR, Inc.

REFERENCES

McKendrick, J.D. 2000. Repeat photography of Badami pipeline river crossings: 1999 progress report. Report for BP Exploration (Alaska) Inc. by Lazy Mountain Research, Palmer, Alaska. 12p.

Appendix F

Coastal Stability Monitoring

Northstar Pipeline Shore Crossing

COASTAL STABILITY MONITORING NORTHSTAR PIPELINE SHORE CROSSING

SUMMER 2013

Northstar Shore Crossing Looking West, 10 August 2013

Prepared for
BP Exploration (Alaska), Inc.
Anchorage, Alaska

Prepared by
Coastal Frontiers Corporation
Chatsworth, California

December 2013

COASTAL STABILITY MONITORING
NORTHSTAR PIPELINE SHORE CROSSING

SUMMER 2013

Prepared for

BP Exploration (Alaska), Inc.
Anchorage, Alaska

Prepared by

Coastal Frontiers Corporation
Chatsworth, California

December 2013

COASTAL STABILITY MONITORING
NORTHSTAR PIPELINE SHORE CROSSING
SUMMER 2013

Executive Summary

The annual monitoring of the Northstar Pipeline Shore Crossing was conducted on 10 August 2013 in order to document any measurable bluff recession during the previous year. The monitoring program is performed annually at this site in accordance with the plan previously approved by the U.S. Army Corps of Engineers. The shore crossing is located on an eroding tundra coast near Pt. Storkersen, five miles west of Prudhoe Bay, Alaska.

Arctic coastal bluff erosion processes and rates of retreat have been studied in Alaska during the past 40 years. Rapid short-term bluff erosion may occur in reaction to occasional high energy storms arriving from the west that produce elevated sea levels ("storm surge"). Since 1996 when a coastal monitoring program was initiated at the Northstar Shore Crossing, measurements of shore erosion have been determined in order to ensure continued security of this coastal facility.

Again this past year, bluff erosion along the project frontage has been quite mild, averaging 1.3 ft along the surveyed transects. At the pipeline crossing no change in the bluff position was noted during the past year. The highest rate of bluff erosion this year occurred at Station 20+00 (3.3 ft/year), a distance of about 1,000 ft east of the shore crossing. The jute fabric cover that is intended to stabilize the bluff face at the shore crossing was re-installed in 2009 following its removal by waves in 2008. At the time of the recent survey, the condition of the jute cover was good.

The modest bluff erosion seen over the past five years (averaging 0.3 to 1.3 ft/year) is in contrast to that noted by the surveys of August 2003 and 2008. Those surveys followed major westerly storms that produced high water levels (+4.5 ft and +4.0 ft (MLLW), respectively) resulting in bluff erosion rates of greater than 5 ft/year. Since the previous survey of August 2012, the summer water levels exceeded a level of +2.0 ft (MLLW) on only two occasions.

At present, the toe of the pipeline shore pad lies about 70 feet landward of the eroding backfill face and the base of the gravel berm that protects the pipeline riser is more than 125 feet from the Mean Lower Low Water (MLLW) shoreline. Given this distance from the coastline and the modest historical bluff recession rate that has averaged 1.4 ft/year at the pipeline crossing since the pipeline was installed, no erosion mitigation measures are presently required.

COASTAL STABILITY MONITORING
NORTHSTAR PIPELINE SHORE CROSSING

SUMMER 2013

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SUMMER 2013

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COASTAL STABILITY MONITORING,
NORTHSTAR PIPELINE SHORE CROSSING

SUMMER 2013

Prepared by Coastal Frontiers Corporation
December 2013

1. INTRODUCTION

An annual evaluation of the bluff erosion experienced at the shore crossing of the Northstar Pipelines is required in order to comply with Special Condition #2 of the Department of the Army Permit N-950372 issued to BPXA in May 1999 (Ref.: Approved Document, Annual Monitoring Program, 18 November 1999). The pipelines connect the Northstar Production Island to Pump Station #1. As shown in Figure 1, the shore crossing lies just east of Pt. Storkersen about five miles west of Prudhoe Bay, Alaska.

In 1996, an evaluation was performed to forecast the expected rate and extent of bluff erosion in the vicinity to support the selection of a suitable site for the pipeline shore crossing facilities. Ground survey and reconnaissance operations were undertaken as well as historical aerial photo analysis of the site dating back to 1949 (Coastal Frontiers Corporation, 1996). The results of various prior studies dealing with Arctic bluff erosion were also investigated in order to provide a larger framework upon which to base prudent decisions.

Survey operations have been conducted each summer to document the condition of the shore crossing since the pipeline was installed in March-April 2000. The most recent results reported herein are based upon the survey conducted on August 10, 2013.

2. ARCTIC COASTAL PROCESSES—AN OVERVIEW

To provide background information for the Northstar study, an extensive discussion of arctic coastal processes was presented in the initial Northstar pipeline shore crossing monitoring report (Coastal Frontiers Corporation, 2000). To summarize, data from previous Arctic researchers identify moderate to high rates of bluff retreat at numerous locations along the Beaufort Sea coast. This finding is consistent with periodic water level increases and wave impacts associated with severe westerly storms, and the occurrence of a fragile permafrost foundation that fails when exposed to summer heat thereby accelerating the collapse of the coastal bluffs. Rates of erosion can vary from negligible to tens of feet per year, dependent on bluff morphology, beach width and composition, storm wave exposure, and climatic conditions.

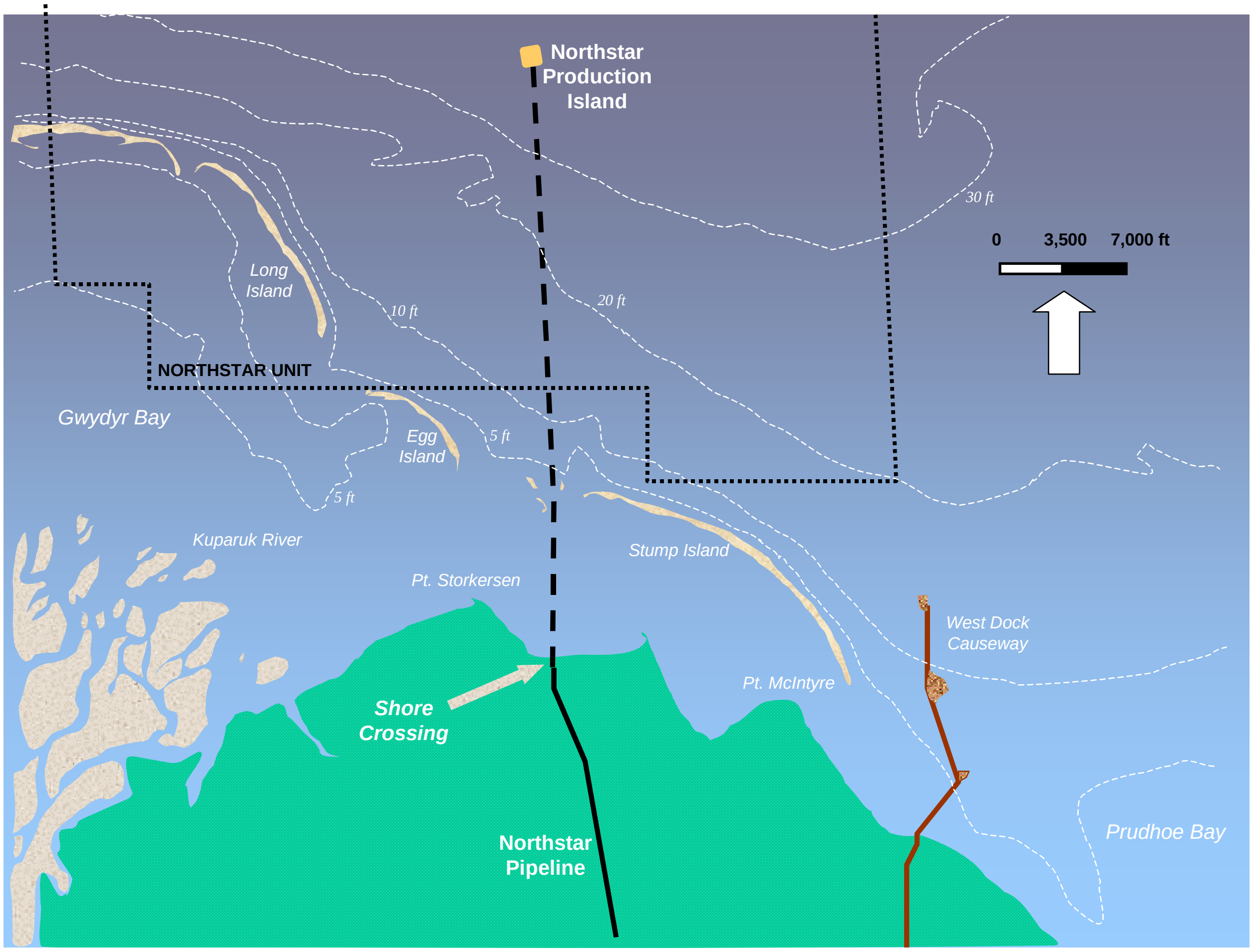

Figure 1. Northstar Project Location Map

3. HISTORICAL BLUFF POSITION, PT. STORKERSEN AREA, 1949 - 1996

The analysis of historical aerial photo comparisons was conducted in 1996 to define the specific nature of bluff and shoreline changes along the Pt. Storkersen coast (Coastal Frontiers Corporation, 1996). Summertime photos were used to establish bluff edge positions for the years 1949, 1955, 1968, 1979, 1988, and 1996. The method of analysis consisted of digitizing the shoreline and bluff edge in order to quantify the changes that occurred during the time intervals between photos.

The photo analysis showed that the coastal bluffs in the vicinity of the Point Storkersen DEW site eroded slowly during the 49-year photo comparison period; particularly when compared to recession rates determined by investigations along other Arctic coastal bluffs (e.g. Miller and Gadd, 1983; Mars and Houseknecht, 2007). Figure 2 presents bluffline positions for each year considered in the analysis. The location of the abandoned Pt. Storkersen DEW site is included in this figure to provide a point of reference. The portion of the bluff that encompasses the pipeline shore crossing (near Air Photo Station 15+00) displayed the lowest erosion rate in the study area for both long-term and short-term periods of observation.

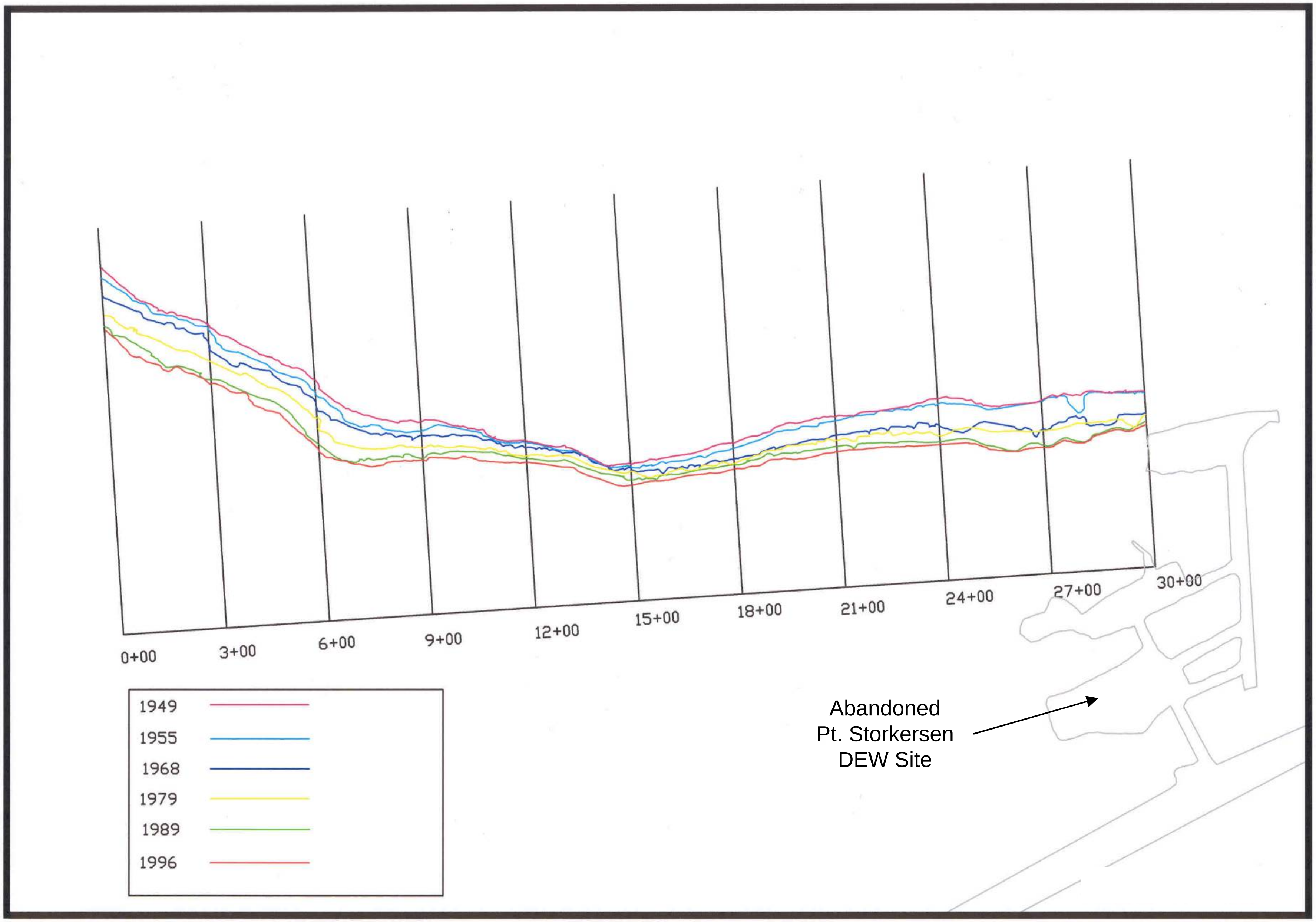

Figure 2. Historical Bluffline Positions Based on Air Photo Interpretation, 1949-1996

Average annual long-term (47 years) and short-term (6 - 13 years) bluff recession rates are presented in Table 1. Figure 3 presents graphically the results of the bluff recession analyses. It is noted that the maximum short-term rates of bluff recession ranged from 6 - 8 ft/year during the 1949-1955 and 1979-1989 time intervals. The maximum rates of bluff recession occurred at Stations 6+00 and 27+00, located about 1,000 feet to the east and west of the pipeline shore crossing location, respectively. The maximum long-term (1949-1996) bluff recession rate of 4.4 ft/year occurred at Station 6+00. The long-term rate of bluff recession over the entire 3,000 ft study area averaged 2.6 ft/year.

Table 1.
Average Annual Bluff Erosion Rates, 1949 - 1996
Northstar Pipeline Shore Crossing Area

Air Photo Station	**1949-1955** ***(6 years)*** ft/year	**1955-1968** ***(13 years)*** ft/year	**1968-1979** ***(11 years)*** ft/year	**1979-1989** ***(10 years)*** ft/year	**1989-1996** ***(7 years)*** ft/year	***1949-1996*** ***(47 years)*** ***Long-Term*** *ft/year*
0+00	-6.1	-4.3	-4.4	-3.2	-1.5	*-4.0*
3+00	-1.8	-3.3	-4.9	-5.0	-2.1	*-3.6*
6+00	-6.4	-2.7	-3.4	-7.7	-2.8	*-4.4*
9+00	-4.2	-1.1	-3.1	-2.9	-1.1	*-2.4*
12+00	-0.8	-1.2	-2.1	-0.8	-1.6	*-1.3*
15+00 Shore Crossing	-1.0	-0.2	-0.2	-3.1	-2.4	*-1.3*
18+00	-2.5	-2.2	-1.3	-0.5	-1.6	*-1.6*
21+00	-2.1	-3.2	-1.4	-1.7	-1.9	*-2.1*
24+00	-2.6	-4.9	-2.5	-1.8	-1.2	*-2.8*
27+00	-0.5	-6.2	-0.3	-4.2	-0.8	*-2.9*
30+00	-1.0	-4.4	-0.3	-1.9	-1.1	*-2.0*
Average =	***-2.6***	***-3.1***	***-2.2***	***-3.0***	***-1.6***	***-2.6***

Coastal Frontiers Corporation, 1996

Note:
In Table 1 and other tabular data in this report, erosion rates are listed as negative values. This sign convention will not be used in referencing erosion rates in the text.

In the vicinity of the pipeline crossing at Air Photo Station 15+00, the maximum rate of short-term bluff recession was 3.1 ft/year measured between 1979 and 1989. The average long-term rate of bluff recession for this section of bluff for the 47-year comparison period was 1.3 ft/year. As is apparent in Figure 3, the pipeline shore crossing site has historically experienced lower bluff recession rates than the adjacent coasts located to either the east or west.

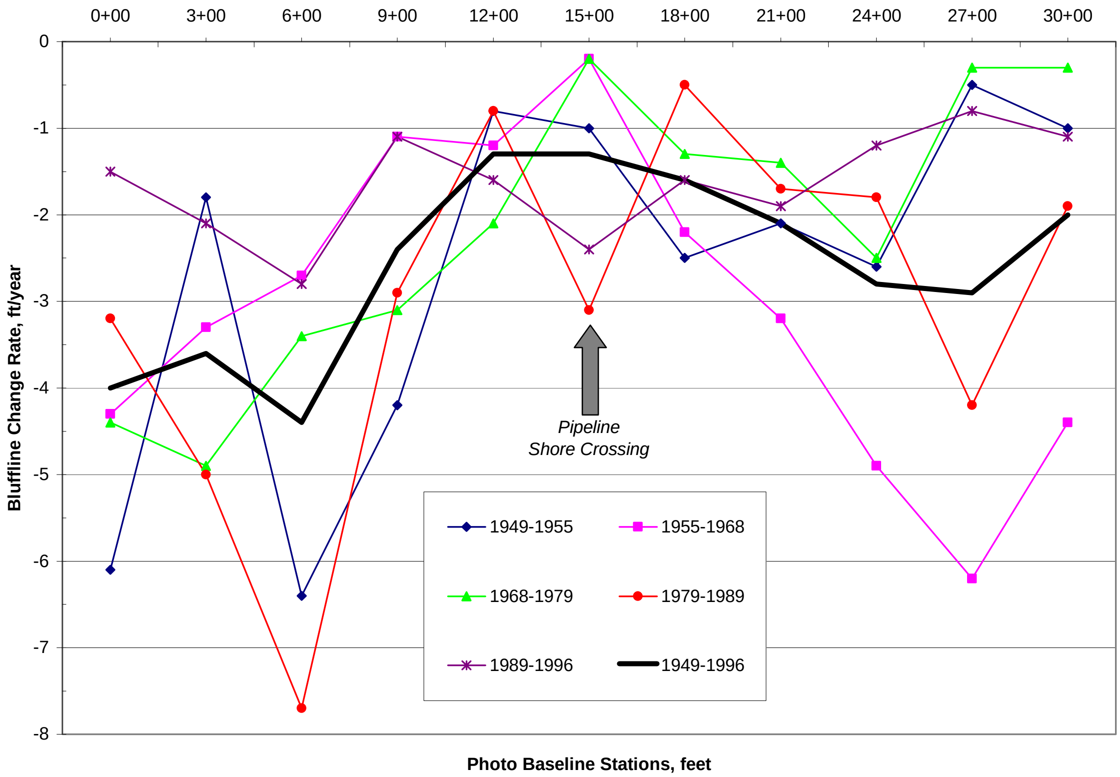

Figure 3. Historical Bluffline Erosion Rates Based on Air Photo Analysis

3.1 Shore Crossing Ground Surveys, August 1996 – August 2013

During August 1996, ground survey operations were conducted to establish a permanent survey baseline in order to monitor the changes in the beach and bluff positions near the site of the Northstar Shore Crossing. To precisely determine the annual coastal changes that have occurred since the Northstar Pipelines were installed, the survey effort has been repeated annually along this same baseline during late July – early August of 2000 through 2013.

As shown in Figure 4, ten shore-perpendicular profiles are surveyed annually from the backshore to wading depth at alongshore intervals of 250 feet and atop the pipeline crossing. The positions of the 1996 and 2013 blufflines are plotted to note the coastal recession that has occurred since the initial survey. The Mean Lower Low Water (MLLW) shoreline at the time of the 2013 survey is also included in the figure. The 2,000 ft long monumented baseline can be re-surveyed at any time to determine changes in bluff position. Appendix A presents cross-sectional profiles of each of these ten transects as surveyed in August of 1996 and 2000 through 2013. These profiles display the low-lying coastal plain (El. +7 to +8 ft, MLLW), the 3 to 4 foot high eroding bluff, the narrow sand beach, and the gently sloping seabed to a water depth of 1 to 2 feet below MLLW. Due to physical interference with facilities on the shore pad, Station 10+00 was replaced after construction was completed in August 2000 with two others: Station 9+85 (15 feet west of Station 10+00) and the pipeline centerline (Station 10+25, approx.).

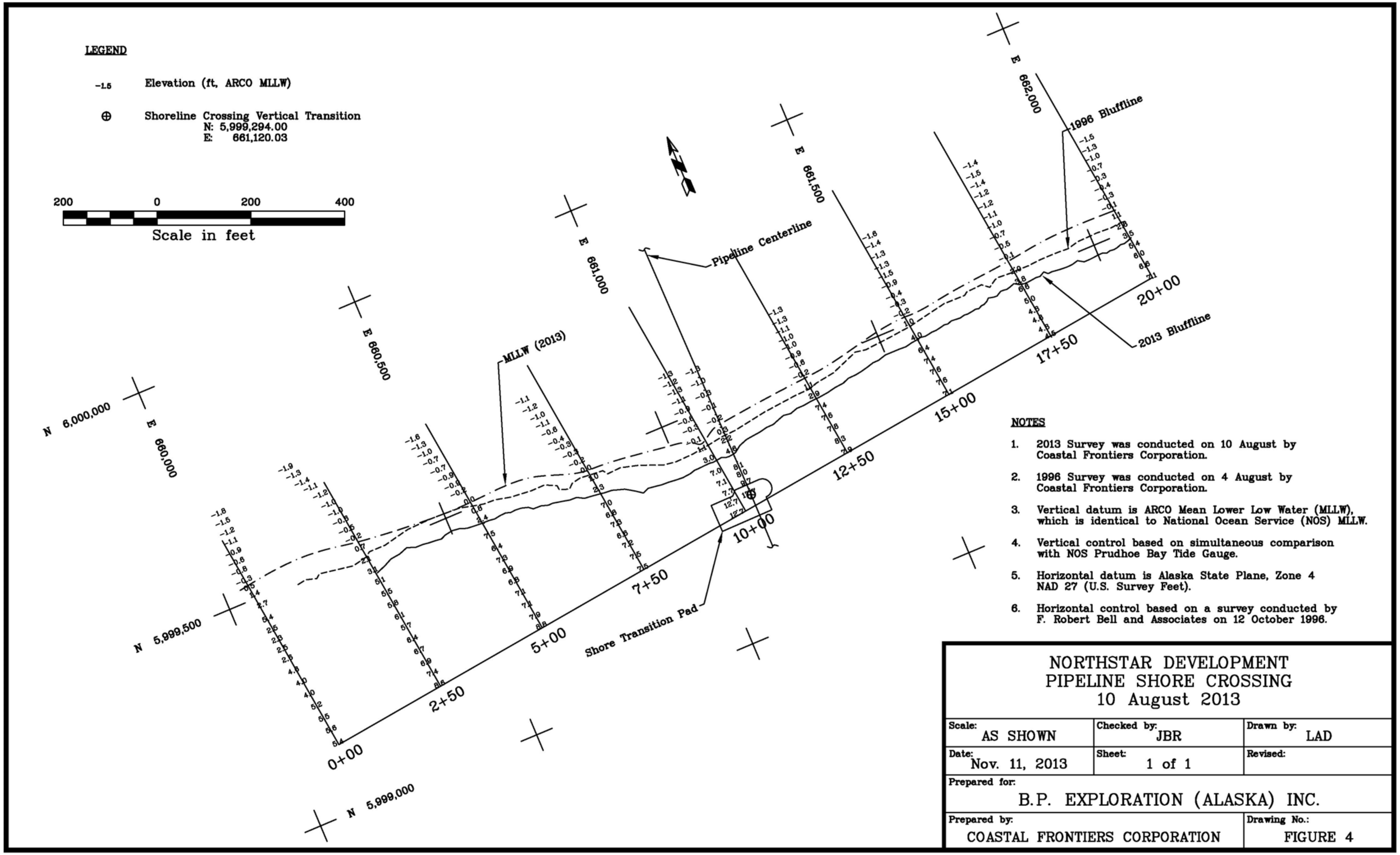

Figure 4. Northstar Shore Crossing Ground Survey Results, 10 August 2013

For each survey, the bluff positions can be directly compared, as is clearly noted on the plotted profiles in Appendix A. No bluff erosion rates are available at the westernmost survey transects (Stations 0+00 and 2+50) due to the lack of a discernable bluff edge. In addition to the surveyed profiles, the field survey efforts of 1996 through 2013 precisely located the continuous bluff edge along the 2,000-ft wide study reach.

The annual bluffline erosion rates noted for the surveys of August 2000 through August 2013 are presented in Table 2. The pipeline centerline is located at Station 10+25. Annual comparisons are made for each survey profile, as well as for the "Pre-Project" (1996 – 2000) and "Post-Project" (2000 – 2013) periods. The average annual bluff erosion rate at the surveyed transects for the 1996 – 2013 period is 2.2 ft/year. Since the pipelines were installed in 2000, the erosion rate is substantially less (1.3 ft/year) than that noted during the 1996-2000 ("Pre-Project") period (4.9 ft/year).

Table 2. Annual Bluff Recession Rates, 1996 – 2013

	Annual Bluff Erosion Rate, ft/year													*Average Rate (ft/year)*	
Profile	2000 - 2001	2001 - 2002	2002 - 2003	2003 - 2004	2004 - 2005	2005 - 2006	2006 - 2007	2007 - 2008	2008 - 2009	2009 - 2010	2010 - 2011	2011 - 2012	2012- 2013	***Pre-Project*** 1996 - 2000	***Post-Project*** 2000 - 2013
0+00	No Discernible Bluff													No Discernible Bluff	
2+50	No Discernible Bluff													No Discernible Bluff	
5+00	0.0	0.0	-10.6	0.0	0.0	0.0	0.0	-10.0	-0.2	0.0	-0.3	-0.2	-0.5	-6.0	-1.7
7+50	-0.7	-0.8	-10.0	-4.0	-0.6	0.0	0.0	-3.7	0.0	0.0	-1.2	-0.3	-3.2	-3.4	-1.9
9+85	-2.2	0.0	-4.5	0.0	-1.8	0.0	0.0	-6.1	0.0	-0.4	-1.2	0.0	-0.5	-4.3	-1.3
10+25	0.0	0.0	-6.9	-1.9	-0.5	0.0	0.0	-5.0	-1.3	-2.1	0.0	0.0	0.0	-5.7	-1.4
12+50	0.0	-0.4	-0.3	0.0	-2.2	0.0	0.0	-5.2	0.0	0.0	0.0	0.0	-1.5	-5.2	-0.7
15+00	-0.3	0.0	-2.1	-2.5	0.0	0.0	0.0	-4.1	0.0	0.0	0.0	-0.2	-0.6	-5.1	-0.8
17+50	-1.5	-1.4	0.0	-1.8	0.0	0.0	0.0	-8.9	0.0	0.0	0.0	0.0	-1.1	-4.5	-1.1
20+00	-2.8	-1.4	-6.8	-1.3	0.0	0.0	0.0	-3.3	-2.4	0.0	0.0	-1.8	-3.3	-5.2	-1.8
Average =	*-0.9*	*-0.5*	*-5.2*	*-1.4*	*-0.6*	*0.0*	*0.0*	*-5.8*	*-0.5*	*-0.3*	*-0.3*	*-0.3*	*-1.3*	*-4.9*	*-1.3*

Denotes Pipeline Centerline

Based on the eight bluffed profiles surveyed, the average bluff position retreated 19.6 ft during the 1996-2000 survey comparison period-yielding an average bluff erosion rate of 4.9 ft/year. This includes the effects of the major westerly storm of August 10-11, 2000, when the storm water level achieved an elevation of +4.8 ft (MLLW); the highest water level ever recorded at the Prudhoe Bay tide gauge. During the following two years, bluff erosion was quite modest. During the 2002-2003 period, the erosion rate increased in response to westerly wave energy accompanied by high water levels. During that year, the bluff erosion along the 2,000-foot study reach averaged 5.2 ft.

The minor erosion experienced during the past five comparison periods (2008-2013) contrasts with that of the 2007-2008 period, when bluff recession averaged 5.8 ft; the highest average annual bluff retreat noted since the pipeline was installed. A major westerly storm accompanied by a high water level of +4.0 ft (MLLW) occurred in late July 2008 that was the primary cause of this bluff recession.

The water level record for the July-October 2013 period is compared to the predicted tide in Figure 5. The highest water level of the year was recorded as +2.9 ft (MLLW) on July 29th. During the 2013 open-water season (July-October) water levels only exceeded +2.0 ft in response to westerly winds during three short-duration events. The water level exceeded +2.0 ft a total of approximately 2% of the time during this period, although this level was achieved during only two brief occasions prior to the survey of early August. The occurrence and duration of water levels exceeding the +2-ft threshold was significantly less in 2013 than was noted in the previous year (3 vs. 10 events amounting to 2.17% vs. 9.05% of time, respectively).

Weather observations for the open-water periods of 2009 through 2011 indicate that easterly winds predominated, occurring 77.3% of the time in 2009, 75.5% in 2010, and 83.5% in 2011. Easterly winds promote lowered coastal water levels thereby reducing direct wave impacts on the bluff face and consequent bluff erosion. However, during the 2012 open water season, westerly and easterly winds occurred with comparable frequency. In the summer of 2013 a return to a period of predominant easterly winds occurred. Over the four-month period spanning July through October, easterly winds occurred 68% of the time. Easterly winds also predominated in each of these months.

For the 13-year period following the installation of the Northstar pipeline, the average annual bluff erosion rate has been 1.4 ft/year at the shore crossing and 1.3 ft/year along the entire study reach (Table 2). The most recent findings of this past August show moderate bluff erosion, averaging 1.3 ft over the survey area. However, no erosion has been noted at the shore crossing (Station 10+25) during the past three years. The greatest bluff retreat, a loss of 3.3 ft, occcured at Station 20+00, approximately 1,000 ft east of the pipline shore crossing.

Figure 6 compares the long-term and maximum short-term erosion rates determined during the 1949-1996 period generated from aerial photo analysis with the results of the more recent ground survey tasks. Average annual bluff erosion rates based on the ground survey results are shown for the Pre-Project (1996-2000) and the Post-Project (2000-2013) periods. Surveyed bluff erosion rates for the 1996 - 2000 period were greater than the long-term averages determined by air photo comparisons that date back to 1949. As the bluff change data is extended to show the conditions of the 2000 – 2013 period (“Post-Project”), the area-wide erosion rate decreased to 1.3 ft/year; 50% less than the long-term average bluff recession rate of 2.6 ft/year determined from the 1949 – 1996 air photo analysis.

The average annual bluff erosion rate at the pipeline shore crossing (Station 10+25) for the 2000-2013 period is 1.4 ft/year, or 25% of the average rate of 5.7 ft/year for the 1996-2000 (“Pre-Project”) period.

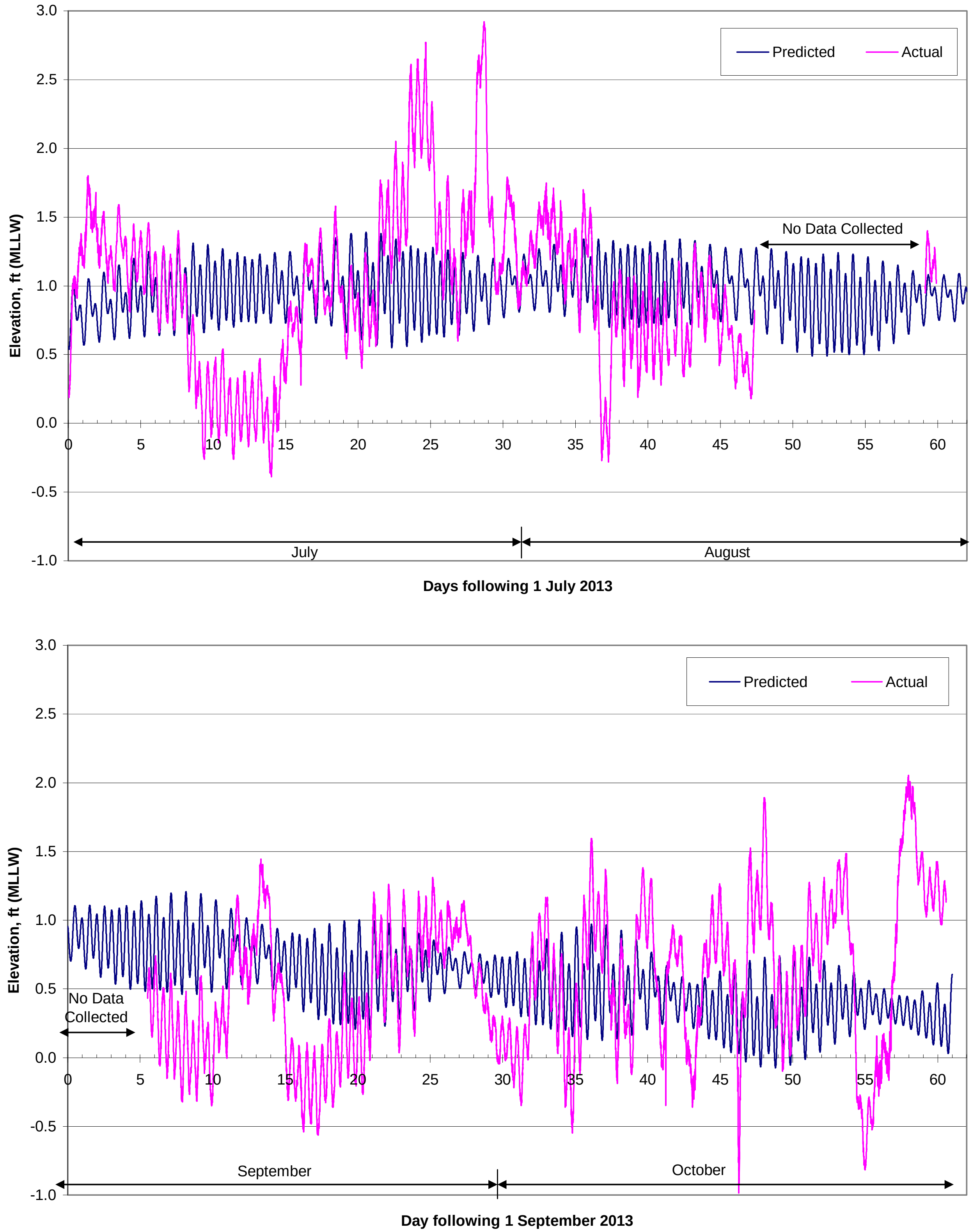

Figure 5. Prudhoe Bay Water Level Record, July – October 2013

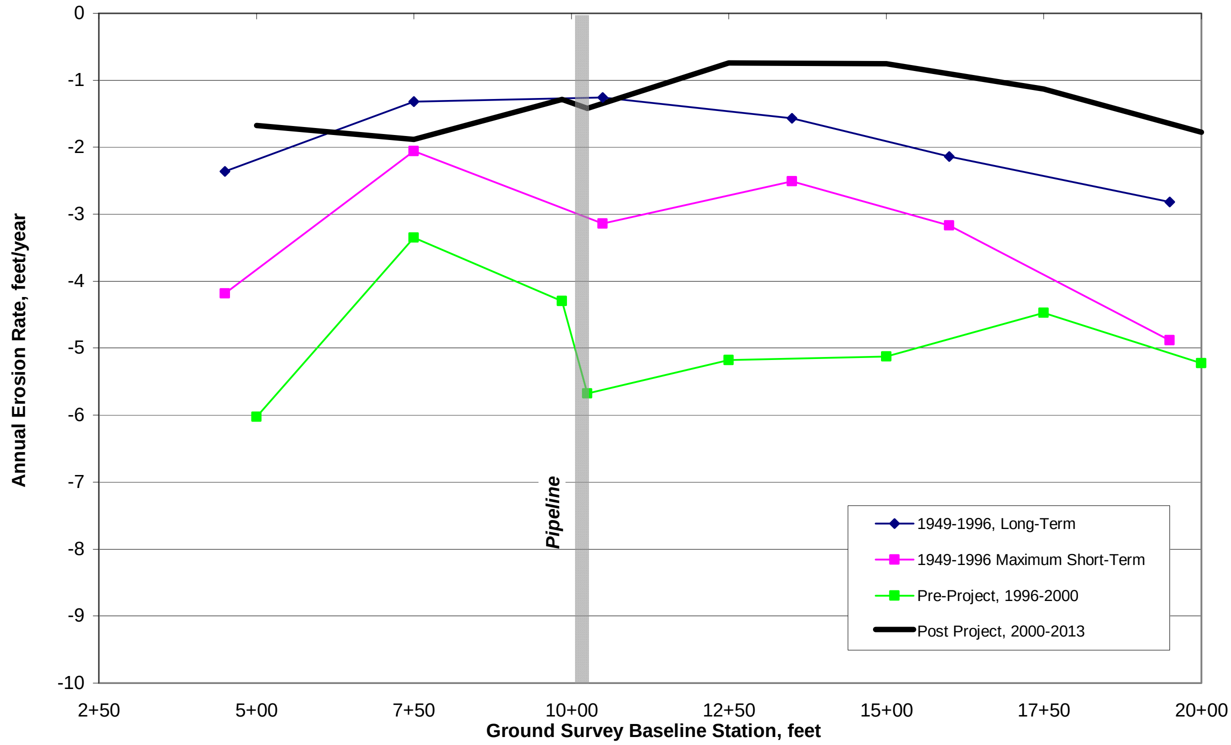

Figure 6. Short- and Long-Term Bluff Erosion Rate Comparison

Once it was determined that the pipeline backfill would erode more readily than the natural tundra bluff, the eroding face of the shore crossing was covered by jute fabric in 2004. During a major westerly storm in late July 2008, waves removed the jute fabric and exposed the eroding backfill. During the summer of 2009, the jute fabric covering was replaced on the eroding bluff face. Its condition in August 2013 is shown in Photo 1. A small scarp and deposits of driftwood debris are visible in the photo and provide the approximate position of recent water inundation at the site.

Photos 2 and 3 show general conditions along the coast. Photo 2 is viewed from the west and shows a large piece of tundra that has detached from the bluff edge and covers the exposed bluff face. This condition will provide additional protection and limit direct wave impacts to the bluff face in the event of strong westerly wind and the associated increased water levels. Photo 3 provides a view of the undulating beach looking west towards the shore crossing. As previously noted, driftwood shown in the photo has accumulated near the back beach, suggesting relatively recent water levels reaching to the base of the bluff.

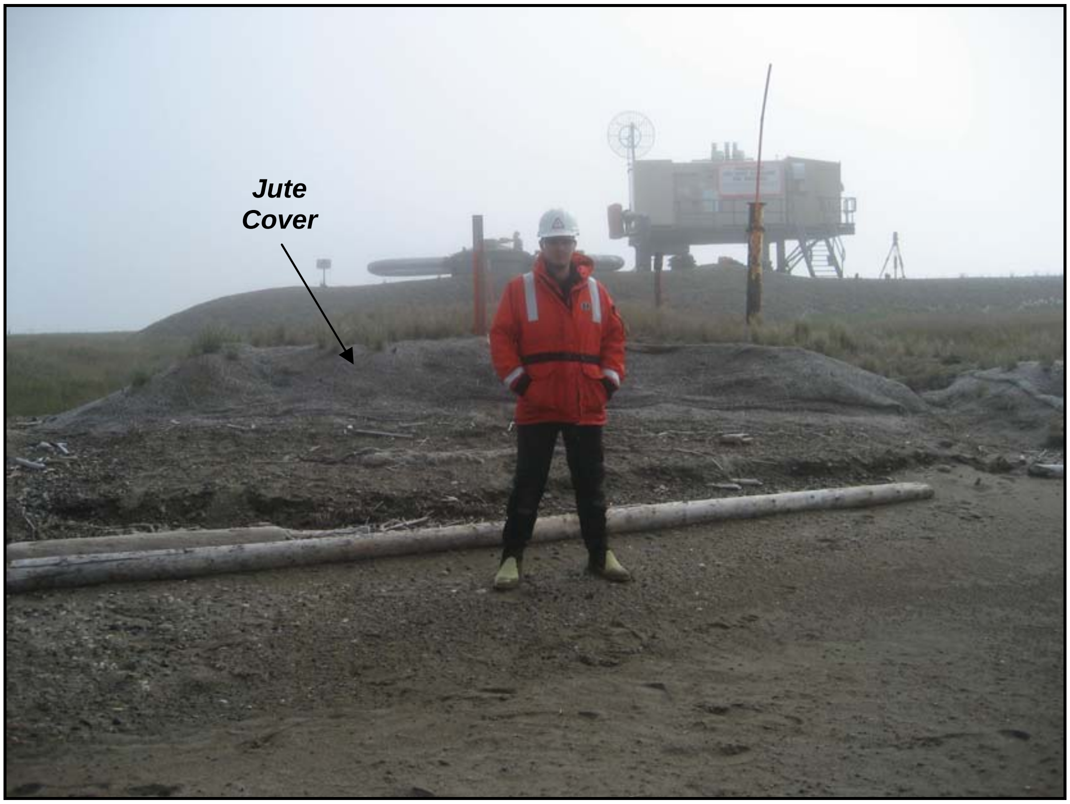

Photo 1. Jute Fabric Cover and Driftwood Debris at Shore Crossing

Photo 2. Bluff Condition to the West of Shore Crossing

Photo 3. Bluff Condition to the East of Shore Crossing

Figure 7 shows the variability of bluff recession rates at each surveyed transect based on the annual survey results. For 11 of the 13 years since the pipelines were installed, bluff changes were modest (less than 3 ft/year). However, in 2003 and 2008, the average rates of erosion over the study region were 5.2 and 5.8 ft/year, respectively. The erosion rates vary significantly for these transect locations during both of these years, suggesting a non-uniform retreat rate along the coast. Maximum rates of retreat have been as high as 9 to 10 ft/year at certain locations (Stations 5+00, 7+50, 17+50). The results of the 2013 survey reveal a slight increase of the average erosion rate compared to the four most recent surveys (2009-2012); however this value is less than 25% of the highest rates of recession noted in 2003 and 2008.

In Figure 8, a timeline of bluff erosion rates is shown for the various periods of comparison (both short- and long-term) for the periods of air photo comparison (1949 – 1996) and ground surveys (1996 – 2013). In addition, the pre- and post-project time frames are shown. The greatest erosion rate over the study area is 4.9 ft/year for the 1996-2000 period. The mildest period for bluff erosion occurred following the installation of the Northstar pipelines (2000-2013) when a rate of 1.3 ft/year was noted. For the pre-project period (1949-2000), the erosion rate was 2.8 ft/year. For the entire study period spanning 1949-2013, the erosion rate is 2.5 ft/year.

Figure 7. Annual Variability of Bluff Recession Rates

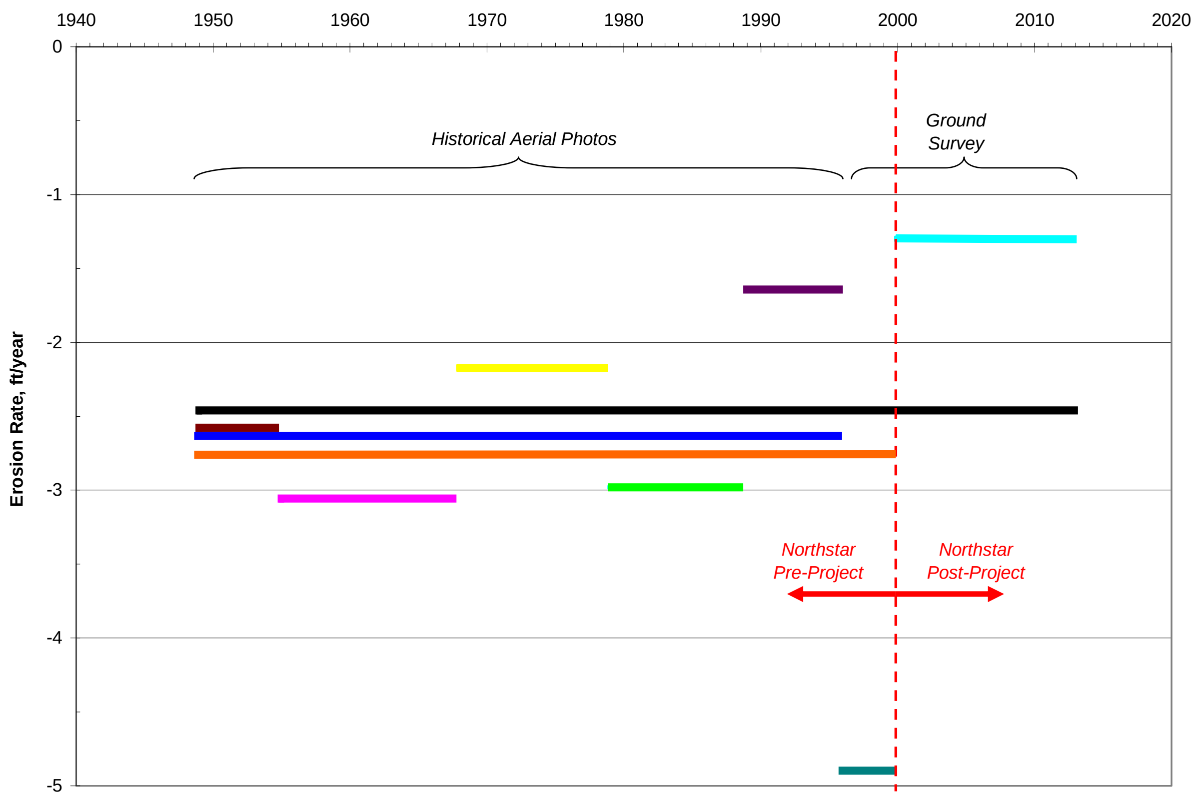

Figure 8. Bluff Erosion Timeline, 1949 – 2013

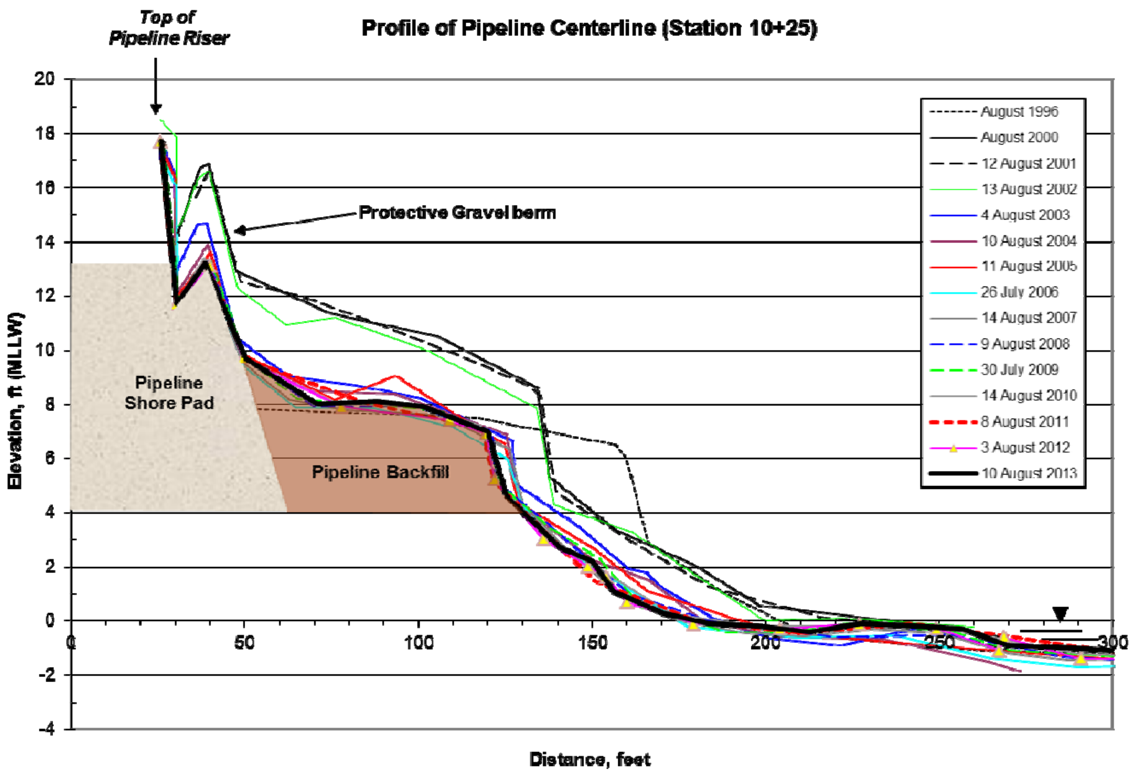

Figure 9. Subsidence and Recession History at Pipeline Shore Crossing (Sta 10+25)

In Figure 9, a comparison is provided of the survey profiles across the pipeline backfill at the shore pad for the 1996 – 2013 period. The backfill experienced subsidence of about 3 feet that was noted in August 2003. A reduction in the elevation of the top of the pipeline riser is also indicated in this figure. This is caused by the thermal effects of the heated oil pipeline that is buried within the backfill.

The initial stages of the subsidence can be seen in the data comparison between the August 2001 and August 2002 surveys when the elevation of the backfill surface was reduced by about 0.5-0.7 ft. Since oil production from Northstar began in late October 2001, this subsidence was in response to the first nine months of pipeline operation. As oil production progressed, the pipeline backfill subsided further. Since 2003, the surface elevation of the pipeline backfill at the shore crossing has been stable. Efforts have been made to stabilize the pipeline backfill by planting native grasses on the backfill surface.

A reduction of a foot or two in the surface elevation of the subaerial beach is also noted at all the profiles. At profiles distant from the pipeline, this reduction is due to regional coastal recession rather than to thermal effects of the pipeline. Similar pipeline-related subsidence has been noted at Northstar Production Island and along the seabed route of the buried pipelines.

While bluff recession at the shore crossing has been absent or quite modest during most years since the pipelines were installed, major westerly storms (such as that of late July 2008) can rapidly erode the coastal bluff. Specifically, severe westerly storm conditions that elevate the coastal water level can cause bluff erosion of 5 to 10 feet during a brief storm period spanning several days.

4. CHANGES IN SHORELINE (MLLW) POSITION

The most immediate indication of conditions that could threaten the pipeline integrity at the Northstar Shore Crossing is the position of the eroding tundra bluff. Another measure of shore stability is the change in position of the shoreline which can wax and wane based on incoming wave conditions and the local coastal sediment supply. Table 3 provides the annual average erosion rates for the MLLW shore and the coastal bluff at each of the survey transects for the 1996 – 2013 period. Because a discernible bluff edge does not exist at Stations 0+00 and 2+50, no bluff erosion rates are noted for these two transects. The average annual recession rates of the MLLW shoreline and the bluff are 2.3 ft/year and 2.2 ft/year, respectively over the 17-year comparison period.

Figure 10 presents this information graphically, and shows the range of recession rates of both the shoreline and the bluff to vary between 1 and 3 ft/year over most of the study range. The only transect that has shown substantially greater erosion than the average range is at the far west end of the study area (Station 0+00) where no bluff exists and long-term shore erosion of 5.8 ft/year has occurred.

Table 3. Bluff and MLLW Shoreline Recession Rates, 1996 – 2013

Station	Average Annual MLLW Shore Recession Rate, ft/year	Average Annual Bluff Recession Rate, ft/year
0+00	-5.8	no bluff
2+50	-1.8	no bluff
5+00	-2.1	-2.7
7+50	-2.6	-2.2
9+85	-1.7	-2.0
10+25	-1.5	-2.4
12+50	-1.7	-1.8
15+00	-2.1	-1.8
17+50	-1.8	-1.9
20+00	-1.4	-2.6
Average =	**-2.3**	**-2.2**

Denotes pipeline crossing

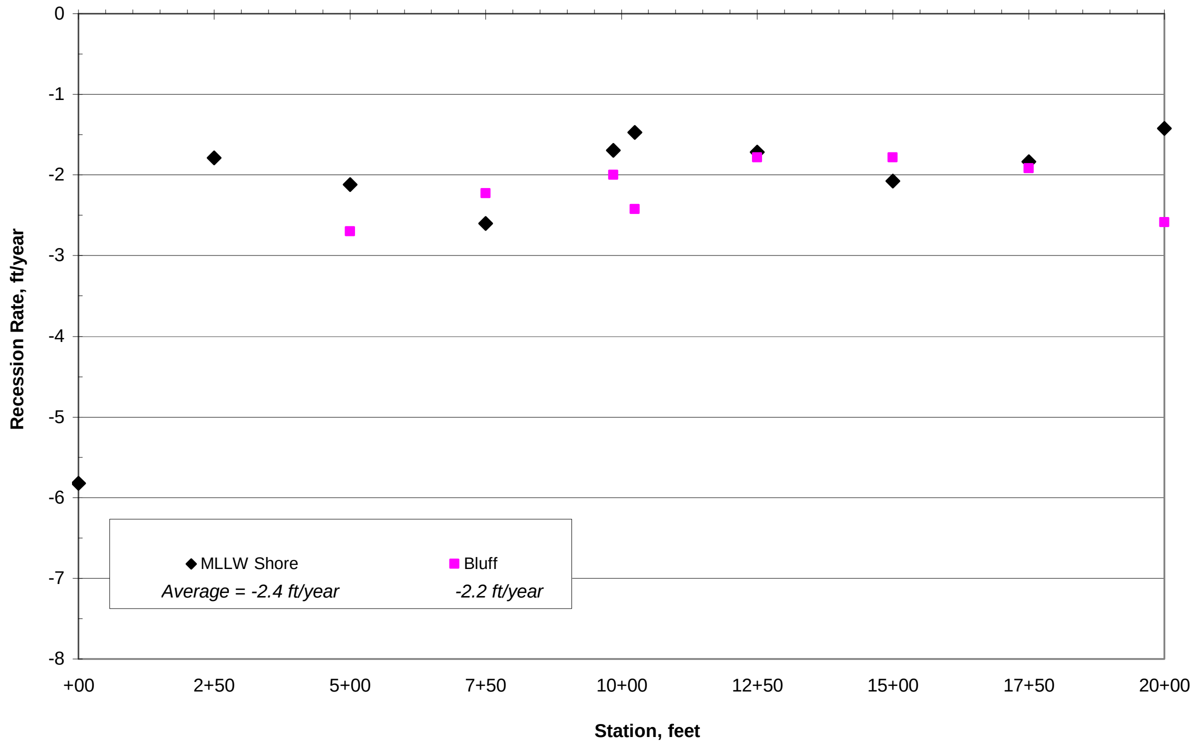

Figure 10. Comparison of Average Rates of Shore and Bluff Recession, 1996 - 2013

Along many of the surveyed transects, the erosion rates of the shore and the bluff are comparable. However, the bluff erosion rate is about 61% greater than the shore erosion rate at the shore crossing (Station 10+25) due to the greater susceptibility of the pipeline backfill to erode relative to the adjacent native tundra.

5. CONCLUSIONS

Prior to the installation of the Northstar Pipelines, the adjacent tundra bluff experienced long-term erosion that averaged 1 to 3 ft/year, based on air photo comparisons spanning the 1949-1996 period. During short-term periods spanning five to ten years, the rates of erosion were higher; typically 3 to 6 ft/year. Direct survey measurements performed in August of 1996 and 2000 indicated bluff erosion rates that were somewhat higher than the long-term values—about 4 to 6 ft/year.

Severe westerly storms with high storm surges have occurred periodically since the Northstar Pipelines were installed in 2000 - particularly during August 2000, August and October 2002, July 2003, and late July 2008. Evidence of these high energy storms include exposed sediments in the face of the eroding bluffs, the presence of dislodged tundra blocks on the beach surface, and discolored blufftop tundra grasses indicative of sea water inundation.

The retreat of the MLLW shoreline has averaged about 38 feet along the study area since 1996. Bluff and beach erosion that occur during high water levels associated with major westerly storms can promote the accumulation of bluff and beach sediments on the profile that can cause a seaward advance (averaging 4 ft following a July 2008 storm) in the MLLW shore position.

The seaward face of the sediment backfill mound that covers the pipelines from the bluff edge to the pipeline service pad has eroded to a greater degree than the adjacent tundra located to the east or west, as shown in Photo 4. This greater susceptibility to wave-induced erosion is expected, given both the lack of natural vegetative cover of the backfill and the thermal effects of the buried pipelines that tend to thaw the backfill. Attempts to vegetate the surface of the sediment backfill have been undertaken and appear to be succeeding. However, given the combination of westerly storms which elevate the coastal water level coupled with the effects of thermal erosion of the bluff during the warm summer months, further erosion of the bluff and the backfill mound will occur. The jute fabric cover that was placed over the face of the shore crossing in 2004 was damaged and removed in 2008 by the wave impacts of a major westerly storm. The jute cover was replaced during the summer of 2009 and was in good condition at the time of the August 2013 inspection (Photos 1 and 4).

Photo 4. Recessed Bluff at Shore Crossing, Looking East

The pipeline backfill at the shore pad has subsided in response to the thermal effects of the heated pipelines within the underlying permafrost. Since the pipeline installation in 2000, the elevation of the surface of the backfill has been lowered by about 3 feet. In 2003, the effects of subsidence reduced the backfill elevation to that of the adjacent native tundra.

At present, the toe of the pipeline shore pad lies about 70 feet landward of the eroding backfill face and the base of the gravel berm that protects the pipeline riser is more than 125 feet from the MLLW shoreline. In 11 of the past 13 years, the lack of westerly storms with high water levels has resulted in negligible bluff erosion (averaging less than 1.5 ft/year). Bluff erosion averaging about 5 ft/year has occurred twice (2002-2003 and 2007-2008), as a result of wave impacts acting at high water levels during severe westerly storms.

Should future monitoring efforts indicate that landward retreat of the backfill is unacceptable, additional gravel can be placed upon the beach at this location to increase the width of the safety buffer. This method of bluff stabilization has performed effectively at other Arctic coastal sites. By creating a sloping gravel beach rather than a vertical bluff face, wave energy can be reduced thereby slowing or eliminating bluff erosion. In addition, thermal insulation of the bluff can be accomplished by the gravel beach installation. Given the limited bluff retreat noted at the site since the Northstar pipelines were installed, erosion mitigation measures are not presently required.

6. REFERENCES

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COASTAL STABILITY MONITORING
NORTHSTAR PIPELINE SHORE CROSSING

SUMMER 2013

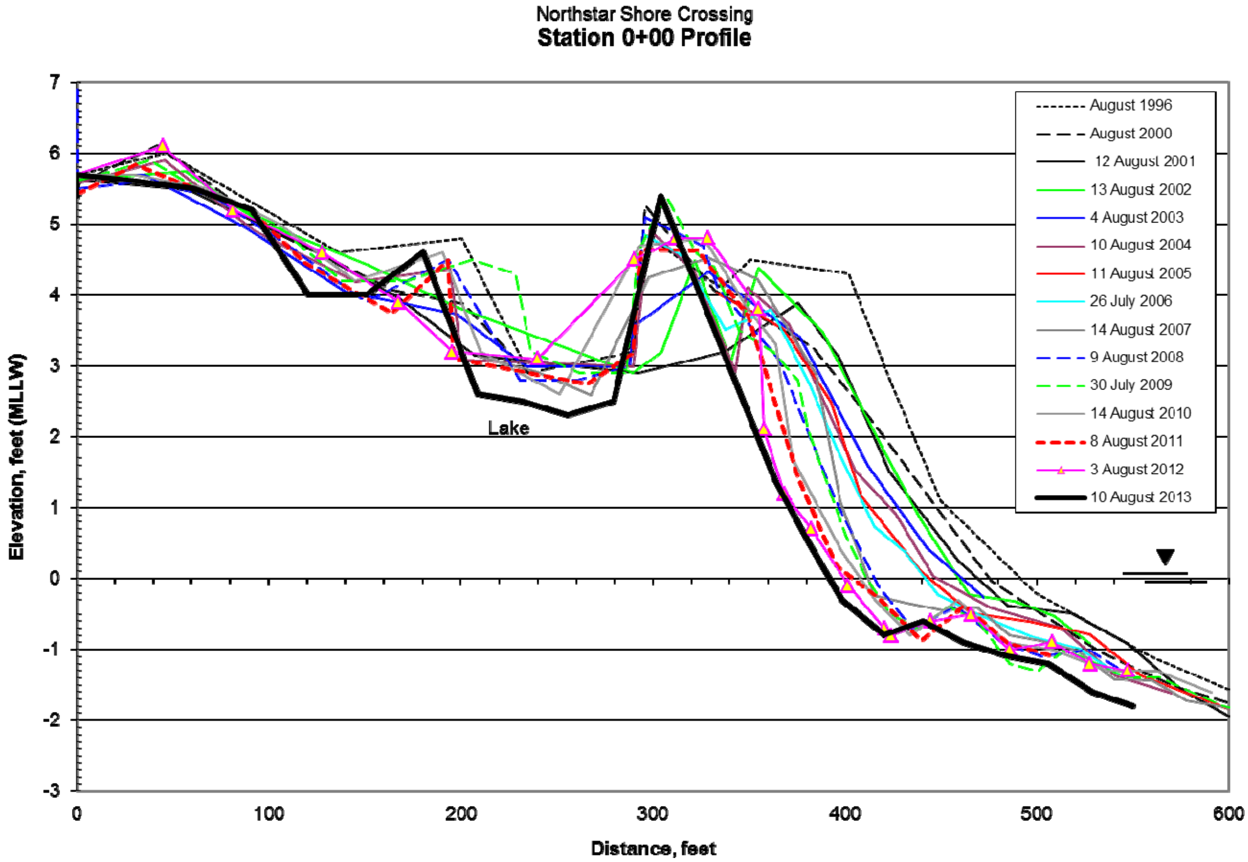
APPENDIX A

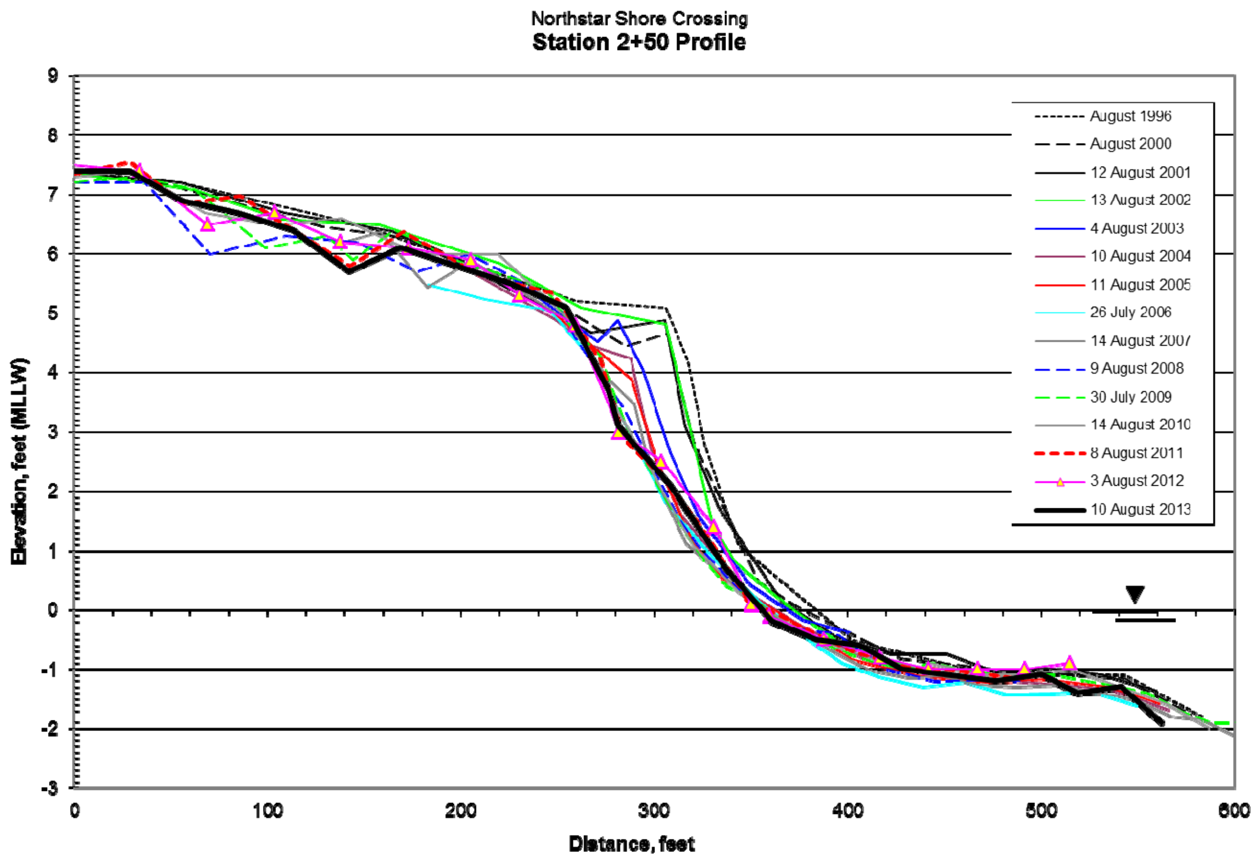
SHORE-PERPENDICULAR PROFILE COMPARISON
August 1996—August 2013

Prepared for
BP Exploration (Alaska), Inc.
Anchorage, Alaska

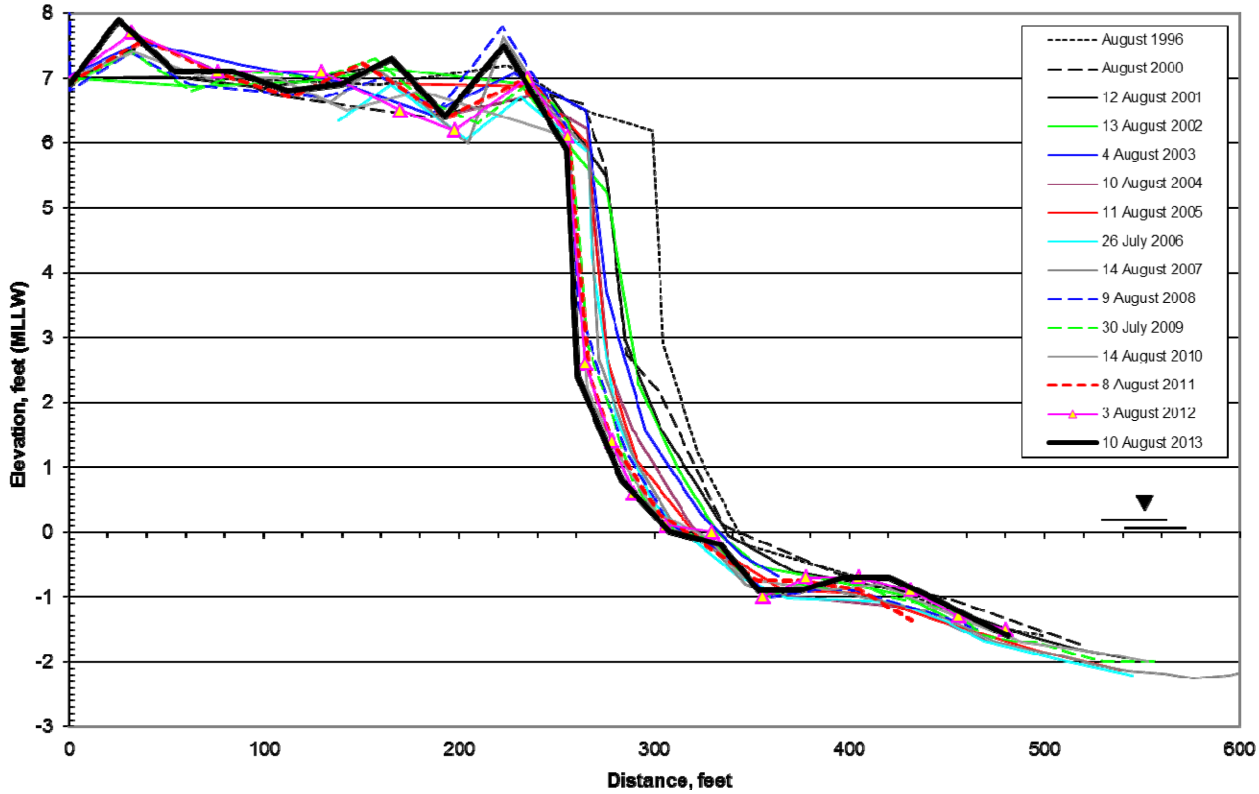
Prepared by
Coastal Frontiers Corporation
Chatsworth, California

December 2013

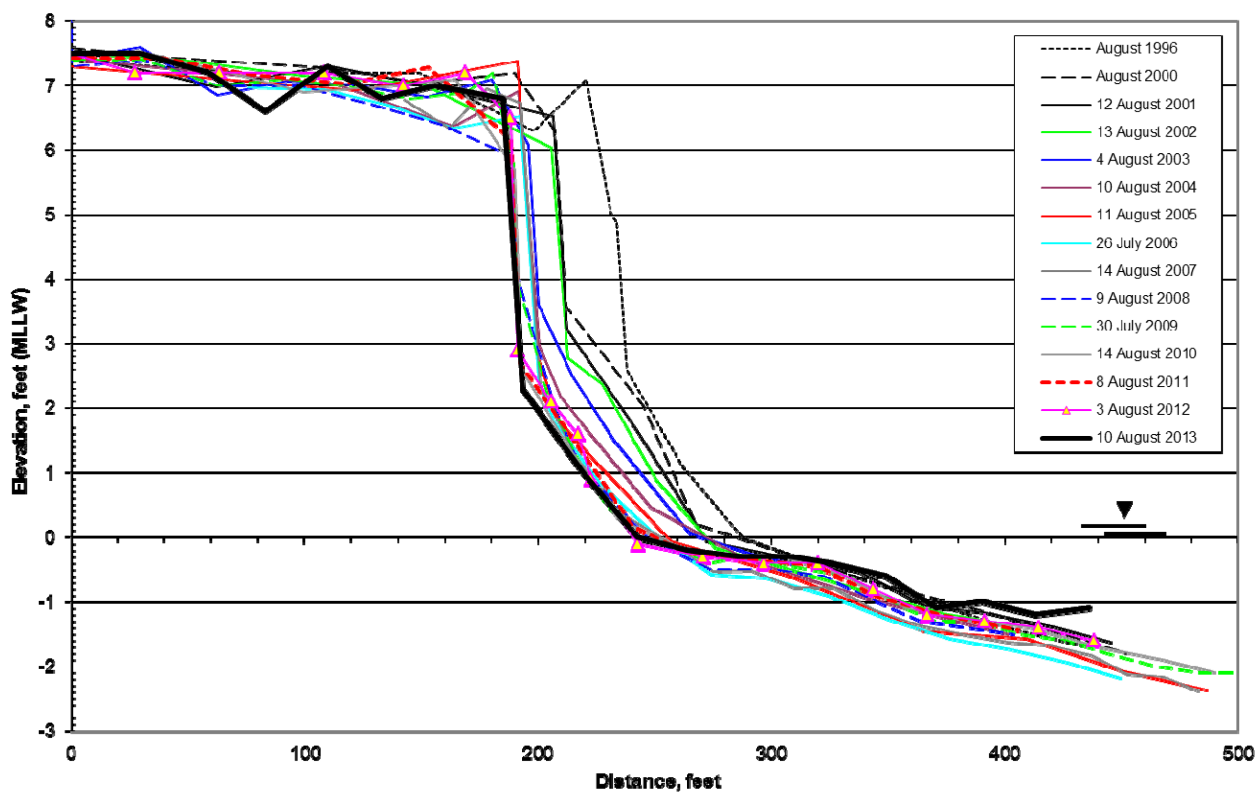

Northstar Shore Crossing
Station 0+00 Profile
Elevation, feet (MLLW)
Distance, feet
Lake
August 1996
August 2000
12 August 2001
13 August 2002
4 August 2003
10 August 2004
11 August 2005
26 July 2006
14 August 2007
9 August 2008
30 July 2009
14 August 2010
8 August 2011
3 August 2012
10 August 2013

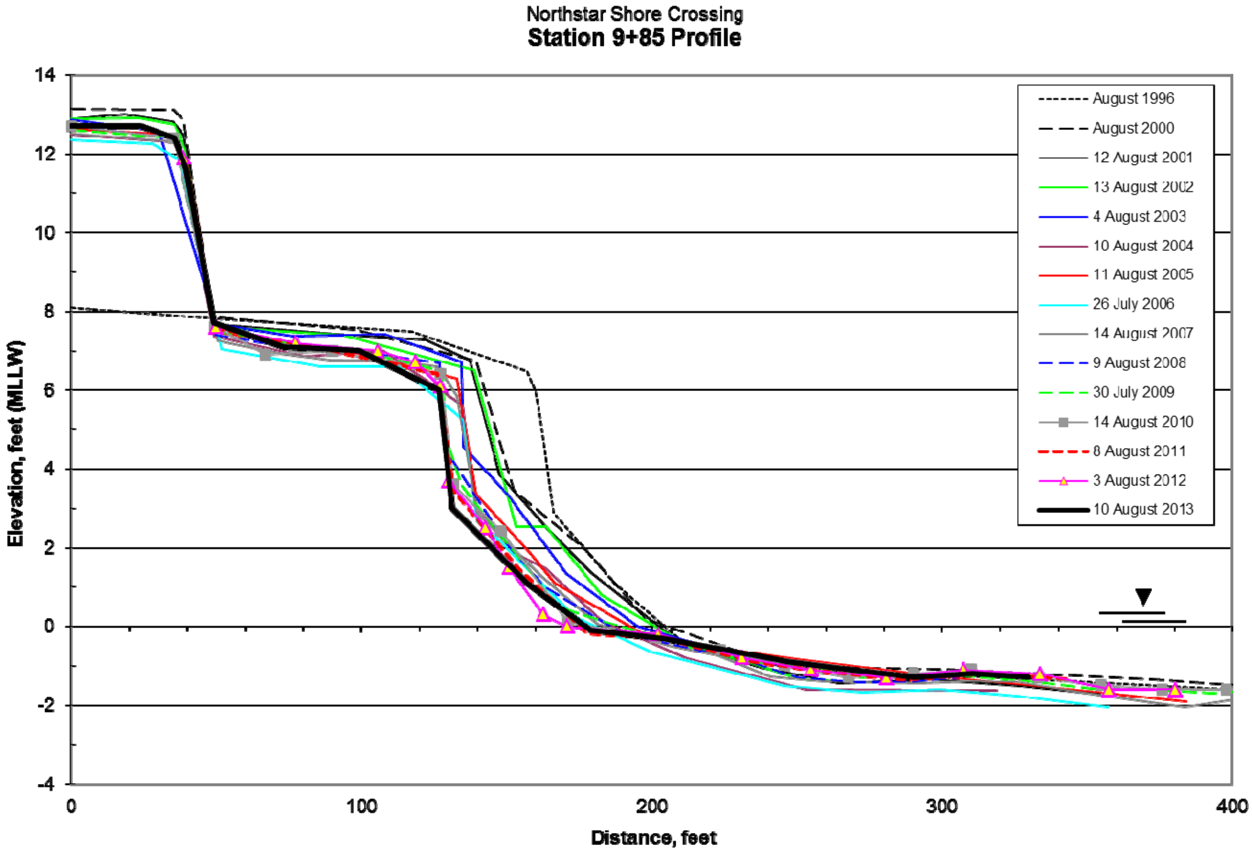

Northstar Shore Crossing
Station 2+50 Profile
Elevation, feet (MLLW)
Distance, feet
August 1996
August 2000
12 August 2001
13 August 2002
4 August 2003
10 August 2004
11 August 2005
26 July 2006
14 August 2007
9 August 2008
30 July 2009
14 August 2010
8 August 2011
3 August 2012
10 August 2013

Northstar Shore Crossing
Station 5+00 Profile

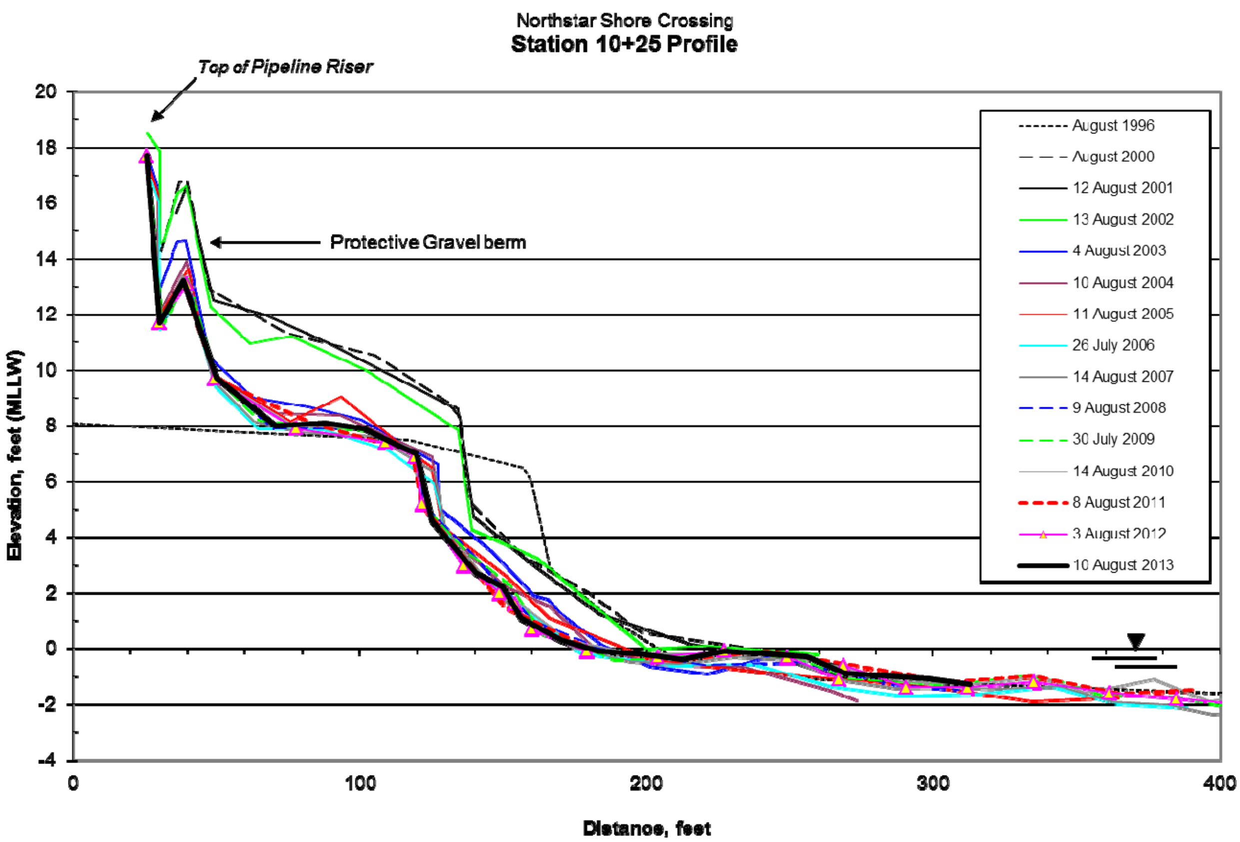


Northstar Shore Crossing
Station 7+50 Profile

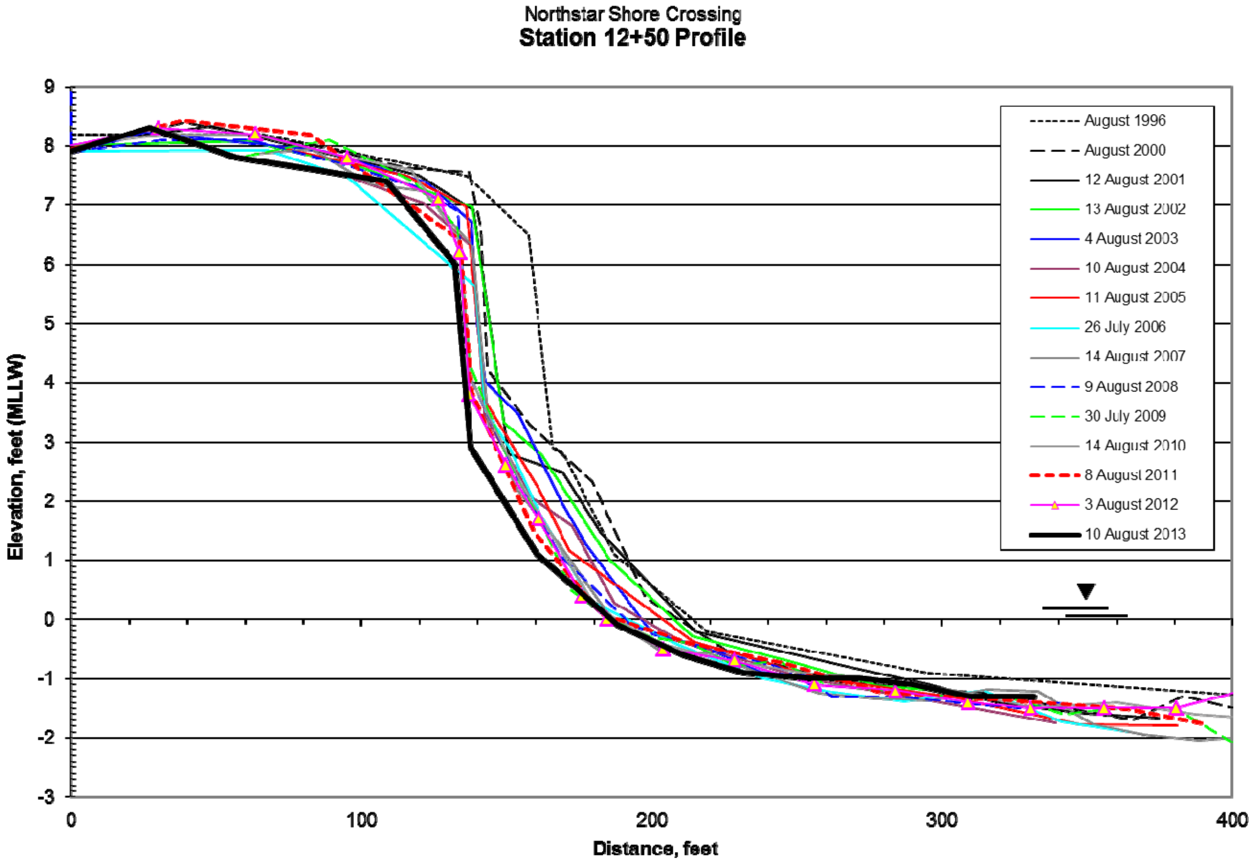


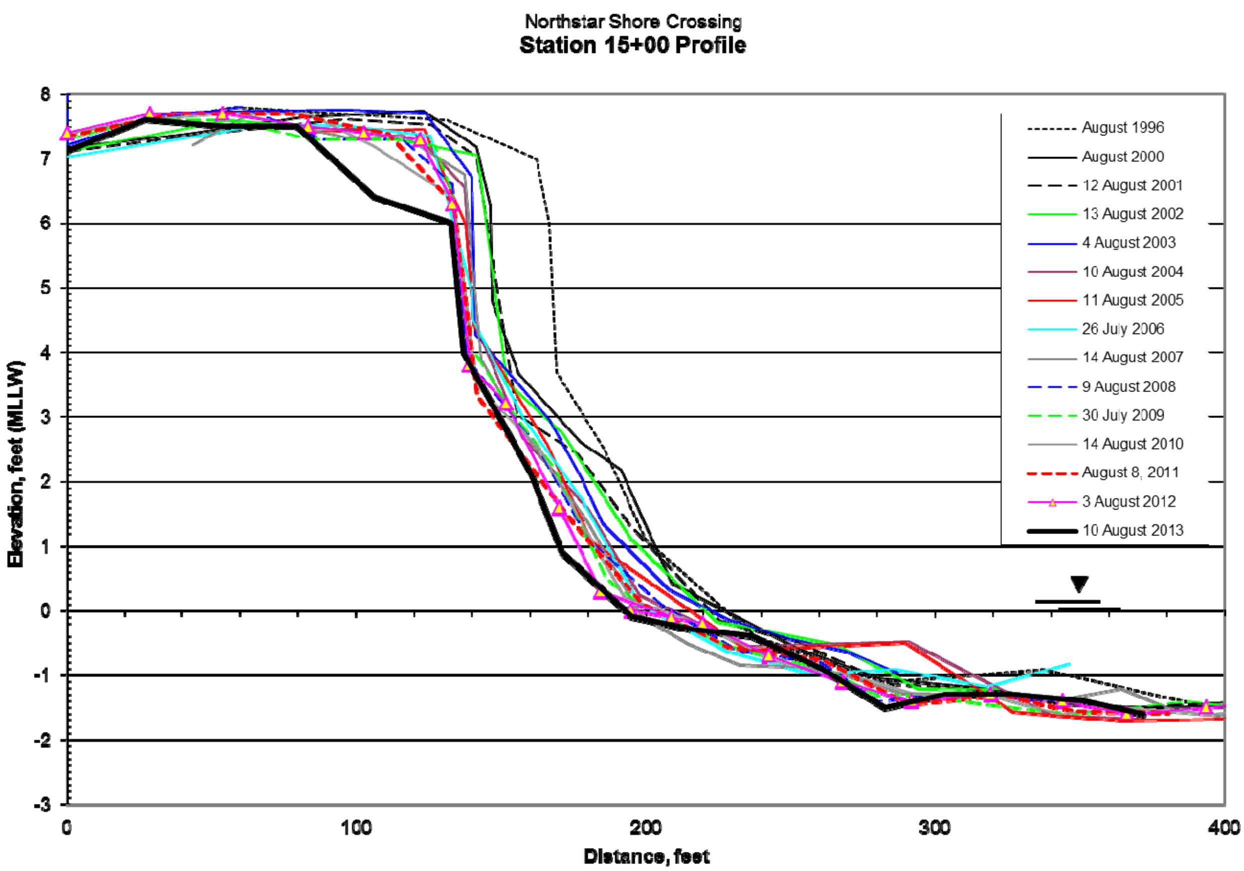


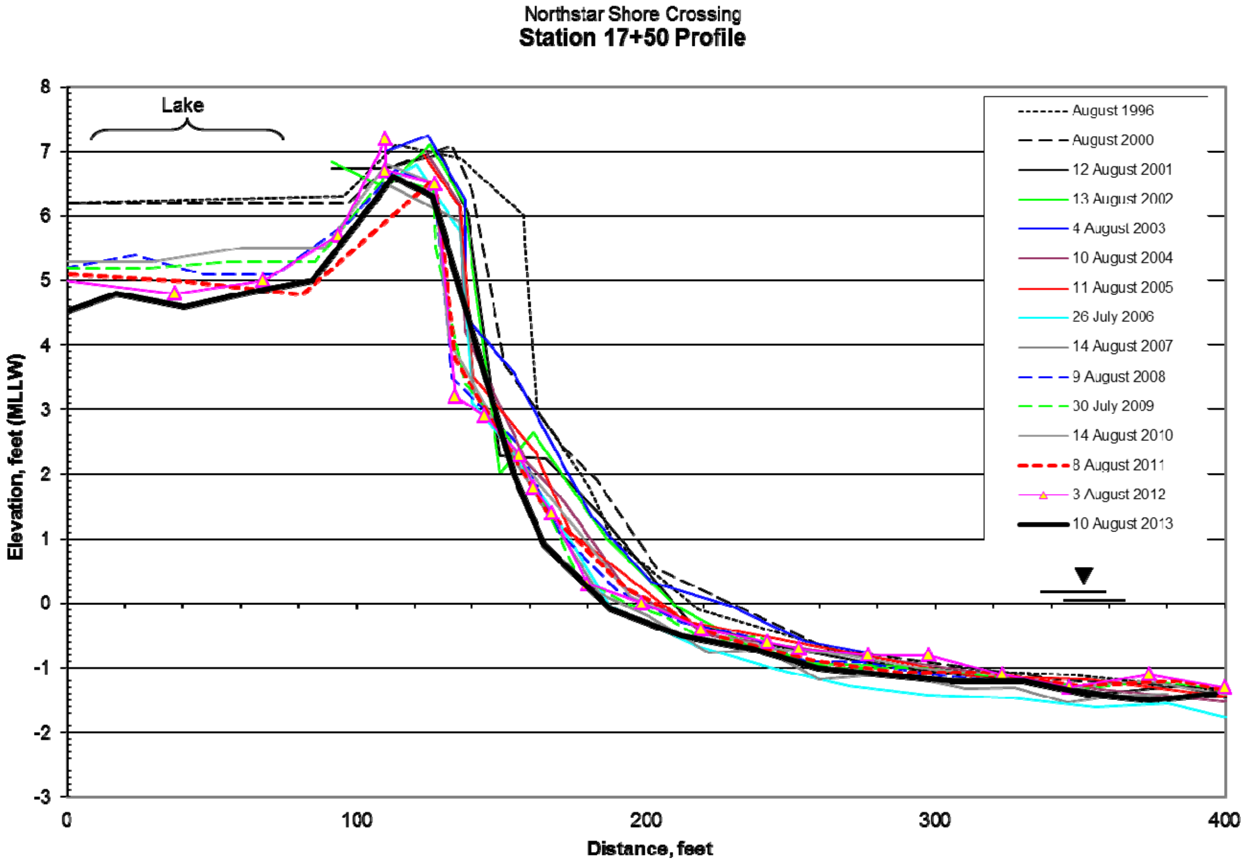
Northstar Shore Crossing
Station 9+85 Profile
14
12
10
8
6
4
2
0
-2
-4
0
100
200
300
400
Elevation, feet (MLLW)
Distance, feet
August 1996
August 2000
12 August 2001
13 August 2002
4 August 2003
10 August 2004
11 August 2005
26 July 2006
14 August 2007
9 August 2008
30 July 2009
14 August 2010
8 August 2011
3 August 2012
10 August 2013



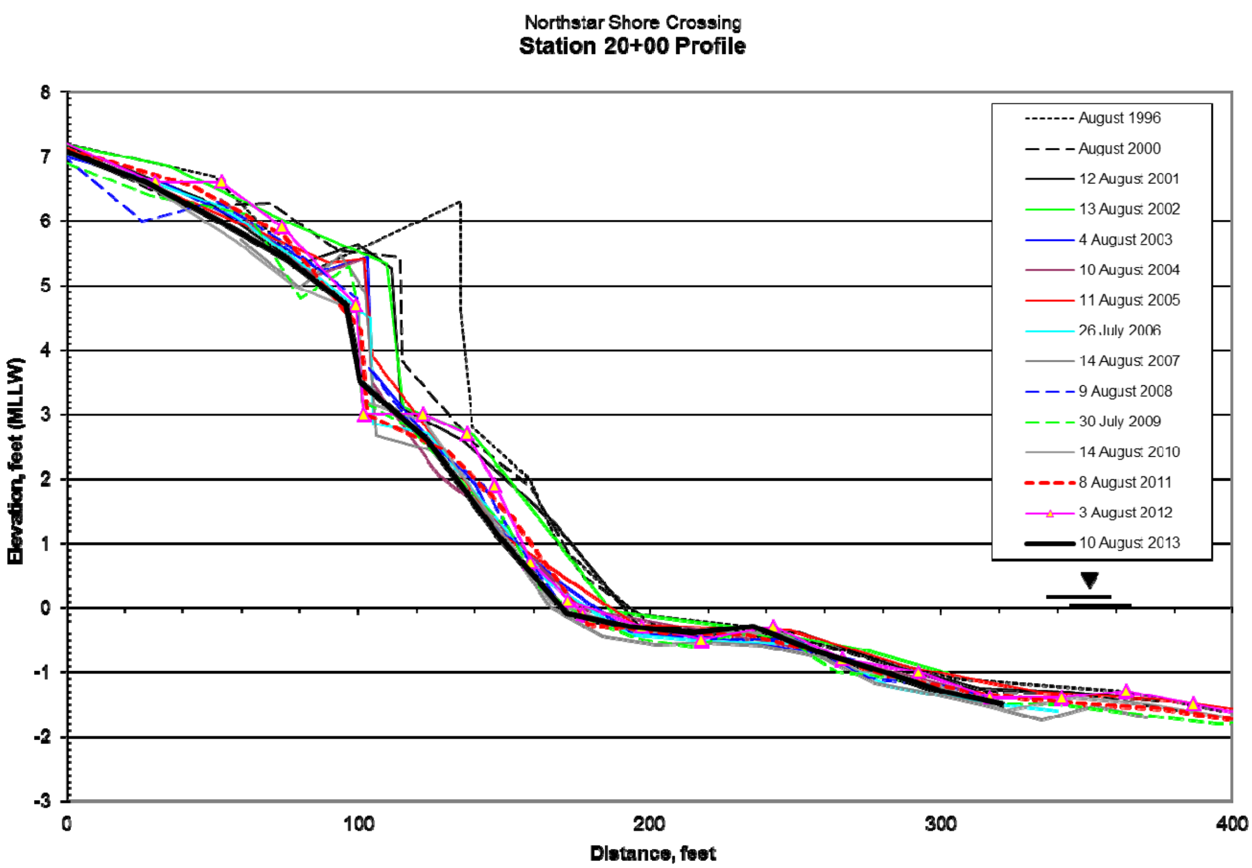
Northstar Shore Crossing
Station 10+25 Profile
Top of Pipeline Riser
Protective Gravel berm
20
18
16
14
12
10
8
6
4
2
0
-2
-4
0
100
200
300
400
Elevation, feet (MLLW)
Distance, feet
August 1996
August 2000
12 August 2001
13 August 2002
4 August 2003
10 August 2004
11 August 2005
26 July 2006
14 August 2007
9 August 2008
30 July 2009
14 August 2010
8 August 2011
3 August 2012
10 August 2013


Northstar Shore Crossing
Station 12+50 Profile
Elevation, feet (MLLW)
Distance, feet
9
8
7
6
5
4
3
2
1
0
-1
-2
-3
0
100
200
300
400
August 1996
August 2000
12 August 2001
13 August 2002
4 August 2003
10 August 2004
11 August 2005
26 July 2006
14 August 2007
9 August 2008
30 July 2009
14 August 2010
8 August 2011
3 August 2012
10 August 2013


Northstar Shore Crossing
Station 15+00 Profile
Elevation, feet (MLLW)
Distance, feet
8
7
6
5
4
3
2
1
0
-1
-2
-3
0
100
200
300
400
August 1996
August 2000
12 August 2001
13 August 2002
4 August 2003
10 August 2004
11 August 2005
26 July 2006
14 August 2007
9 August 2008
30 July 2009
14 August 2010
August 8, 2011
3 August 2012
10 August 2013



Northstar Shore Crossing
Station 17+50 Profile
Lake
Elevation, feet (MLLW)
Distance, feet
August 1996
August 2000
12 August 2001
13 August 2002
4 August 2003
10 August 2004
11 August 2005
26 July 2006
14 August 2007
9 August 2008
30 July 2009
14 August 2010
8 August 2011
3 August 2012
10 August 2013



Northstar Shore Crossing
Station 20+00 Profile
Elevation, feet (MLLW)
Distance, feet
August 1996
August 2000
12 August 2001
13 August 2002
4 August 2003
10 August 2004
11 August 2005
26 July 2006
14 August 2007
9 August 2008
30 July 2009
14 August 2010
8 August 2011
3 August 2012
10 August 2013

Appendix G

Rehabilitation Report

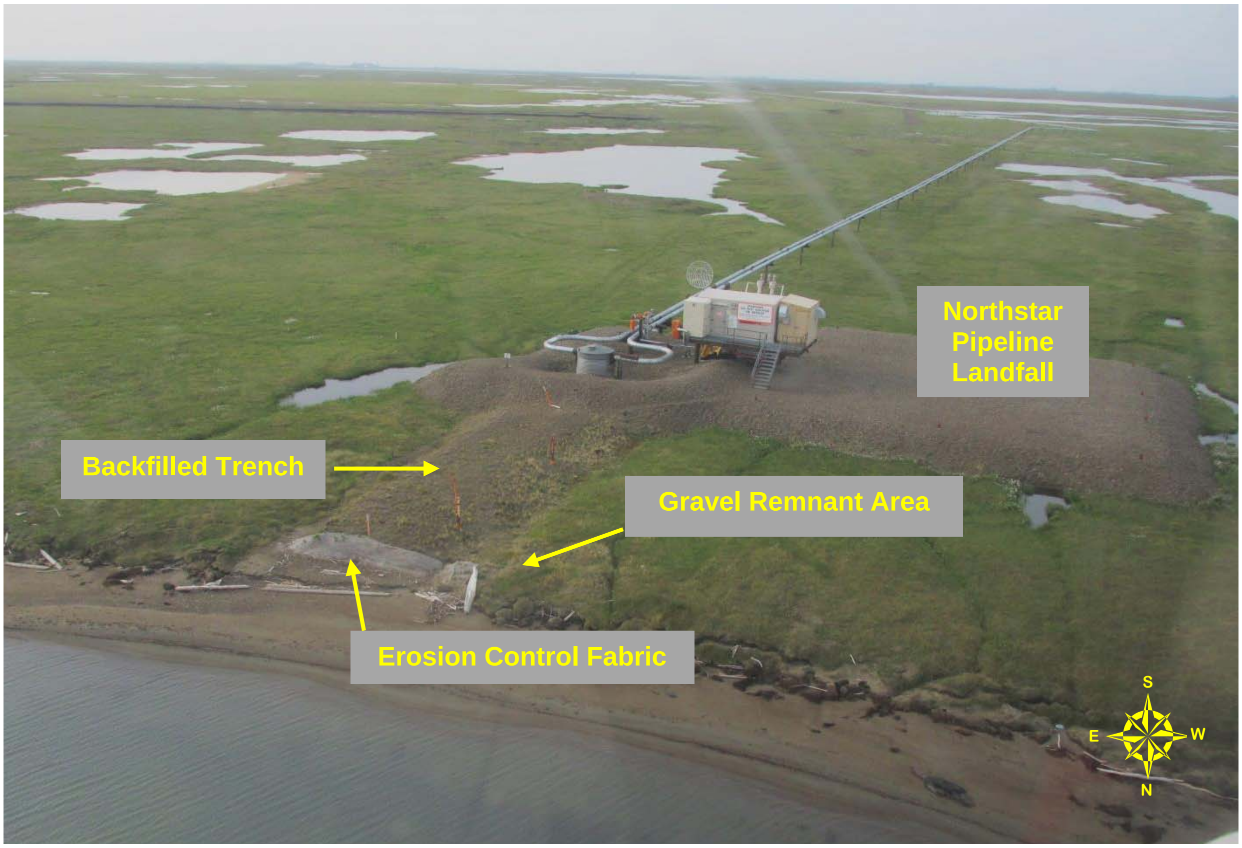
Northstar Pipeline Landfall Shore Crossing

REHABILITATION REPORT FOR THE NORTHSTAR PIPELINE LANDFALL SHORE CROSSING, PRUDHOE BAY OILFIELD, ALASKA

USACE PERMIT–950372, BEAUFORT SEA 441

Prepared by
Janet Kidd / ABR, Inc.—Environmental Research & Services, Fairbanks, AK
and
BP Environmental Studies Group, Anchorage, AK

15 November 2013



Oblique aerial view of the Northstar Pipeline Landfall Shore Crossing, Western Operating Area, Prudhoe Bay Oilfield, 3 August 2013. Photograph taken by ABR, Inc.

INTRODUCTION

This report has been prepared to provide information through 2013 on the rehabilitation monitoring of the Northstar Pipeline Landfall Shore Crossing, and follows BP Exploration (Alaska), Inc.'s (BPXA) standard format for rehabilitation reports. This is the 10th rehabilitation report submitted for this site.

LOCATION: The site is located on the shoreline of Prudhoe Bay where the pipeline comes ashore, approximately 6 km west of West Dock in the Western Operating Area of the Prudhoe Bay Oilfield (Figure 1). Location coordinates are: 70.404° N and 148.692° W. Access to the site is by helicopter or by shallow-draft boat.

HISTORY: The Northstar development pipeline was constructed in winter 1999–2000. During construction, the trench in which the pipe was buried when it reached the shore was backfilled with gravel and sand. A thin layer (2–5 cm) of gravel also was left on the west side of the trench (referred to as the remnant gravel area) where gravel was temporarily stockpiled while the trench was being backfilled. Approval to build the pipeline included the stipulation that a program be developed to monitor shoreline erosion at the landfall site.

In 2000, soil samples were collected from the backfilled trench and analyzed for fertility and salinity. Results indicated that the soil was saline and lacking in nutrients needed to support plant growth. To promote the establishment of vegetative cover, fertilizer and seed of *Puccinellia borealis* (arctic alkaligrass), a salt-tolerant native grass cultivar, were broadcast on the backfilled area and the front face of the backfilled trench in July 2001. In July 2002, an inspection by agency and BP personnel determined that the vegetation cover on the site was not robust enough to control erosion. In September 2002, the backfilled trench was reseeded with *P. borealis* and the remnant gravel area was seeded for the first time with the same species.

Soil samples were collected again in September 2002, and analysis indicated that mean EC (an indirect measure of salinity) had declined to 3.0 mmhos/cm, indicating slightly saline conditions. By 2003, mean EC had declined to 0.4 mmhos/cm, indicating that the soil was no longer saline.

Annual monitoring of the shoreline crossing from 2001–2003 found that the seaward side slope of the backfilled trench had been subject to coastal erosion, particularly during fall storms. The erosion prompted the installation of erosion control fabric in 2004. The side slope was fertilized along with the backfilled and remnant gravel areas. New fabric was installed in 2009, after the original fabric deteriorated and approximately 1.5 m of the backfilled trench eroded between 2008 and 2009.

Monitoring of site conditions has been conducted annually since 2000. Previous reports were prepared by Lazy Mountain Research Co., LLC (Lazy Mountain Research) (2000–2003), Lazy Mountain Research, LGL Alaska Research Associates, Inc., (LGL Alaska Research) and BPXA (2004), LGL Alaska Research and BPXA (2005–2008), OASIS Environmental Inc. and BPXA (2009–2011), and ABR and BPXA (2012).

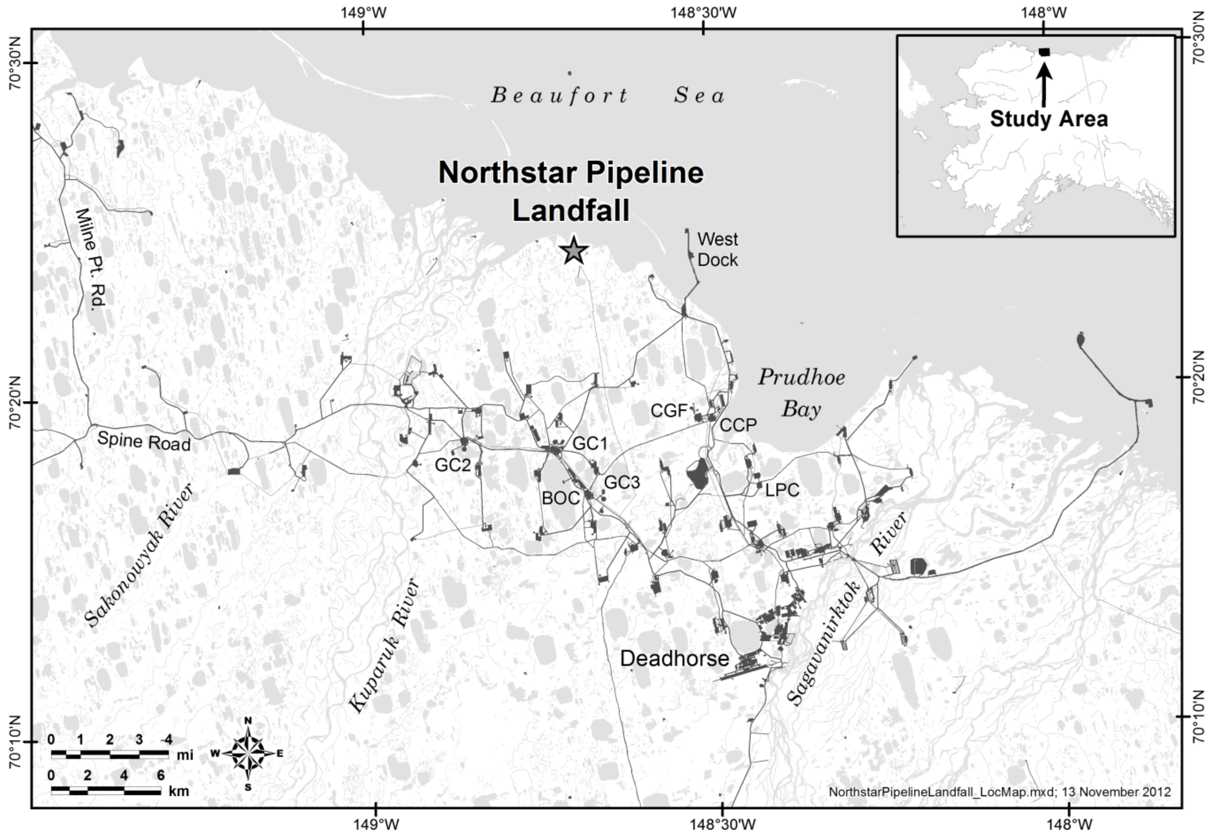


Figure 1. Location of Northstar Pipeline Landfall Shore Crossing, Prudhoe Bay Oilfield, Alaska.

SITE SIZE: The backfilled trench is approximately 22.5 m long and 12 m wide (0.07 acre). The remnant gravel area is approximately 9 × 9 m in area (0.02 acre).

SITE DESCRIPTION: Vegetation on the surface of the backfilled trench was moderate and dominated by the seeded *P. borealis* (Figure 2), although several forbs and other grasses also have established. On the remnant gravel area, vegetation has developed sufficiently that it appears similar to the surrounding tundra (Figure 3). The seaward side slope of the backfilled trench only has sparse cover of *P. borealis*. The surrounding vegetation is dominated by Moist Sedge Meadow Tundra.

REHABILITATION GOALS, OBJECTIVES, AND PERFORMANCE STANDARDS: The rehabilitation approach and schedule are summarized in Table 1. No specific performance standards were established for this site.

Figure 2. Views (north) of the backfilled trench in 15 September 2005 and 3 August 2013, Northstar Pipeline Landfall Shore Crossing.

Figure 3. Views (east) of the remnant gravel area (foreground) and the backfilled trench (background) 10 July 2009 and 3 August 2013, Northstar Pipeline Landfall Shore Crossing.

Table 1. Summary and timeline of rehabilitation treatments applied and monitoring conducted during 2000–2013, and those planned for 2014, at the Northstar Pipeline Landfall Shore Crossing, North Slope, Alaska.

Site Component	Year 0 (2000) (completed)	Year 0 (2001) (completed)	Years 2–3 (2002–2003) (completed)	Year 4 (2004) (completed)	Years 5–8 (2005–2008) (completed)	Year 9 (2009) (completed)	Year 10 (2010) (completed)	Year 11 (2011) (completed)	Years 12–13 (2012–2013) (completed)	Year 14 (2014) (planned)
Backfilled Trench	Site Preparation: • Backfill– mixture of sand and gravel used to bury pipeline. Monitoring • Soil properties	Treatment • Seed—*P. borealis* at 9.4 lbs/acre) • Fertilizer—(10-20-20 NPK at 357 lbs/ acre)	Treatment • Seed—*P. borealis* at 7 lbs/acre) Monitoring • Vegetation • Soil properties	Treatment • Fertilizer—(0:45:0 NPK at 277 lbs/ acre) Monitoring • Soil properties	Monitoring • Vegetation	Treatment • Install new erosion control netting • Apply fertilizer Monitoring • Vegetation	Monitoring • Vegetation • Soil properties	Monitoring • Vegetation	Monitoring • Vegetation (qualitative)	Monitoring • Vegetation (qualitative)
Trench Side Slope	Site Preparation: • Backfill– mixture of sand and gravel used to bury pipeline. Monitoring • Soil properties	Treatment • Seed—*P. borealis* at 9.4 lbs/acre) • Fertilizer—(10-20-20 NPK at 357 lbs/ acre)	Treatment • Seed—*P. borealis* at 7 lbs/acre	Treatment • Install erosion control mat • Fertilizer—(0-45-0 NPK at 277 lbs/ acre) Monitoring • Soil properties	Treatment • Repair section of erosion control mat	Treatment • New erosion control mat installed				Treatment • Install new erosion control mat, if necessary • Backfill gullied area with cocomat tubes of soil and transplant *Leymus* sprigs
Gravel remnant area			Treatment • Seed—*P. borealis* at 7 lbs/acre) Monitoring • Vegetation	Treatment • Fertilizer—(0-45-0 NPK at 277 lbs/ acre) Monitoring Vegetation	Monitoring • Vegetation	Monitoring • Vegetation	Monitoring • Vegetation	Monitoring • Vegetation	Monitoring • Vegetation (qualitative)	Monitoring • Vegetation (qualitative)
Overall Site	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings	Monitoring • Surface stability (qualitative) • Photograph site Progress report summarizing rehabilitation efforts and findings

MONITORING

PLANT MONITORING: The success of the rehabilitation treatments applied at the Northstar Pipeline Landfall Shore Crossing was qualitatively assessed on 3 August 2013. A moderate cover of vascular plants has established on the backfilled trench (Figure 2). The dominant species was the seeded grass *P. borealis*, although we identified 12 additional indigenous vascular species, including grasses, forbs, and shrubs (Table 2). Only trace cover of vegetation, consisting exclusively of *P. borealis*, was found growing through the mesh fabric on the seaward side slope of the backfilled trench (Figure 4). Vegetation recovery on the remnant gravel area has progressed to the point where the plant community appears similar to the surrounding tundra (Figure 3); 11 indigenous species were recorded in this area (Table 2).

ELEVATION MONITORING: The backfilled trench and the remnant gravel area appeared mostly stable in 2013 (Figures 2 and 3). The seaward side slope of the backfilled trench where erosion control fabric was installed appeared stable and similar to conditions in 2012 (Figure 4). An erosion gulley has formed beneath the fabric at the west end (Figure 5), probably due to snow melt running off the backfilled trench or summer rainfall. The backfilled trench behind it, however, appears to be unaffected. It is possible this gulley will enlarge over time, in which case the side slope will require further treatment.

SOIL MONITORING: No soil monitoring was conducted in 2013.

WILDLIFE USE OF AREA: Use of the site by wildlife was assessed by casual observation during the site visit. Caribou scat was observed in the backfilled trench area and tracks of a bear (probably a polar bear) were seen along the shore.

Figure 4. Views (east) of side slope treated with erosion control matting, Northstar Pipeline Landfall Shore Crossing, 28 July 2012 and 3 August 2013.

Table 2. List of vascular plant species found at the Northstar Pipeline Landfall Shore Crossing, 3 August 2013.

Lifeform / Species	Side slope of Trench	Backfilled Trench	Remnant Gravel Area
Native Grass Cultivars			
Puccinellia borealis	×	×	×
Indigenous Species			
Grasses			
Alopecurus alpinus			
Arctagrostis latifolia		×	
Festuca baffinensis		×	
F. brachyphylla		×	×
Poa arctica		×	×
Sedges			
Carex aquatilis			×
C. membranacea		×	
Forbs			
Artemisia arctica			×
Cerastium beeringianum		×	×
Cochlearia officinalis		×	×
Draba sp.		×	×
Descurainia sophioides			×
Potentilla hyperborea		×	×
Shrubs			
Dryas integrifolia		×	
Salix arctica		×	×
S. ovalifolia		×	×

PROGRESS TOWARD PERFORMANCE STANDARDS AND RECOMMENDED REMEDIAL ACTION

No specific performance standards have been established for this site. Monitoring in 2013 found a moderate cover of live vascular plants has established on the backfilled trench. Erosion and poor soil characteristics have prevented plants from establishing on the seaward side slope of the backfilled trench. The remnant gravel area appeared stable and vegetated with a productive cover of predominantly indigenous vascular plants.

Erosion of the trench side slope has been minimal since 2009, due primarily to the protection provided by the erosion control fabric. The rooting system of plants can also protect against erosion, but vegetation on the side slope is too sparse to provide this function. If the site is

Figure 5. Close-up of area at west end of erosion control fabric where a slight gully has formed (yellow arrow), Northstar Pipeline Landfall Shore Crossing, 3 August 2013.

inspected annually, the fabric can be maintained and replaced as necessary, but ultimately this treatment alone is not a permanent solution for erosion control. For added protection against erosion, a productive cover of vegetation should be established on the side slope of the trench. One possible option for achieving this objective is to plant sprigs of the dune grass, *Leymus mollis* (American dunegrass), through the mesh fabric. It is not certain, however, that the additional vegetation cover would control erosion of the side slope in the event of a significant storm.

To prevent the erosion gully that has developed beneath the fabric from deepening and expanding, cocomat tubes full of soil will be installed in the gullied area and sprigged with *Leymus* in 2014.

REPORTING

This report will be distributed to the following agency by 15 November 2013:

1. U.S. Army Corps of Engineers

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Appendix H

Northstar Development 2013

Pipeline Route Monitoring Program

COASTAL

FRONTIERS

Northstar Production Island, Ice Road, and Kuparuk River Overflood on June 5, 2013

NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM

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NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM

FINAL REPORT

Prepared for:

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Anchorage, Alaska

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EXECUTIVE SUMMARY

This report presents the results of the Northstar Development 2013 Pipeline Route Monitoring Program. The work was performed on behalf of BP Exploration (Alaska) Inc. (BPXA) by Coastal Frontiers Corporation.

The 2013 Monitoring Program was the fourteenth annual post-construction investigation of the pipeline route, and the twelfth to be conducted after the initiation of oil production on Northstar Production Island. It was designed to accomplish four specific tasks:

1. Obtain detailed bathymetric data on the pipeline route;
2. Determine the locations and characteristics of ice gouges in the sea bottom on the pipeline route;
3. Determine the locations of strudel drainage features in the ice in a 5,000-ft wide monitoring corridor centered on the pipeline alignment; and
4. Determine the locations and characteristics of strudel scour depressions in the sea bottom on the pipeline route, and at additional sites in the 5,000-ft monitoring corridor where strudel drainage features had been observed.

These tasks are similar to those undertaken from 2000 through 2005 and identical to those undertaken since 2006, when the width of the monitoring corridor for strudel scours was decreased from 10,000 to 5,000 ft. To maximize the utility of the existing data, statistical characterizations of the strudel drains and strudel scours that had occurred in the 5,000-ft corridor were derived for each survey year prior to 2006.

The field work was conducted in two phases: (1) a helicopter-based reconnaissance of strudel drainage features in early June, and (2) a vessel-based survey program in late July. The instrumentation used for the summer survey included multi-beam sonar (to obtain detailed bathymetric data in deep water), single-beam sonar (to obtain bathymetric data in shallow water and serve as a back-up to the multi-beam system in deep water), and side scan sonar (to locate ice gouges and strudel scours). Navigation and position data were acquired using the Global Positioning System (GPS) with real-time differential corrections (DGPS).

The principal findings of the 2013 monitoring program are summarized below:

1. ***Bathymetry on Pipeline Alignment:*** The bathymetric profile on the pipeline alignment bore a close resemblance to that recorded in 2012. Between Northstar Production Island and Stump Island, the most significant changes consisted of: (1) a general reduction in bathymetric relief, (2) in-filling of two relict strudel scour depressions, and (3) sediment accumulation in an inactive subsidence area immediately north of Stump Island. Between Stump Island and the shore crossing, the profile was virtually identical to that in 2012 and similar to the pre-construction profile obtained in 1996.

2. ***Sea Bottom Subsidence***: For the first time since oil began flowing in the fall of 2001, no areas of active subsidence were detected on the pipeline alignment in 2013. This finding is consistent with the trend toward decreasing subsidence noted in 2011 and 2012, and may reflect a reduction in radiant heat from the oil sales line occasioned by declining flow rates.

3. ***Pipeline Trench Backfill Thickness:*** One modest deficiency in the backfill thickness relative to the 6-ft minimum value stipulated in the pipeline permit was detected in the inactive subsidence area immediately north of Stump Island. Shortfalls had been noted at this location in each of the past four years. The deficiency was extremely small, with a maximum shortfall of 0.2 ft and a length of 63 ft along the pipeline alignment. Approximately 1,000 cy of fill were placed in this area after the discovery of active subsidence in 2009, followed by 500 cy in 2010 and an additional 500 cy in 2011. As no new subsidence was detected at this site in either 2012 or 2013, the probable cause of the deficiency is incomplete remediation of the shortfalls identified in prior years.

4. ***Ice Gouges:*** Nine ice gouges were detected on the Northstar pipeline route during the 2013 survey. Five represented newly-discovered features, while four were relict gouges that had been discovered during prior surveys. The incision depths of the new gouges ranged from 0.5 to 1.6 ft, the incision widths from 7 to 32 ft, and the water depths from 17.4 to 35.7 ft. The number of new gouges was extremely low by historical standards, while the severity was consistent with historical precedent. Although one gouge crossed the pipeline alignment, it did not cause the backfill thickness to violate the 6-ft minimum value stipulated in the pipeline permit.

5. ***Ice Wallows:*** No new ice wallows were identified during the 2013 survey, but two of the 18 wallows first discovered in 2011 were found again. The incision depths of the relict wallows were 0.6 and 0.8 ft, the incision widths were 17 and 18 ft, and the water depths were 20.8 and 21.3 ft.

6. ***Kuparuk River Overflood:*** The 2013 Kuparuk River overflood was vigorous by historical standards but remained within the footprint established by previous flood boundaries. On the pipeline alignment, the seaward edge was located approximately 16,100 ft north of Stump Island and only 5,600 ft south of Northstar Production Island. Sixty seven drainage features were detected in the 5,000-ft wide monitoring corridor, more than in any prior year except 2012. Sixty five were located to the north of Stump Island, while two were located to the south in Gwydyr Bay. During the fourteen-year period of record (2000-2013), the number of drains observed in the 5,000-ft corridor has ranged from eight to 83 while averaging 37 per year.

7. ***Strudel Scours:*** When a sonar search for strudel scours was conducted on the pipeline route and at the 67 drainage sites observed during the overflood period, 70 new depressions were discovered in the sea bottom. Sixty three of the scours were circular in plan form, while seven were linear. The water depths of the circular scours ranged from 7.5 to 19.8 ft, the scour depths from 0.5 to 2.6 ft, and the maximum horizontal dimensions from 9 to 87 ft. In the case of the linear scours, the water depths ranged from 9.8 to 14.7 ft, the scour depths from 1.2 to 2.2 ft, and the lengths from 57 to 617 ft. The numbers of circular and linear scours were high by historical standards, but the severity of the scouring was relatively low. None of the scours impinged on the backfill over the pipelines.

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NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM

1. INTRODUCTION

This report presents the results of the Northstar Development 2013 Pipeline Route Monitoring Program. The work was performed on behalf of BP Exploration (Alaska) Inc. (BPXA) by Coastal Frontiers Corporation.

The Northstar Unit lies to the northwest of Prudhoe Bay, extending offshore from Gwydyr Bay to water depths of approximately 50 ft (Figure 1). During the spring and summer of 2000, Northstar Production Island was constructed in a water depth of 38 ft at the site of the former Seal Island, and twin pipelines were installed to convey gas to the island and oil to shore. The pipelines extend south from the production island through the western end of Stump Island, and continue across Gwydyr Bay to a landfall approximately one-half mile east of Point Storkersen (Figure 2). To prevent damage from ice gouges and strudel scours, the lines were buried in a trench excavated in the sea bottom.

The 2013 Monitoring Program was the fourteenth annual post-construction investigation of the pipeline route, and the twelfth to be conducted after the initiation of oil production in 2001. It was designed to accomplish four specific tasks:

1. Obtain detailed bathymetric data on the pipeline route;
2. Determine the locations and characteristics of ice gouges in the sea bottom on the pipeline route;
3. Determine the locations of strudel drainage features in the ice in a 5,000-ft wide monitoring corridor centered on the pipeline alignment; and
4. Determine the locations and characteristics of strudel scour depressions in the sea bottom on the pipeline route, and at additional sites in the 5,000-ft monitoring corridor where strudel drainage features had been observed.

These tasks are similar to those undertaken from 2000 through 2005, when the width of the strudel scour monitoring corridor was 10,000 ft, and identical to those undertaken from 2006 through 2012, when the corridor width was 5,000 ft. The narrower corridor was adopted in 2006 to allow greater focus on the region adjacent to the pipelines. To maximize the utility of the data acquired previously, statistical characterizations of the strudel drains and strudel scours that had occurred in the 5,000-ft corridor were derived for each year from 2000 through 2005 (Coastal Frontiers, 2007).

The 2013 field work was conducted in two phases: (1) a helicopter-based reconnaissance of strudel drainage features in early June, and (2) a vessel-based survey program in late July. The instrumentation used for the summer survey included multi-beam sonar (to obtain detailed bathymetric data in deep water), single-beam sonar (to obtain bathymetric data in shallow water and serve as a back-up to the multi-beam system in deep water), and side scan sonar (to locate ice gouges and strudel scours). Navigation and position data were acquired using the Global Positioning System (GPS) with real-time differential corrections (DGPS).

The vertical datum for all elevations in this report is ARCO Mean Lower Low Water (MLLW), which represents the Northstar Development project datum. Based on a detailed investigation conducted in 1997, ARCO MLLW is identical to National Ocean Service (NOS) MLLW for engineering purposes (Coastal Frontiers, 1997). Tidal datum information developed from the NOS tide gauge in Prudhoe Bay for the 1983-2001 epoch indicates that Mean Sea Level lies 0.34 ft above MLLW.

The horizontal datum for all positions is Alaska State Plane Zone 4 (ASP 4) relative to the North American Datum of 1927 (NAD27). The units are U.S. Survey Feet. Geographic coordinates also are displayed on some of the study products. Once again, the reference is NAD27. Compass orientations are expressed in degrees relative to Grid North (°G). As indicated in Figure 2, stationing along the pipeline route refers to the distance in feet south of the pipeline exit on Northstar Production Island (*e.g.*, Station 70+00 lies 7,000 ft south of the island).

The coordinates of the five points that define the pipeline alignment between the production island and shore crossing are provided in Table 1. In the interest of clarity, "pipeline alignment" will be used to refer to the as-built path of the pipeline between these points. "Pipeline route" will be used in a more general sense to describe the pipeline alignment along with the surrounding sea floor.

This report provides a detailed account of the Northstar Development 2013 Pipeline Route Monitoring Program. Section 2 summarizes the results of prior surveys. Section 3 describes the study methods while Section 4 presents the results. Key findings and conclusions are summarized in Section 5. References are provided in Section 6, followed by tables and figures. Plates are embedded in the text. Six oversize drawings comprised of ten

24-in. x 36-in. sheets are bound separately as Appendix A. The assistance of Mr. Stuart Sanchez of the BP Cartography Department in preparing Figures 1, 2 and 10 and Drawings CFC-815-03-001, -002, and -003, is gratefully acknowledged.

2. PRIOR SURVEYS

Pre-construction surveys were undertaken annually in the Northstar Development project area from 1995 through 1999 to support pipeline design and construction planning (Coastal Frontiers, 1996; 1997; 1998; 1999; 2000). The first post-construction survey of the pipeline route was conducted in August 2000 (Coastal Frontiers, 2001a). At that time, the backfill thickness over the top of the pipelines was found to be less than the 6-ft minimum value specified in the pipeline permit at thirteen locations. To achieve compliance with the permit, a gravel placement program was undertaken from the sea ice in April 2001 (Coastal Frontiers, 2001b). Full compliance with the 6-ft minimum backfill thickness was confirmed when the second post-construction survey was undertaken in late July and early August, 2001 (Coastal Frontiers, 2002).

Oil began flowing through the Northstar sales pipeline in the fall of 2001. When the third post-construction survey was performed in early August, 2002, a decrease in the elevation of the sea bottom typically ranging from one to four feet was noted on much of the pipeline alignment (Coastal Frontiers, 2003). The most probable explanation is that the trench backfill, which was frozen at the time of placement in spring 2000, experienced thawing and subsidence due to the heat radiating from the oil sales line. As a result, the backfill thickness did not attain the 6-ft minimum acceptable value at ten locations on the pipeline alignment. The two areas with the greatest shortfalls (1.0 and 0.8 ft) were located in the nearshore region of Gwydyr Bay within 500 ft of the pipeline shore crossing. Additional backfill was provided at these sites through a gravel placement program conducted from the sea ice in spring 2003. The remaining eight areas, with minor shortfalls ranging from 0.1 to 0.4 ft, were omitted from the gravel program.

When the 2003 survey program was undertaken in late July and early August, full compliance with the 6-ft minimum backfill thickness was noted along the entire length of the pipeline alignment (Coastal Frontiers, 2004). This finding confirmed that the spring 2003 gravel placement program in the nearshore area, coupled with wave-induced sediment transport in the offshore area, had completely erased the ten shortfalls identified in 2002. Nevertheless, a detailed reanalysis of the 2003 bathymetric data performed in 2009 indicated that sea bottom subsidence had occurred on limited portions of the pipeline route during the period between the 2002 and 2003 surveys (Coastal Frontiers, 2009b).

The 2004 survey program revealed the presence of a 9.5-ft deep, 55-ft wide strudel scour centered only 10 ft east of the pipeline alignment (Coastal Frontiers, 2005). The scour depth directly over the pipelines was 6.5 ft, leaving approximately 1.8 ft of backfill above the top-of-pipeline profile. With the exception of this scour, the 6-ft minimum backfill thickness was maintained over the entire length of the pipeline alignment. A diver inspection was undertaken soon after the survey to confirm that the pipelines had not become exposed, after which the depression was filled with gravel dumped from a barge.

In 2005, the bathymetric profile on the pipeline alignment closely resembled that which existed in 2004 (Coastal Frontiers, 2006). At four locations, however, the elevation of the sea bottom on or adjacent to the pipeline alignment had decreased by approximately one foot. Nevertheless, the permit stipulation requiring a 6-ft minimum backfill thickness was fulfilled over the entire length of the pipelines.

The bathymetric data acquired in 2006 indicated that seven areas on the pipeline alignment had been altered by recent subsidence (Coastal Frontiers, 2007). The lengths of the subsidence areas ranged from 150 to 750 ft while the maximum depths (measured relative to the ambient sea bottom) ranged from 1.1 to 4.8 ft. A pronounced depression that appeared to have resulted from strudel drainage was discovered in one of the subsidence areas. This feature, with a maximum horizontal dimension of 60 ft and maximum scour depth of 5.8 ft, was centered 26 ft west of the pipeline alignment.

In three of the 2006 subsidence areas, the decrease in elevation caused the pipeline trench backfill thickness to fall below the minimum acceptable value of 6 ft. The shortfall attained a maximum value of 0.8 ft and extended 38 ft along the pipeline alignment at one site, while the corresponding values were 0.5 ft and 33 ft at the second site. At the third, the decrease in elevation attributable to the combined effects of subsidence and strudel scouring caused a backfill deficiency of up to 3.3 ft that extended 97 ft along the pipeline alignment. To remedy these three deficiencies, five barge loads of gravel representing approximately 2,900 cy were dumped onto the pipeline alignment in late August.

In 2007, subsidence was noted in twelve areas (Coastal Frontiers, 2008). Two of these represented expansions of the sites identified in 2006, while the remaining ten were new sites. The lengths of the subsidence areas varied from 80 to 790 ft along the pipeline alignment, while the maximum subsidence depths varied from 1.0 to 3.2 ft. Although the minimum acceptable backfill thickness of 6 ft was maintained over the entire length of the pipelines, BPXA commissioned a preemptive gravel placement program under which approximately 3,400 cy of material were dumped on five of the sites in mid-August.

A significant discovery in 2007 was a unique sub-population of newly-formed ice gouges that included a maximum incision depth (5.1 ft) nearly three times larger than the prior maximum, and a maximum incision width (76 ft) nearly twice as large as the prior maximum. The probable cause of the unprecedented gouging was an intense easterly storm that brought large ice floes to the Northstar project area in October 2006. The simultaneous occurrence of severe oceanographic conditions and drift ice is likely to have created a "perfect storm" for the generation of exceptional gouges which formed when the ice floes were driven aground by high winds, large waves, and strong currents (Coastal Frontiers, 2008).

During the 2008 survey, twelve areas of recent subsidence were detected on the pipeline alignment (Coastal Frontiers, 2009a). At five of these sites, the subsidence represented an expansion of that noted in 2007. The lengths of the subsidence areas ranged from 70 to 1,170 ft, while the maximum subsidence depths ranged from 1.1 to 2.5 ft. In the deepest subsidence area, the backfill thickness was found to be up to 0.4 ft less than the minimum acceptable value over 202 ft in a 303-ft span. To correct this deficiency, BPXA dumped approximately 1,500 cy of gravel into the depression in August 2008.

The 2009 survey revealed the presence of seven active subsidence areas on the pipeline alignment (Coastal Frontiers, 2009b). Two of these were new, while the other five had been identified as subsidence areas in one or more prior years. The lengths of the seven areas ranged from 80 to 890 ft; the maximum subsidence depths ranged from 0.8 to 1.8 ft. In the largest subsidence area, which was 396 ft long, the decrease in sea bottom elevation caused the backfill thickness to fall as much as 1.3 ft below the minimum acceptable value. The shortfall was addressed in August 2009, when approximately 1,000 cy of gravel was barged to the site and dumped into the depression.

Thirteen areas of active subsidence were detected on the pipeline alignment in 2010 (Coastal Frontiers, 2011). The lengths of these areas varied between 80 and 3,740 ft, while the maximum subsidence depths varied between 1.0 and 2.9 ft. At four of the thirteen sites, the subsidence represented an expansion of that noted in 2009. At six others, subsidence had been detected in one or more prior years but not in 2009. The remaining three sites had not experienced subsidence previously. The combined length of these areas, 10,330 ft, exceeded that recorded in any prior year. Insufficient backfill thickness prevailed at four locations. The maximum shortfalls ranged from 0.1 to 0.8 ft, while the lengths ranged from 2 to 128 ft. BPXA conducted a gravel placement program prior to freeze-up under which approximately 2,900 cy of material were dumped into the four shortfall areas.

In contrast to 2010, only two areas of active subsidence were detected in 2011 (Coastal Frontiers, 2012). Both were relatively small, with one measuring 240 ft long and up to 1.1 ft deep and the other measuring 420 ft long and up to 1.0 ft deep. No subsidence had been detected in the first area previously, while the subsidence in the second represented an expansion of that noted in 2010. The combined length of the active subsidence areas (660 ft) was the smallest since 2005, and substantially less than in 2010. Although the trench backfill thickness exceeded the minimum acceptable value of 6 ft in both areas, modest deficiencies were detected in two other regions off Stump Island where shortfalls had been detected in the past. The first, with a length of 46 ft and maximum shortfall of 0.5 ft, was located in an area where a shortfall of up to 0.8 ft had been identified in 2010. The second, with a length of 103 ft and maximum shortfall of 0.4 ft, was located in an area where a shortfall of up to 1.3 ft had been identified in 2009, and up to 0.6 ft in 2010. As no new subsidence was evident at either site in 2011, the probable cause of the deficiencies was incomplete remediation of the shortfalls detected previously. A gravel placement program was conducted prior to freeze-up under which approximately 500 cy of material were dumped into each of the two depressions.

As in 2007, extraordinary ice gouging was detected on the Northstar pipeline route during the 2011 survey. The number of new gouges, 130, surpassed the prior historical maximum of 54 gouges by a wide margin, while both the mean incision depth of 1.0 ft and maximum incision depth of 3.5 ft had been exceeded only in 2007. In addition, 18 ice wallows with incision depths ranging from 1.0 to 5.6 ft and incision widths from 11 to 79 ft were noted. The probable cause of these features was the simultaneous occurrence of a severe easterly storm and deep-keeled drift ice in October 2010.

Only one active subsidence area was identified on the pipeline alignment in 2012 (Coastal Frontiers, 2013). The feature was 540 ft long and up to 1.6 ft deep. While no subsidence was evident at this location in 2011, it had been detected on four prior occasions: 2006, 2007, 2009, and 2010. The length of active subsidence was the smallest since record-keeping began in 2003, and a small fraction of that recorded only two years earlier (10,330 ft in 2010). Although the backfill thickness exceeded the 6-ft minimum acceptable value throughout this area, three modest deficiencies were detected off Stump Island in another region where subsidence had been observed in the past, and where a shortfall had been noted in each of the past three years. Two of the deficiencies were extremely small, with a maximum shortfall of 0.2 ft in each case and lengths of 7 and 24 ft. The third was somewhat larger but nevertheless small by historical standards; the maximum shortfall was 0.4 ft while the length was 78 ft. As in 2011, the deficiencies probably reflected incomplete remediation of the shortfalls noted in prior years.

While subsidence was muted in 2012, strudel scouring was not; the 71 circular scours and 11 linear scours detected in the pipeline monitoring corridor both represented historical maxima. The average and maximum scour depths of the linear features also represented historical maxima (2.0 and 4.4 ft, respectively). However, the severity of the scouring was unexceptional for the circular features. Two of the circular scours impinged on the backfill over the pipelines, but neither caused the backfill thickness to fall below the minimum permissible value of 6 ft. The large number of scours appears to have resulted primarily from an on-ice pipeline corrosion assessment program that entailed creating a snowcat trail on the pipeline alignment and drilling holes through the ice at 50-ft centers. Some of the auger holes and the cracks that developed on the edges of the trail apparently became strudel drains when the river overflood arrived in late May, leading to the formation of scour depressions in the sea bottom.

3. STUDY METHODS

The Northstar Development 2013 Pipeline Route Monitoring Program was conducted in two parts: (1) a helicopter-based reconnaissance of strudel drainage features at the end of the Kuparuk River overflood, and (2) a vessel-based survey program during the open-water season. The methods employed for the former are described in Section 3.1, while those employed for the latter are described in Section 3.2. Data processing and analysis procedures are summarized in Sections 3.3 and 3.4, respectively. The resolution and accuracy attained during the survey are reviewed in Section 3.5.

3.1 Strudel Scour Reconnaissance

A helicopter reconnaissance of the Kuparuk River overflood was conducted on June 4, 5, and 6 to determine the extent to which strudel drainage had occurred in the vicinity of the pipeline route. The specific objectives were to map the seaward limit of the overflood, and to map the locations of all drainage features located within a 5,000-ft wide corridor centered on the pipeline alignment. The mission was conducted at the end of the overflood period rather than at its peak to ensure that the maximum extent of the flood was documented.

Mapping was performed using a Garmin GPSMap 196 unit. The overflood limit of the river water was documented by recording successive positions while flying over the observed boundary at an approximate altitude of 200 ft and speed of 60 knots. Individual strudel drains in the ice sheet were mapped by hovering directly over the feature of interest and then recording a position fix. In addition, the nature of the drain (circular or linear) and a representative dimension (diameter of a circular drain or width of a linear crack drain) were recorded in a log book. Multiple position fixes were used to delineate each crack drain.

To improve the accuracy of the GPS position data, differential corrections broadcast in real time via satellite by the U.S. Government's Wide Area Augmentation System (WAAS) were received by the GPS unit. Although the Federal Aviation Administration initially rated the accuracy of WAAS-corrected GPS positions at 23 ft, equipment manufacturers Trimble and Magellan subsequently reported that an accuracy of 3 to 10 ft is typical in the continental U.S. (Lewis, 2001; Magellan, 2001). To estimate the accuracy attainable with WAAS in the Northstar project area, a position check was conducted on August 3 using a Hemisphere R-110 receiver and the survey monument "Dickory" on the West Dock Causeway. The root-mean-square (rms) error was found to be 1.7 ft.

3.2 Survey Program

The summer survey program consisted of acquiring bathymetric, ice gouge, and strudel scour data on the pipeline route, and searching for strudel scours at other locations in the 5,000-ft monitoring corridor where drainage features had been observed during the spring reconnaissance mission. The data were acquired on July 19, 20, and 21. The wind and sea conditions were favorable on these days, with wind speeds ranging from 5 to 12 kt and wave heights from negligible to 1 ft. Sea ice remained absent from the operating area throughout the survey.

The equipment systems used for the survey effort are summarized in Table 2 and portrayed graphically in Figure 3. The key elements consisted of a Reson SeaBat 7125-SV2 multi-beam echo sounder, an Odom Hydrotrac single-beam echo sounder, an EdgeTech 4125D digital side scan sonar system with Coda mosaic software, a Coda Octopus F185 GPS-aided vessel reference unit, and a C-Nav3050 GPS receiver. Survey operations in prevailing water depths greater than about 8 ft were conducted from the 43-ft research vessel *Annika Marie*, while those in shallower waters were conducted from a 15-ft inflatable boat.

The side scan sonar system served as the primary tool for identifying ice gouges and strudel scours. Side scan provides a two-dimensional, photo-like image that varies with the surface relief and acoustic reflectivity of the sea bottom. A range of 164 ft (50 m) was employed, resulting in coverage that extended 164 ft to either side of the vessel track (Figure 3). The unit was operated at a frequency of 400 kHz, based on 1997 field tests that confirmed sufficient resolution to distinguish small gouges and scours on the sea bottom (Coastal Frontiers, 1998).

The multi-beam sonar system was used both to measure depths along the track lines, and to map features such as ice gouges and strudel scours. Unlike side scan, multi-beam sonar provides a true three-dimensional image of the sea bottom, with a vertical resolution of approximately 0.3 ft. The advantages of this technology relative to single-beam sonar are explained by Poplin, *et al.* (2000).

As suggested by Figure 3, the SeaBat 7125-SV2 uses a wide acoustic beam to acquire data in a swath on the sea floor. Although a cross-track beam angle as large as 165° can be employed in the wide-angle mode, data acquisition was restricted to the central 140° of the beam and data processing to the central 130° to reduce the potential for inaccuracies introduced by reflection from the sea surface and refraction in the water column. These restrictions, coupled with the modest water depths in the study area, produced effective swath widths that typically ranged from 25 to 140 ft (with the minimum value occurring at the inshore limit of multi-beam data acquisition).

The SeaBat was operated at a frequency of 200 kHz, with the return signal divided into 320 sub-beams. Each sub-beam produced a sounding in an identically-sized footprint over the width of the swath. The along-track dimension of the footprint was governed by the along-track beam width of 1.1°, while the cross-track dimension represented 1/320th of the swath width on the sea bottom.

The single-beam sonar system was used as a backup to the multi-beam system on the *Annika Marie*. A narrow-beam transducer with a 3° beam width was employed instead of a conventional 8° transducer to minimize the effect of "aliasing" (explained in Section 3.5) on the measurement of ice gouge and strudel scour depths.

GPS position data were acquired with a C-Nav3050 receiver on the *Annika Marie*, and a Hemisphere R-110 receiver on the inflatable boat. Real-time differential corrections broadcast by C-Nav were used to improve the accuracy of the GPS positions obtained by the C-Nav receiver, while WAAS corrections (Section 3.1) were used to improve the accuracy of those obtained by the Hemisphere receiver.

During the mobilization period that preceded the survey, the tasks performed consisted of installing and testing the sonar and navigation equipment on the *Annika Marie,* testing the ability of the data acquisition computer to record simultaneous data from the multi-beam sonar system, vessel reference unit, and GPS receiver, and testing the ability of the side scan sonar system to integrate data from the GPS receiver.

When all of the equipment was operating properly, the following "patch tests" were conducted to calibrate the multi-beam sonar system for angular offsets between the transducer and the vessel reference unit, and to check for a possible delay between the acquisition of depth and position data ("navigation latency"):

- *Roll Offset*: The angular offset between the static roll angle of the multi-beam transducer and the vessel reference unit was determined by surveying reciprocal lines over a flat bottom.
- *Pitch Offset:* The angular offset between the static pitch angle of the multi-beam transducer and the vessel reference unit was determined by surveying reciprocal lines over a sloped bottom.

- *Yaw Offset:* The angular offset between the 'bow' of the multi-beam transducer and the vessel reference unit was determined by surveying overlapping parallel lines over a sloped bottom.
- *Latency:* Navigation latency was eliminated by allowing the data acquisition computer to adopt the time base of the GPS system. For added confidence, reciprocal lines were surveyed over a bathymetric feature to confirm that the latency was negligible.

On the seaward portion of the pipeline route (from Northstar Production Island to the vicinity of Station 211+50, which is located just north of Stump Island), data were acquired on five parallel track lines. The center line approximated the pipeline alignment, while the flanking lines were offset 150 and 300 ft to the east and west. The survey activities were conducted from the *Annika Marie* in the following manner:

1. Prior to the commencement of data logging, all instruments except the single-beam sonar system were powered up and checked for proper functioning. A small test file was logged on the data acquisition computer and checked to ensure that simultaneous, time-tagged output from the multi-beam sonar system, vessel reference unit, and GPS receiver was being acquired. Similarly, a small test file was logged on the side scan sonar system and checked to ensure that geo-located side scan data were being acquired.
2. The single-beam sonar system was not powered up to minimize the potential for acoustic crosstalk with the multi-beam system. It remained available for use throughout the survey program, but never was needed on the *Annika Marie* because the multi-beam system functioned properly.
3. A conductivity-temperature-depth (CTD) profile was obtained to permit post-survey correction of the multi-beam sonar data for variations in the speed of sound in the water column.
4. The intended vessel track line was displayed at the helmsman's station using a video monitor connected to the data acquisition computer. The vessel's location, heading, and speed derived from the differentially-corrected GPS (DGPS) data also were displayed to aid the helmsman.
5. The side scan sonar towfish was deployed. Because the intended track lines included areas of shallow water, the fish was towed from the side of the vessel approximately 3 ft below the sea surface, rather than astern on a long tether.
6. The vessel was brought onto the intended track line and data acquisition was initiated. Fix marks were recorded on the computer data file at 30-second intervals regulated by

the data acquisition computer. The vessel speed during data acquisition was approximately 5 knots.

7. The digital data from the side scan and multi-beam sonar systems were monitored on separate video displays. Areas of possible ice gouging and strudel scouring were noted in a log book to aid in the subsequent analysis of the data.
8. Data acquisition was terminated in the vicinity of Northstar Production Island when heading offshore, and in water depths of approximately 8 ft when heading onshore.
9. At the end of each survey session, another CTD profile was obtained and the computer data files were checked for completeness.

On the landward portion of the pipeline route (from just north of Stump Island to the shore crossing), heave-compensated single-beam sonar bathymetric data and DGPS position data were acquired from the inflatable boat. A conventional 8º transducer was used with the single-beam sonar system instead of a narrow-beam transducer because the error introduced by aliasing (explained in Section 3.5) was minimal in the shallow water depths involved. Between Station 211+50 and Stump Island, seven parallel track lines were surveyed: the pipeline alignment and flanking lines offset 50, 150 and 300 ft to either side. South of Stump Island, three parallel track lines were surveyed, consisting of the pipeline alignment and flanking lines offset 50 ft to either side. In addition, cross-ties were surveyed perpendicular to the pipeline alignment to acquire supplemental data on the condition of the pipeline trench backfill. On the north side of Stump Island, the nominal spacing between adjacent cross-ties was 100 ft from Station 210+00 to Station 212+00, and 50 ft from Station 212+00 to Station 213+00. On the south side, the spacing was 250 ft. The resulting bathymetric and position data were stored in digital form on a portable computer. The calibration of the single-beam sonar system was checked before and after each survey session using a submersible survey rod to measure the exact depth of water over a flat portion of the sea bottom.

At those locations where drainage features had been observed in the ice and the water depth was sufficient to accommodate the *Annika Marie*, the search for strudel scours was conducted using the multi-beam and side scan sonar systems. In most instances, several passes were sufficient to determine whether a scour depression had been created at a particular drainage location. If a scour was detected on the side scan record, its configuration was mapped using the multi-beam system. The inflatable survey vessel equipped with single-beam sonar was used to search for scours at drainage sites where shallow water depths precluded access by the *Annika Marie*.

3.3 Data Processing

The multi-beam sonar, GPS, and side scan sonar digital data were processed in the following manner:

1. The differentially-corrected GPS (DGPS) position data were edited graphically to eliminate outliers.
2. Excessive vessel motion, surfing, and rapid course changes can severely degrade the quality of the data produced by the multi-beam sonar system. To determine if such events had occurred during the survey activities, the data from the vessel reference unit were reviewed along with comments logged by the field crew. The analysis indicated that the motions of the *Annika Marie* remained within acceptable limits during the entire period of data acquisition.
3. The vessel reference unit data and edited position data were merged with the corresponding raw range data from the multi-beam echo sounder to produce data files containing northing, easting, and depth. Corrections for the draft of the transducer, the measured speed of sound in sea water, and the offsets of the vessel reference unit then were applied, along with tide corrections to adjust the depths to ARCO MLLW Datum. The tide corrections were obtained from the NOS tide gauge on West Dock (National Ocean Service, 2013). Because vessel squat was negligible at the slow speeds at which the survey was conducted, corrections for this phenomenon were omitted from the data processing procedure.
4. Preliminary depth and spike filters were used to eliminate questionable multi-beam soundings that may have resulted from acoustic crosstalk, multiple returns, and aeration in the water column. The data then were thinned to the center points of a 3-ft grid to produce manageable file sizes suitable for TIN (Triangular Irregular Network) modeling. To ensure that the maximum depths of all ice gouges and strudel scours were included in the thinned data set, a separate 15-ft grid was created and the deepest point in each 15-ft grid cell was added to the file containing the 3-ft grid points.
5. As indicated above, the single-beam sonar data acquired from the inflatable boat were compensated for vessel heave in real time, prior to storage in the data acquisition computer. Processing consisted of applying instrument calibration, tide, and draft corrections to adjust the soundings to ARCO MLLW Datum. The processed data then were edited to remove outliers and thinned to a 3-ft center-point grid and a 15-ft deep-biased grid in the manner described above for the multi-beam sonar data.
6. The thinned multi-beam data from the *Annika Marie* and thinned single-beam data from the inflatable boat were merged and used to create digital terrain maps of the

pipeline route and strudel scour search areas using the software package Terramodel. In those areas where the multi-beam and single-beam data overlapped, only the multi-beam data were retained.

7. The digital side scan sonar data were compiled to create a digital mosaic image of the pipeline route, to aid in the identification of ice gouges and strudel scours.

8. A track plot containing generalized bathymetric contours was developed for the pipeline route (Drawing CFC-815-13-001). Additional drawings were prepared to display the 2013 sea bottom profile on the pipeline alignment in conjunction with the top-of-pipeline profile (Drawing CFC-815-13-002), and cross-sections through the pipeline alignment (Drawing CFC-815-13-003). Finally, an index map was prepared to indicate the locations of the preceding three drawings (Drawing CFC-815-03-001). The index map also displays the five points that define the as-built pipeline alignment, consisting of the Northstar Island pipeline exit, points-of-intersection PI-A, PI-B, and PI-1, and the shore crossing vertical transition (Table 1).

3.4 Data Analysis

Data analysis consisted of three primary tasks: (1) comparing the sea bottom profile on the as-built pipeline alignment with the top-of-pipeline profile to determine the depth of backfill over the pipelines; (2) reviewing the bathymetric data for evidence of sea bottom subsidence on the pipeline route; and (3) reviewing the bathymetric and side scan sonar data for evidence of ice gouges and strudel scours.

The sea bottom and top-of-pipeline profiles were compared with the aid of Drawing CFC-815-13-002. The investigation of sea bottom subsidence on the pipeline route was conducted in the following manner:

1. Detailed bathymetric contour maps and three-dimensional representations of the pipeline route were prepared from the digital terrain maps developed during data processing (Section 3.3).

2. The contour maps and three-dimensional representations were scrutinized to determine whether linear depressions indicative of subsidence were present on the pipeline route. Whenever a depression was discovered, transverse and longitudinal profiles developed from the corresponding three-dimensional representation were used to measure its length and maximum depth below the surrounding sea floor. The location in terms of stationing along the pipeline route was derived from the corresponding contour map.

3. The location and dimensions of each depression were compared with those of depressions mapped in prior years to determine if the feature represented a new area of

subsidence, a subsidence area that had developed in one or more prior years and expanded during the past year, or a subsidence area that had developed in one or more prior years and remained inactive during the past year.

4. Although ten subsidence areas were identified, all were found to be relict features that had formed in prior years and remained inactive between 2012 and 2013.

The procedures used to identify ice gouges and quantify their characteristics are summarized below:

1. Each contour map of the pipeline route was enhanced by superimposing the contours on the corresponding portion of the digital side scan sonar mosaic. The enhanced contour map then was reviewed for evidence of gouging. Typically, the presence of a gouge was indicated by a series of closely-spaced contours and a characteristic signature on the underlying side scan sonar record. When a potential gouge was found, confirmation of its existence was sought using the corresponding three-dimensional representation of the sea bottom.
2. If the gouge was evident in the three-dimensional representation, transverse and longitudinal profiles were used to measure the maximum incision depth relative to the surrounding sea floor. The coordinates at the point of maximum incision were logged as the gouge location, and the ridge height (relative to the surrounding sea floor), incision width (at the elevation of the surrounding sea floor), and trend (directional orientation) were measured at that site. These parameters are defined graphically in Figure 4. The enhanced contour map and three-dimensional representation were scrutinized to determine whether the feature was a single gouge, a multiplet (a gouge created by multiple keels on the same ice feature), or a wallow (a depression created when a grounded ice floe is agitated by waves, currents, or other ice; Reimnitz and Kempema, 1982).
3. If the gouge extended beyond the swath imaged by the multi-beam sonar system on a particular track line, the side scan sonar mosaic and the enhanced contour map from the adjacent line were searched to determine whether the feature could be detected on that line as well. A gouge that crossed multiple track lines was logged as one feature, with the coordinates, ridge height, incision width, and trend measured at the point of maximum incision.
4. If a gouge signature on the side scan sonar mosaic was not evident on the contour map or three-dimensional representation, it was excluded from further consideration. This situation arose when the incision depth was less than the 0.3 ft resolution of the multi-beam sonar system.

5. On the southern portion of the pipeline route, where water depths less than 8 ft precluded the use of multi-beam and side scan sonar, the search for ice gouges was conducted by reviewing the single-beam sonar record. No gouges were detected in this region.
6. Each measurable gouge was assigned a unique identification number, such as "Gouge #13-05". The first portion, "13", indicates the year of discovery, while the second portion, "05", represents the unique number assigned to that gouge. Wallows were identified separately from gouges using a similar format (*e.g.*, Wallow #11-12).
7. The locations and characteristics of all measurable gouges and wallows were tabulated, and the locations of these features were superimposed on the vessel track plot (Drawing CFC-815-13-001).

The procedures used to search for strudel scour depressions in the sea bottom are summarized below:

1. Bathymetric contour maps and three-dimensional representations of the individual strudel scour search areas were prepared from the digital terrain maps developed during data processing (Section 3.3). Contour maps and three-dimensional representations of the pipeline route already existed from the analyses of subsidence and ice gouging described above.
2. Each contour map and three-dimensional representation pertaining to the zone of river overflood was reviewed for evidence of strudel scouring. The intent of this review was to search for scours formed by drains that may have been obscured or overlooked during the 2013 reconnaissance flight.
3. If a scour was evident in the three-dimensional representation, transverse profiles were used to measure its maximum horizontal dimension and maximum depth below the surrounding sea floor. The coordinates of the deepest point were logged as the scour location.
4. Each scour was assigned a unique identification number, such as "#13-48. The first portion, "13", indicates the year of discovery, while the second portion, "48", represents the unique number assigned to that scour.
5. On the southern portion of the pipeline route and at those drainage sites in the 5,000-ft monitoring corridor where shallow water depths precluded the use of multi-beam and side scan sonar, the search for strudel scours was conducted by reviewing the contour maps and three-dimensional representations created from the single-beam sonar data. Estimates of the scour depth, maximum horizontal dimension, and location were derived from these products. The resulting values are inherently less accurate than

those derived from multi-beam data due to the more limited nature of single-beam coverage.

6. Two overview maps encompassing the entire study area were prepared. Drawing CFC-815-03-002 illustrates the overflood limit and the locations of individual drainage features in the ice observed during the early-June reconnaissance flight. Drawing CFC-815-03-003 displays the same information in concert with the locations of all strudel scour depressions in the sea bottom detected during the ensuing summer survey.

3.5 Resolution and Accuracy

This subsection provides estimates of the resolution and accuracy attained during the 2013 survey. The estimates are based primarily on equipment specifications and prior experience.

Side Scan Sonar Resolution

The ability of a side scan sonar system to detect sea floor features depends not only on the characteristics of the system itself, but also on the operating conditions and the nature of the targets. During the 2013 survey program, when a side scan range of 164 ft (50 m) was employed, the nominal horizontal resolution of the side scan system was 1.3 ft in the along-track (transverse) direction and 0.1 ft in the across-track (range) direction. These values are much smaller than the horizontal dimensions of the ice gouges and strudel scours under consideration. It should be recognized, however, that the nominal resolution tends to deteriorate with increasing motion of the towfish (which can result from wave disturbance and from changes in vessel heading). Also noteworthy is the influence of the target, the return from which varies in accordance with its geometry and acoustic reflectivity (*i.e.*, a high-relief target with a different density than that of the surrounding sea bottom is easier to detect than a low-relief target with a density similar to that of the surrounding sea bottom).

Judging from prior experience as well as from the results of the 2013 survey program, the side scan sonar system routinely imaged ice gouges with a vertical relief less than the 0.3-ft resolution of the bathymetric sonar. Notwithstanding this high resolution, it is possible that a limited number of poorly-defined targets escaped detection. This situation could have arisen, for example, in the case of low-relief gouges or scours located in the outer portion of the side scan range.

Bathymetric Sonar Resolution

The horizontal resolution of the SeaBat 7125-SV2 multi-beam sonar system is governed by the size of the footprint on the sea bottom insonified by each sub-beam. For a depth of 36.6 ft below the transducer (the maximum value during the 2013 survey, resulting in the lowest resolution), the footprint of each sub-beam measured 0.6 ft in the cross-track direction and 0.7 ft in the along-track direction. As in the case of the side scan sonar horizontal resolution discussed above, these dimensions are smaller than those of the ice gouges and strudel scours under consideration. With respect to vertical resolution, experience has indicated that the multi-beam system can detect scours and gouges with a minimum vertical relief of 0.3 ft (Poplin, *et al.*, 2000). Because the raw depth data are corrected for vessel motion, the resolution is insensitive to the sea state under non-extreme conditions.

In the case of the inflatable boat, where the single-beam data were acquired with an 8° transducer, the maximum water depth of 10.3 ft below the transducer produced a maximum beam width of 1.4 ft at the sea floor. The vertical resolution was 0.3 ft, and therefore was comparable to that of the multi-beam system.

Side Scan Sonar Accuracy

Although the side scan sonar system was used to search for strudel scours and ice gouges on the sea bottom, it was not used to measure the vertical dimensions, horizontal dimensions, or positions of these features.

Bathymetric Sonar Accuracy

Because the multi-beam sonar system uses extremely narrow acoustic beams and compensates for vessel motion, the accuracy of the positions and horizontal dimensions derived from the resulting record is determined primarily by the accuracy of the differentially-corrected GPS (DGPS) position data. A position check conducted on the West Dock Causeway on July 21 using the C-Nav receiver and the survey monument “Dickory” yielded a root-mean-square (rms) error of 1.5 ft. Hence, the rms accuracy of the position derived for each ice gouge and strudel scour from the multi-beam sonar data also is estimated to be 1.5 ft.

The accuracy with which the incision width of a gouge or the maximum horizontal dimension of a scour can be determined depends on a complex relationship between factors that include the feature geometry, the distance off the vessel track line, and orientation of the feature relative to the track line. Based on a comparison of the incision widths reported for individual gouges in the year of discovery and subsequently as relict features, it is estimated that horizontal dimensions are accurate to within 3 ft.

The absolute accuracy of each depth measured with the SeaBat 7125-SV2 multi-beam sonar system is approximately ±0.5 ft. This value, computed as the square root of the sum of the squares, reflects a measurement uncertainty of ±0.2 ft, and a water level uncertainty of ±0.4 ft. The accuracy with which the depth of a strudel scour or ice gouge can be determined relative to the ambient sea floor depends only on the measurement uncertainty, and hence is estimated to be ±0.2 ft.

The horizontal and vertical accuracies attainable with the single-beam sonar system are comparable to those of the multi-beam system.

In addition to water level and measurement uncertainties, a phenomenon known as "aliasing" must be considered when evaluating the vertical accuracy of bathymetric sonar data. In the case of single-beam sonar, aliasing occurs on a sloping sea bottom because the depth recorded by the sonar system is based on the acoustic return from the closest point in the beam path (Figure 5). The difference between the depth recorded by the sonar and the actual maximum depth in the beam path increases with increasing sea floor inclination and increasing beam footprint. Unlike water level and measurement errors, which can cause the apparent depth to be either greater or less than the actual depth, aliasing always introduces a shoal bias (*i.e.*, the apparent depth is less than the actual depth).

In the case of multi-beam sonar, the influence of aliasing is minimized by the narrow, shaped nature of each acoustic sub-beam, which produces a relatively small footprint on the sea bottom. In addition, the recorded depth is determined by the return from the center of the footprint rather than from the closest point in the beam path.

The influence of aliasing on the strudel scour, ice gouge, and ice wallow depths measured during the 2013 survey was small, due in part to the use of multi-beam sonar for most of these measurements and in part to the modest water depths in the study area. Based on an analysis of all such features mapped in 2013, the maximum aliasing error is estimated to be 0.1 ft both for the scour depths and also for the gouge and wallow incision depths. It should be noted that the aliasing errors were derived by assuming the least favorable sonar beam geometry for each feature. Hence, the actual aliasing errors may have been smaller.

As indicated above, aliasing introduces a shoal bias that causes the measured depth of a scour, gouge, or wallow to be less than the actual depth. A conservative estimate of the actual depth can be obtained by summing the measured depth, the uncertainty introduced by measurement error (±0.2 ft), and the maximum possible aliasing error. In the case of a strudel scour with a measured scour depth of 2.5 ft and a maximum possible aliasing error of 0.1 ft, for example, the actual scour depth would be estimated as follows:

$$\begin{aligned}\text{Actual Depth} &= (\text{Measured Depth} + \text{Measurement Uncertainty} + \text{Max. Aliasing Error})\\ &= (2.5 \pm 0.2 + 0.1)\ \text{ft}\\ &= 2.6\ \text{ft} \pm 0.2\ \text{ft}\end{aligned}$$

4. RESULTS

The subsections that follow present the results of the Northstar Development 2013 Pipeline Route Monitoring Program. Section 4.1 provides an overview of the study products. The bathymetry on the pipeline route is discussed in Section 4.2, with particular emphasis on the depth of backfill over the pipelines. Ice gouge and strudel scour data are reviewed in Sections 4.3 and 4.4, respectively.

4.1 Study Products

The findings of the 2013 survey program are presented in Tables 4 through 10, Figures 6 through 13, and six 24-in. x 36-in. drawings (10 sheets) bound separately as Appendix A. Table 3 provides the title and number of sheets associated with each drawing.

4.2 Bathymetry on Pipeline Route

The bathymetric data acquired on the pipeline route in 2013 are presented in Drawings CFC-815-13-002 and -003. The former displays a profile of the sea bottom on the pipeline alignment. In the interest of clarity, the vertical scale has been exaggerated by a factor of 40. The drawing also includes a pre-construction profile of the sea bottom obtained in 1996 (Coastal Frontiers, 1997), a post-construction profile obtained in 2012 (Coastal Frontiers, 2013), and a profile indicating the top of the pipelines. The top-of-pipeline profile was developed from data obtained by H&B Surveyors during pipeline installation. In addition, the drawing displays a dashed line 6 ft above the top-of-pipeline profile signifying the 6-ft minimum backfill thickness specified in the pipeline permit.

Drawing CFC-815-13-003 displays representative cross sections through the pipeline route derived from the digital terrain maps created during data processing (Section 3.3). The vertical scale has been exaggerated by a factor of two. Cross sections are provided at 1,000-ft intervals, except that Station 225+00 is shown instead of 220+00 because the latter is located on Stump Island. The plots for Stations 010+00 through 200+00 are based on multi-beam data, those for Stations 225+00 through 310+00 on single-beam data, and that for Station 210+00 on a combination of the two. Cross sections obtained during the thirteen prior annual surveys (2000-2012) also are included to the extent that they are available.

Key aspects of the 2013 bathymetric data are summarized below:

1. The bathymetric profile on the pipeline alignment bore a close resemblance to that recorded in 2012. Between Northstar Production Island and Stump Island, the most significant changes consisted of a general reduction in bathymetric relief, in-filling of two relict strudel scour depressions, and sediment accumulation in an inactive subsidence area immediately north of Stump Island (Subsidence Area 09-G; Drawing CFC-815-13-002). Between Stump Island and the shore crossing, the profile was virtually identical to that in 2012 and similar to the pre-construction profile obtained in 1996.
2. For the first time since oil began flowing in the fall of 2001, no areas of active subsidence were detected on the pipeline alignment in 2013. This finding is consistent with the trend toward decreasing subsidence noted in 2011 and 2012 (Coastal Frontiers, 2013), and may reflect a reduction in radiant heat from the oil sales line occasioned by declining flow rates.
3. One modest deficiency in the backfill thickness relative to the 6-ft minimum value stipulated in the pipeline permit was detected in Subsidence Area 09-G, where shortfalls had been noted in each of the past four years. The deficiency was extremely small, with a maximum shortfall of 0.2 ft and length of 63 ft along the pipeline alignment (Table 4). Approximately 1,000 cy of fill were placed in this area after the discovery of active subsidence in 2009, followed by 500 cy in 2010 and an additional 500 cy in 2011. As no new subsidence was detected at this site in either 2012 or 2013, the probable cause of the deficiency is incomplete remediation of the shortfalls identified in prior years.

During the one-year period between the 2012 and 2013 surveys, the maximum shortfall in Subsidence Area 09-G decreased from 0.4 to 0.2 ft while the length of the shortfall decreased from 109 to 63 ft. BPXA elected not to conduct a gravel placement program in 2013 in the expectation that the shortfall will be remedied by natural processes of sediment accumulation.

4.3 Ice Gouges

Nine ice gouges with incision depths greater than or equal to the 0.3 ft resolution of the bathymetric sonar systems were detected on the Northstar pipeline alignment and the four flanking lines offset 150 and 300 ft to the east and west. Five represented newly-discovered features, while four were relict gouges that had been discovered during prior surveys.

The locations of the gouges are indicated in Drawing CFC-815-13-001. Table 5 summarizes the characteristics of the newly-discovered gouges along with those from each of the thirteen prior years (2000-2012). Table 6 provides the characteristics of each individual gouge mapped in 2013 (both newly-discovered and relict).

The data obtained for the newly-discovered gouges are summarized below:

1. Water Depth: The five newly-discovered gouges were located in water depths that ranged from 17.4 to 35.7 ft.
2. Incision Depth: The measured incision depths ranged from 0.5 to 1.6 ft, with a mean value of 0.9 ft.
3. Incision Width: The measured incision widths varied between 7 and 32 ft. The mean value was 16 ft.
4. Ridge Height: The measured ridge heights ranged from 0.1 to 0.9 ft, with a mean value of 0.3 ft.
5. Gouge Trend: The measured orientations ranged from 264 to 311°G. (Note: for convenience, all gouge orientations in this report are expressed between 181° and 360°G even though the direction of gouge formation is indeterminate.)
6. Gouge Type: Four of the newly-discovered features were single gouges, while one was a multiplet.

The incision depths and incision widths of the newly-discovered gouges are plotted against water depth in Figures 6 and 7, respectively. The figures also include comparable data for all of the new gouges discovered during each of the thirteen prior annual survey programs (2000-2012). The following conclusions are suggested by a comparison of the gouge data from 2013 with those from the prior surveys:

1. The number of gouges was extremely low by historical standards, with five newly-discovered gouges in 2013 versus an annual average of 30.3 during the fourteen-year period of record. The historical maximum, 130 gouges, occurred in 2011 while the minimum, 4 gouges, occurred in 2009.
2. The severity of the gouging was consistent with historical precedent. Specifically, the mean incision depth of 0.9 ft and mean ridge height of 0.3 ft were identical to the long-term average values recorded on the Northstar pipeline route from 2000 through 2013. The mean incision width of 16 ft and mean water depth of 30.7 ft were somewhat larger than the long-term averages, but the minimum and maximum values of all four parameters were contained within the envelopes established in prior years (Figures 6 and 7).

3. As in most prior years, the majority of the gouges followed the southeast-northwest orientation of the bathymetric contours.

The characteristics of the four relict gouges identified in 2013 are listed at the end of Table 6. In each case, the maximum measured incision depth was less than that noted in 2012. The reductions in depth, which were caused by sediment in-filling, ranged from 0.1 to 0.3 ft.

As shown in Drawing CFC-815-13-001, only one of the nine gouges mapped in 2013 crossed the pipeline alignment (Gouge #13-04). Although the maximum incision depth, 1.6 ft, was the largest recorded in 2013, the gouge did not cause the backfill thickness to violate the 6-ft minimum value stipulated in the pipeline permit (Drawing CFC-815-13-002).

As discussed previously in Section 3.4, ice wallows are depressions in the sea bottom that form when grounded ice floes are agitated by waves, currents, or other ice (Reimnitz and Kempema, 1982). Wallows can occur both as terminal features at the ends of gouges, and as isolated features without associated gouge tracks. Wallows were discovered on the pipeline route during four of the prior thirteen surveys, in 2002, 2007, 2008, and 2011 (Coastal Frontiers, 2012).

No new wallows were identified during the 2013 survey, but two of the 18 wallows first discovered in 2011 were found again. Table 7 summarizes the characteristics of all newly-discovered wallows for each of the fourteen years in which monitoring of the pipeline route has been conducted (2000-13). The incision depths and incision widths of these features are plotted against water depth in Figures 8 and 9, respectively.

Table 8 lists the characteristics of the two relict wallows mapped in 2013. In each case, the maximum incision depth was less than that noted a year earlier. The wallow locations are shown in Drawing CFC-815-13-001.

4.4 Strudel Scours

The 2013 Kuparuk River overflood, although vigorous by historical standards, nevertheless remained within the footprint established by previous flood boundaries (Figure 10). As shown in Drawing CFC-815-03-002, the flood water was partially contained by Stump and Long Islands, but extended well offshore on the Northstar pipeline route. The seaward edge was located approximately 16,100 ft north of Stump Island and only 5,600 ft south of Northstar Production Island (Plate 1).

Plate 1. Kuparuk River Overflood (June 5, 2013)

Sixty seven drainage features were detected in the 5,000-ft wide monitoring corridor in 2013, more than in any prior year except 2012. Sixty five were located to the north of Stump Island, while two were located to the south in Gwydyr Bay. During the fourteen-year period of record (2000-2013), the number of drains observed in the 5,000-ft corridor has ranged from eight to 83 while averaging 37 per year.

Fifty two of the 67 drainage features were circular or oblong in plan form. The remaining 15 features were linear crack drains with lengths exceeding 50 ft (Plate 2). Fifteen drains were located within 300 ft of the pipeline alignment, while 25 were farther to the west and 27 farther to the east (Drawing CFC-815-03-002).

During the summer field program, 63 of the drainage sites were investigated using side scan and multi-beam sonar. Although shallow water depths prevented the *Annika Marie* from reaching the other four sites, each was investigated with single-beam sonar operated from the inflatable survey vessel. A total of seventy scour depressions was detected, consisting of single depressions at 16 drainage sites, multiple depressions at ten drainage

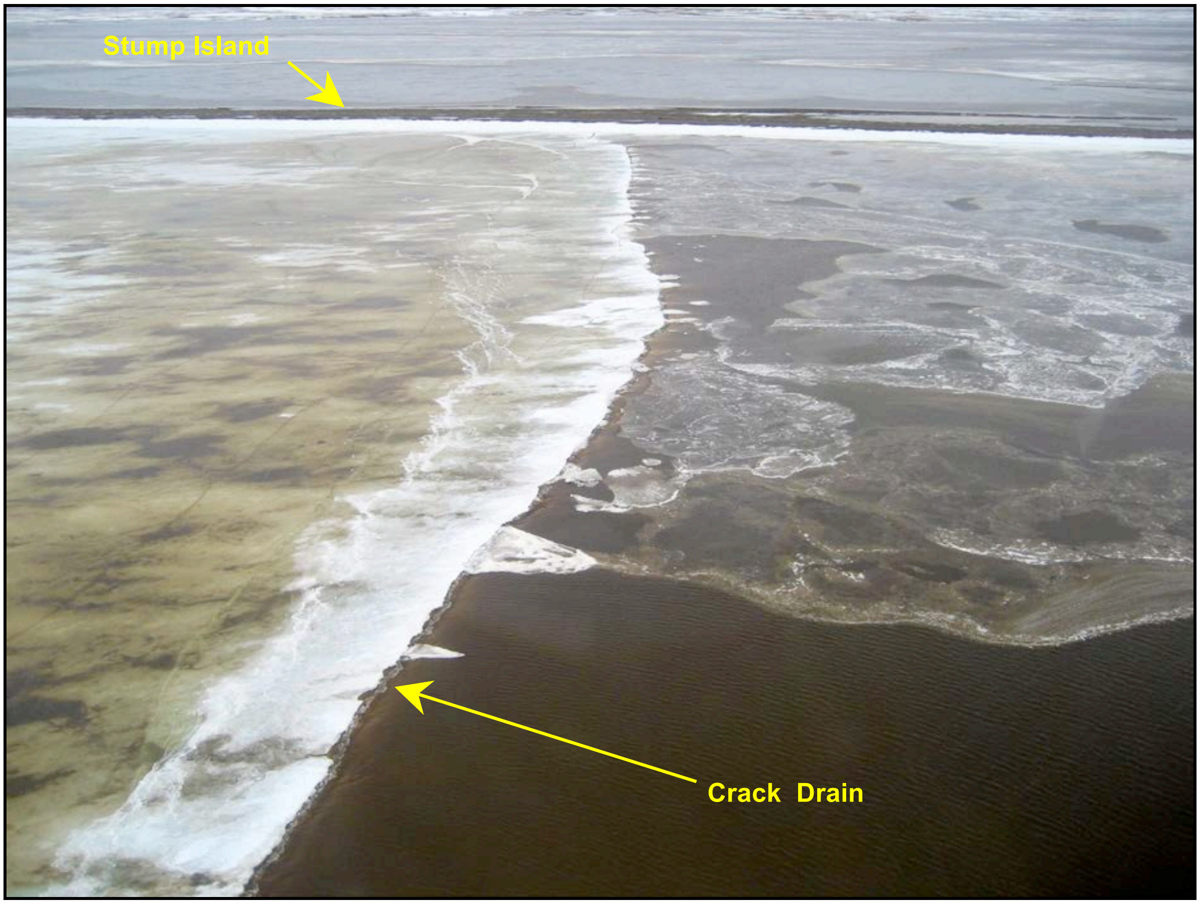

Plate 2. Linear Crack Drain off Stump Island (June 5, 2013)

sites (primarily along the crack drains), and six at locations where drainage features were not evident during the June reconnaissance flight It is likely that the drains at these sites were obscured by meltwater at the time of the flight (Plate 2).

In addition to searching the drainage sites observed during the helicopter reconnaissance mission, a deliberate attempt was made to locate the three deepest strudel scours found in 2012: #12-68, with a scour depth of 3.7 ft, #12-77, with a scour depth of 5.9 ft, and #12-78, with a scour depth of 4.4 ft (Coastal Frontiers, 2013). None of these features was detectable in 2013, indicating that they had been completely filled with sediment. This finding is consistent with the fact that the depressions were located in the relatively shallow, exposed region north of Stump Island where the rates of wave-induced sediment transport tend to be high.

The locations of the 70 newly-discovered scours are shown in Drawing CFC-815-03-003. Table 9 presents a statistical characterization of these features along with comparable data for all newly-discovered scours in each of the thirteen prior years (2000-2012). In the case of features categorized as "circular", the term "maximum horizontal dimension" refers to the largest horizontal extent measured at the elevation of the surrounding sea bottom (*i.e.*, the diameter of a perfectly circular scour or the major axis of an oblong scour). In the case of features categorized as "linear", "maximum horizontal dimension" refers to the length measured along the scour orientation. The characteristics of each individual scour detected in 2013 are provided in Table 10.

The data acquired for the 70 newly-discovered scours are summarized below:

1. Scour Type: Sixty three of the scours were circular in plan form, while seven were linear.
2. Water Depth: The circular scours occurred in water depths of 7.5 to 19.8 ft, while the linear scours occurred in depths of 9.8 to 14.7 ft.
3. Scour Depth: The scour depths of the circular scours ranged from 0.5 to 2.6 ft below the surrounding sea bottom, with a mean value of 1.3 ft. The scour depths of the linear scours ranged from 1.2 to 2.2 ft while averaging 1.8 ft.
4. Maximum Horizontal Dimension: The maximum horizontal dimensions of the circular scours ranged from 9 to 87 ft. The mean value was 27 ft. The lengths of the linear scours varied between 57 and 617 ft, with an average value of 181 ft.

Scatter plots of scour depth versus water depth, scour maximum horizontal dimension versus water depth, and scour maximum horizontal dimension versus scour depth are presented for the 63 newly-discovered scours in Figures 11, 12, and 13. The figures also display the data acquired for all newly-discovered circular scours in the 5,000-ft monitoring corridor from 2000 through 2012. Because of their distinctly different nature, linear scours have been excluded.

As in past years, the scatter plots indicate that the greatest scour depths and maximum horizontal dimensions occur in water depths of 5 to 20 ft. This region has been designated as the "Primary Strudel Zone", based on the frequency and severity of scour formation (Leidersdorf, *et al.*, 2007). Inshore of the Primary Strudel Zone, where the presence of bottomfast ice typically prevents the occurrence of strudel drainage until late in the overflood period, the scouring tends to be milder. In 2013, as in each of the two prior years, all of the scour depressions were located in the Primary Strudel Zone.

Figure 13 suggests that strudel scour maximum horizontal dimensions tend to increase with scour depth. The data exhibit substantial scatter, however, with a correlation coefficient (R^2) of only 0.13 (essentially unchanged since 2011).

A comparison of the strudel scour data acquired in the 5,000-ft monitoring corridor in 2013 with those from the prior surveys yields the following insights:

1. The numbers of circular and linear scours (63 and 7, respectively) were high by historical standards. During the fourteen-year period of record, the annual maximum for circular scours was 71 while the average was 25.9/yr. The annual maximum for linear scours was 11; the average was only 1.9/year.
2. Notwithstanding the large number of scours, the severity of the scouring was relatively low. In the case of the circular features, the mean values of scour depth and maximum horizontal dimension (1.3 and 27 ft, respectively) were slightly below the historical averages, and the maximum values (2.6 ft and 87 ft) were substantially below the historical maxima. In the case of the linear scours, the average depth of 1.8 ft was equal to the historical average while the maximum depth of 2.2 ft was well below the historical maximum. Both the average and maximum lengths of the linear scours (181 and 617 ft, respectively) were well below the corresponding historical values.

During the eleven years following the introduction of hot oil into the Northstar pipeline (2002-2012), strudel scours impacted the pipeline trench backfill on 13 occasions. Five of the scours, with depths ranging from 1.1 to 9.5 ft, were located in the Primary Strudel Zone. The remaining eight scours, with depths from 0.3 to 2.8 ft, were located in Gwydyr Bay in the Secondary Strudel Zone. In contrast to 2012, when two backfill disturbances occurred in the Primary Strudel Zone, none were recorded in either zone in 2013.

5. SUMMARY AND CONCLUSIONS

1. ***Bathymetry on Pipeline Alignment:*** The bathymetric profile on the pipeline alignment bore a close resemblance to that recorded in 2012. Between Northstar Production Island and Stump Island, the most significant changes consisted of: (1) a general reduction in bathymetric relief, (2) in-filling of two relict strudel scour depressions, and (3) sediment accumulation in an inactive subsidence area immediately north of Stump Island. Between Stump Island and the shore crossing, the profile was virtually identical to that in 2012 and similar to the pre-construction profile obtained in 1996.

2. ***Sea Bottom Subsidence***: For the first time since oil began flowing in the fall of 2001, no areas of active subsidence were detected on the pipeline alignment in 2013. This finding is consistent with the trend toward decreasing subsidence noted in 2011 and 2012, and may reflect a reduction in radiant heat from the oil sales line occasioned by declining flow rates.

3. ***Pipeline Trench Backfill Thickness:*** One modest deficiency in the backfill thickness relative to the 6-ft minimum value stipulated in the pipeline permit was detected in the inactive subsidence area immediately north of Stump Island. Shortfalls had been noted at this location in each of the past four years. The deficiency was extremely small, with a maximum shortfall of 0.2 ft and a length of 63 ft along the pipeline alignment. Approximately 1,000 cy of fill were placed in this area after the discovery of active subsidence in 2009, followed by 500 cy in 2010 and an additional 500 cy in 2011. As no new subsidence was detected at this site in either 2012 or 2013, the probable cause of the deficiency is incomplete remediation of the shortfalls identified in prior years.

4. ***Ice Gouges:*** Nine ice gouges were detected on the Northstar pipeline route during the 2013 survey. Five represented newly-discovered features, while four were relict gouges that had been discovered during prior surveys. The incision depths of the new gouges ranged from 0.5 to 1.6 ft, the incision widths from 7 to 32 ft, and the water depths from 17.4 to 35.7 ft. The number of new gouges was extremely low by historical standards, while the severity was consistent with historical precedent. Although one gouge crossed the pipeline alignment, it did not cause the backfill thickness to violate the 6-ft minimum value stipulated in the pipeline permit.

5. ***Ice Wallows:*** No new ice wallows were identified during the 2013 survey, but two of the 18 wallows first discovered in 2011 were found again. The incision depths of the

relict wallows were 0.6 and 0.8 ft, the incision widths were 17 and 18 ft, and the water depths were 20.8 and 21.3 ft.

6. ***Kuparuk River Overflood:*** The 2013 Kuparuk River overflood was vigorous by historical standards but remained within the footprint established by previous flood boundaries. On the pipeline alignment, the seaward edge was located approximately 16,100 ft north of Stump Island and only 5,600 ft south of Northstar Production Island. Sixty seven drainage features were detected in the 5,000-ft wide monitoring corridor, more than in any prior year except 2012. Sixty five were located to the north of Stump Island, while two were located to the south in Gwydyr Bay. During the fourteen-year period of record (2000-2013), the number of drains observed in the 5,000-ft corridor has ranged from eight to 83 while averaging 37 per year.

7. ***Strudel Scours:*** When a sonar search for strudel scours was conducted on the pipeline route and at the 67 drainage sites observed during the overflood period, 70 new depressions were discovered in the sea bottom. Sixty three of the scours were circular in plan form, while seven were linear. The water depths of the circular scours ranged from 7.5 to 19.8 ft, the scour depths from 0.5 to 2.6 ft, and the maximum horizontal dimensions from 9 to 87 ft. In the case of the linear scours, the water depths ranged from 9.8 to 14.7 ft, the scour depths from 1.2 to 2.2 ft, and the lengths from 57 to 617 ft. The numbers of circular and linear scours were high by historical standards, but the severity of the scouring was relatively low. None of the scours impinged on the backfill over the pipelines.

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TABLES

Table 1. As-Built Pipeline Alignment

Location	Station (ft)	Northing[1] (ft)	Easting[1] (ft)
Northstar Island Pipeline Exit	000+00	6,030,751.45	659,661.09
Point of Intersection A	008+60	6,029,892.74	659,708.41
Point of Intersection B	201+50	6,010,637.63	660,868.08
Point of Intersection 1	222+70	6,008,522.00	660,999.00
Shore Crossing Vertical Transition	314+98	5,999,294.00	661,120.03

(Source: Coastal Frontiers, 2001a)

Note:

1 The horizontal datum is Alaska State Plane Zone 4 (ASP 4) relative to North American Datum of 1927 (NAD27).

Table 2. Equipment Systems

<u>Sonar Systems</u>

Reson Seabat 7125-SV2 Multi-Beam Echo Sounder

Odom Hydrotrac Digital Echo Sounder (single-beam bathymetric sonar)

EdgeTech 4125D Dual Frequency Scan Sonar System with Coda Mosaic Software

<u>Motion and Heading Sensor</u>

Coda Octopus F185 GPS-Aided Vessel Reference Unit

<u>Navigation, Positioning and Heading Systems</u>

Garmin GPSMap 196 GPS Receiver

C-Nav3050 GPS Receiver

Hemisphere R-110 GPS Receiver

<u>Data Acquisition System</u>

Laptop Computer

Hypack Hydrographic Survey Software

<u>Calibration Equipment</u>

Seabird SBE-19 CTD Profiler (for determining speed of sound in water column)

Table 3. Drawing Summary

Drawing Number	Title	Sheets	Appendix
Project Area			
CFC-815-03-001	Drawing Index Map	1	A
CFC-815-03-002	Strudel Drainage Feature and Overflood Limit Location Map	1	A
CFC-815-03-003	Strudel Scour and Strudel Drainage Feature Location Map	1	A
Pipeline Route			
CFC-815-13-001	Survey Track Lines	3	A
CFC-815-13-002	Bathymetric Profile on Pipeline Alignment	1	A
CFC-815-13-003	Cross Sections through Pipeline Alignment	3	A

Table 4. Area of Shortfall in Pipeline Trench Backfill Thickness

Subsidence Area	Location		Length	Max. Shortfall in Backfill Thickness[1]
	(Station Start)	(Station End)	(ft)	(ft)
09-G[2]	212+08	212+71	63	0.2

Notes:

1 The shortfall in backfill thickness is computed relative to the 6-ft minimum value specified in the pipeline permit.

2 Approximately 1,000 cy of gravel fill were placed in Subsidence Area 09-G after completion of the 2009 Pipeline Route Monitoring Program, followed by 500 cy after completion of the 2010 Program and an additional 500 cy after completion of the 2011 Program. No gravel fill was placed in this area in either 2012 or 2013.

Table 5. Summary of Ice Gouge Characteristics Measured during the Northstar Development 2000 through 2013 Pipeline Route Monitoring Programs[1, 2]

Characteristic	2000		2001		2002		2003	
	Mean	**Range**	**Mean**	**Range**	**Mean**	**Range**	**Mean**	**Range**
	9 Gouges		***30 Gouges***		***54 Gouges***		***27 Gouges***	
Incision Depth (ft)	0.9	0.5 – 1.7	0.7	0.4 – 1.4	0.7	0.3 – 1.6	0.7	0.3 – 1.3
Incision Width[3] (ft)	11	6 – 25	10	3 – 25	9	4 – 39	7	3 – 16
Ridge Height (ft)	0.6	0.1 – 1.3	0.2	0.0 – 0.7	0.3	0.0 – 1.9	0.2	0.0 – 1.1
Water Depth[4] (ft)	24.1	10.7 – 35.8	28.2	8.8 – 36.8	24.9	9.0 – 36.9	30.2	19.1 – 34.5
	2004		**2005**		**2006**		**2007**	
	Mean	**Range**	**Mean**	**Range**	**Mean**	**Range**	**Mean**	**Range**
	22 Gouges		***35 Gouges***		***33 Gouges***		***20 Gouges***	
Incision Depth (ft)	0.7	0.3 – 1.4	0.8	0.3 – 1.8	0.9	0.4 – 1.8	1.3	0.4 – 5.1
Incision Width[3] (ft)	7	3 – 15	8	4 – 25	13	3 – 40	23	5 – 76
Ridge Height (ft)	0.2	0.0 – 1.1	0.3	0.0 – 1.2	0.2	0.0 – 1.1	0.3	0.0 – 0.8
Water Depth[4] (ft)	27.1	16.9 – 35.3	23.2	9.0 – 36.5	31.7	19.8 – 36.1	18.8	8.2 – 36.1

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Table 5. Summary of Ice Gouge Characteristics Measured during the Northstar Development 2000 through 2013 Pipeline Route Monitoring Programs (continued)[1, 2]

Characteristic	2008		2009		2010		2011	
	Mean	Range	Mean	Range	Mean	Range	Mean	Range
	12 Gouges		*4 Gouges*		**24 Gouges**		**130 Gouges**	
Incision Depth (ft)	0.8	0.5 – 1.1	0.6	0.3 – 1.0	0.7	0.3 – 1.2	1.1	0.3 – 3.5
Incision Width[3] (ft)	10	3 – 22	10	6 – 12	10	4 - 20	15	3 - 55
Ridge Height (ft)	0.2	0.0 – 0.6	0.1	0.0 – 0.4	0.2	0.0 – 0.8	0.3	0.0 – 1.2
Water Depth[4] (ft)	27.7	18.4 – 37.3	26.0	11.0 – 36.3	31.8	18.0 – 36.9	28.5	16.4 – 37.2

Characteristic	2012		2013			2000-2013	
	Mean	Range	Mean	Range		Mean	Range
	19 Gouges		*5 Gouges*			**424 Gouges (Average 30.3/yr)**	
Incision Depth (ft)	0.9	0.3 – 1.5	0.9	0.5 – 1.6		0.9	0.3 – 5.1
Incision Width[3] (ft)	12	5 – 40	16	7 – 32		12	3 – 76
Ridge Height (ft)	0.3	0.0 – 1.1	0.3	0.1 – 0.9		0.3	0.0 – 1.9
Water Depth[4] (ft)	30.6	22.0 – 34.5	30.7	17.4 – 35.7		27.6	8.2 – 37.3

Table 5. Summary of Ice Gouge Characteristics Measured during the Northstar Development 2000 through 2013 Pipeline Route Monitoring Programs (continued)[1, 2]

Notes:

[1] Table 5 is based on all newly-discovered ice gouges mapped on the pipeline route during each of the annual monitoring programs. Relict gouges (*i.e.*, gouges re-discovered after detection in a prior year) are excluded from this table, but included in Table 6.

[2] If the incision depth of a relict gouge was found to exceed the incision depth measured in the year of discovery, the gouge statistics for the year of discovery were recalculated after substituting the greater incision depth and associated characteristics of the relict for those measured in the year of discovery. This situation arose not because the gouge had become deeper, but because variations in the vessel track caused a deeper portion of the feature to be surveyed in a subsequent year.

[3] For multiplet gouges, the incision width of the deepest branch of the feature was used in preparing this table (rather than the width of the entire multiplet).

[4] The vertical datum is ARCO MLLW, which is identical to NOS MLLW.

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Table 6. Ice Gouge Characteristics Measured during the Northstar Development 2013 Pipeline Route Monitoring Program

Gouge No.[1]	Northing[2] (ft)	Easting[2] (ft)	Water Depth[3] (ft)	Incision Depth (ft)	Incision Width[4] (ft)	Ridge Height (ft)	Gouge Trend (°G)	Gouge Type[5]
Newly-Discovered Gouges								
13-01	6,030,242	659,436	35.7	0.9	7	0.1	278	S
13-02	6,030,224	659,341	35.5	0.7	12	0.1	278	S
13-03	6,030,184	659,454	35.6	0.5	12	0.2	311	S
13-04	6,026,340	660,088	29.5	1.6	16	0.3	264	S
13-05	6,020,198	659,981	17.4	0.7	32(32)	0.9	298	M
Relict Gouges[6]								
02-01	6,030,367	659,391	35.8	0.4(0.5)	7	0.2	315	S
09-02	6,029,814	659,803	35.7	0.4(0.7)	11	0.2	316	S
11-01	6,030,396	659,379	35.9	0.6(0.8)	8	0.2	276	S
11-02	6,030,261	659,389	35.7	0.7(0.8)	20	0.5	267	S

Notes:

1 The prefix indicates the year in which the gouge was first discovered (*e.g.* "13-" indicates gouge was first discovered in 2013).

2 The horizontal datum is Alaska State Plane Zone 4 (ASP 4) relative to North American Datum of 1927 (NAD27). Gouge locations are displayed in Drawing CFC-815-13-001.

3 The vertical datum is ARCO MLLW, which is identical to NOS MLLW.

4 For the sole multiplet gouge, the incision width of the entire multiplet at the point of maximum incision is shown in parentheses after the incision width of the deepest branch of the feature.

5 "S" indicates single ice gouge; "M" indicates multiplet gouge.

6 For each relict gouge rediscovered in 2013, the incision depth found in 2012 is shown in parentheses after the corresponding value found in 2013.

Table 7. Summary of Ice Wallow Characteristics Measured during the Northstar Development 2000 through 2013 Pipeline Route Monitoring Programs[1]

Characteristic	2000, 2001		2002		2003, 2004, 2005, 2006		2007	
	Mean	Range	Mean	Range	Mean	Range	Mean	Range
	0 Wallows		*4 Wallows*		*0 Wallows*		*8 Wallows*	
Incision Depth (ft)	–	–	2.9	1.9 – 3.6	–	–	1.5	0.6 – 3.8
Incision Width (ft)	–	–	41	32 – 50	–	–	37	20 – 95
Ridge Height (ft)	–	–	0.7	0.0 – 1.6	–	–	0.2	0.0 – 0.3
Water Depth[2](ft)	–	–	20.3	19.3 – 21.4	–	–	26.5	12.5 – 34.7

	2008		2009		2010		2011	
	Mean	Range	Mean	Range	Mean	Range	Mean	Range
	1 Wallow		*0 Wallows*		*0 Wallows*		*18 Wallows*	
Incision Depth (ft)	1.9	–	–	–	–	–	2.5	1.0 – 5.6
Incision Width (ft)	31	–	–	–	–	–	40	11 - 79
Ridge Height (ft)	0.6	–	–	–	–	–	0.4	0.1 – 1.5
Water Depth[2] (ft)	16.6	–	–	–	–	–	24.1	13.8 – 33.3

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Table 7. Summary of Ice Wallow Characteristics Measured during the Northstar Development 2000 through 2013 Pipeline Route Monitoring Programs (continued)[1]

Characteristic	2012, 2013			2000-2013	
	Mean	Range		Mean	Range
	0 Wallows			31 Wallows (Average 2.2/yr)	
Incision Depth (ft)				2.3	0.6 – 5.6
Incision Width (ft)				39	11 – 95
Ridge Height (ft)				0.4	0.0 – 1.6
Water Depth[2](ft)				24.0	12.5 – 34.7

Notes:

1 Table 7 is based on all newly-discovered ice wallows mapped on the pipeline route during each of the annual monitoring programs. Relict wallows (*i.e.*, wallows re-discovered after detection in a prior year) are excluded from this table.

2 The vertical datum is ARCO MLLW, which is identical to NOS MLLW.

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Table 8. Ice Wallow Characteristics Measured during the Northstar Development 2013 Pipeline Route Monitoring Program

Wallow No.[1]	Northing[2] (ft)	Easting[2] (ft)	Water Depth[3] (ft)	Incision Depth[4] (ft)	Incision Width (ft)	Ridge Height (ft)
Relict Wallows[4]						
11-11	6,019,731	660,013	21.3	0.6(0.9)	18	0.2
11-12	6,019,694	660,027	20.8	0.8(1.5)	17	0.2

Notes:

1 The prefix indicates the year in which the wallow was first discovered (e.g. "11-" indicates wallow was first discovered in 2011). All of the wallows mapped in 2013 were relict features.

2 The horizontal datum is Alaska State Plane Zone 4 (ASP 4) relative to North American Datum of 1927 (NAD27). Wallow locations are displayed in Drawing CFC-815-13-001.

3 The vertical datum is ARCO MLLW, which is identical to NOS MLLW.

4 For each relict wallow rediscovered in 2013, the incision depth found in 2012 is shown in parentheses after the corresponding value found in 2013.

Table 9. Summary of Strudel Scour Characteristics Measured in the 5,000-ft Monitoring Corridor during the Northstar Development 2000 through 2013 Pipeline Route Monitoring Programs[1]

Characteristic	2000			2001			2002			2003		
	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)
Circular Scours												
Scour Depth	36	2.0	0.6 – 4.7	23	1.7	0.5 – 5.0	28	2.0	0.7 – 4.4	34	1.4	0.3 – 7.2
Max. Horiz. Dim.[2]	54	36	8 – 115	23	28	13 – 51	31	28	11 - 78	34	24	11 – 39
Water Depth[3]	54	11.1	6.7 – 17.0	23	11.4	4.4 – 17.4	31	12.9	4.0 – 19.9	34	11.3	2.8 – 21.8
Linear Scours												
Scour Depth	2	1.5	1.1 – 1.9	2	2.1	1.8 – 2.3	0	–	–	0	–	–
Max. Horiz. Dim.[4]	2	207	160 - 254	2	688	455 – 920	0	–	–	0	–	–
Water Depth[3]	2	13.9	13.7–14.1	2	13.2	13.1–13.3	0	–	–	0	–	–

	2004			2005			2006			2007		
	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)
Circular Scours												
Scour Depth	13	3.1	0.4 – 9.5	3	1.8	0.5 – 2.8	22	2.5	0.5 – 6.0	6	1.6	0.6 – 4.0
Max. Horiz. Dim.[2]	13	49	21 – 76	3	20	13 – 25	22	31	10 – 88	6	16	5 – 39
Water Depth[3]	13	9.9	7.8 – 12.8	3	5.0	2.3 – 9.6	22	9.2	4.5 – 17.1	6	4.8	2.0 – 12.6
Linear Scours												
Scour Depth	0	–	–	0	–	–	4	1.3	0.8 – 1.8	0	–	–
Max. Horiz. Dim.[4]	0	–	–	0	–	–	4	62	23 – 133	0	–	–
Water Depth[3]	0	–	–	0	–	–	4	12.1	8.6 – 13.5	0	–	–

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Table 9. Summary of Strudel Scour Characteristics Measured in the 5,000-ft Monitoring Corridor during the Northstar Development 2000 through 2013 Pipeline Route Monitoring Programs (continued)[1]

Characteristic	2008			2009			2010			2011		
	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)
Circular Scours												
Scour Depth	0	–	–	7	0.8	0.3 – 2.1	30	2.0	0.5 – 5.3	6	1.4	1.0 – 2.0
Max. Horiz. Dim.[2]	0	–	–	7	22	20 – 26	30	24	12 - 66	6	23	10 – 41
Water Depth[3]	0	–	–	7	4.2	4.0 – 4.4	30	8.7	2.7 – 11.7	6	11.6	9.0 – 15.6
Linear Scours												
Scour Depth	0	–	–	1	1.4	–	0	–	–	0	–	–
Max. Horiz. Dim.[4]	0	–	–	1	90	–	0	–	–	0	–	–
Water Depth[3]	0	–	–	1	10.1	–	0	–	–	0	–	–

Characteristic	2012			2013				2000-2013		
	Data Points	Mean (ft)	Range (ft)	Data Points	Mean (ft)	Range (ft)		Data Points	Mean (ft)	Range (ft)
Circular Scours								**363 Scours (Avg. = 25.9/yr)**		
Scour Depth	71	1.5	0.4 – 5.9	63	1.3	0.5 – 2.6		342	1.7	0.3 – 9.5
Max. Horiz. Dim.[2]	71	22	7 – 78	63	27	9 – 87		363	28	5 – 115
Water Depth[3]	71	13.2	8.1 – 17.1	63	13.3	7.5 – 19.8		363	11.5	2.0 – 21.8
Linear Scours								**27 Scours (Avg. = 1.9/yr)**		
Scour Depth	11	2.0	0.8 – 4.4	7	1.8	1.2 – 2.2		27	1.8	0.8 – 4.4
Max. Horiz. Dim.[4]	11	225	55 – 560	7	181	57 – 617		27	218	23 – 920
Water Depth[3]	11	10.8	7.3 – 17.2	7	12.8	9.8 – 14.7		27	11.9	7.3 – 17.2

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Table 9. Summary of Strudel Scour Characteristics Measured in the 5,000-ft Monitoring Corridor during the Northstar Development 2000 through 2013 Pipeline Route Monitoring Programs (continued)[1]

Notes:

1 Table 9 is based on all newly-discovered strudel scours mapped during each annual monitoring program.

2 The maximum horizontal dimension of each circular scour refers to the largest horizontal extent measured at the elevation of the surrounding sea bottom (*i.e.*, the diameter of a perfectly circular scour or the major axis of an oblong scour).

3 The vertical datum is ARCO MLLW, which is identical to NOS MLLW.

4 The maximum horizontal dimension of each linear scour refers to the length measured along the scour orientation. In the case of both linear features detected in 2001 and three of the 11 linear features detected in 2012, the scour was discontinuous along its maximum horizontal dimension (*i.e.*, scoured portions of the sea bottom were interspersed with unscoured portions).

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Table 10. Strudel Scour Characteristics Measured in the 5,000-ft Monitoring Corridor during the Northstar Development 2013 Pipeline Route Monitoring Program

Strudel Scour No.[1]	Water Depth[2] (ft)	Scour Depth (ft)	Max. Horiz. Dimension[3,4] (ft)	Location[5]	
				Northing (ft)	Easting (ft)
Newly-Formed Scours[6]					
13-01	19.8	0.8	12	6,018,378	661,346
13-02	18.9	1.7	13	6,018,402	661,789
13-03	18.9	1.5	16	6,018,395	661,807
13-04	18.9	1.3	11	6,018,387	661,824
13-05	18.9	1.2	11	6,018,385	661,836
13-06	19.0	0.8	9	6,018,373	661,865
13-07	19.1	0.8	17	6,018,367	661,888
13-08	18.9	0.9	16	6,017,175	660,897
13-09	16.7	0.8	17	6,016,671	659,587
13-10	14.8	1.1	64	6,015,763	658,285
13-11	13.8	2.6	45	6,015,460	658,250
13-12	14.0	0.8	18	6,015,406	658,255
13-13	13.8	2.4	37	6,015,288	658,278
13-14	15.0	0.7	20	6,015,556	659,354
13-15	15.0	0.9	61	6,015,615	659,337
13-16	15.0	0.9	22	6,015,651	659,299
13-17	16.6	1.1	20	6,015,391	662,271
13-18	*14.7*	*1.2*	*78 (300°)*	*6,014,876*	*660,935*
13-19	*14.2*	*2.2*	*85 (257°)*	*6,014,777*	*660,320*
13-20	13.7	1.3	25	6,014,293	661,108
13-21	13.7	0.9	19	6,014,316	661,141
13-22	13.5	1.7	27	6,014,216	660,957
13-23	13.5	1.6	37	6,014,189	660,925
13-24	12.9	1.2	39	6,014,136	660,517

(Page 1 of 4)

Table 10. Strudel Scour Characteristics Measured in the 5,000-ft Monitoring Corridor during the Northstar Development 2013 Pipeline Route Monitoring Program (continued)

Strudel Scour No.[1]	Water Depth[2] (ft)	Scour Depth (ft)	Max. Horiz. Dimension[3,4] (ft)	Location[5]	
				Northing (ft)	Easting (ft)
13-25	12.7	0.6	12	6,013,917	660,393
13-26	12.8	0.7	14	6,013,889	660,656
13-27	*12.8*	*1.3*	*57 (267°)*	*6,013,887*	*660,840*
13-28	12.8	0.8	10	6,013,870	660,667
13-29	11.9	2.0	43	6,013,778	659,309
13-30	11.9	1.5	42	6,013,830	659,334
13-31	12.0	0.6	15	6,013,854	659,347
13-32	12.3	0.5	15	6,013,900	659,498
13-33	12.3	0.8	36	6,013,913	659,552
13-34	12.5	1.6	46	6,013,968	659,655
13-35	12.5	2.3	43	6,013,951	659,749
13-36	12.3	1.0	15	6,013,900	659,869
13-37	12.3	1.0	13	6,013,894	659,889
13-38	12.5	1.4	33	6,013,877	660,006
13-39	12.6	1.4	30	6,013,889	660,300
13-40	12.6	2.1	31	6,013,845	660,458
13-41	*12.8*	*1.8*	*75 (267°)*	*6,013,794*	*660,614*
13-42	12.7	2.2	21	6,013,772	660,756
13-43	12.5	1.0	29	6,013,635	661,538
13-44	13.1	1.5	19	6,013,944	661,398
13-45	*13.1*	*1.9*	*154 (285°)*	*6,013,772*	*661,344*
13-46	13.1	1.9	57	6,013,697	661,620
13-47	13.0	1.3	13	6,013,723	661,548
13-48	13.2	1.1	37	6,013,682	661,697
13-49	13.2	1.1	21	6,013,681	661,739

(Page 2 of 4)

Table 10. Strudel Scour Characteristics Measured in the 5,000-ft Monitoring Corridor during the Northstar Development 2013 Pipeline Route Monitoring Program (continued)

Strudel Scour No.[1]	Water Depth[2] (ft)	Scour Depth (ft)	Max. Horiz. Dimension[3,4] (ft)	Location[5]	
				Northing (ft)	Easting (ft)
13-50	13.3	1.0	14	6,013,687	661,767
13-51	12.4	2.2	87	6,012,910	661,722
13-52	*12.5*	*2.1*	*202 (306°)*	*6,012,647*	*661,887*
13-53	11.5	1.6	19	6,012,244	660,670
13-54	11.9	1.0	35	6,012,027	661,161
13-55	11.9	0.8	20	6,012,012	661,189
13-56	11.9	1.1	21	6,012,004	661,262
13-57	11.9	1.1	18	6,012,004	661,288
13-58	11.1	1.0	20	6,011,496	661,547
13-59	11.0	1.8	18	6,011,439	662,053
13-60	11.2	1.6	26	6,011,262	662,760
13-61	11.8	1.0	25	6,011,288	662,837
13-62	10.6	1.9	62	6,011,287	661,845
13-63	10.7	1.4	58	6,011,167	661,871
13-64	10.3	1.8	47	6,011,056	661,887
13-65	10.2	1.1	15	6,011,007	661,904
13-66	10.2	1.1	14	6,010,993	661,897
13-67	*9.8*	*2.2*	*617 (202°)*	*6,010,639*	*661,755*
13-68	7.6	1.8	28	6,009,600	660,801
13-69	7.5	0.9	16	6,009,589	660,841
13-70	7.5	0.8	17	6,009,579	660,884

(Page 3 of 4)

Table 10. Strudel Scour Characteristics Measured in the 5,000-ft Monitoring Corridor during the Northstar Development 2013 Pipeline Route Monitoring Program (continued)

Notes:

[1] The prefix indicates the year in which the strudel scour was first discovered (*e.g.* "13-" indicates strudel scour was first discovered in 2013).

[2] The vertical datum is ARCO MLLW, which is identical to NOS MLLW.

[3] The maximum horizontal dimension of each circular scour refers to the largest horizontal extent measured at the elevation of the surrounding sea bottom (*i.e.*, the diameter of a perfectly circular scour or the major axis of an oblong scour).

[4] Linear scours are indicated in italics with the scour orientation displayed in parentheses after the maximum horizontal dimension. For example, "617 (298°)" indicates a linear scour with a maximum horizontal dimension of 617 ft and an orientation of 298° Grid. The maximum horizontal dimension refers to the length measured along the scour orientation.

[5] The horizontal datum is Alaska State Plane Zone 4 (ASP 4) relative to North American Datum of 1927 (NAD27). Scour locations are displayed in Drawing CFC-815-03-003.

[6] No relict scours were found in 2013.

(Page 4 of 4)

FIGURES

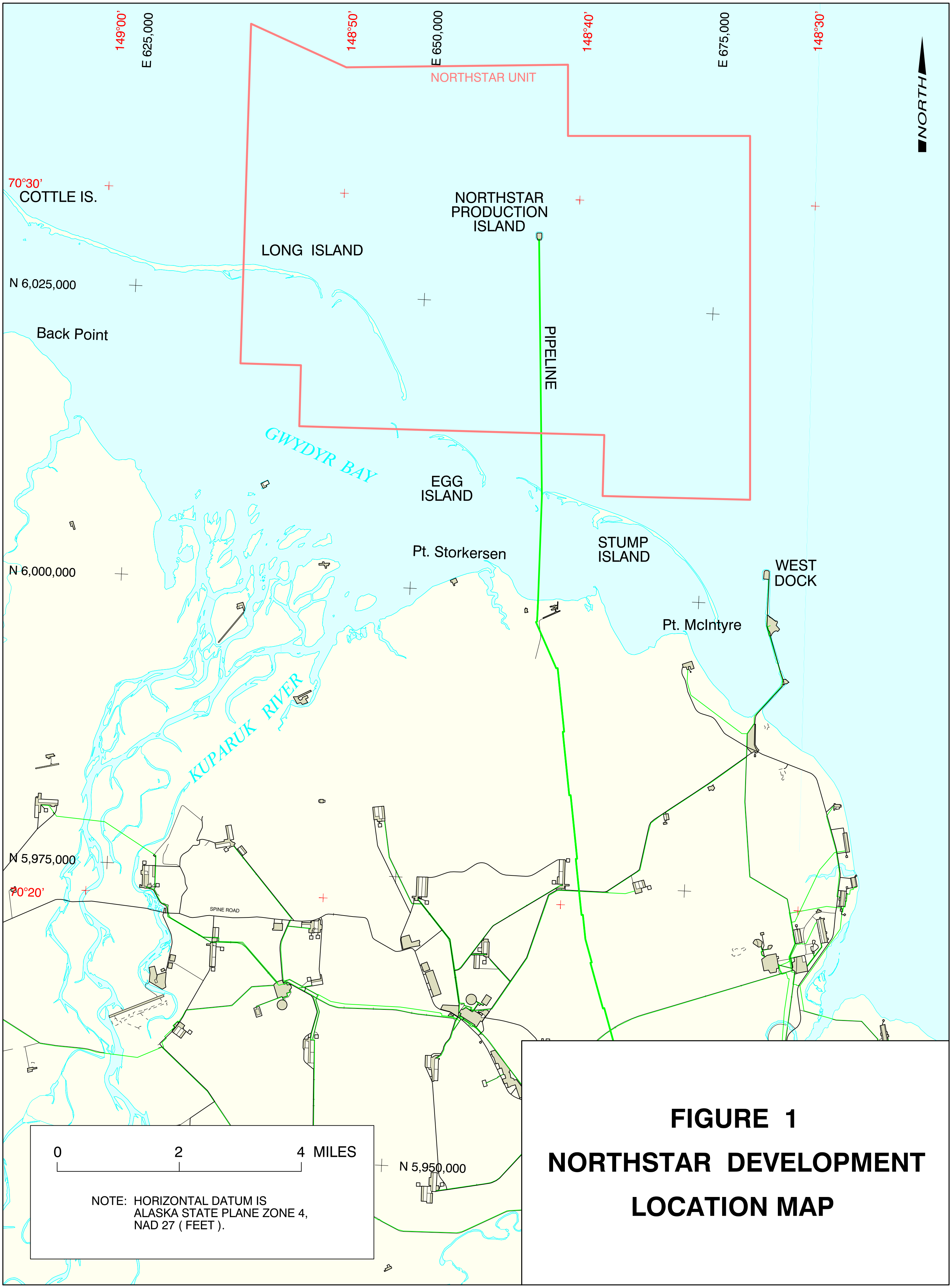
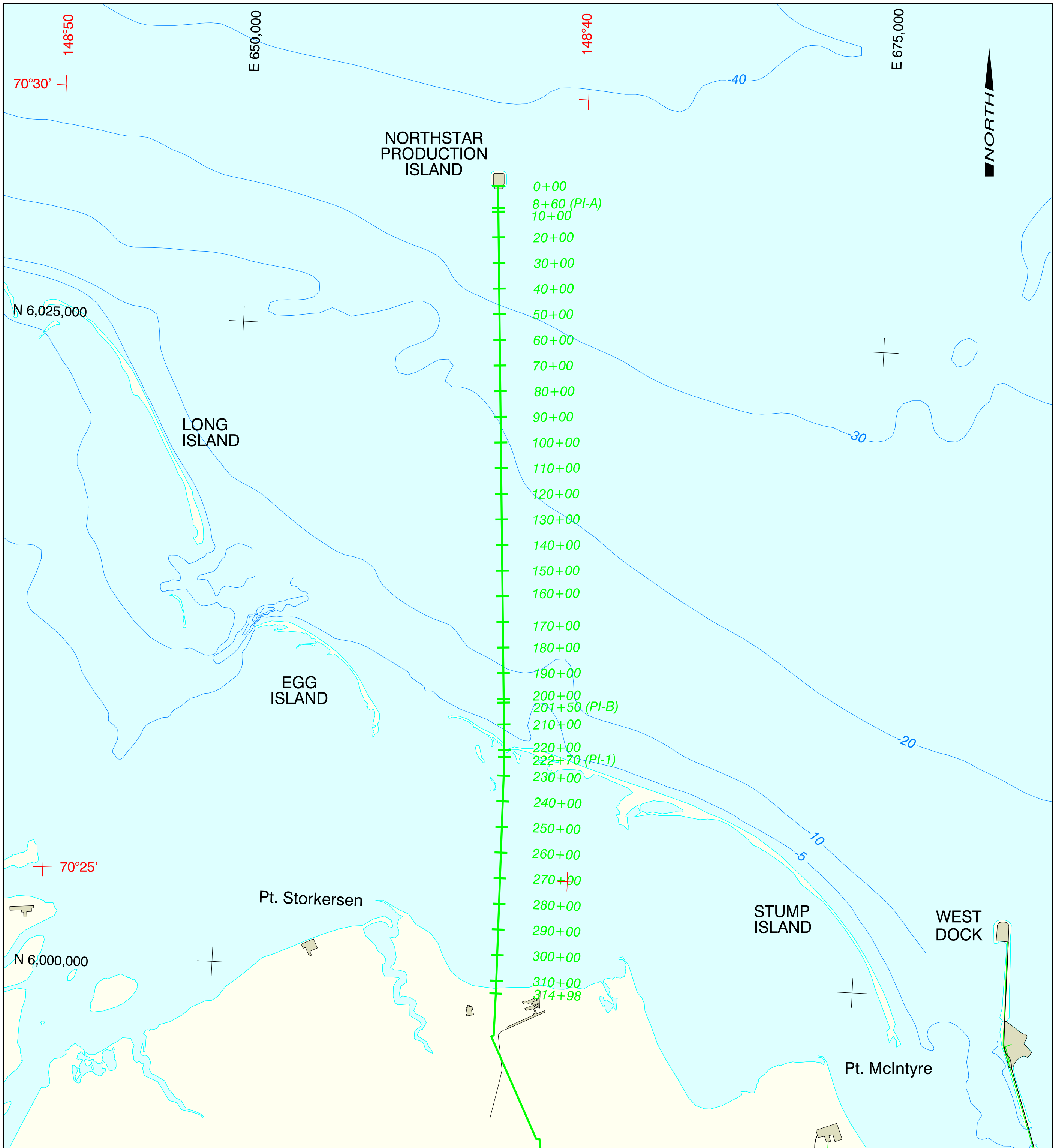


FIGURE 1

NORTHSTAR DEVELOPMENT

LOCATION MAP

np14400a.dgn



0 1 2 MILES

NOTE:
1. HORIZONTAL DATUM IS ALASKA STATE PLANE ZONE 4, NAD 27 (FEET).
2. VERTICAL DATUM IS ARCO MLLW (FEET).
3. GENERALIZED BATHYMETRIC CONTOURS DERIVED FROM NOAA ARCHIVES.

LEGEND:

70+00 STATION 70+00 ON AS-BUILT PIPELINE ALIGNMENT

AS-BUILT PIPELINE ALIGNMENT

FIGURE 2

NORTHSTAR DEVELOPMENT PIPELINE ROUTE

np14558d.dgn

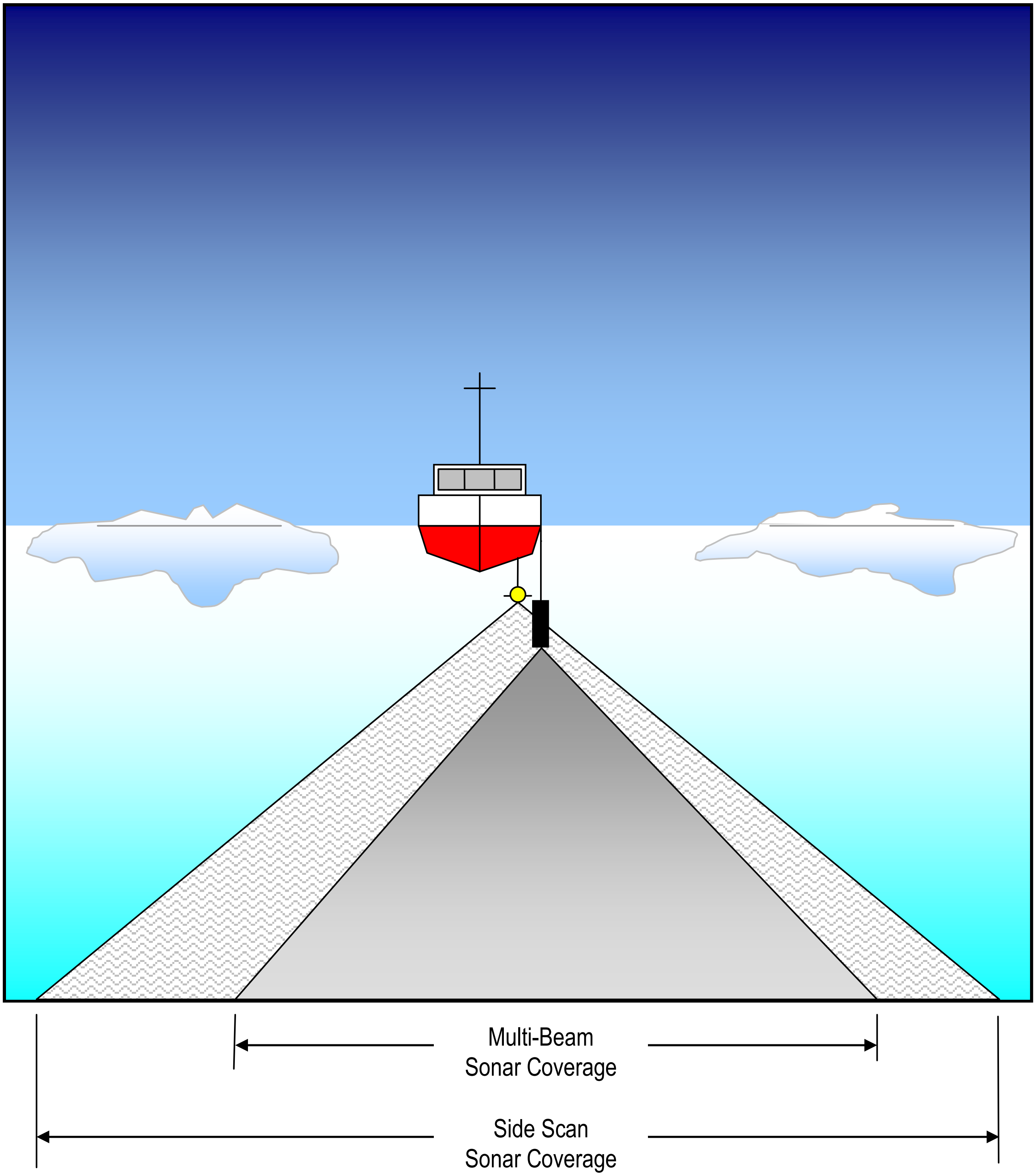


Figure 3. Sea Bottom Survey Using Side Scan and Multi-Beam Sonar

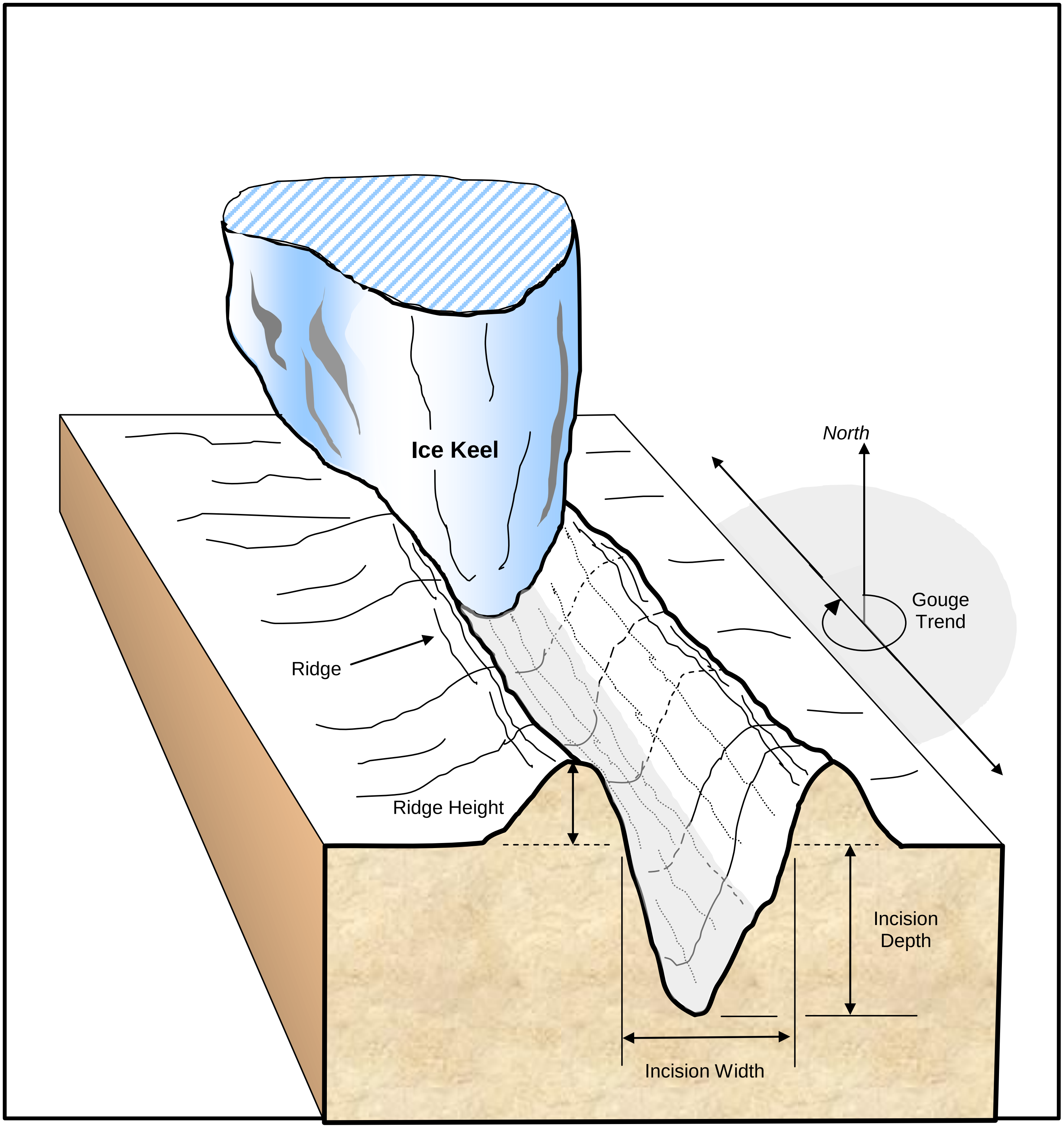


Figure 4. Ice Gouge Terminology

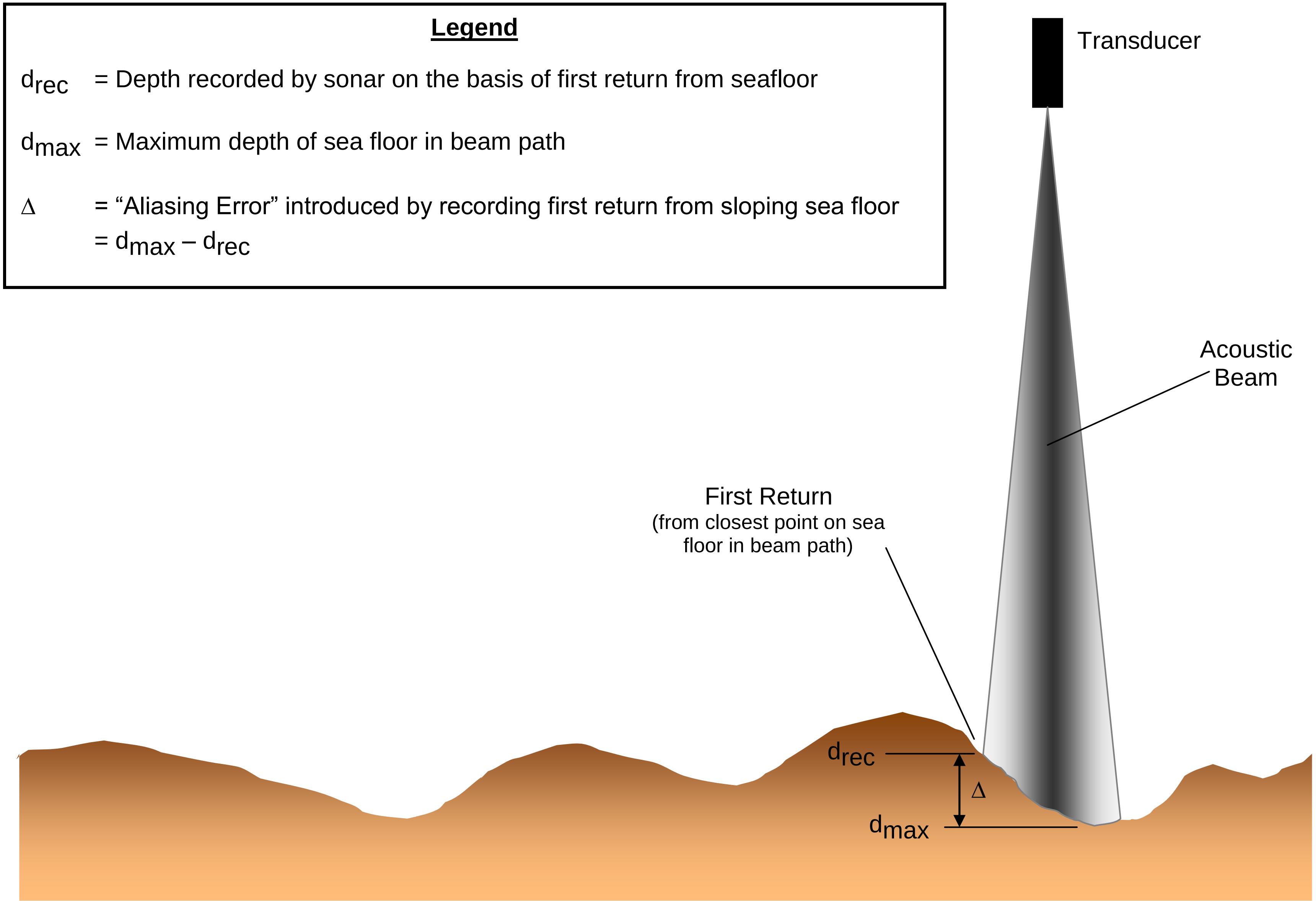


Figure 5. Aliasing Error in Single-Beam Sonar Bathymetric Measurements

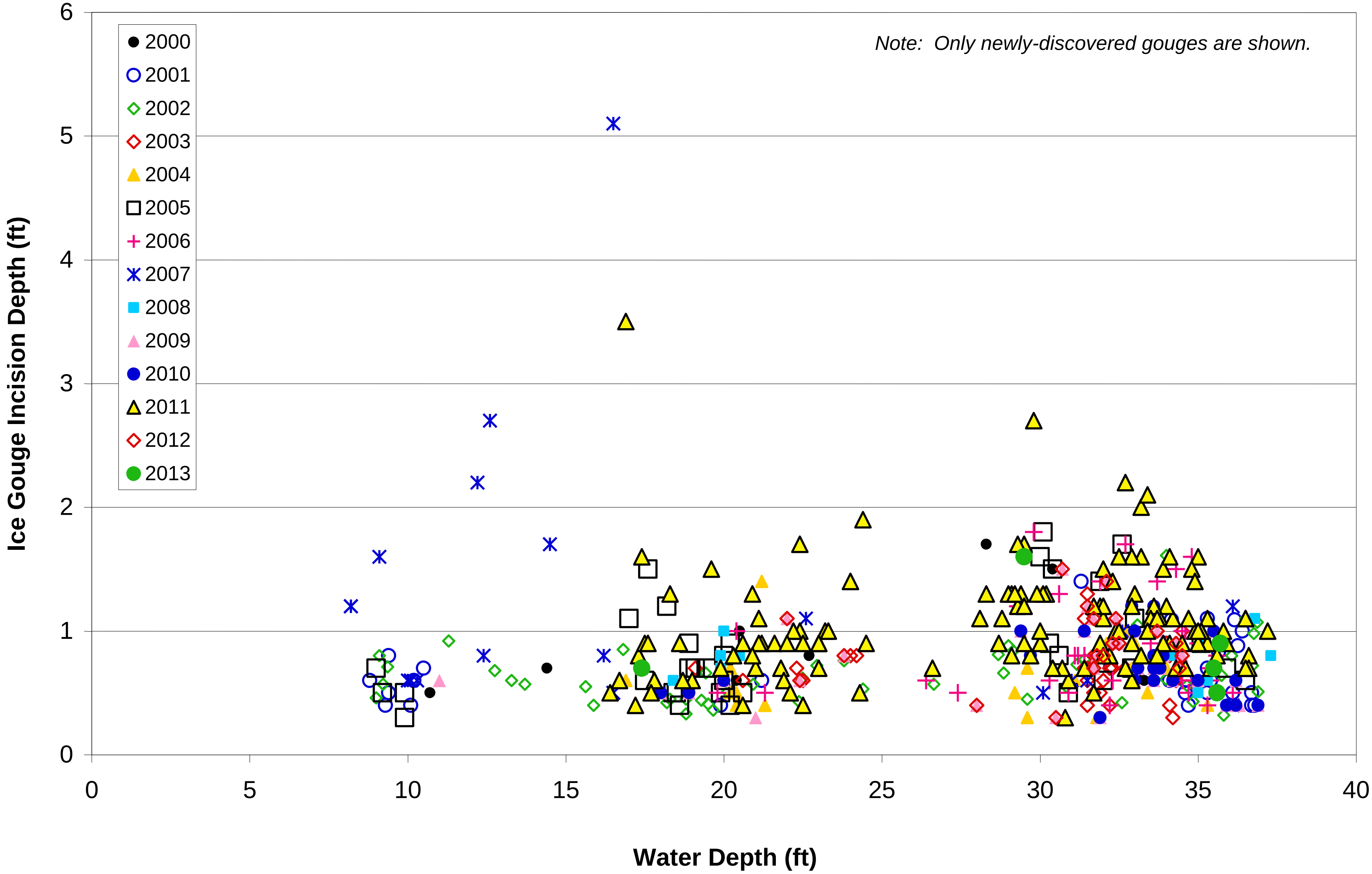


Figure 6. Ice Gouge Incision Depth vs. Water Depth

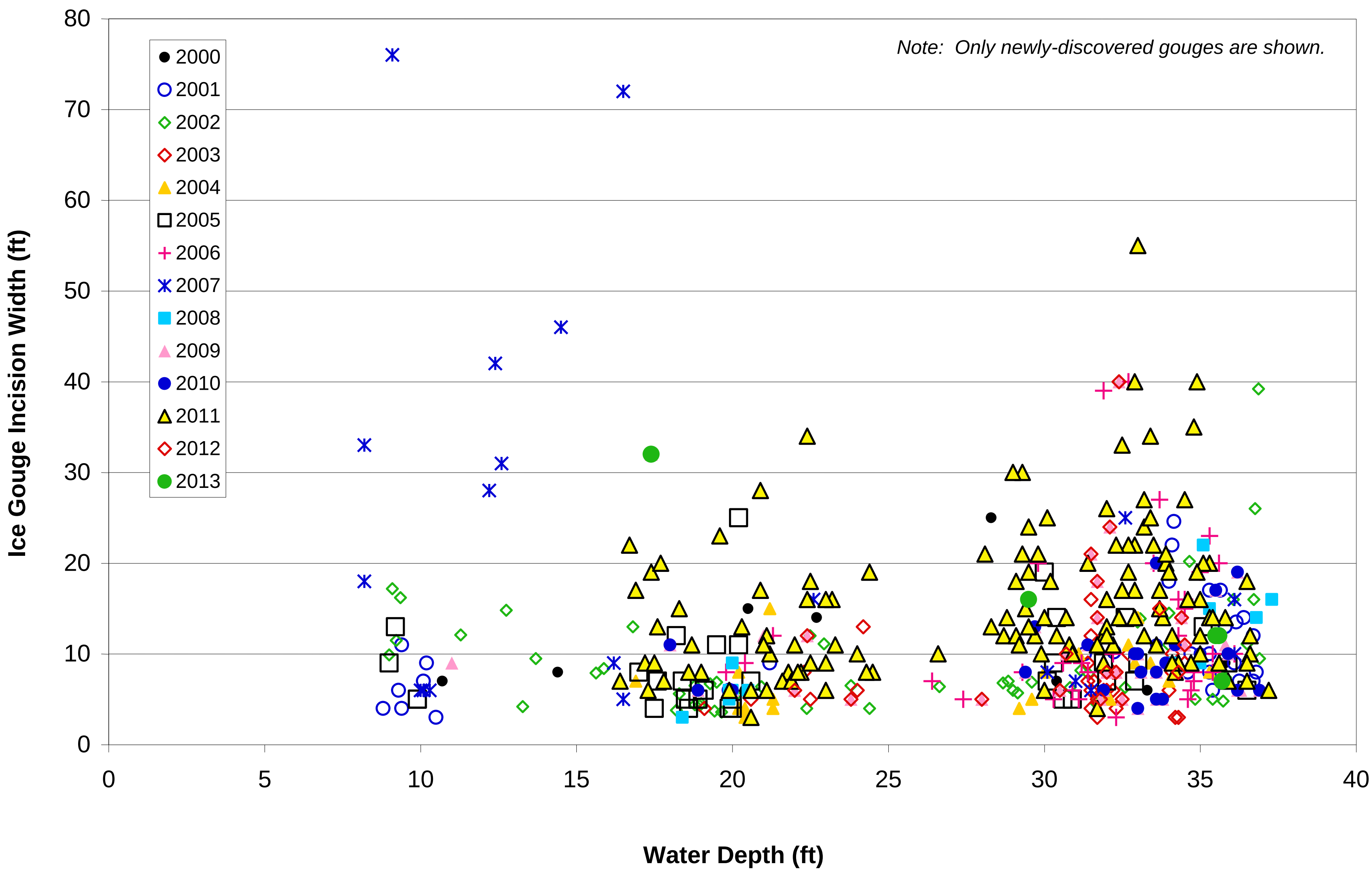


Figure 7. Ice Gouge Incision Width vs. Water Depth

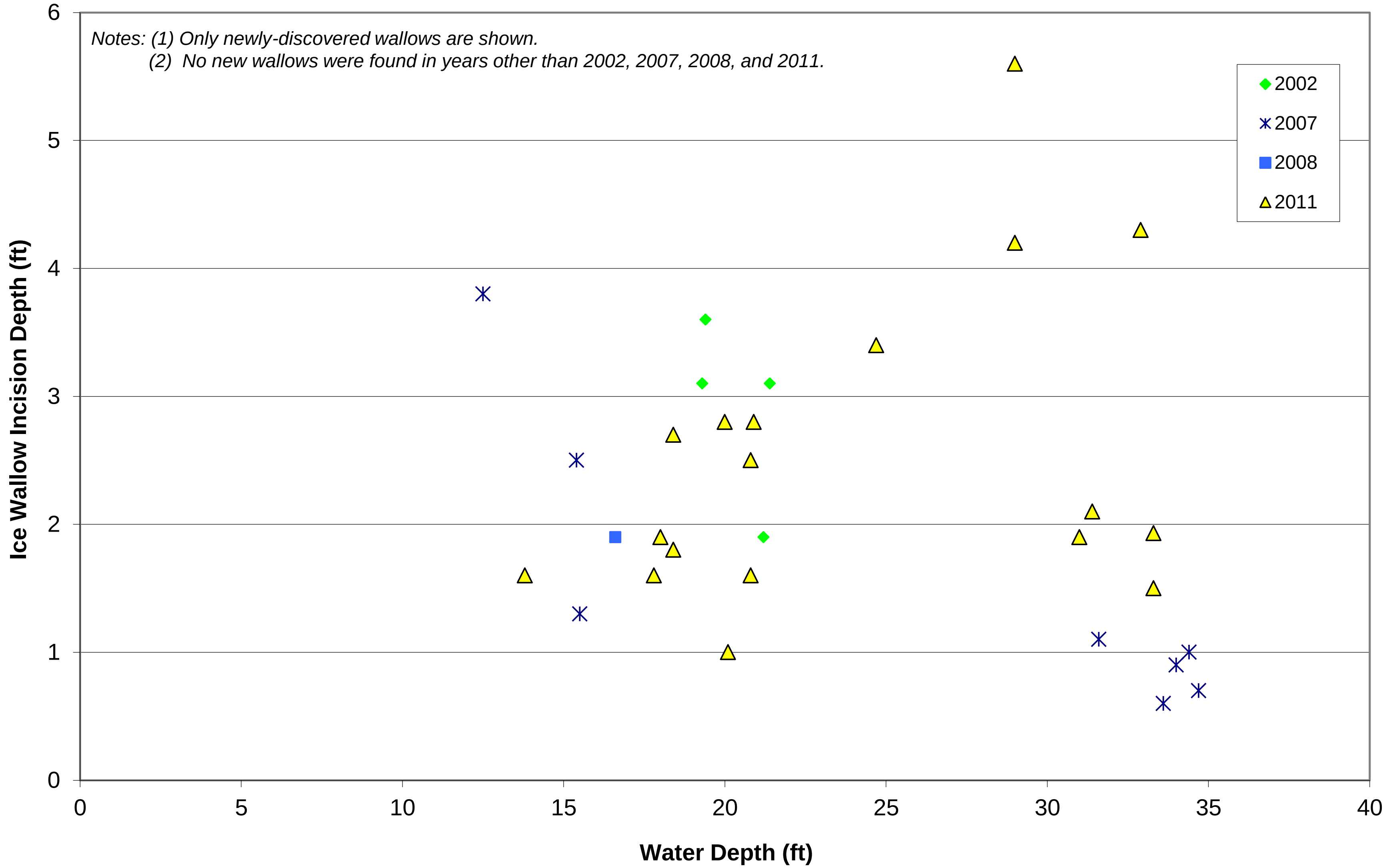


Figure 8. Ice Wallow Incision Depth vs. Water Depth

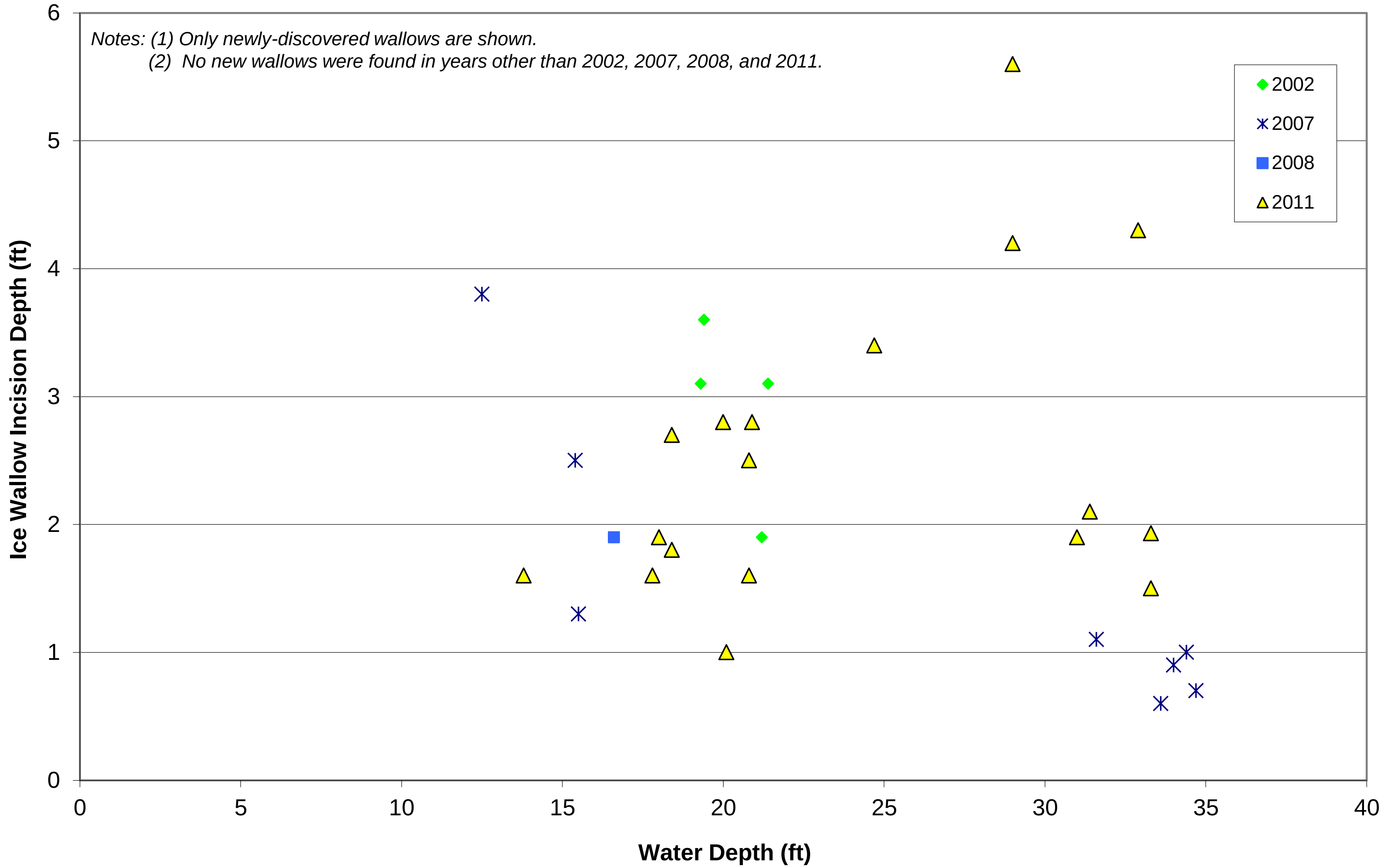


Figure 9. Ice Wallow Incision Width vs. Water Depth

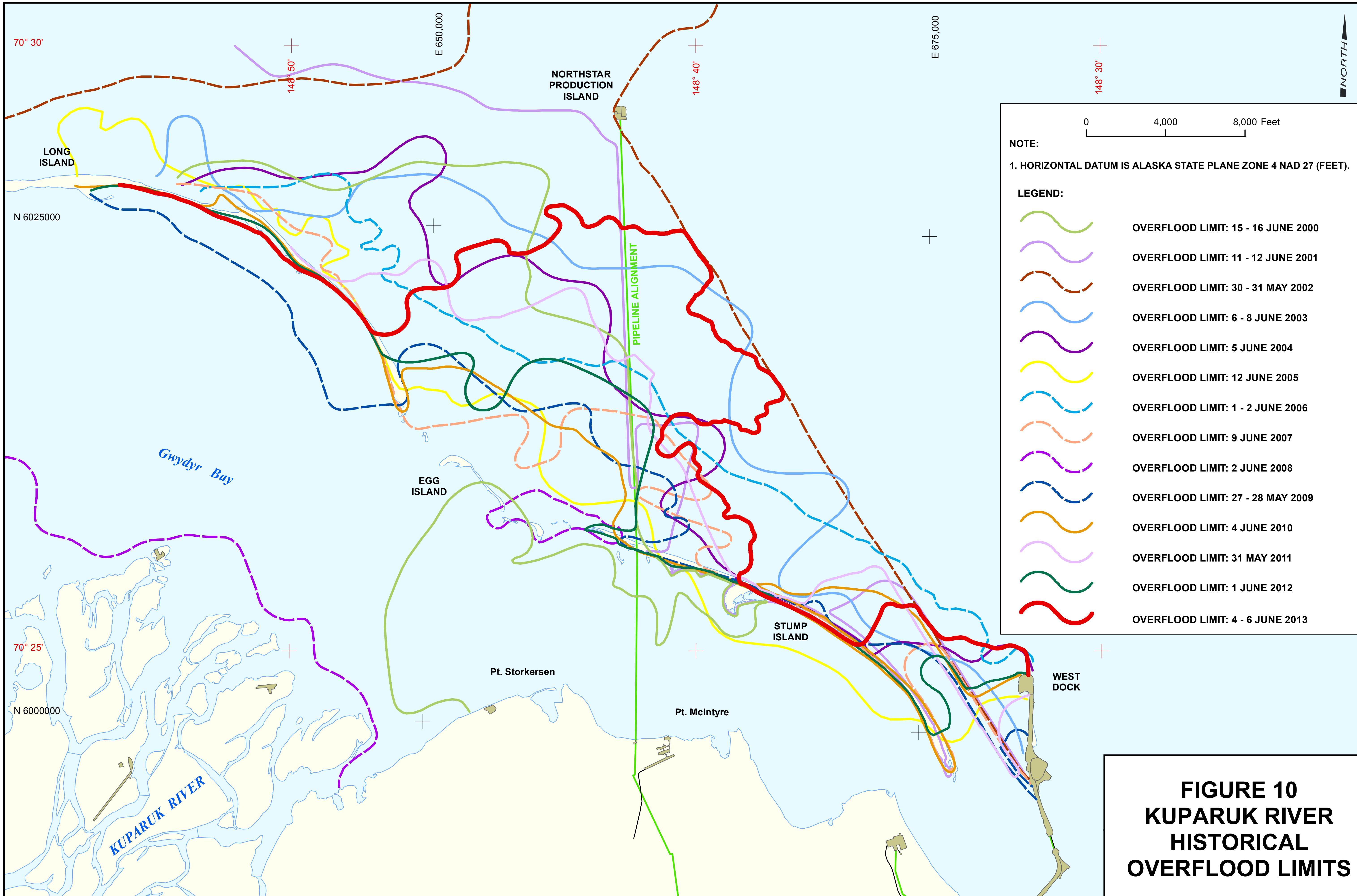


FIGURE 10
KUPARUK RIVER HISTORICAL OVERFLOOD LIMITS

np16440d.mxd

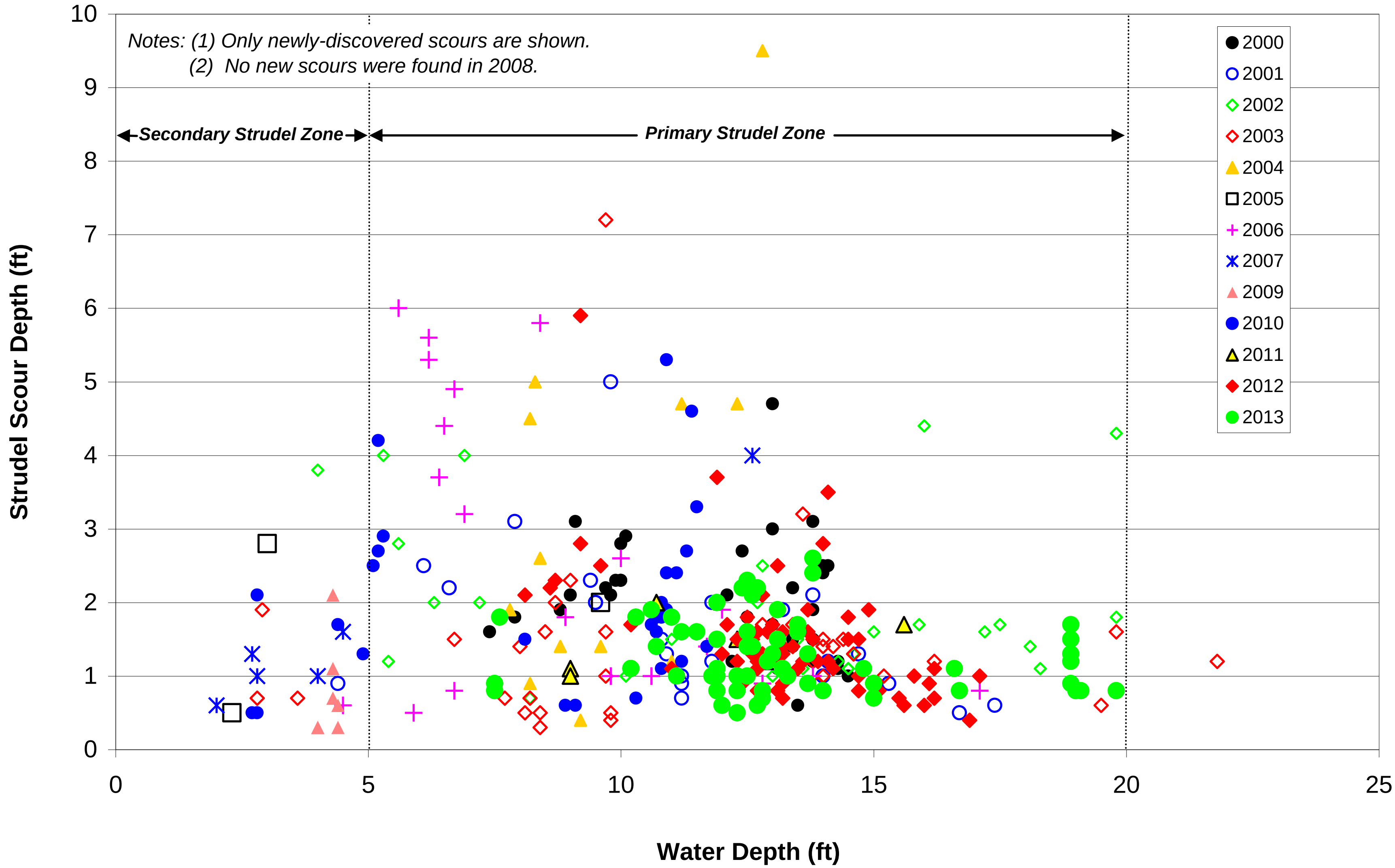


Figure 11. Strudel Scour Depth vs. Water Depth for Circular Scours

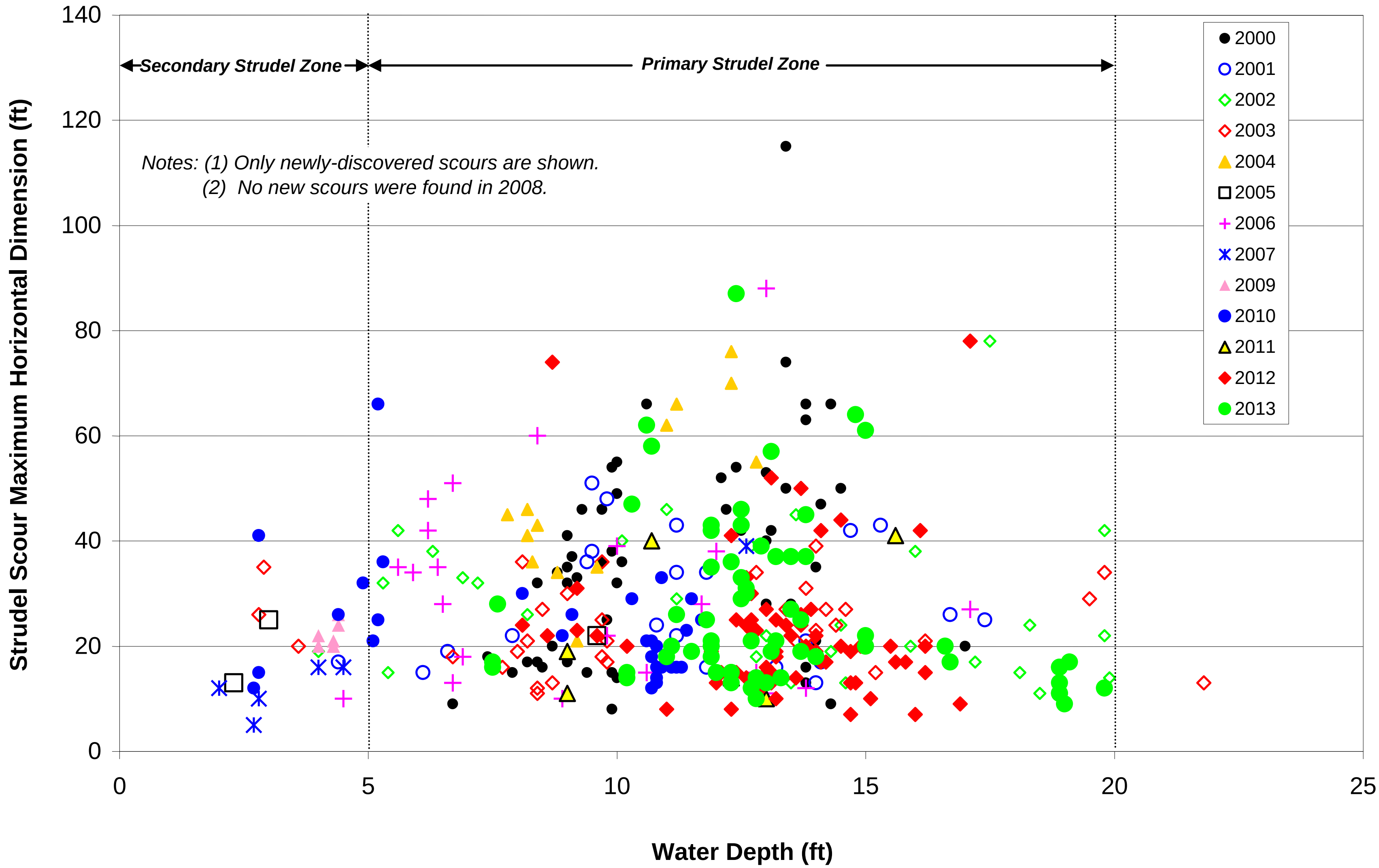


Figure 12. Strudel Scour Maximum Horizontal Dimension vs. Water Depth for Circular Scours

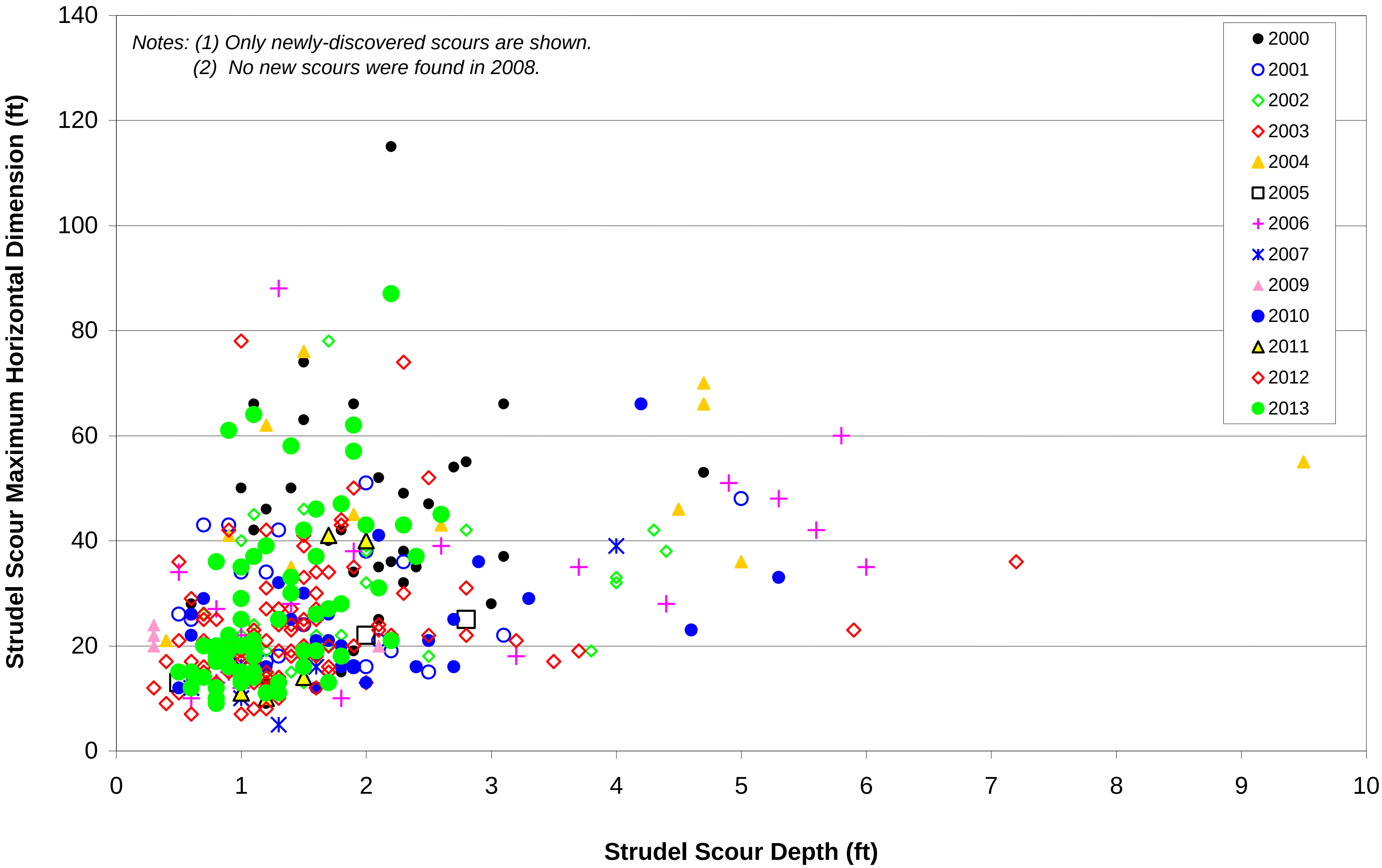


Figure 13. Strudel Scour Maximum Horizontal Dimension vs. Strudel Scour Depth for Circular Scours

NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
APPENDIX A: DRAWINGS

Prepared for:

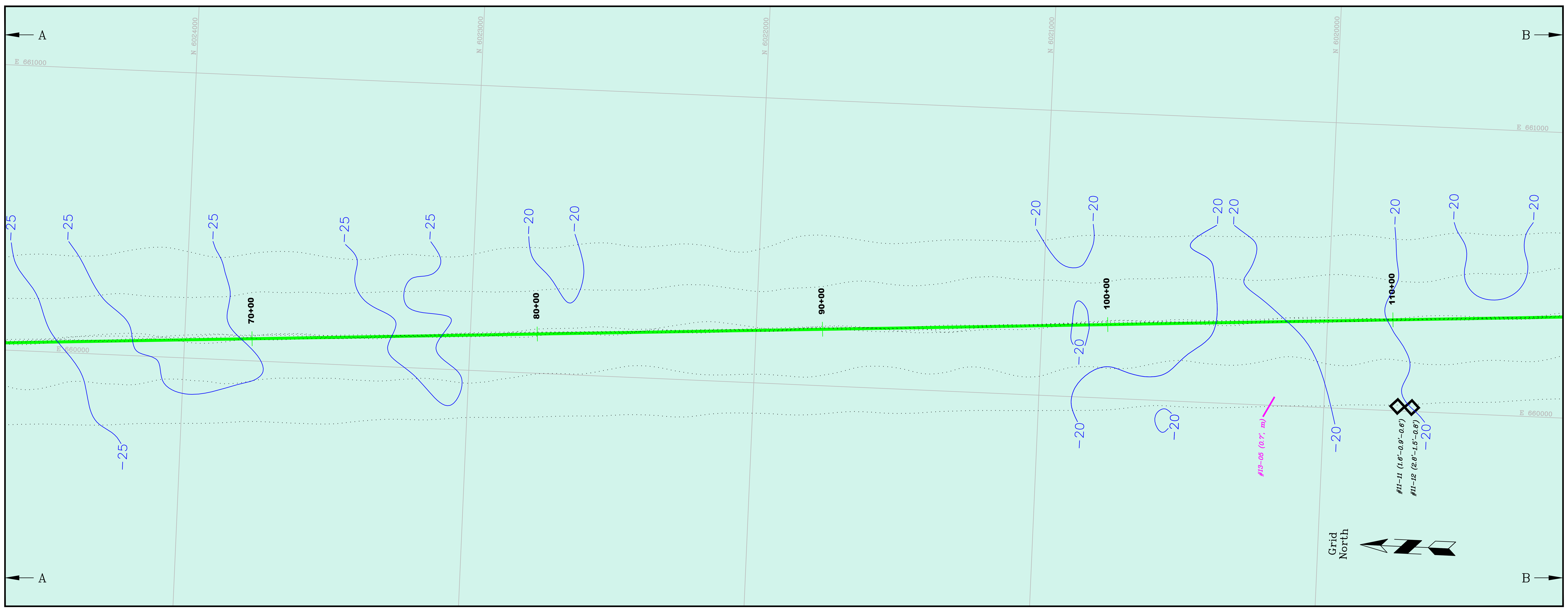
BP Exploration (Alaska) Inc.
Anchorage, Alaska

Coastal Frontiers Corporation
882A Patriot Drive
Moorpark, CA 93021
(818) 341-8133

NORTHSTAR PRODUCTION ISLAND
LONG ISLAND
EGG ISLAND
STUMP ISLAND
WEST DOCK
Pt. Storkersen
Pt. McIntyre
Gwydyr Bay
Kuparuk River
E 650,000
E 675,000
N 6,025,000
N 6,000,000
70° 30'
70° 25'
148° 50'
148° 40'
148° 30'
NORTH
1 : 24,000
0 2,000 4,000 Feet
NOTE:
1. 2013 SEA BOTTOM SURVEY PERFORMED BETWEEN 19 AND 21 JULY.
2. HORIZONTAL DATUM IS ALASKA STATE PLANE ZONE 4 NAD 27 (FEET).
LEGEND:
70+00 STATION 70+00 ON PIPELINE ALIGNMENT
PIPELINE ALIGNMENT
Drawing No. CFC-815-13-002 (Bathymetric Profile on Pipeline Alignment)
Drawing No. CFC-815-13-001, Sheet 1
Drawing No. CFC-815-13-001, Sheet 2
Drawing No. CFC-815-13-001, Sheet 3
Drawing No. CFC-815-13-003, Sheet 1 (Cross Sections through Pipeline Alignment)
Drawing No. CFC-815-13-003, Sheet 2 (Cross Sections through Pipeline Alignment)
Drawing No. CFC-815-13-003, Sheet 3 (Cross Sections through Pipeline Alignment)
0+00
8+60 (PI-A)
10+00
20+00
30+00
40+00
50+00
60+00
70+00
80+00
90+00
100+00
110+00
120+00
130+00
140+00
150+00
160+00
170+00
180+00
190+00
200+00
201+50 (PI-B)
210+00
220+00
222+70 (PI-1)
230+00
240+00
250+00
260+00
270+00
280+00
290+00
300+00
310+00
314+98
Drawing No. CFC-815-03-001
NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE
MONITORING PROGRAM
DRAWING INDEX MAP

Drawing No. CFC-815-03-002
NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
STRUDEL DRAINAGE FEATURE AND OVERFLOOD LIMIT LOCATION MAP

Drawing No. CFC-815-03-003
NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
STRUDEL SCOUR AND STRUDEL DRAINAGE FEATURE LOCATION MAP



NOTES

1. See Drawing CFC–815–03–001 for location of track lines shown in this drawing.
2. 2013 survey performed between 19 and 21 July.
3. Horizontal datum is Alaska State Plane Zone 4, NAD27 (feet).
4. Vertical datum is ARCO Mean Lower Low Water (MLLW), which is identical to National Ocean Service (NOS) MLLW.
5. Contour interval is 5 feet.
6. Drawing not to be used for navigation.

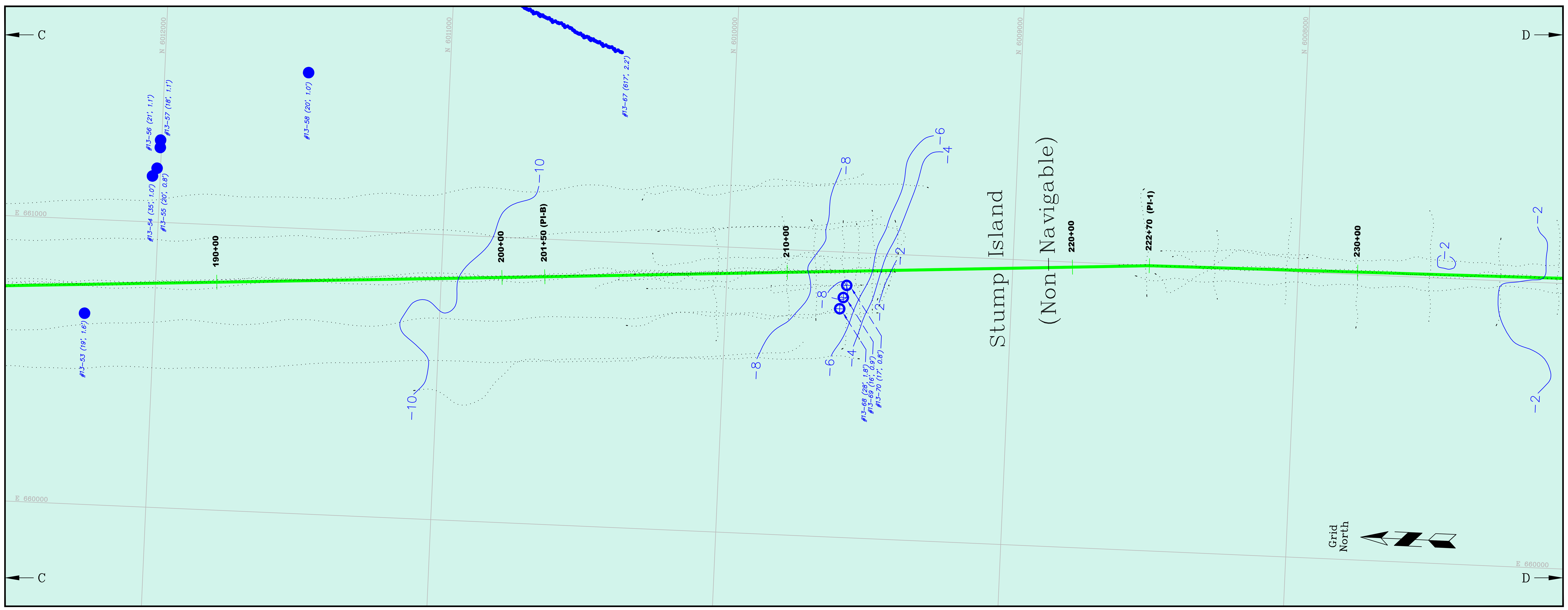
LEGEND

	Vessel track line
−20	Elevation contour (feet, ARCO MLLW)
#13–05 (0.7', m)	Ice gouge #13–05 first detected in 2013 with maximum incision depth of 0.7 feet ("*m*" indicates multiplet gouge)
#11–02 (1.1'–0.8'–0.7', s)	Ice gouge #11–02 first detected in 2011 with maximum incision depth of 1.1 feet; found again in 2012 with maximum incision depth of 0.8 feet, and in 2013 with maximum incision depth of 0.7 feet. ("*s*" indicates single gouge)
#11–11 (1.6'–0.9'–0.6')	Ice Wallow #11–11 first detected in 2011 with maximum incision depth of 1.6 feet; found again in 2012 with maximum incision depth of 0.9 feet, and in 2013 with maximum incision depth of 0.6 feet.
	Pipeline alignment
70+00	Station 70+00 on pipeline alignment
A	Match line A

200 0 200 600

Scale 1" = 200 feet

NORTHSTAR DEVELOPMENT 2013 PIPELINE ROUTE MONITORING PROGRAM SURVEY TRACK LINES		
Scale: 1" = 200'	Checked by: GEH	Drawn by: LAD
Date: 15 January 2014	Sheet: 1 of 3	Revised:
Prepared for: B.P. EXPLORATION (ALASKA) INC.		
Prepared by: COASTAL FRONTIERS CORPORATION		Drawing No.: CFC–815–13–001



NOTES

1. See Drawing CFC-815-03-001 for location of track lines shown in this drawing.
2. 2013 survey performed between 19 and 21 July.
3. Horizontal datum is Alaska State Plane Zone 4, NAD27 (feet).
4. Vertical datum is ARCO Mean Lower Low Water (MLLW), which is identical to National Ocean Service (NOS) MLLW.
5. Contour interval is 5 feet in water depths greater than 10 feet, and 2 feet in water depths less than 10 feet.
6. Drawing not to be used for navigation.

LEGEND

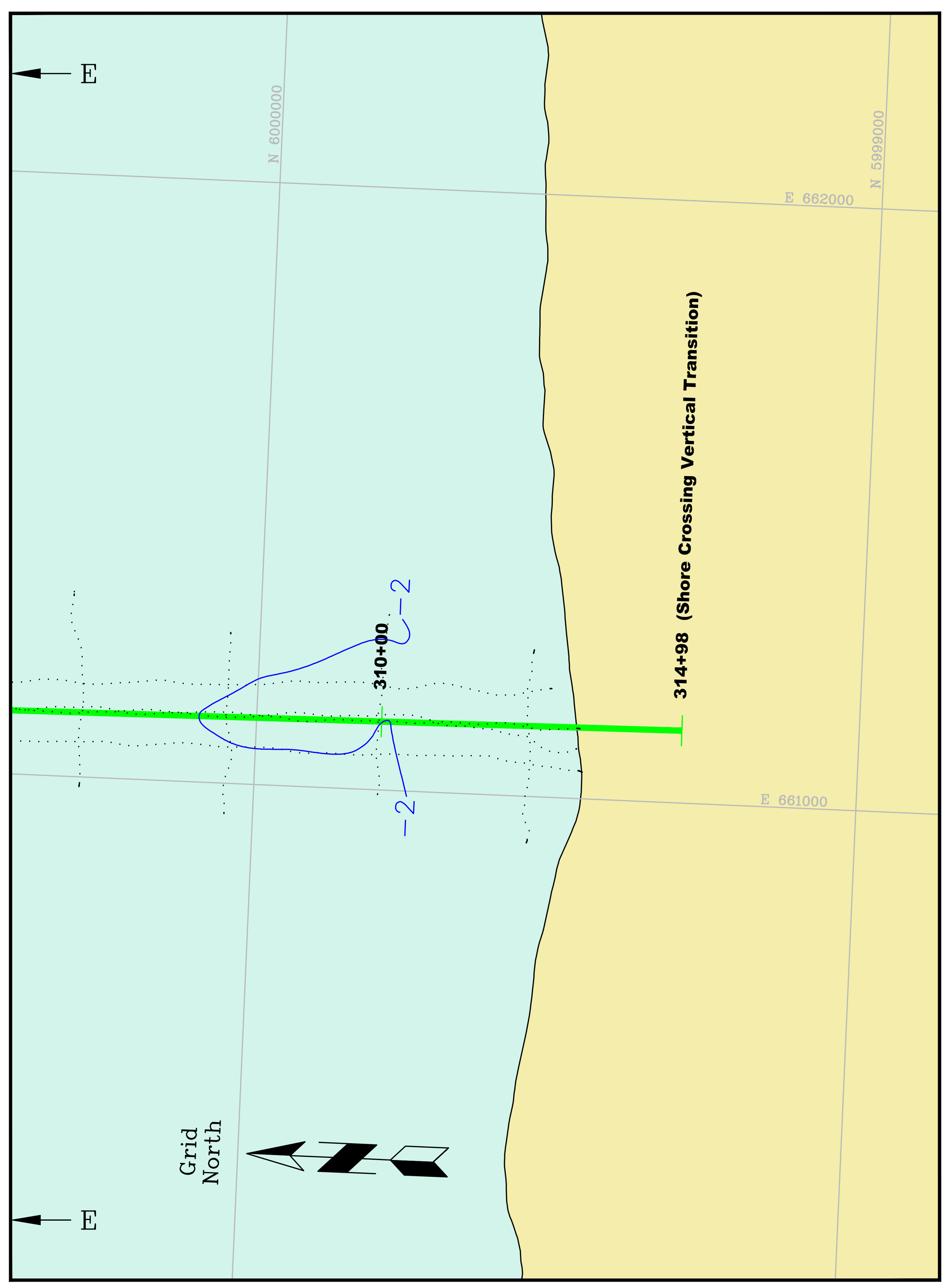
	Vessel track line
-20	Elevation contour (feet, ARCO MLLW)
#13-01 (12', 0.8')	Strudel Scour #13-01, first detected in 2013 with maximum horizontal dimension of 12 feet and maximum depth of 0.8 feet ("●" indicates circular scour mapped with multi-beam sonar)
#13-68 (28', 1.8')	Strudel Scour #13-68, first detected in 2013 with maximum horizontal dimension of 28 feet and maximum depth of 1.8 feet ("⊕" indicates circular scour mapped with single-beam sonar only)
#13-18 (178', 1.2')	Strudel Scour #13-18, first detected in 2013 with maximum horizontal dimension of 178 feet and maximum depth of 1.2 feet (" " indicates linear scour mapped with multi-beam sonar)
	Pipeline alignment
150+00	Station 150+00 on pipeline alignment
C	Match line C

200 0 200 600

Scale 1" = 200 feet

NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
SURVEY TRACK LINES

Scale: 1" = 200'	Checked by: GEH	Drawn by: LAD
Date: 15 January 2014	Sheet: 2 of 3	Revised:
Prepared for: B.P. EXPLORATION (ALASKA) INC.		
Prepared by: COASTAL FRONTIERS CORPORATION		Drawing No.: CFC-815-13-001



NOTES

1. See Drawing CFC-815-03-001 for location of track lines shown in this drawing.
2. 2013 survey performed between 19 and 21 July.
3. Horizontal datum is Alaska State Plane Zone 4, NAD27 (feet).
4. Vertical datum is ARCO Mean Lower Low Water (MLLW), which is identical to National Ocean Service (NOS) MLLW.
5. Contour interval is 2 feet.
6. Drawing not to be used for navigation.

LEGEND

Vessel track line

-4 Elevation contour (feet, ARCO MLLW)

Pipeline alignment

280+00 Station 280+00 on pipeline alignment

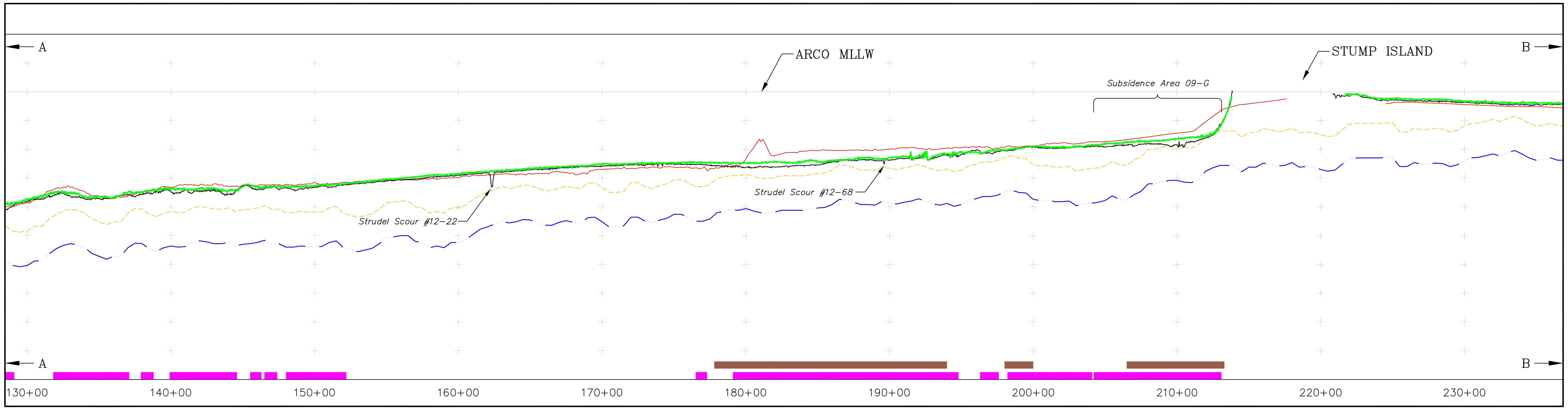
E Match line E

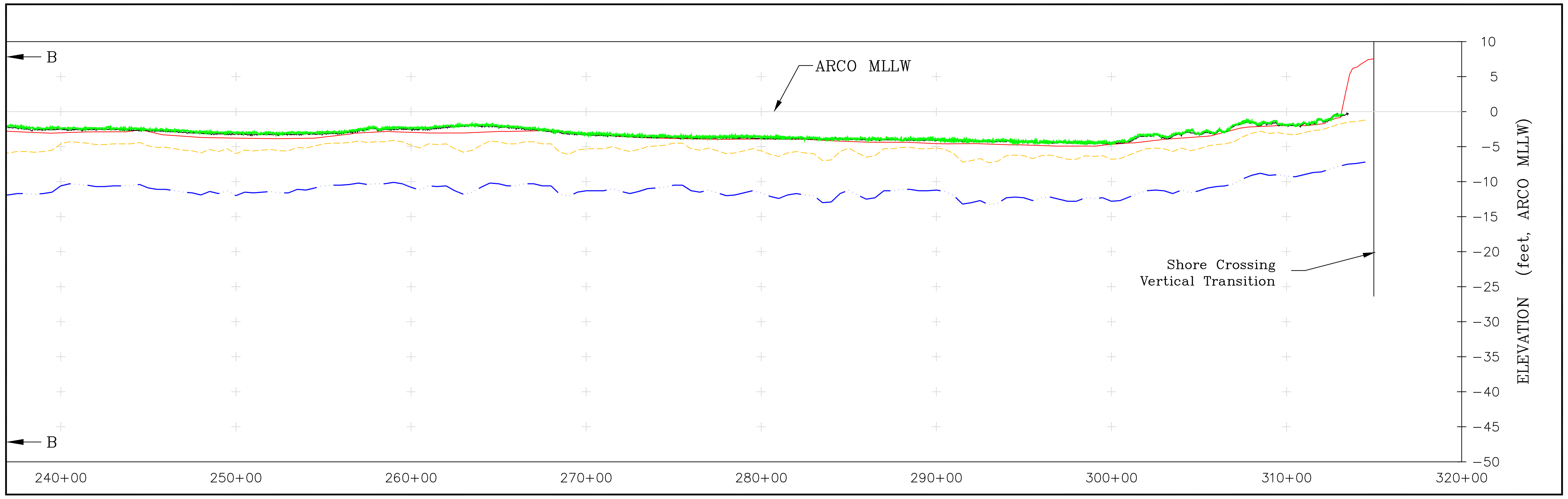
200 0 200 600

Scale 1" = 200 feet

NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
SURVEY TRACK LINES

Scale: 1" = 200'	Checked by: GEH	Drawn by: LAD
Date: 15 January 2014	Sheet: 3 of 3	Revised:
Prepared for: B.P. EXPLORATION (ALASKA) INC.		
Prepared by: COASTAL FRONTIERS CORPORATION		Drawing No.: CFC-815-13-001





NOTES

1. See Drawing No. CFC−815−03−001 for location of profile shown in this drawing.
2. 1996 sea bottom survey was performed between 28 July and 4 August. 2012 sea bottom survey was performed between 22 and 25 July. 2013 sea bottom survey was performed between 19 and 21 July.
3. Top−of−Pipeline survey was performed by H&B Surveyors during pipeline installation between 26 March and 16 April 2000.
4. Horizontal datum is Alaska State Plane Zone 4, NAD 27 (feet).
5. Vertical datum is ARCO Mean Lower Low Water (MLLW), which is identical to National Ocean Service (NOS) MLLW.
6. Vertical scale is exaggerated by a factor of 40.
7. Pipeline alignment:

   Northstar Island Pipeline Exit
   Station 0+00
   N: 6,030,751.45
   E: 659,661.09

   PI−A
   Station 8+60
   N: 6,029,892.74
   E: 659,708.41

   PI−B
   Station 201+50
   N: 6,010,637.63
   E: 660,868.08

   PI−1 (Stump Island)
   Station 222+70
   N: 6,008,522.00
   E: 660,999.00

   Shore Crossing Vertical Transition
   Station 314+98
   N: 5,999,294.00
   E: 661,120.03

8. Bathymetric data acquisition in the region marked "STUMP ISLAND" was precluded by the presence of the island.
9. Drawing not to be used for navigation.

LEGEND

- 2013 Sea Bottom Profile
- 2012 Sea Bottom Profile
- 1996 Sea Bottom Profile
- Top−of−Pipeline Profile
- 6 ft above Top−of−Pipeline Elevation
- Active Subsidence Documented between 2003 and 2012
- Gravel Backfill Added between 2004 and 2011
- A Match Line A

400 0 400 1200

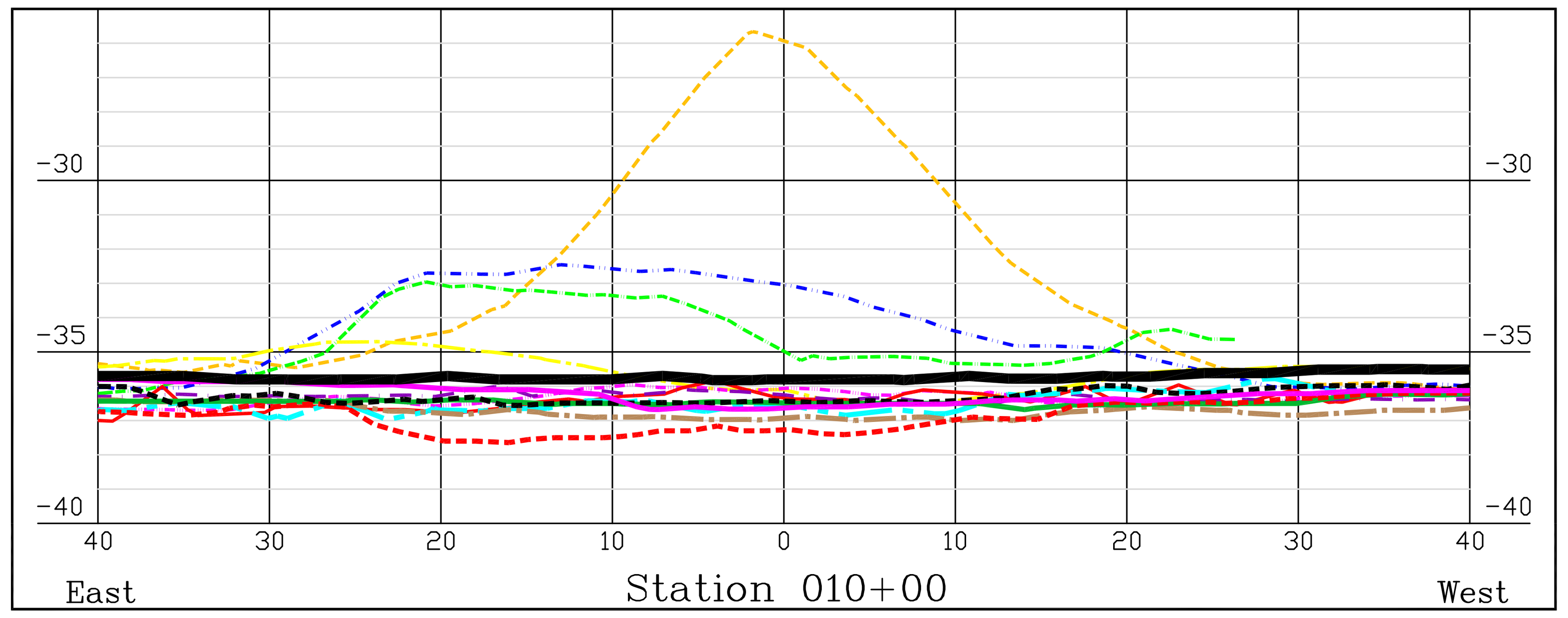
Horizontal Scale 1" = 400 ft

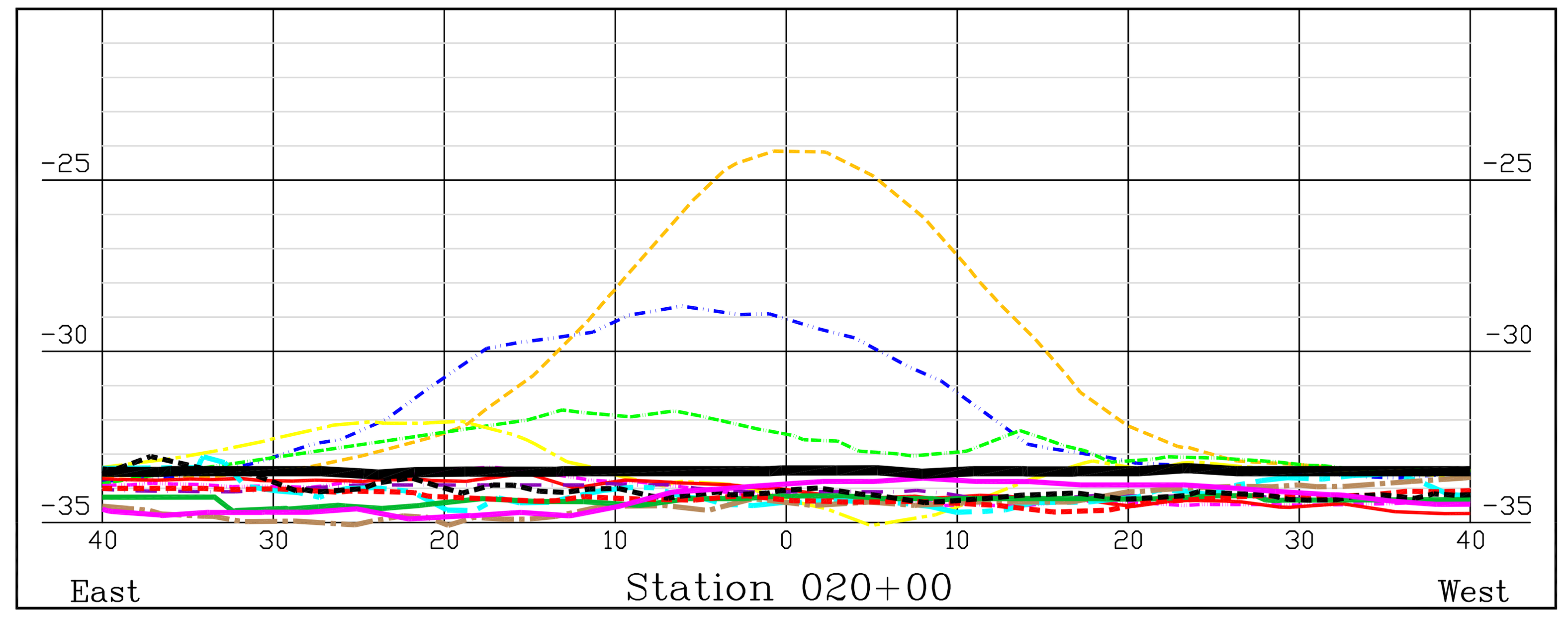
NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
BATHYMETRIC PROFILE ON PIPELINE ALIGNMENT

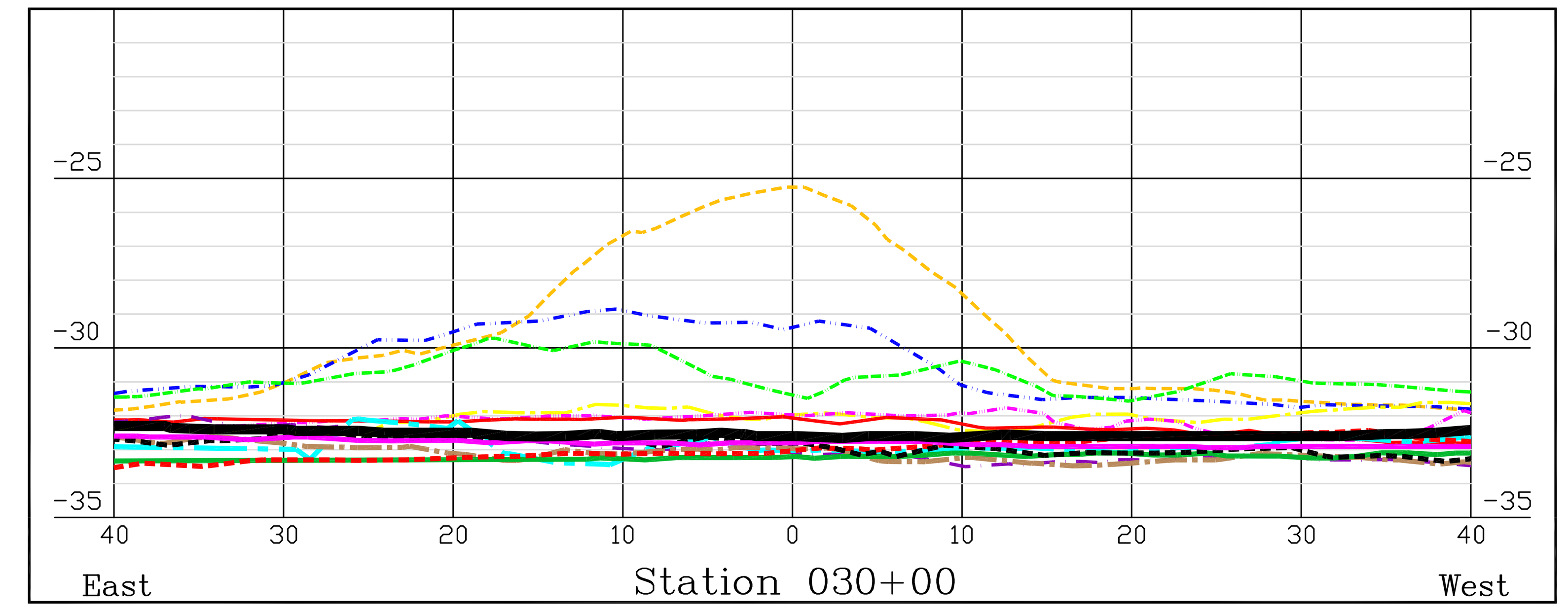
Horizontal Scale: 1" = 400'	Checked by: CBL	Drawn by: GEH
Date: 25 July 2013	Sheet: 1 of 1	Revised: 17 January 2014

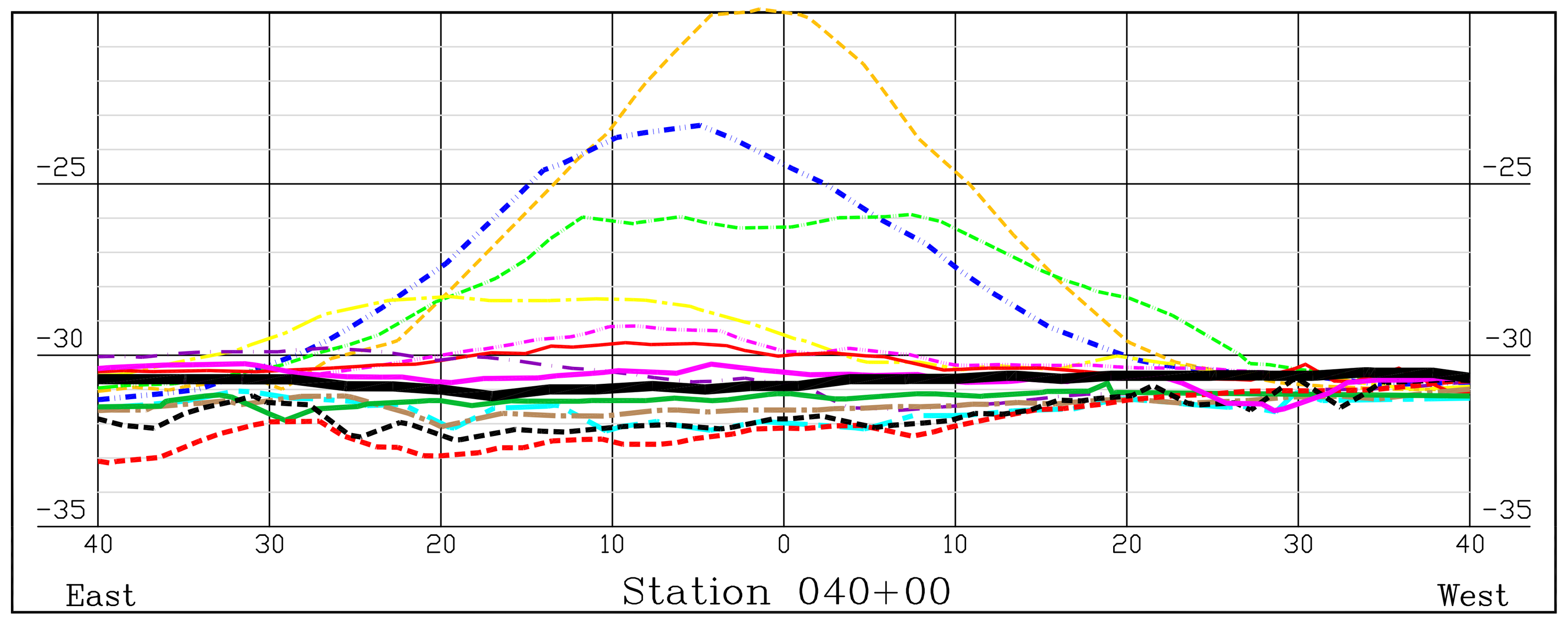
Prepared for: B.P. EXPLORATION (ALASKA) INC.

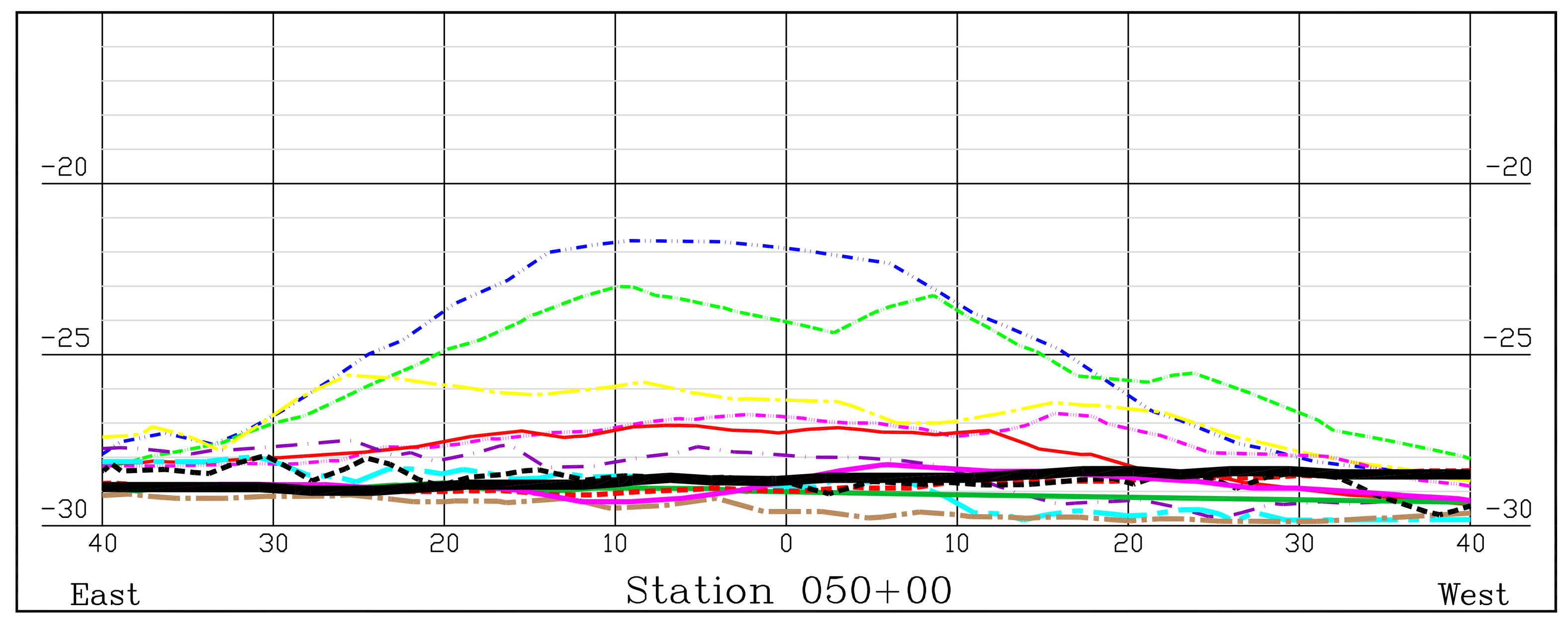
Prepared by: COASTAL FRONTIERS CORPORATION	Drawing No.: CFC−815−13−002

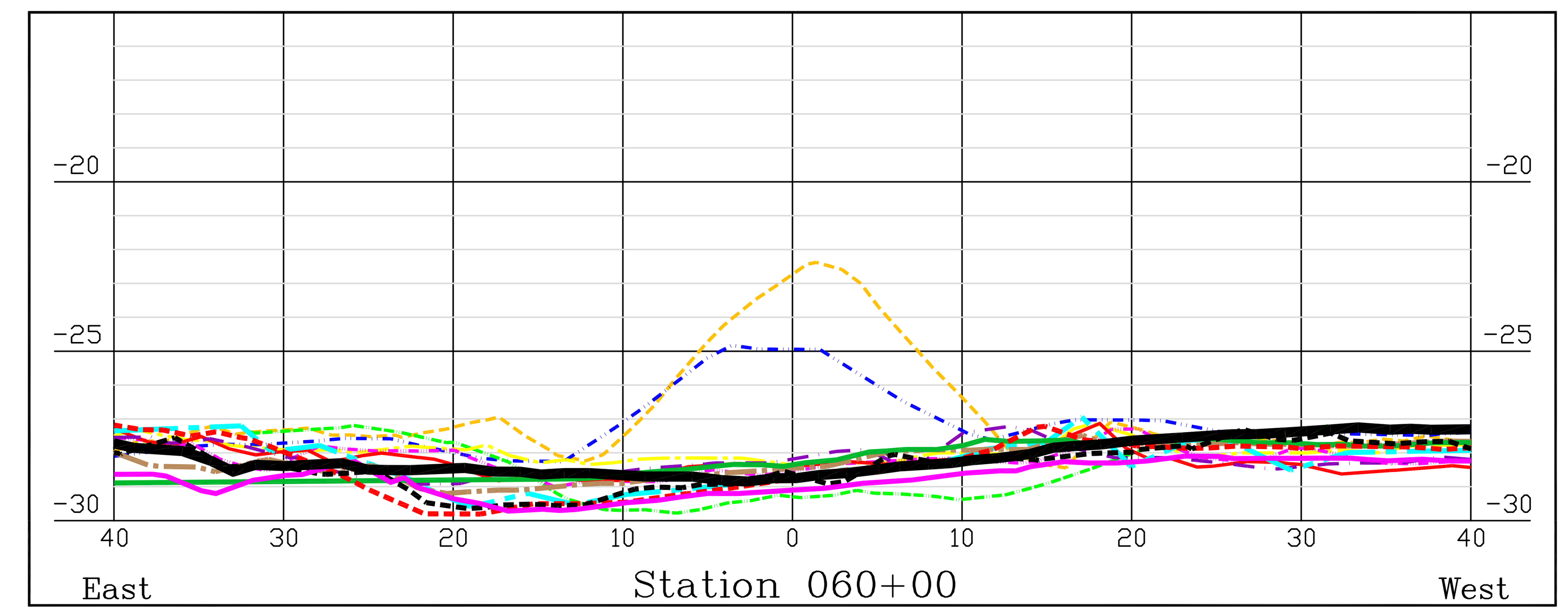


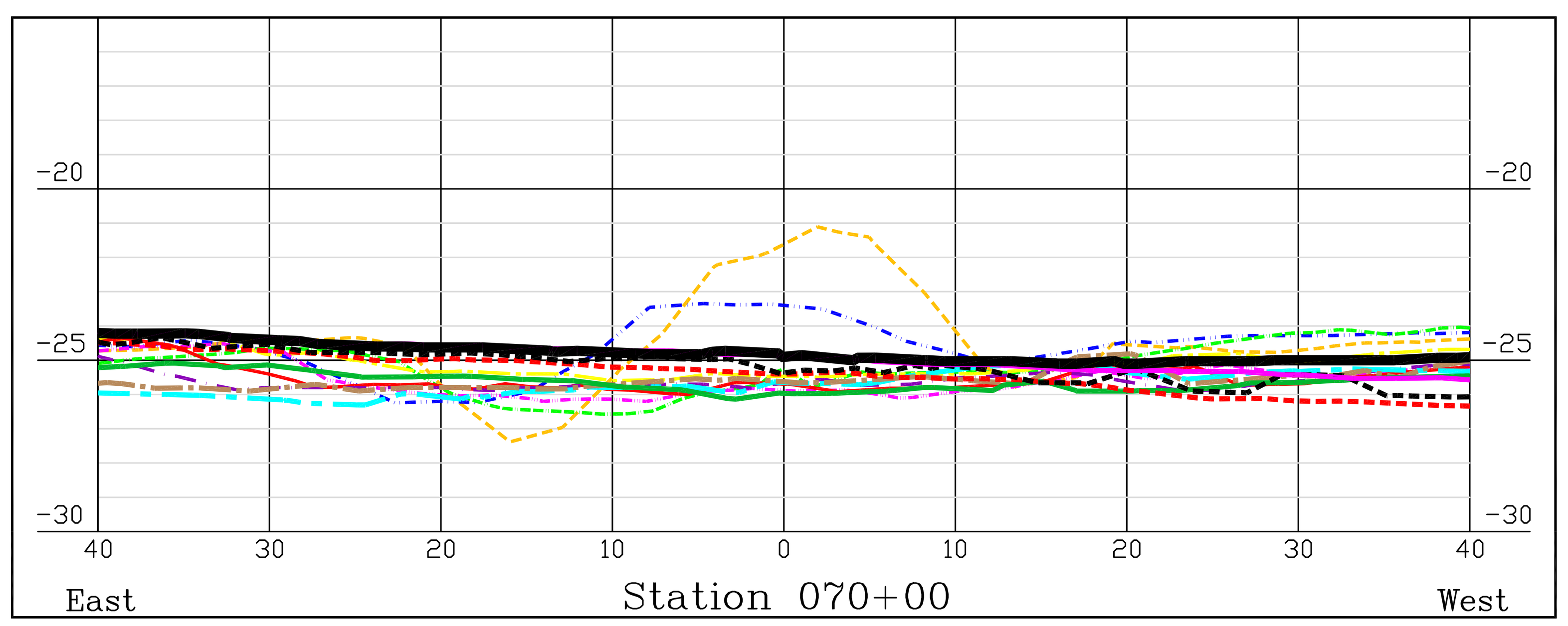


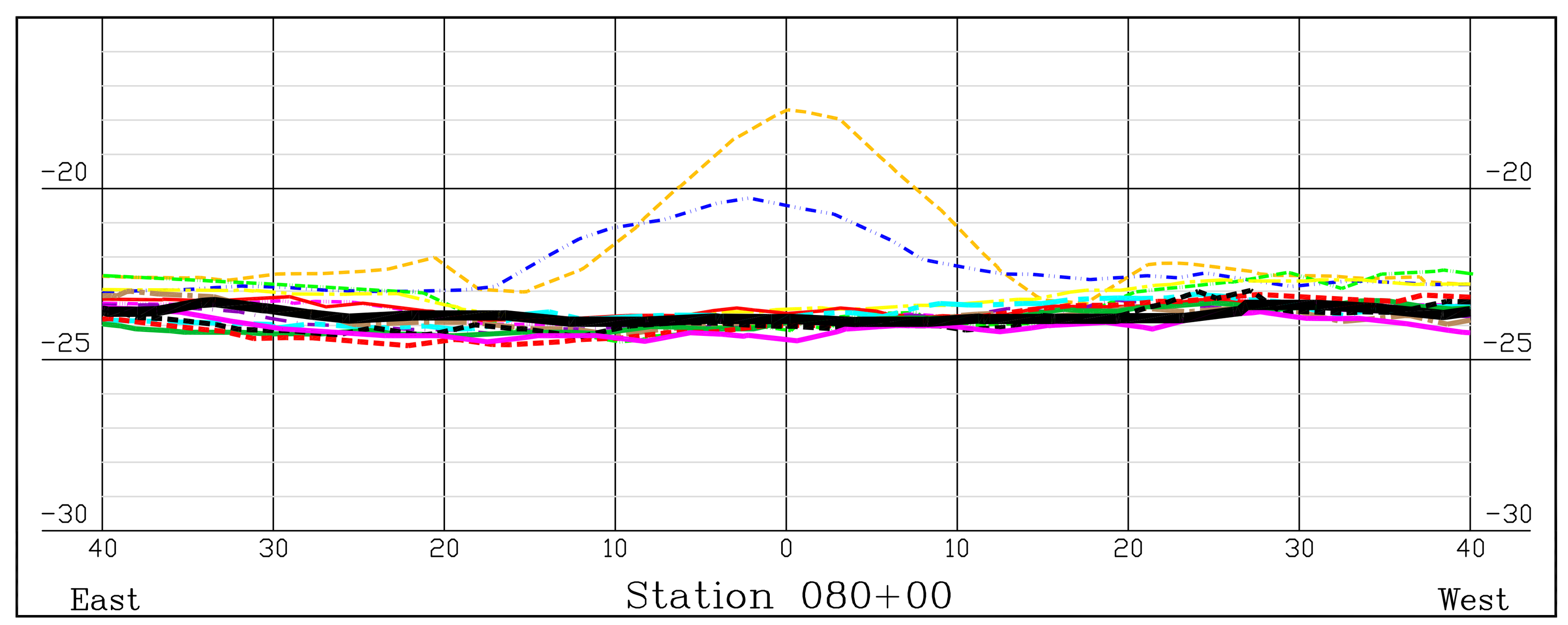


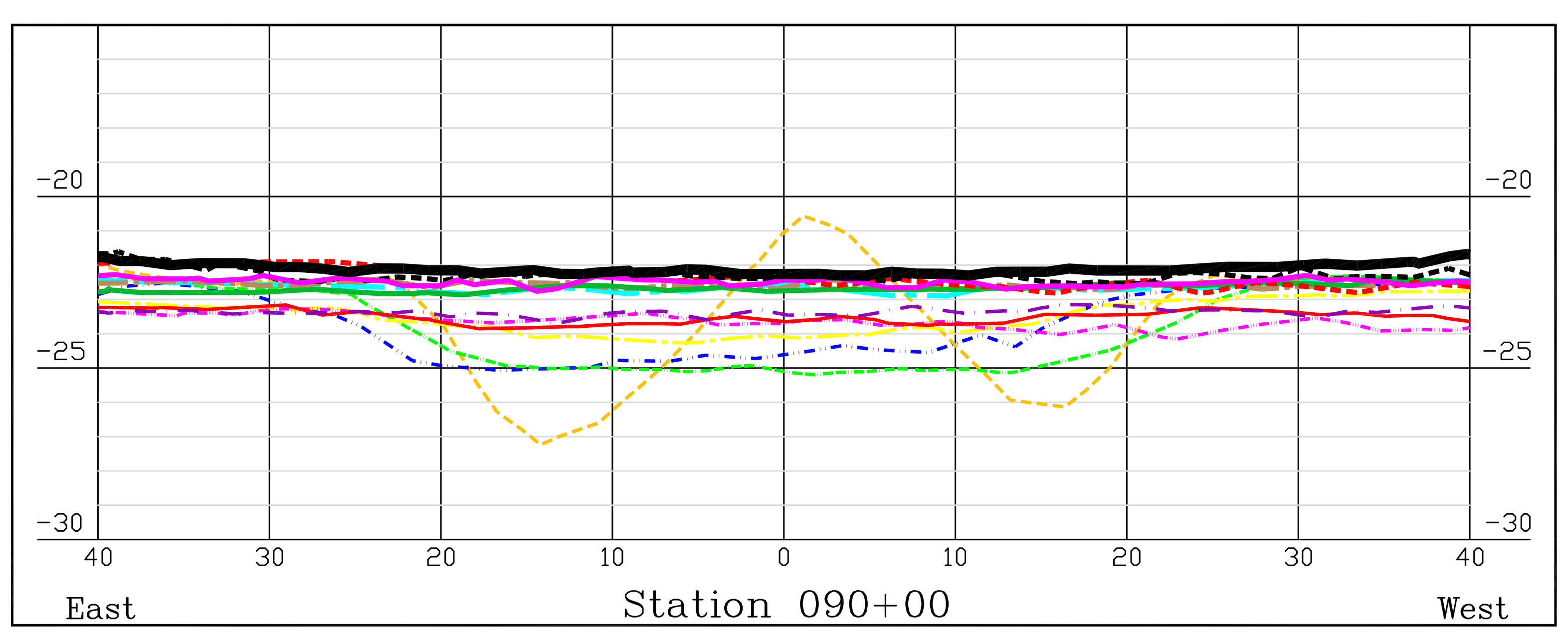


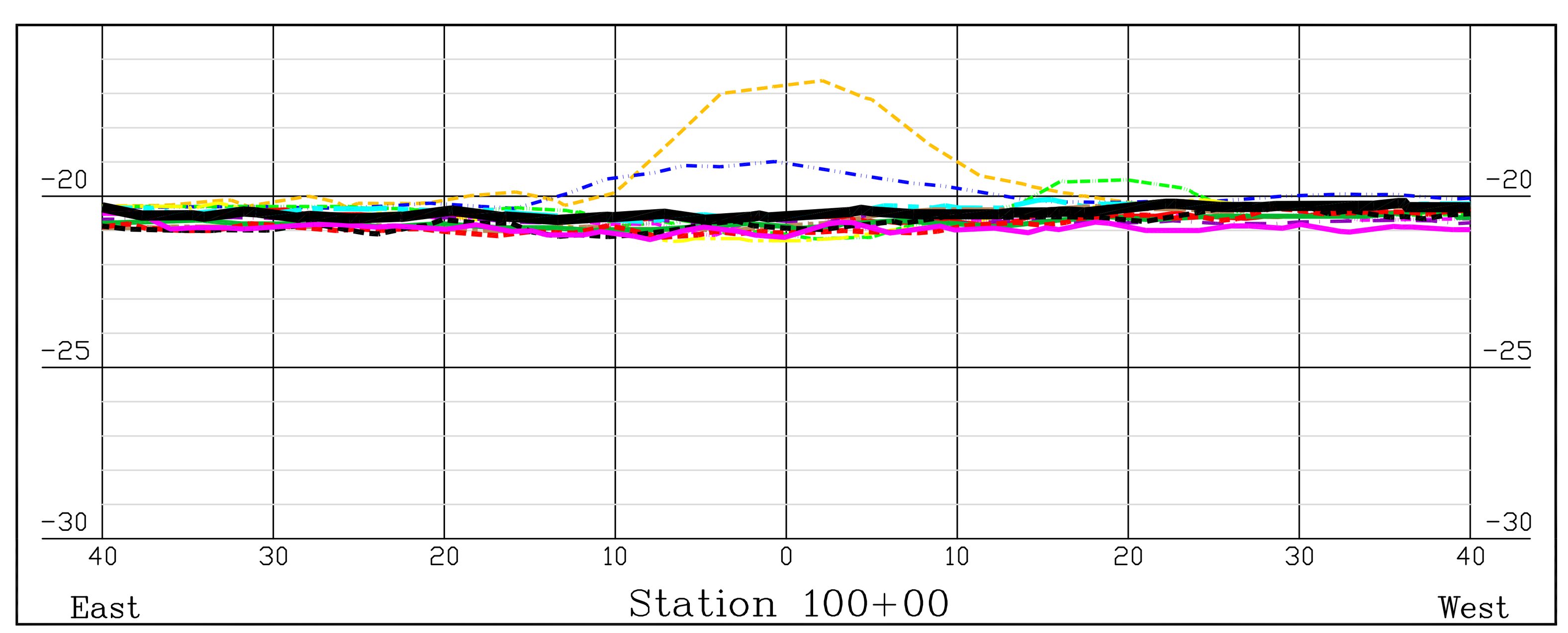












NOTES

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2. Distances indicated on cross-section plots are in feet, and are referenced to the centerline of the pipeline alignment.
3. Vertical datum is ARCO Mean Lower Low Water (MLLW, feet), which is identical to National Ocean Service (NOS) MLLW.
4. Vertical scale is exaggerated by a factor of 2.
5. Survey dates are as follows:
   - 2000: 8 August
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   - 2003: 31 July – 2 August
   - 2004: 7 – 8 August
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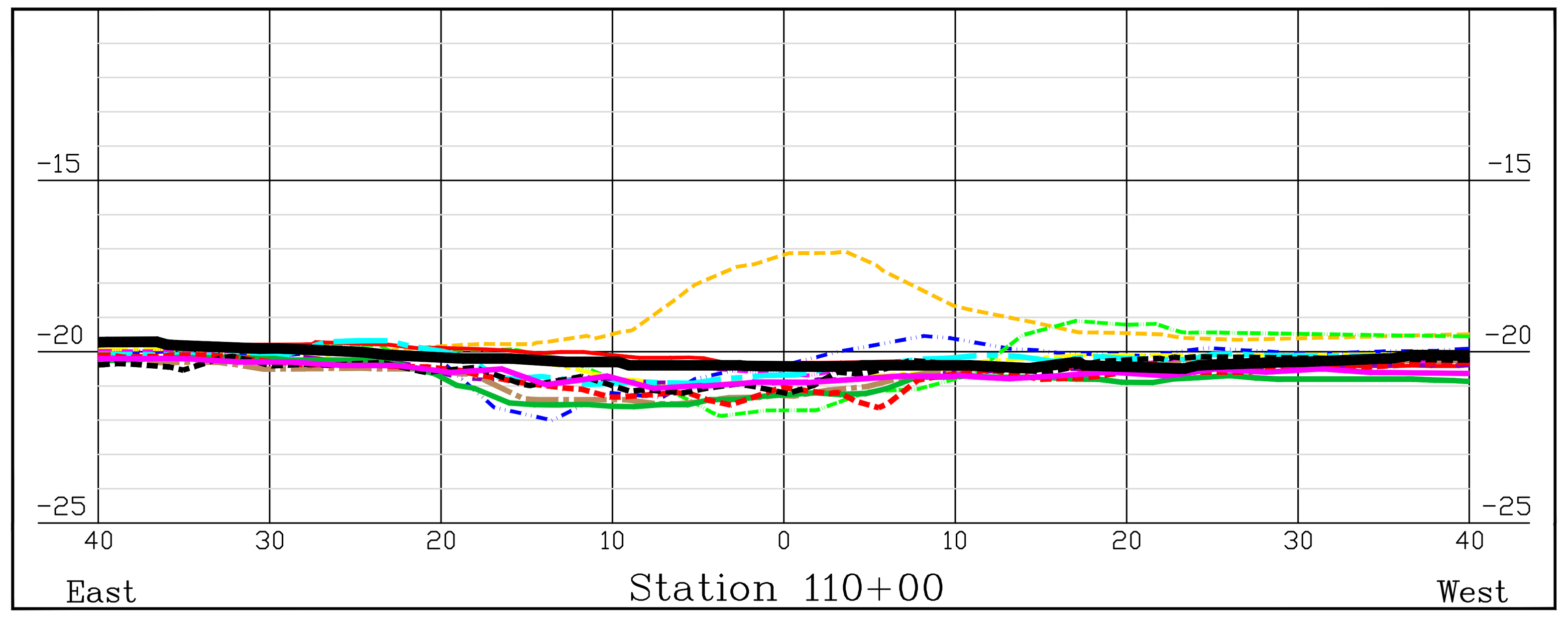
   - 2007: 23 July – 7 August
   - 2008: 18 July – 7 August
   - 2009: 24 July – 2 August
   - 2010: 20 – 30 July
   - 2011: 22 – 30 July
   - 2012: 22 – 25 July
   - 2013: 19 – 21 July
6. Multi-beam sonar data were used to develop cross sections for Stations 010+00 through 200+00 in 2000, 2001, 2003, 2004, 2005, 2007, and 2008, and Stations 010+00 through 210+00 in 2002, 2006, 2009, 2010, 2011, 2012, and 2013. Single-beam sonar data were used landward of these stations.

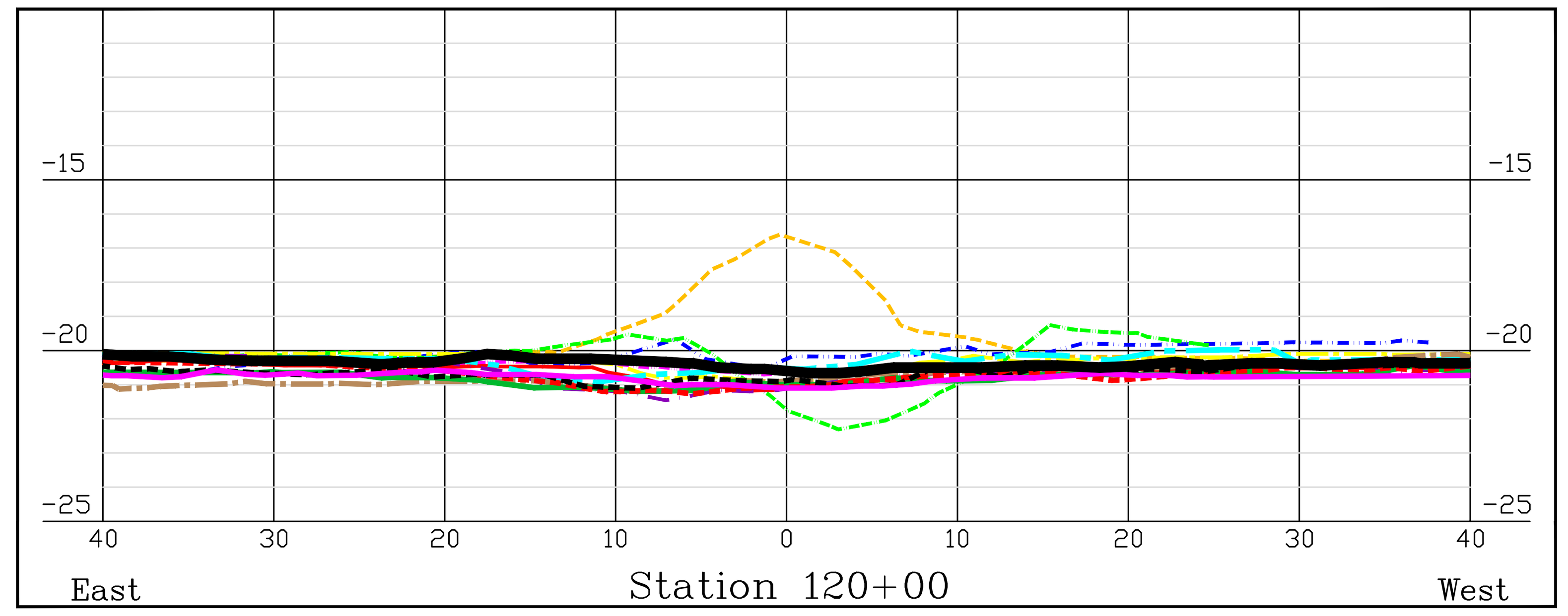
LEGEND

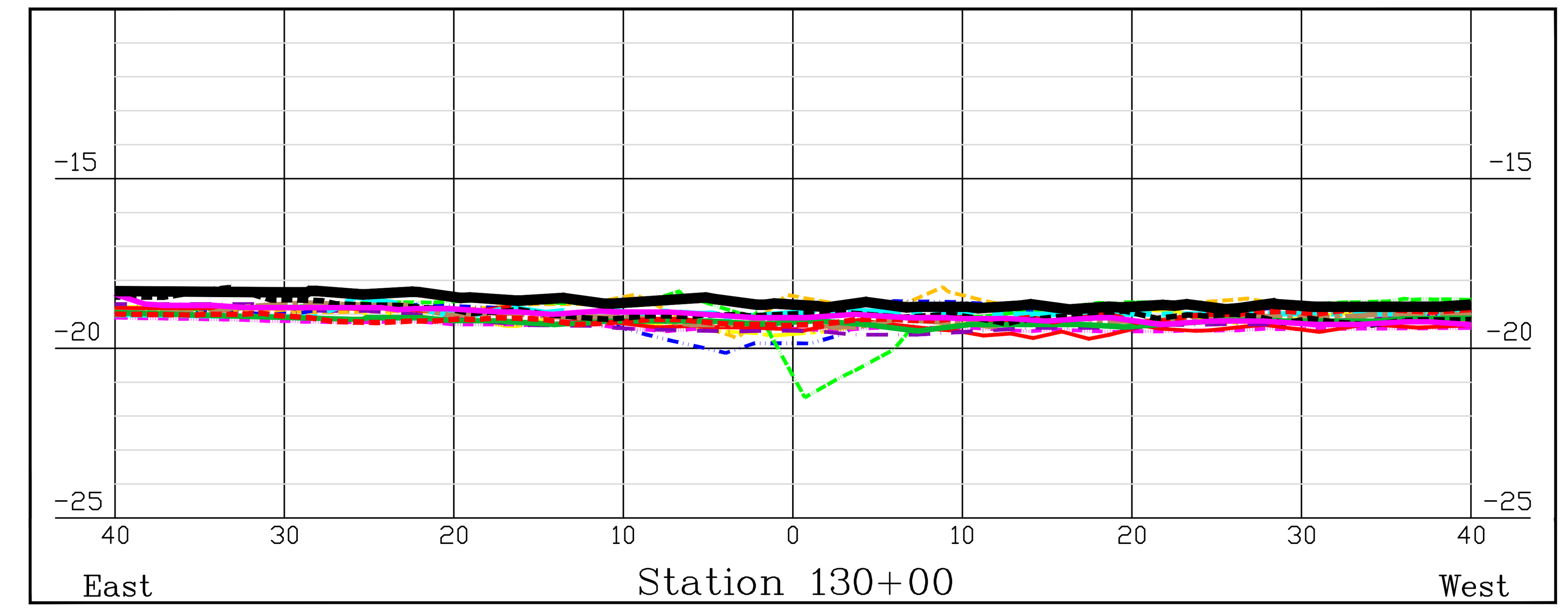
2013 Sea Bottom
2012 Sea Bottom
2011 Sea Bottom
2010 Sea Bottom
2009 Sea Bottom
2008 Sea Bottom
2007 Sea Bottom
2006 Sea Bottom
2005 Sea Bottom
2004 Sea Bottom
2003 Sea Bottom
2002 Sea Bottom
2001 Sea Bottom
2000 Sea Bottom

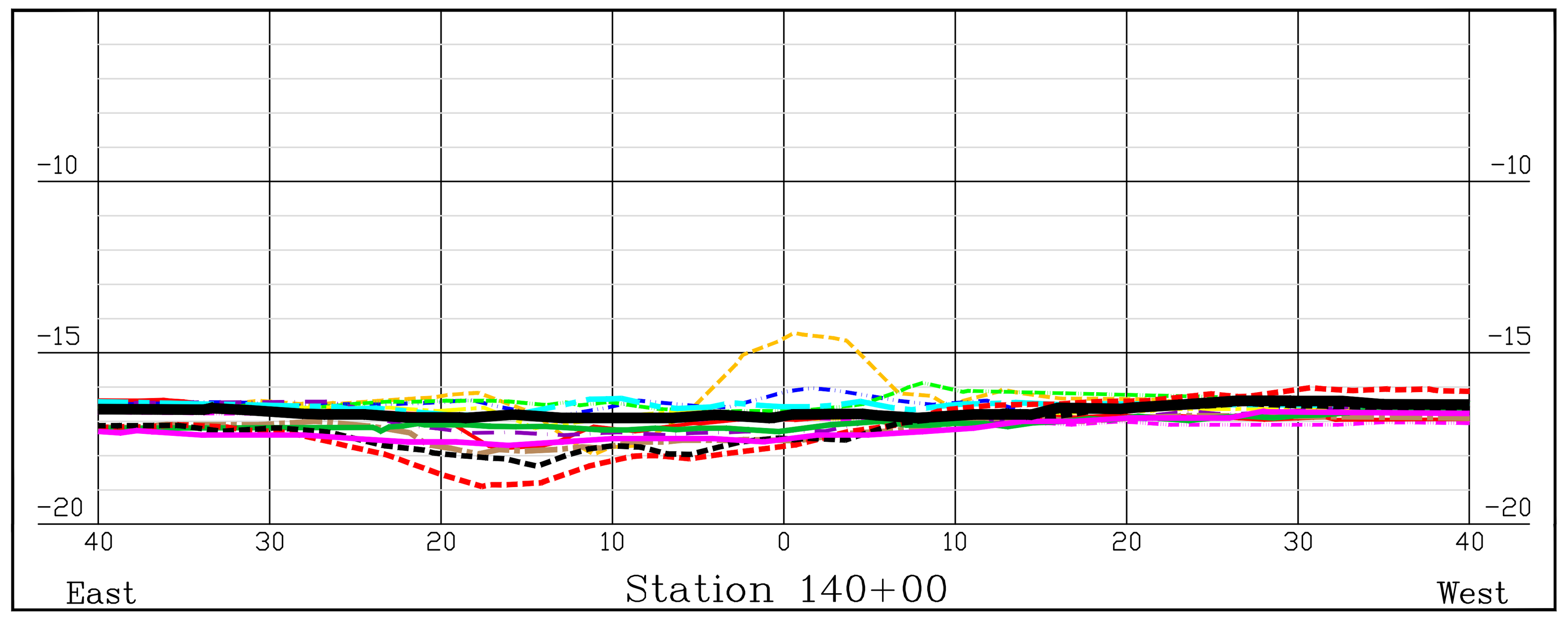
NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
CROSS SECTIONS THROUGH PIPELINE ALIGNMENT

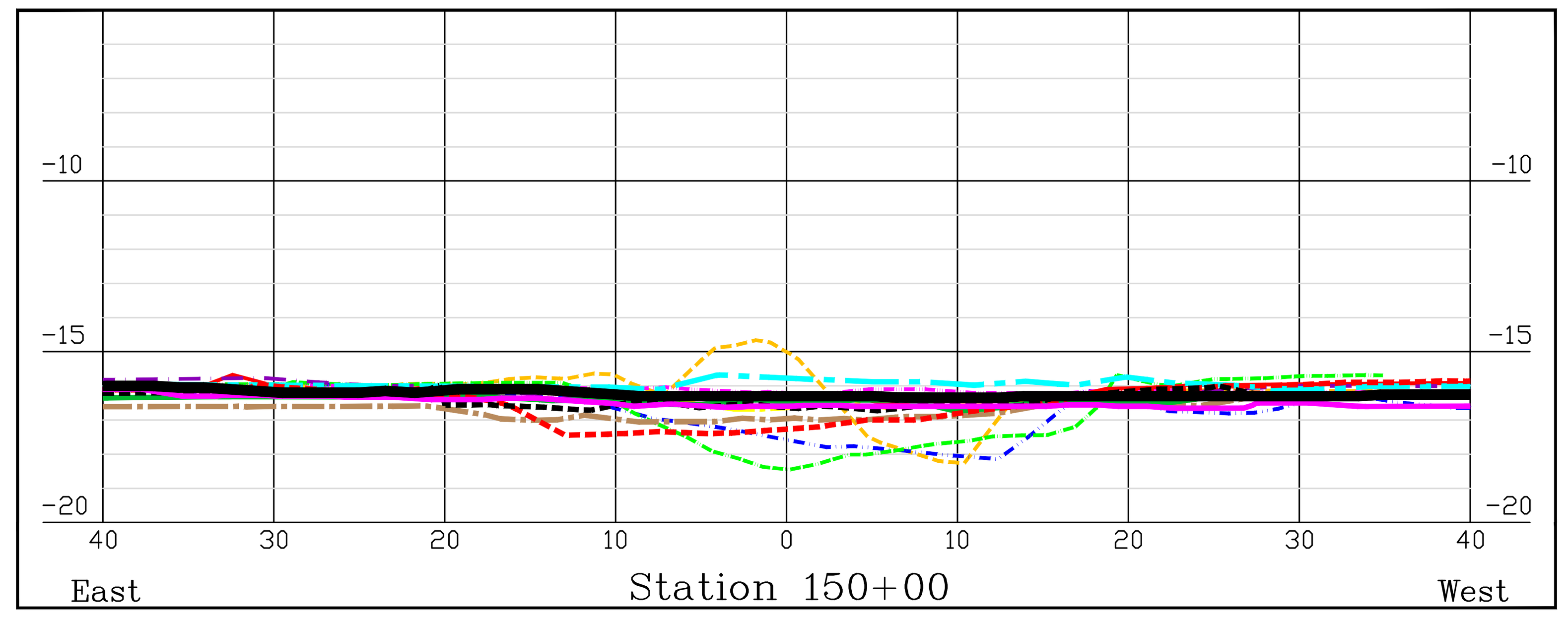
Scale: as noted	Checked by: GEH	Drawn by: LAD
Date: 15 January 2014	Sheet: 1 OF 3	Revised:
Prepared for: BP EXPLORATION (ALASKA) INC.		
Prepared by: COASTAL FRONTIERS CORPORATION		Drawing No.: CFC-815-13-003

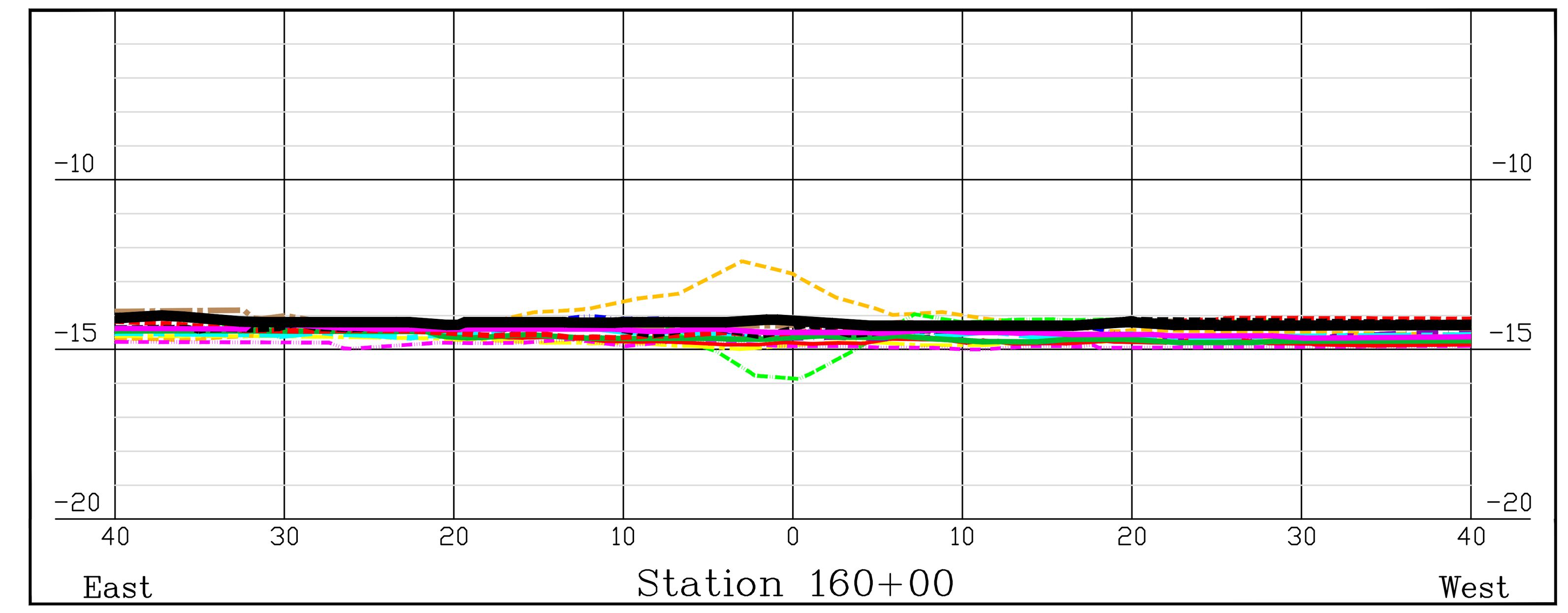


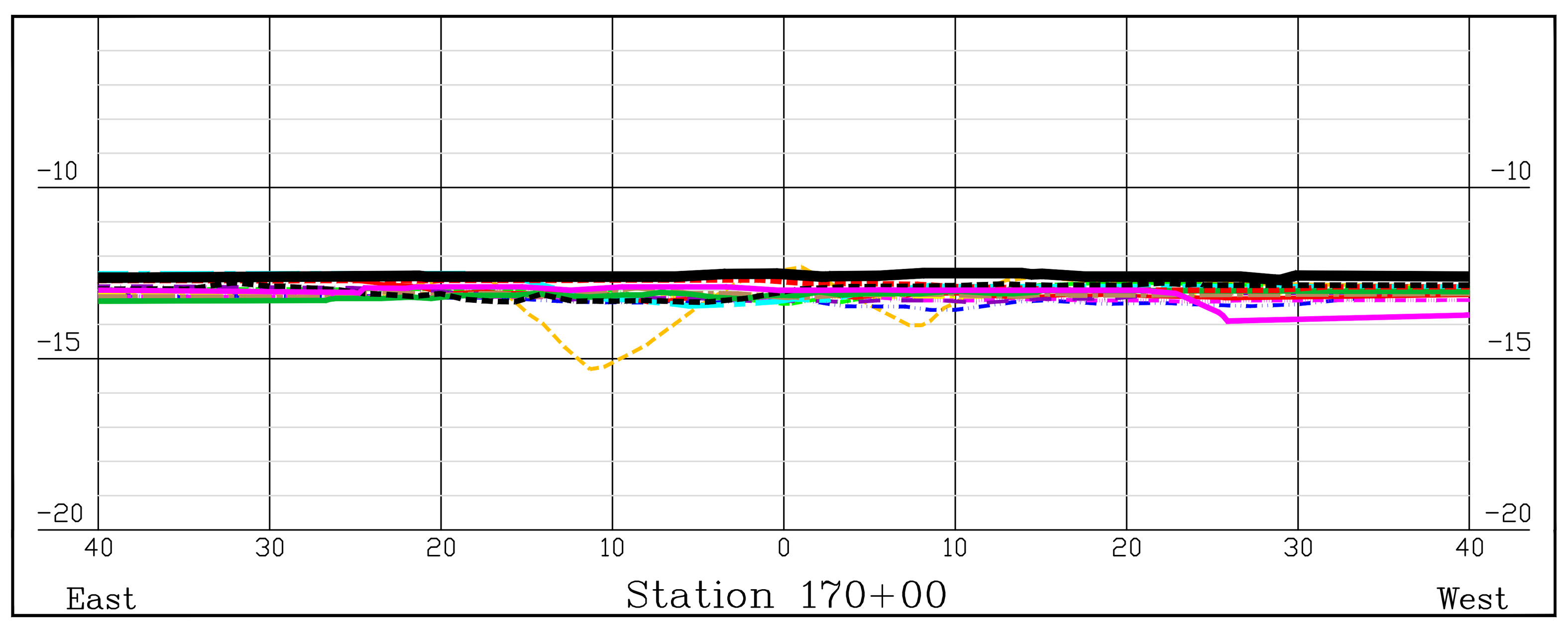


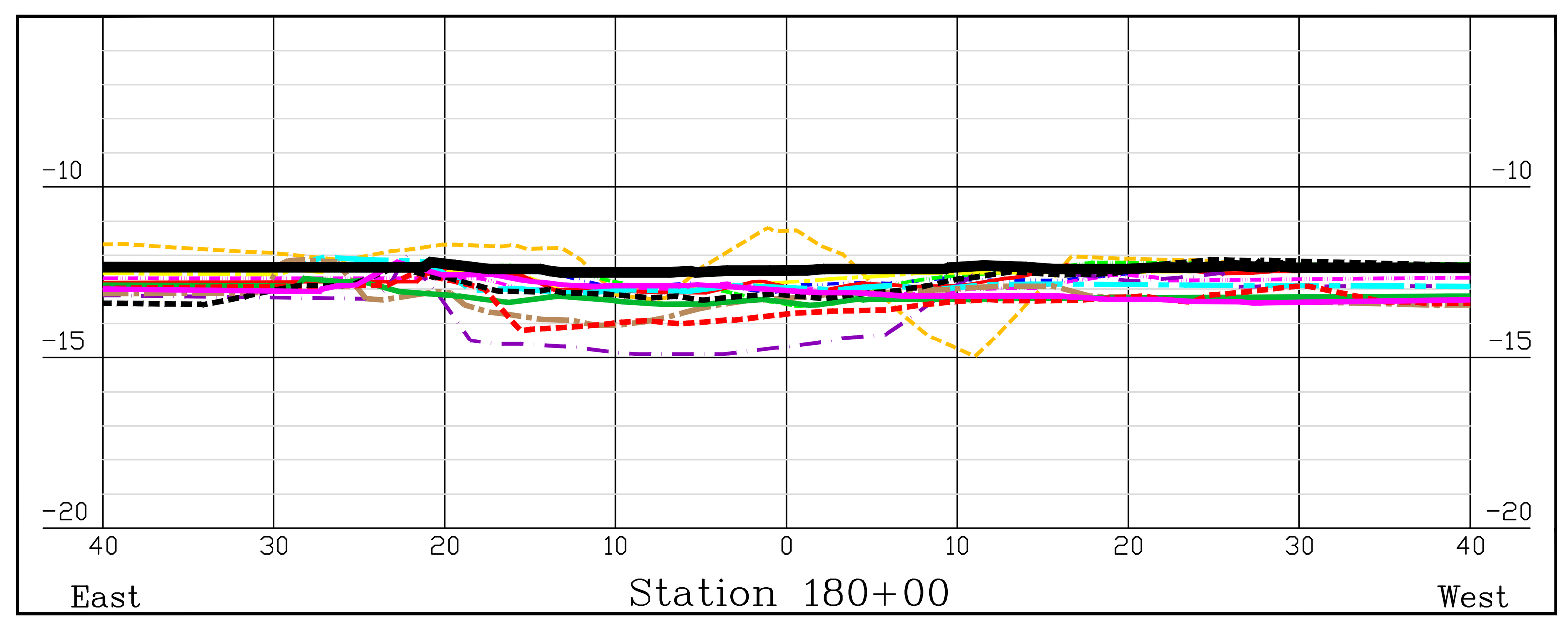


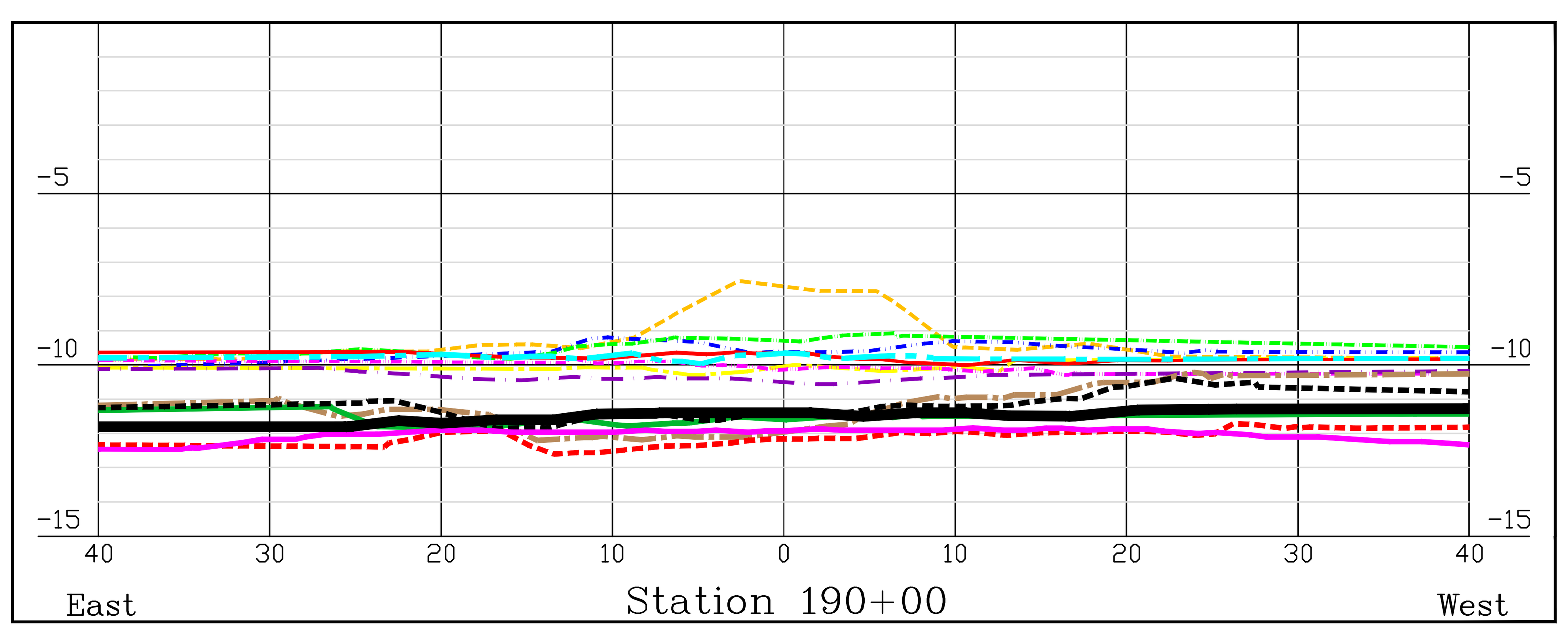


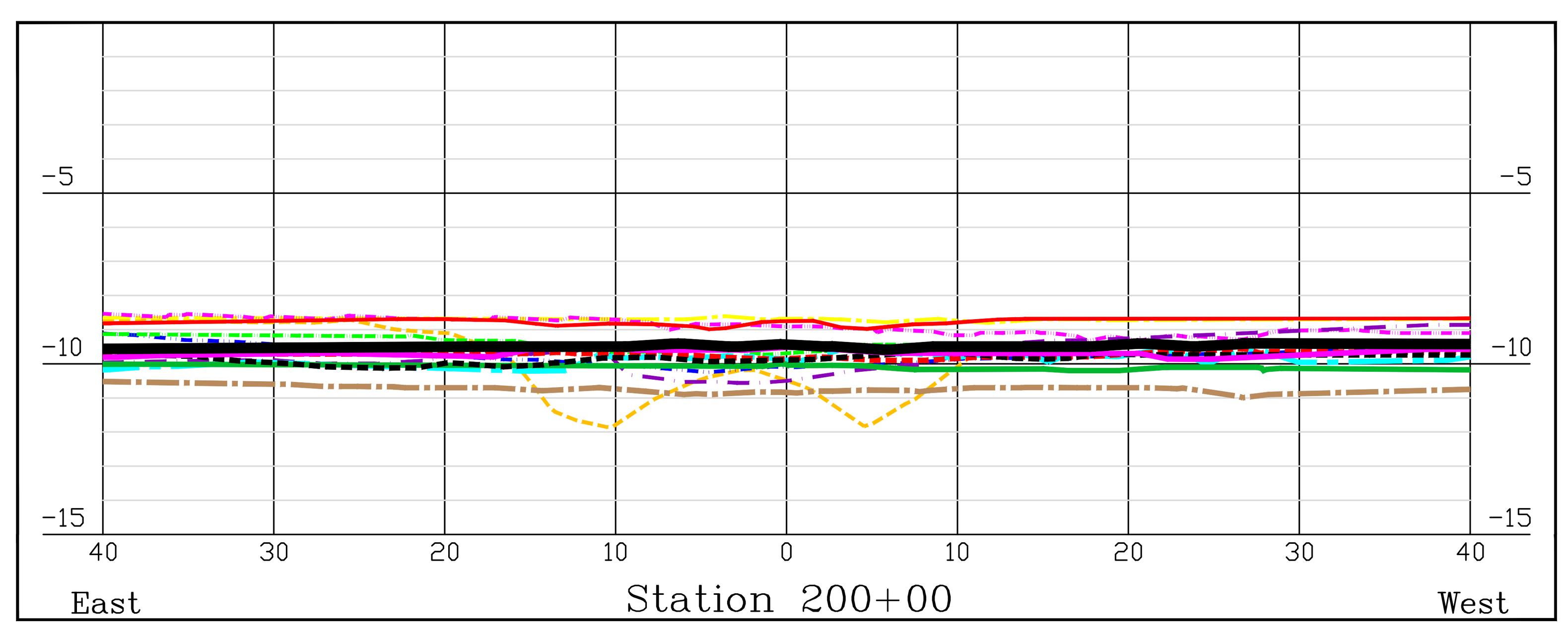












NOTES

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LEGEND

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2012 Sea Bottom
2011 Sea Bottom
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2008 Sea Bottom
2007 Sea Bottom
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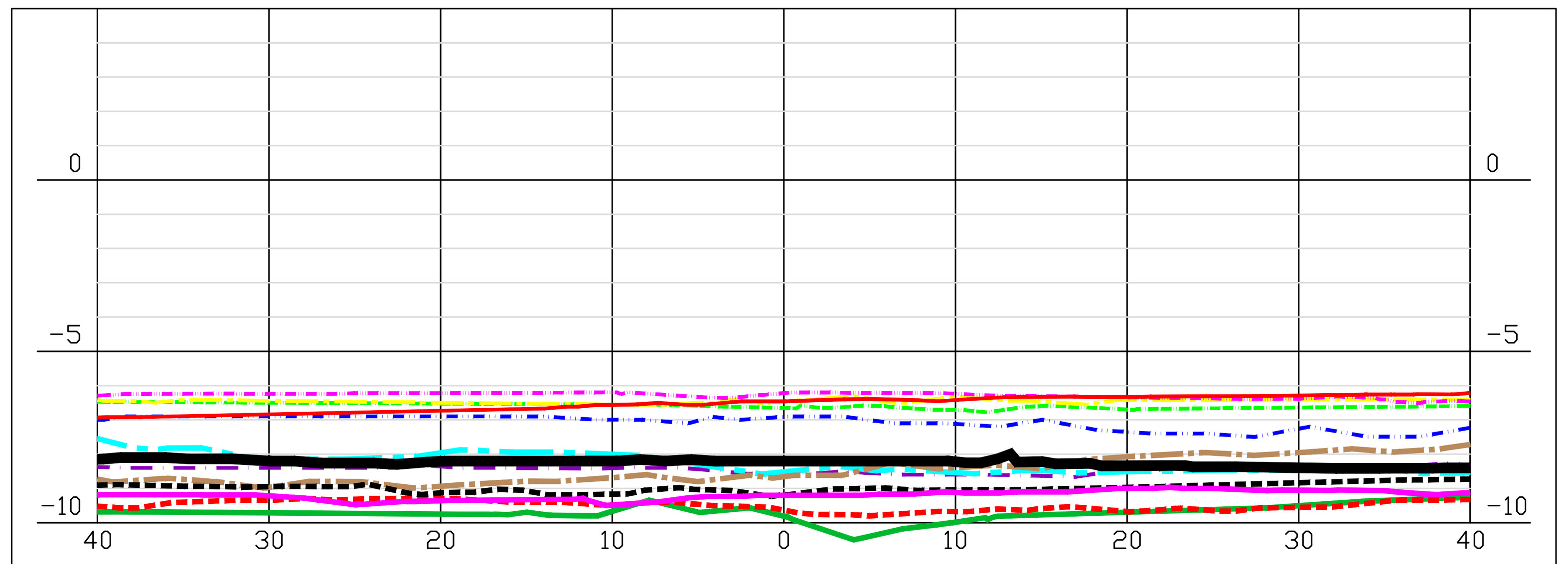
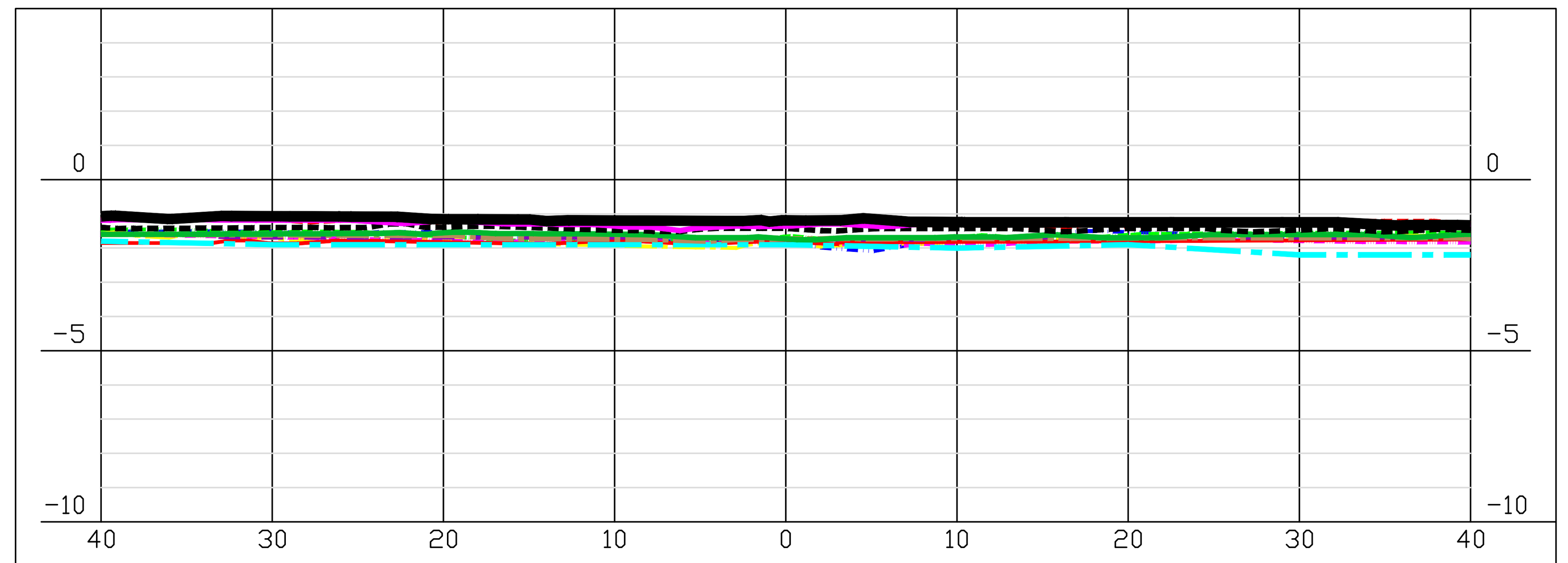
2004 Sea Bottom
2003 Sea Bottom
2002 Sea Bottom
2001 Sea Bottom
2000 Sea Bottom

NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
CROSS SECTIONS THROUGH PIPELINE ALIGNMENT

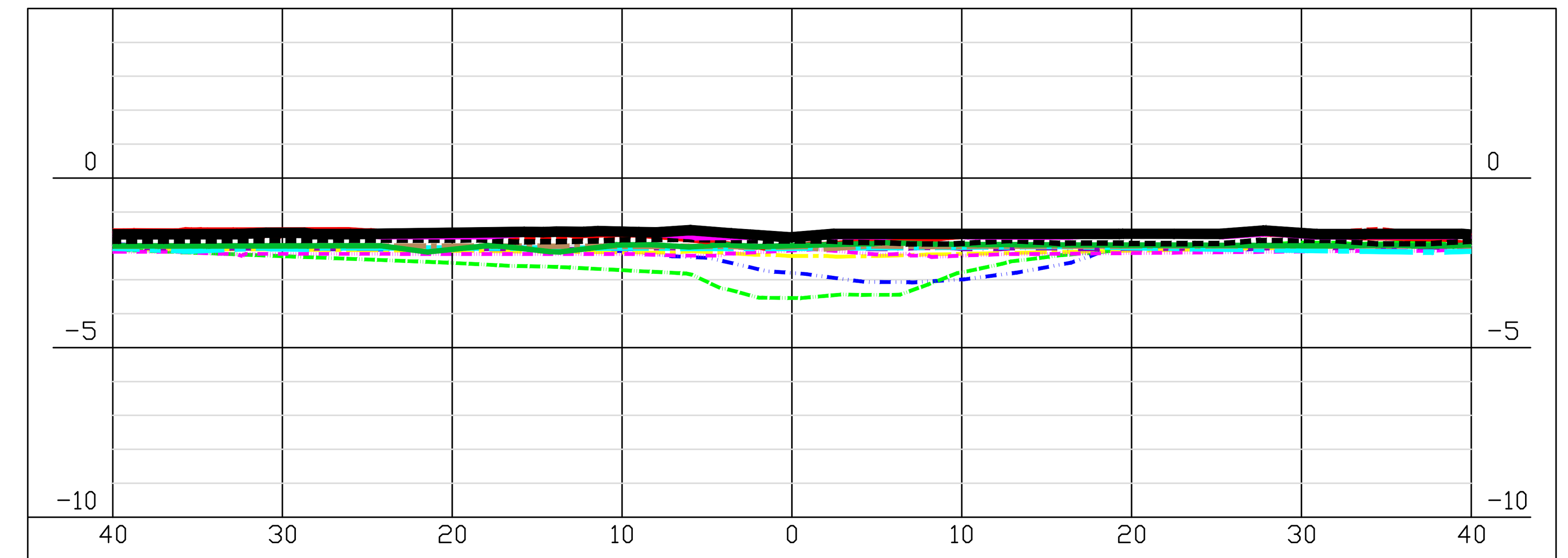
Scale: as noted	Checked by: GEH	Drawn by: LAD
Date: 15 January 2014	Sheet: 2 OF 3	Revised:
Prepared for: BP EXPLORATION (ALASKA) INC.		
Prepared by: COASTAL FRONTIERS CORPORATION		Drawing No.: CFC-815-13-003



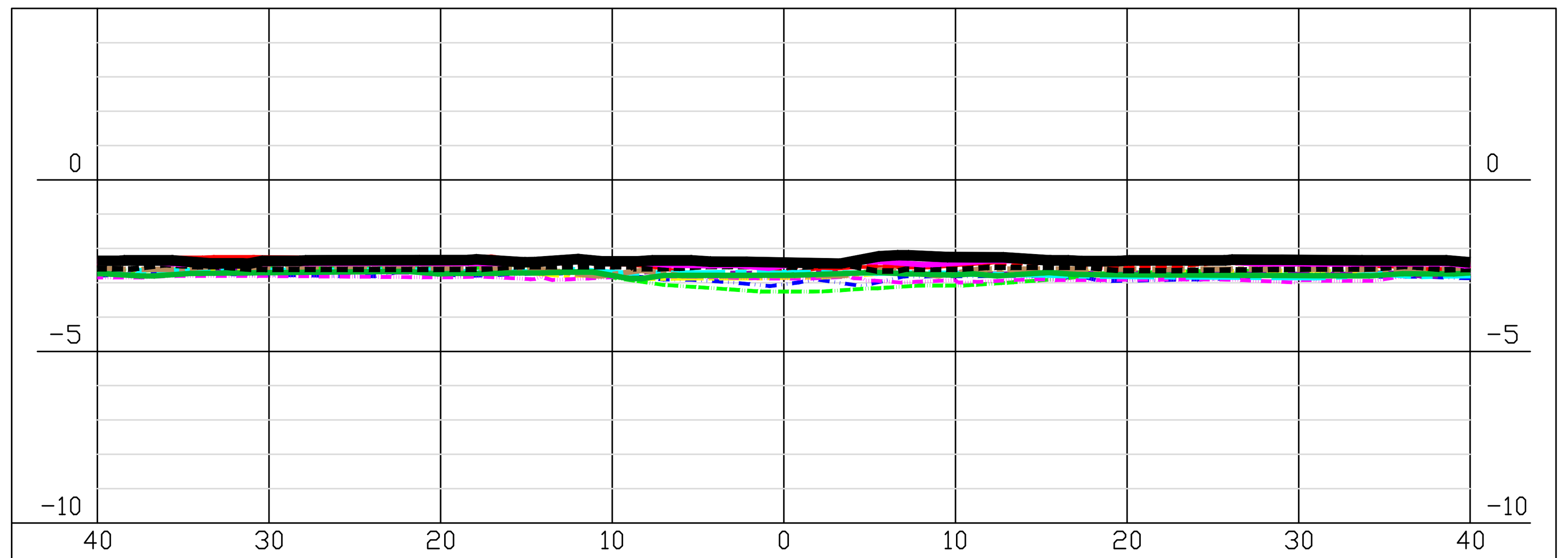
East Station 210+00 West



East Station 225+00 West



East Station 230+00 West



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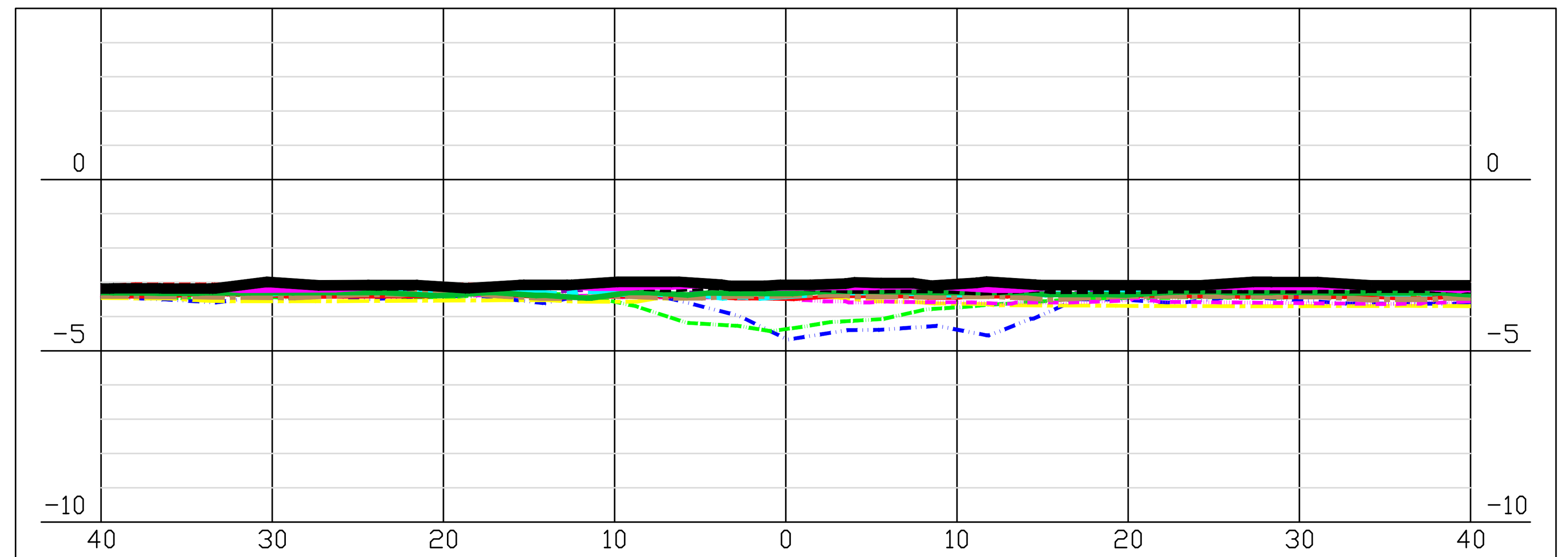
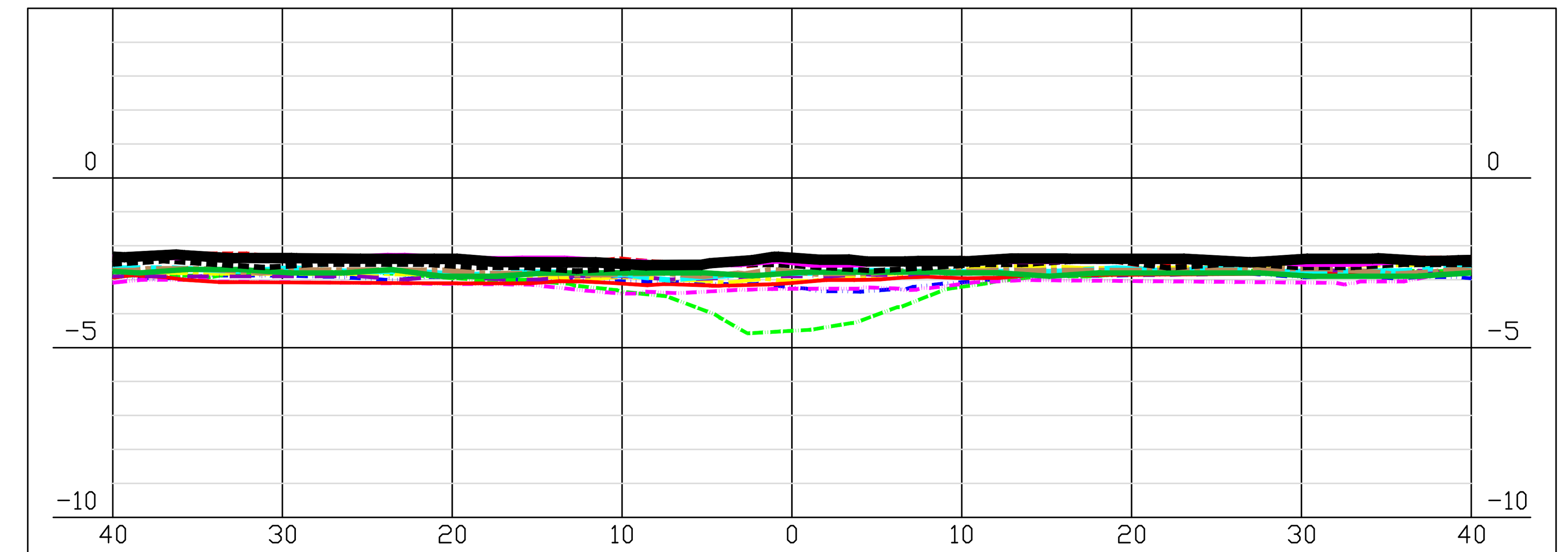


East Station 250+00 West



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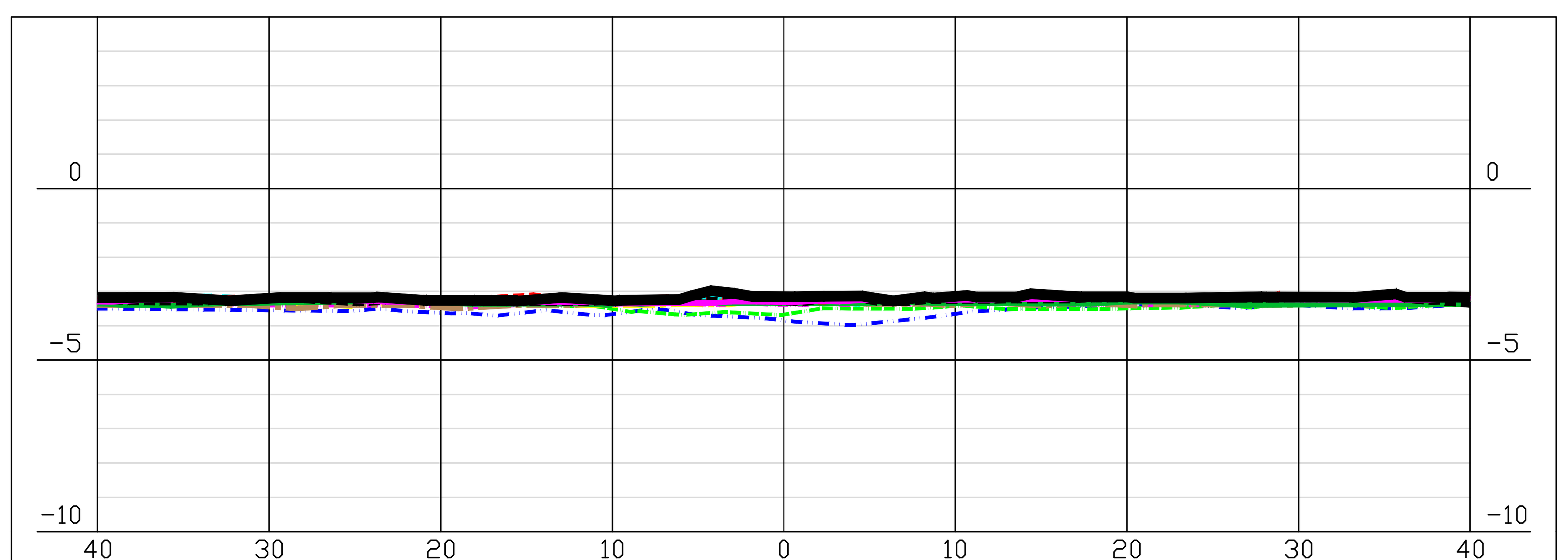
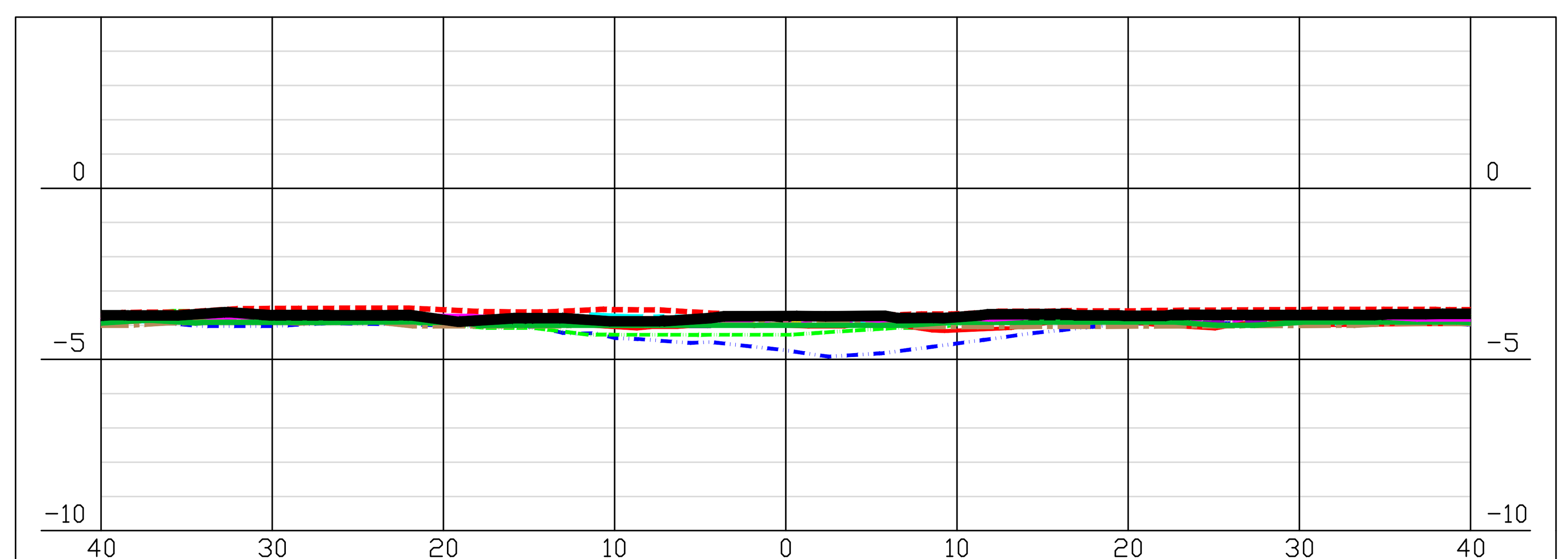
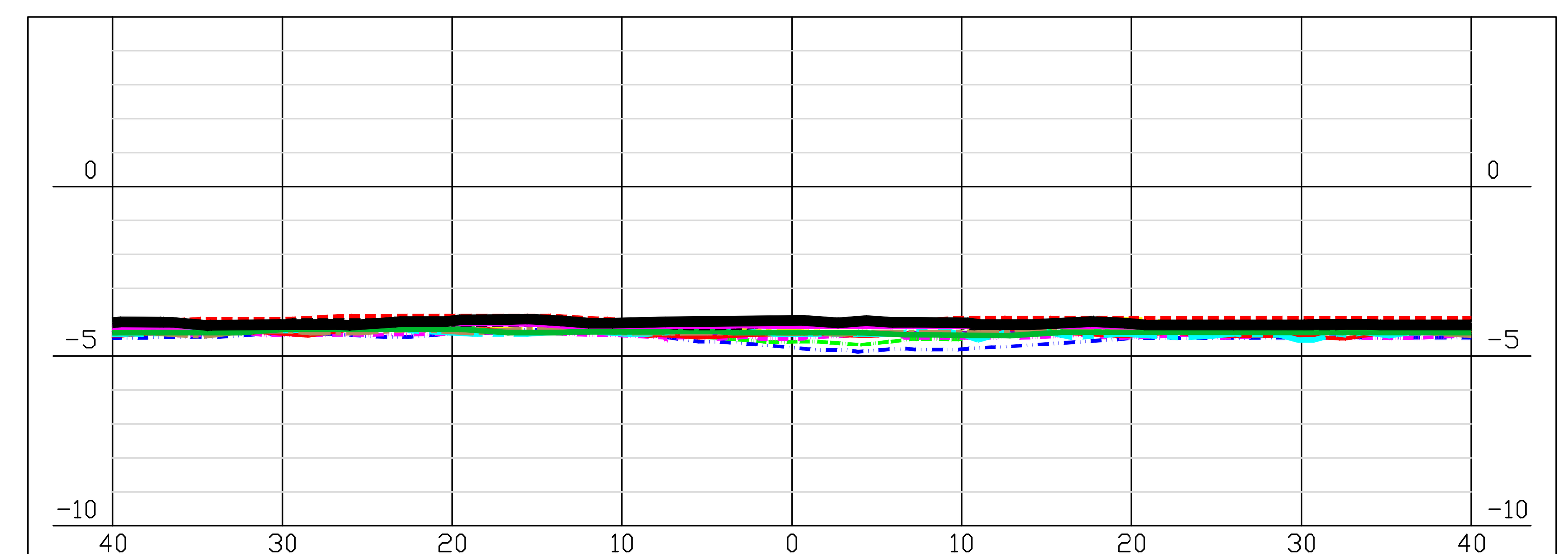


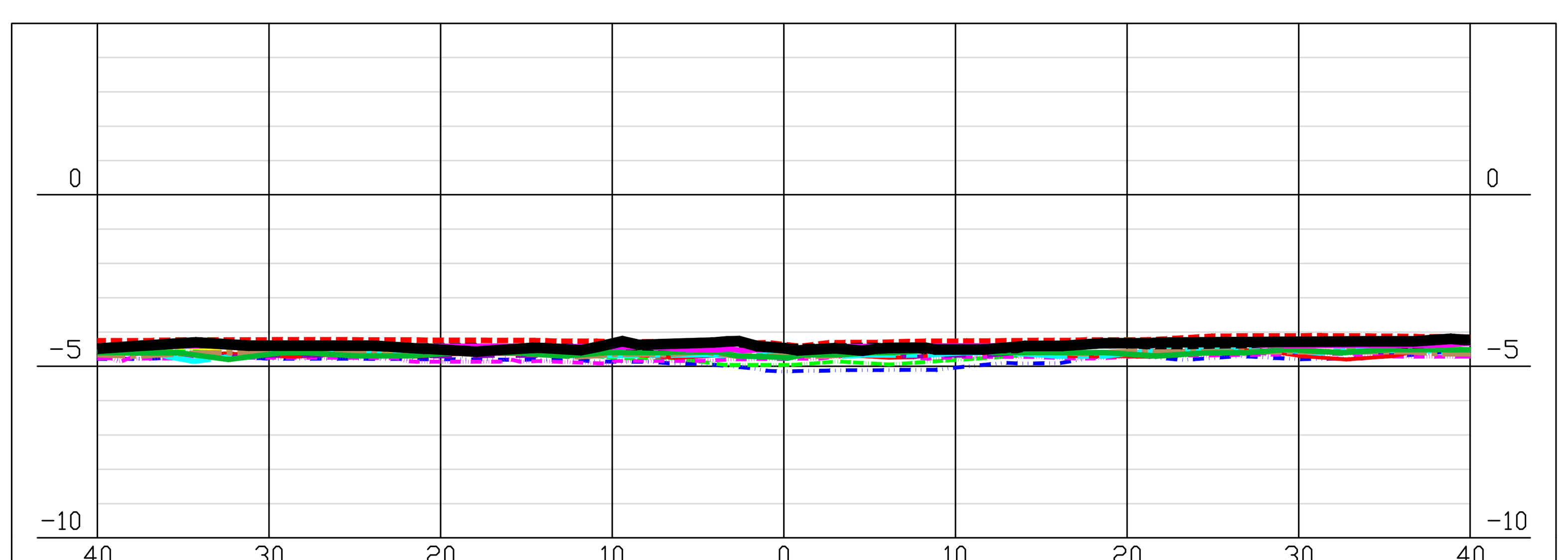
East Station 270+00 West



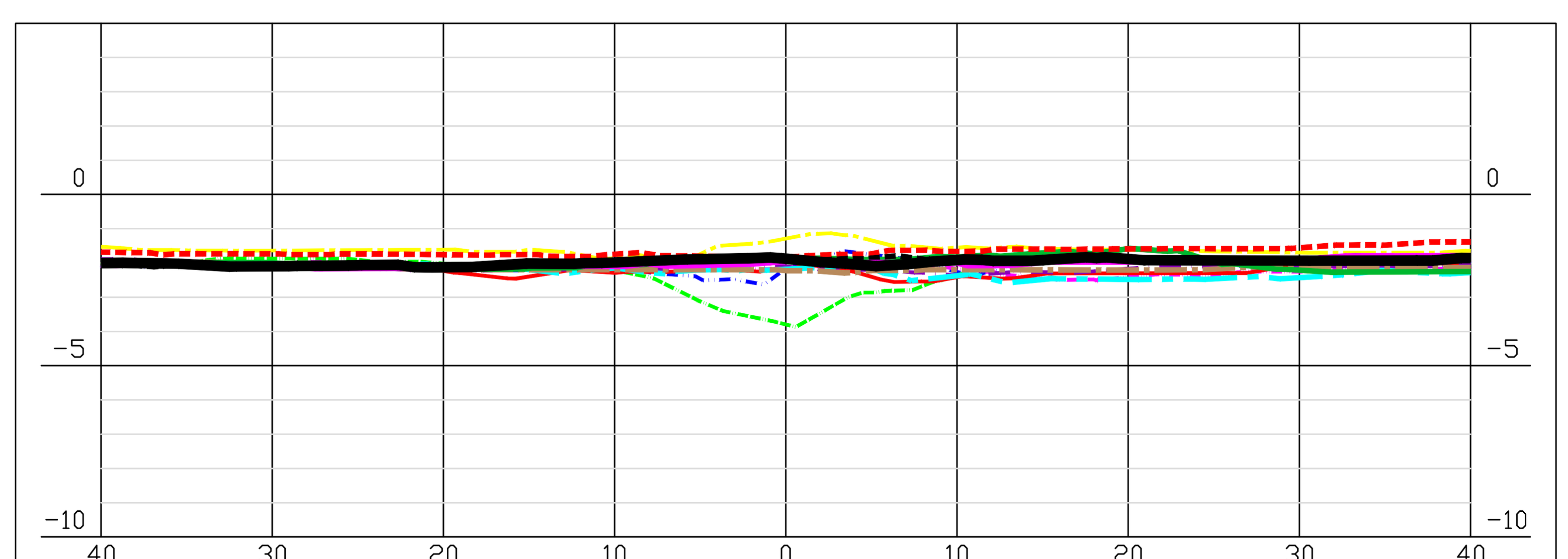
East Station 280+00 West



East Station 290+00 West



East Station 300+00 West



East Station 310+00 West

NOTES

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3. Vertical datum is ARCO Mean Lower Low Water (MLLW, feet), which is identical to National Ocean Service (NOS) MLLW.
4. Vertical scale is exaggerated by a factor of 2.
5. Survey dates are as follows:

2001:	27 July – 6 August	2007:	23 July – 7 August
2002:	3 – 10 August	2008:	18 July – 7 August
2003:	31 July – 2 August	2009:	24 July – 2 August
2004:	7 – 8 August	2010:	20 – 30 July
2005:	31 July – 3 August	2011:	22 – 30 July
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7. Cross sections derived from single-beam sonar data are located within a 100-ft wide corridor centered on the nominal station designation.
8. Cross-section data are not available from the 2000 survey for the stations shown on this sheet.

LEGEND

- 2013 Sea Bottom
- 2012 Sea Bottom
- 2011 Sea Bottom
- 2010 Sea Bottom
- 2009 Sea Bottom
- 2008 Sea Bottom
- 2007 Sea Bottom
- 2006 Sea Bottom
- 2005 Sea Bottom
- 2004 Sea Bottom
- 2003 Sea Bottom
- 2002 Sea Bottom
- 2001 Sea Bottom

NORTHSTAR DEVELOPMENT
2013 PIPELINE ROUTE MONITORING PROGRAM
CROSS SECTIONS THROUGH PIPELINE ALIGNMENT

Scale: as noted	Checked by: GEH	Drawn by: LAD
Date: 15 January 2014	Sheet: 3 OF 3	Revised:

Prepared for: BP EXPLORATION (ALASKA) INC.

Prepared by: COASTAL FRONTIERS CORPORATION | Drawing No.: CFC-815-13-003

Appendix I

SPCO Surveillance Summary

Appendix I - 2013 SPCO Surveillance Summary

SPCO Approval Date	Pipeline	Report #	Description	SPCO Observations	Follow-up
2/25/2013	Badami Oil	13-SPCO-S-121	Section 14 - Plans and Permitting	satisfactory	none required
2/25/2013	Badami Oil	13-SPCO-S-122	Section 14 - Plans and Permitting	satisfactory	none required
5/15/2013	Badami Oil	13-SPCO-S-186	Section 8 - Covenants of Lessee	satisfactory	none required
5/15/2013	Badami Oil	13-SPCO-S-187	Section 15 - Conduct of Operations	satisfactory	none required
5/15/2013	Badami Oil	13-SPCO-S-188	Section 18 - Orders by the Commissioner	satisfactory	none required
5/15/2013	Badami Oil	13-SPCO-S-189	Stipulation 1.6 - Surveillance and Monitoring	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-139	Section 6 - Reservation of Certain Rights to the State	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-140	Section 8 - Covenants of Lessee	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-141	Section 15 - Conduct of Operations	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-142	Section 18 - Orders by the Commissioner	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-143	Stipulation 1.4 - Quality Assurance and Control	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-144	Stipulation 1.6 - Surveillance and Monitoring	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-145	Stipulation 1.11 - Regulation of Access	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-146	Stipulation 2.1 - Environmental Briefings	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-147	Stipulation 2.3 - Erosion and Sedimentation Control	satisfactory	none required
4/17/2013	Badami Utility	13-SPCO-S-148	Stipulation 2.8 - Right-of-Way Traffic	satisfactory	none required
5/15/2013	Badami Utility	13-SPCO-S-190	Section 8 - Covenants of Lessee	satisfactory	none required
5/15/2013	Badami Utility	13-SPCO-S-191	Section 15 - Conduct of Operations	satisfactory	none required
5/15/2013	Badami Utility	13-SPCO-S-192	Section 18 - Orders by the Commissioner	satisfactory	none required
5/15/2013	Badami Utility	13-SPCO-S-193	Stipulation 1.6 - Surveillance and Monitoring	satisfactory	none required
1/7/2013	Endicott	13-SPCO-S-079	Section 4 - Covenants of Lessee	satisfactory	one item corrected on the spot
1/7/2013	Endicott	13-SPCO-S-080	Section 7 - Reservation of Certain Rights to the State	satisfactory	none required
1/7/2013	Endicott	13-SPCO-S-081	Section 10 - Duty of Lessee to Prevent or Abate	satisfactory	one item corrected on the spot and [illegible]
1/7/2013	Endicott	13-SPCO-S-082	Stipulation 1.3.3 - Responsibilities	satisfactory	none required
1/7/2013	Endicott	13-SPCO-S-083	Stipulation 1.3.6 - Responsibilities	satisfactory	none required
1/7/2013	Endicott	13-SPCO-S-084	Stipulation 1.9.1 - Conduct of Operations	satisfactory	none required
1/7/2013	Endicott	13-SPCO-S-085	Stipulation 1.10.1 - Surveillance and Maintenance	satisfactory	one item corrected on the spot
1/7/2013	Endicott	13-SPCO-S-086	Stipulation 2.4.6.1 - Big Game Movements	satisfactory	none required
5/15/2013	Endicott	13-SPCO-S-194	Section 4 - Covenants of Lessee	satisfactory	none required

Appendix I - 2013 SPCO Surveillance Summary

SPCO Approval Date	Pipeline	Report #	Description	SPCO Observations	Follow-up
5/15/2013	Endicott	13-SPCO-S-195	Section 10 - Duty of Lessee to Prevent or Abate	satisfactory	none required
5/15/2013	Endicott	13-SPCO-S-196	Stipulation 1.3 - Responsibilities	satisfactory	none required
5/15/2013	Endicott	13-SPCO-S-197	Stipulation 1.10 - Surveillance and Maintenance	satisfactory	none required
2/25/18	Endicott Oil	13-SPCO-S-123	Section 6 - Construction Plans and Quality Assurance	satisfactory	none required
1/7/2013	Milne Oil	13-SPCO-S-087	Section 4 - Covenants by Lessee	satisfactory	one item corrected on the spot and
1/7/2013	Milne Oil	13-SPCO-S-088	Section 7 - Reservation of Certain Rights to the State	satisfactory	none required
1/7/2013	Milne Oil	13-SPCO-S-089	Stipulation 1.3.3 - Responsibilities	satisfactory	none required
1/7/2013	Milne Oil	13-SPCO-S-090	Stipulation 1.3.6 - Responsibilities	satisfactory	none required
1/7/2013	Milne Oil	13-SPCO-S-091	Stipulation 1.9.1 - Conduct of Operations	satisfactory	none required
1/7/2013	Milne Oil	13-SPCO-S-092	Stipulation 1.10.1 - Surveillance and Maintenance	satisfactory	one item corrected on the spot and
1/7/2013	Milne Oil	13-SPCO-S-093	Stipulation 1.11.1 - Health and Safety	satisfactory	none required
1/7/2013	Milne Oil	13-SPCO-S-094	Stipulation 2.3.1.1 - Erosion and Sedimentation Control	satisfactory	none required
1/7/2013	Milne Oil	13-SPCO-S-095	Stipulation 2.4.6.1 - Big Game Movements	satisfactory	none required
2/25/18	Milne Oil	13-SPCO-S-125	Section 6 - Construction Plans and Quality Assurance	satisfactory	none required
5/15/2013	Milne Oil	13-SPCO-S-198	Section 4 - Covenants of Lessee	satisfactory	none required
5/15/2013	Milne Oil	13-SPCO-S-199	Section 10 - Duty of Lessee to Prevent or Abate	satisfactory	none required
5/15/2013	Milne Oil	13-SPCO-S-200	Stipulation 1.3 - Responsibilities	satisfactory	none required
5/15/2013	Milne Oil	13-SPCO-S-201	Stipulation 1.10 - Surveillance and Maintenance	satisfactory	none required
1/7/2013	Milne Products	13-SPCO-S-096	Section 6 - Reservation of Certain Rights to the State	satisfactory	none required
1/7/2013	Milne Products	13-SPCO-S-097	Stipulation 2.4.1 - Big Game Movements	satisfactory	none required
2/25/18	Milne Products	13-SPCO-S-124	Section 14 - Plans and Permitting	satisfactory	none required
5/15/2013	Milne Products	13-SPCO-S-202	Section 8 - Covenants of Lessee	satisfactory	none required
5/15/2013	Milne Products	13-SPCO-S-203	Section 20 - Information	satisfactory	none required
5/15/2013	Milne Products	13-SPCO-S-204	Stipulation 1.13 - Reporting	satisfactory	none required
1/7/2013	Northstar Gas	13-SPCO-S-102	Section 6 - Reservation of Certain Rights to the State	satisfactory	none required
1/7/2013	Northstar Gas	13-SPCO-S-103	Section 8 - Covenants of Lessee	satisfactory	none required
1/7/2013	Northstar Gas	13-SPCO-S-104	Stipulation 2.3 - Erosion and Sedimentation Control	satisfactory	none required
1/7/2013	Northstar Gas	13-SPCO-S-105	Stipulation 2.6 - Big Game Movements	satisfactory	none required
2/25/18	Northstar Gas	13-SPCO-S-127	Section 14 - Plans and Permitting	satisfactory	none required

Appendix I - 2013 SPCO Surveillance Summary

SPCO Approval Date	Pipeline	Report #	Description	SPCO Observations	Follow-up
5/15/2013	Northstar Gas	13-SPCO-S-205	Section 8 - Covenants of Lessee	satisfactory	none required
5/15/2013	Northstar Gas	13-SPCO-S-206	Section 15 - Conduct of Operations	satisfactory	none required
5/15/2013	Northstar Gas	13-SPCO-S-207	Section 20 - Information	satisfactory	none required
5/15/2013	Northstar Gas	13-SPCO-S-208	Stipulation 1.6 - Surveillance and Monitoring	satisfactory	none required
5/15/2013	Northstar Gas	13-SPCO-S-209	Stipulation 1.14 - Reporting	satisfactory	none required
1/7/2013	Northstar Oil	13-SPCO-S-098	Section 6 - Reservation of Certain Rights to the State	satisfactory	none required
1/7/2013	Northstar Oil	13-SPCO-S-099	Section 8 - Covenants of Lessee	satisfactory	none required
1/7/2013	Northstar Oil	13-SPCO-S-100	Stipulation 2.3.1.1 - Erosion and Sedimentation Control	satisfactory	none required
1/7/2013	Northstar Oil	13-SPCO-S-101	Stipulation 2.6 - Big Game Movements	satisfactory	none required
2/25/18	Northstar Oil	13-SPCO-S-126	Section 14 - Plans and Permitting	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-175	Section 6 - Reservation of Certain Rights to the State	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-176	Section 8 - Covenants of Lessee	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-177	Section 15 - Conduct of Operations	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-178	Section 18 - Orders by the Commissioner	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-179	Stipulation 1.4 - Quality Assurance and Control	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-180	Stipulation 1.6 - Surveillance and Monitoring	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-181	Stipulation 1.8 - Survey Monuments	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-182	Stipulation 1.11 - Regulation of Access	satisfactory	none required
4/17/2013	Northstar Oil	13-SPCO-S-183	Stipulation 2.3 - Erosion and Sedimentation Control	satisfactory	none required
5/15/2013	Northstar Oil	13-SPCO-S-210	Section 8 - Covenants of Lessee	satisfactory	none required
5/15/2013	Northstar Oil	13-SPCO-S-211	Section 15 - Conduct of Operations	satisfactory	none required
5/15/2013	Northstar Oil	13-SPCO-S-212	Section 20 - Information	satisfactory	none required
5/15/2013	Northstar Oil	13-SPCO-S-213	Stipulation 1.6 - Surveillance and Monitoring	satisfactory	none required
5/15/2013	Northstar Oil	13-SPCO-S-214	Stipulation 1.14 - Reporting	satisfactory	none required
9/13/2013	Endicott	14-SPCO-S-001	Section 7 - Reservation of Certain Rights to the State	satisfactory	none required
9/15/2013	Endicott	14-SPCO-S-002	Section 10 - Duty of Lessee to Prevent or Abate	satisfactory	none required
11/29/2013	Northstar Gas	14-SPCO-S-026	Section 6 - Reservation of Certain Rights to the State	satisfactory	none required

Appendix J

2013 SPCO and BP Correspondence

Appendix J - 2013 SPCO and BP Correspondence

Date	Sender/Recipient	Subject
1/8/2013	SPCO to Don Turner	SPCO Surveillances of Endicott, Milne Point, and Northstar ROWs
1/9/2013	SPCO to Don Turner	Notice of Refund for Badami Sales Oil (ADL 415472) Pipeline ROW Lease
1/15/2013	Don Turner to SPCO	2013 Quality Assurance Manual Submittal
1/18/2013	SPCO to Don Turner	SPCO Request for Recording Fee for the Release of Interest for the Badami Utility Pipeline Construction Right-of-Way
4/17/2013	SPCO to Don Turner	SPCO Lease Compliance Report and Surveillances of Badami Utility Pipeline ROW
4/17/2013	SPCO to Don Turner	SPCO Lease Compliance Report and Surveillances of Northstar Oil Pipeline
4/25/2013	BPTA to SPCO	Transfer of Right-of-way Lease ADL 415965 (Badami Utility Pipeline)
4/25/2013	BPTA to SPCO	Transfer of Right-of-way Lease ADL 415472 (Badami Oil Pipeline)
5/1/2013	SPCO to Don Turner	Corrected Pro-rated Rental Amount Due for the Badami Utility Pipeline ROW Lease, ADL 415965
5/8/2013	SPCO to Don Turner	SPCO Review of Updated Quality Assurance Manual
5/16/2013	SPCO to Don Turner	SPCO Surveillances of 2012 Annual ADNR Surveillance and Monitoring Report
6/14/2013	SPCO to William Clifton	Memorandum of Understanding/Reimbursement Agreement, Badami Pipelines for SY14 Budget
6/14/2013	SPCO to William Clifton	Memorandum of Understanding/Reimbursement Agreement, Endicott Pipeline for SY14 Budget
6/14/2013	SPCO to William Clifton	Memorandum of Understanding/Reimbursement Agreement, Milne Point Products Pipeline (NGL) for SY14 Budget
6/14/2013	SPCO to William Clifton	Memorandum of Understanding/Reimbursement Agreement, Milne Point Pipeline for SY14 Budget
6/14/2013	SPCO to William Clifton	Memorandum of Understanding/Reimbursement Agreement, Northstar Pipelines for SY14 Budget
6/20/2013	Don Turner to SPCO	BP Transportation (Alaska) Contact Change

Appendix J - 2013 SPCO and BP Correspondence

Date	Sender/Recipient	Subject
8/2/2013	SPCO to Don Turner	Notice of Spectrum Alaska's proposed LNG project
8/16/2013	SPCO to Don Turner	SPCO Surveillances of Endicott Pipeline ROW
8/30/2013	SPCO to Don Turner	SPCO's Observation of Pipeline Debris on Endicott ROW
9/3/2013	Don Turner to SPCO	Spectrum Alaska, LLC LNG Project
9/10/2013	Don Turner to SPCO	Polar Natural Gas Pipeline ROW Lease Proposed Application - ADL 419237
9/12/2013	Don Turner to SPCO	SPCO's Observation of Pipeline Debris on Endicott ROW
9/16/2013	SPCO to Don Turner	SPCO's Surveillances of Endicott Pipeline ROW
9/18/2013	SPCO to Michelle Brown	State Reimbursement/Badami Pipelines, SY13 5th Quarter Billing
9/18/2013	SPCO to Michelle Brown	State Reimbursement/Endicott Pipeline, SY13 5th Quarter Billing
9/18/2013	SPCO to Michelle Brown	State Reimbursement/Milne Point Product Pipeline, SY13 5th Quarter Billing
9/18/2013	SPCO to Michelle Brown	State Reimbursement/Milne Point Pipeline, SY13 5th Quarter Billing
9/18/2013	SPCO to Michelle Brown	State Reimbursement/Northstar Pipelines, SY13 5th Quarter Billing
11/4/2013	SPCO to Don Turner	Appraisal Adjustments Due for Northstar Oil and Gas Pipeline Right-of-Way Leases
12/16/2013	SPCO to Don Turner	SPCO Surveillances of Northstar Pipelines Landfall and ROW and Endicott Oil Pipeline ROW