Operator:
TRANS ALASKA PIPELINE SYSTEM

# Low Flow Impact Study

## FINAL REPORT

**June 15, 2011**

***Prepared by the Low Flow Study Project Team at the request of Alyeska Pipeline Service Company***

# Executive Summary

This report presents findings, mitigations, and recommendations of the Low Flow Impact Study (LoFIS) for the Trans Alaska Pipeline System (TAPS). The study was performed to evaluate the potential risks to future operation of TAPS at throughputs and oil temperatures that are considerably lower than those assumed for the original pipeline design.

## *Conclusions*

The LoFIS identified water dropout and corrosion, ice formation, wax deposition, geotechnical concerns, and other issues that pose operational risks to the TAPS at throughputs ranging from 600,000 barrels per day (BPD) to 300,000 BPD (note that all references to throughput volumes represent volumes at Pump Station [PS01] unless otherwise indicated). However, the TAPS can continue to be operated safely and with reasonably high operational confidence down to throughputs of about 350,000 BPD if the following important issues are addressed to maintain normal flowing operation at these low throughputs:

- Water dropout and corrosion: The specified maximum water content in the TAPS is 0.35 percent, although short-lived spikes as high as several percent occasionally occur. The water, which is typically entrained in the oil in the form of small droplets for current throughputs of roughly 630,000 BPD, is expected to start separating out in a flowing layer at the bottom of pipe when the flow drops below roughly 500,000 BPD. As a result, water concentrations will increase, especially at pipeline low points and upward-facing slopes, which will increase the potential for internal corrosion damage at the bottom of pipe.

- Ice formation: Unless the crude oil is heated, its temperature will drop below the freezing point of water during the winter months as flow rates decline below roughly 550,000 BPD. Engineering analysis and testing indicate that freezing of the water in the oil is very likely at this point. Operational impacts could include icing and consequent disabling of check valves (CVs); ice accumulations at tees, bends, instruments, strainers, and inside mainline valve bodies; and formation of ice in water slugs created via pig passage.

  It is important to note that the hot residuum that is returned to the pipeline by the refineries at North Pole, Alaska is currently an important source of heat. If this heat source is not reliable or available and an alternate source of heat is not implemented, the throughput at which wintertime crude oil temperatures consistent with freezing of the water in the oil is increased from 550,000 BPD to 780,000 BPD.

- Wax precipitation and deposition: Wax deposition on the pipe walls has increased significantly since the crude oil temperature dropped below the wax appearance temperature (roughly 75 ºF) in the mid-1990s. Wax deposition will continue at current levels as the throughput declines, even if the oil is heated in the future. In addition, settlement of wax particles in the pipeline will occur as a result of lower oil flow velocities and during pipeline shutdowns. The wax deposited on the pipe wall and the settled wax particles will then be collected and hardened by scraper pigs.

- Geotechnical concerns: Lower crude oil temperatures will permit soils surrounding the buried portions of the pipeline to freeze, which will create ice lenses in certain soil conditions. Ice lenses could cause differential movement of the pipe via frost heave mechanisms. Assuming no heating of the crude oil, ice lens formation is predicted to occur at a throughput of 350,000 BPD. Unacceptable pipe displacement limits and possible overstress conditions in the pipe would be reached at a flow volume of 300,000 BPD.

- Additional operational issues:

  – Feasibility of pigs to remove wax at throughputs less than 350,000 BPD: Pig bypass orifices must be large enough to maintain sufficient bypass flow to disperse the waxy sludge in front of the pig, while remaining small enough to provide enough differential pressure to overcome frictional resistance and keep the pig moving. Additional risk may be posed by the buildup of wax deposits in the interior spaces of the pig that further reduce the bypass flow rate. The buildup may be sensitive to the pig design.

  – Reduction in pipeline leak detection efficiency: Instrument limitations and the increased impact of additional slackline areas could degrade the leak detection capability and create a potential inability to meet regulatory leak detection requirements.

  – TAPS shutdown and restart issues: During shutdowns, the water in the pipeline flows and settles to pipeline low points. The potential for water to freeze and potentially plug the pipeline increases at lower throughputs (and commensurate lower pipeline temperatures). Even if ice blockages do not occur, the ice that forms can negatively impact downstream pump stations if the ice passes into relief valves, mainline pumps, or other sensitive equipment. Significant wax accumulations are also possible during shutdowns due to settlement of precipitated wax in the cooling crude and may cause significant problems for cleaning pigs following the shutdown. Restart problems can result from gelling of the crude oil in the pipeline at low temperatures.

Absent any mitigation of these issues, the reliable operating throughput for the pipeline is about 550,000 BPD under normal conditions.

With the mitigations in place, the reliable operating throughput is estimated to be about 350,000 BPD. Flow volumes of less than about 350,000 BPD subject TAPS operations and pipeline integrity to greater degrees of uncertainty that require investigation and study beyond that accomplished through the LoFIS. As flow rates decline below 350,000 BPD, issues related to low flow will increase the problematic impact on the TAPS operation. Measures to mitigate these issues utilizing the existing 48-inch pipe at throughputs below 350,000 BPD have not been determined at the date of this report.

Specific areas of uncertainty at throughputs below 350,000 BPD include the following:

- Increasing volumes of water accumulation at pipeline low points and in front of pipeline pigs and the associated issues of:
  - Additional corrosion caused by the water.
  - Locating where water will accumulate during a pipeline shutdown.
  - The potential for large accumulations of ice during winter shutdowns of the pipeline.
- The ability to pig the pipeline at low volumes due to throughput velocities that are insufficient to sweep away the wax in front of the pig.
- Unknown operational factors related to the increased numbers of pipeline pigs and multiple pigs in a pipeline segment.
- The potential for large accumulations of wax related to increased wax precipitation and the ability to keep the wax particles entrained within the crude oil stream at low velocities.
- The ability to monitor corrosion with instrumented pigs in the slackline areas.

- The ability to utilize instrumented pigs at low velocities with increased wax accumulations and longer transit times.
- The viability of internal corrosion chemical treatments.
- Cold restart issues related to the increased percentage of residuum in the southern pipeline segment and associated increased gel strengths.
- The effects of crude heaters on the generation of wax.
- Ability to reliably operate and manage large numbers of crude heaters to maintain the crude oil above freezing at low flow rates and to provide provisions for pipeline slowdowns.
- Questionable viability of the leak detection system at low flow rates.
- Operational unknowns caused by extremely low throughput rates that result from pipeline slowdowns when the throughput is already low.
- Operational unknowns resulting from a combination of issues such as ice and wax accumulations after a shutdown, restarting the pipeline with ice, and gelled crude oil.
- The composition of future crude oil and the resulting effects of high proportions of heavy and viscous oil in the pipeline.

Each year that volumes decline further, the TAPS is operated at a throughput never before experienced, not even when the pipeline was first started. Likely there are issues related to operating the pipeline below 350,000 BPD that have not yet been identified.

## *Recommendations*

The Plan Forward presented in Section 3 was developed to enable safe operation of the pipeline at throughput of approximately 350,000 BPD. Reservations about current knowledge of pipeline physical processes at lower flow rates (as described above) decrease confidence that the pipeline can be reliably operated at throughputs lower than 350,000 BPD.

A summary of major recommendations is provided below:

1. Minimize the risk of ice formation in the winter. Implement strategies to maintain crude oil temperatures on the pipeline at a level that will allow reliable cold weather operations. If heat from the sources at North Pole cannot be relied upon, additional heat sources that are capable of duplicating heat from the sources at North Pole may be required. In addition, heat the oil in proximity to but upstream of locations subject to low oil temperatures, including PS03, PS04, PS05, and PS09, and possibly PS07. Consider enhancing the insulation of the aboveground portions of the pipeline north of North Pole to minimize the ice formation during extended winter shutdowns and reduce the cost of running heaters. Finally, establish a minimum temperature of 105 ºF for crude entering the TAPS from fields on the North Slope.

2. Mitigate freezing of water in the pipeline during an extended wintertime shutdown. Identify contingency measures and equipment to enable the handling of ice and wax pushed into the pump stations following shutdown, and provide bypass to the back pressure control valves at the Valdez Marine Terminal (VMT) to allow for ice to enter the terminal without plugging the control valves.

3. Develop procedures to reduce the risk of a throughput interruption that will result in pipeline crude oil temperatures below the freezing point. Maximize available VMT storage capacity during winter months, and investigate a winter wind loading restriction waiver for the VMT to reduce potential for pipeline slowdown.

4. Modify the current water specification to prohibit water slugs above 0.35 percent. Such modification will limit the amount of water contained in the crude oil stream. This will reduce the amount of water that settles out to pipeline low points during winter shutdowns and reduce the number of low points with significant water accumulations.

5. Implement contingency procedures, practices, and facilities to minimize the potential formation of ice as a result of extended pipeline shutdowns and reduced throughput in the winter months. Further evaluate the installation of enhanced insulation at critical pipeline low points to reduce the rate of ice formation during an extended pipeline shutdown. Evaluate contingency use of freeze point inhibitors. Evaluate contingency equipment to locally respond to water accumulations during a shutdown. Finally, implement real-time monitoring and off-line simulation tools to track and forecast pipeline crude oil temperatures, pipeline water accumulations during shutdowns, and associated ice formation.

6. Reduce the risk of internal pipeline corrosion from increased water holdup in the pipeline by regularly injecting corrosion inhibitor and biocide chemicals into the

crude stream at PS01 and PS04.[1] Continue regular pigging and modify pig designs, as required, to sweep out increasing amounts of accumulated water and wax in the pipeline. Finally, implement real-time monitoring and off-line simulation tools to track and forecast pipeline water transport on a transient basis. At throughputs below 400,000 BPD, reduce the water specification to 0.2 percent to reduce the accumulation of water in flowing conditions.

7. Manage continued or increased wax deposition by implementing a pig washer to reduce the costs of pig cleaning and wax disposal as a hazardous waste; installing a pig launcher and receiver at PS09 or other locations having the capacity to handle ice and wax before mainline units are affected; and evaluating the adequacy of the VMT tank mixers to handle the increased solids. Establish a program to monitor wax and crude oil solids to include regularly monitoring changes in crude oil composition and impacts to gelled crude rheological models. In addition, enhance the Alyeska DRA Monitoring and Analysis (DRAMA) software to enable better monitoring of wax accumulation due to increased pressure drops between pig runs.

8. Implement a formal pigging technology development program that evaluates water and wax issues, establishes an optimal pigging frequency, conducts an annual review of the pigging program and pig design, continues to evaluate the viability of pigging and pig design with respect to higher precipitated wax volumes at low velocities, and determines the viability of pipeline pigging following a pipeline shutdown, including removal of wax and ice from the pipe.

9. Revisit Alyeska's previous pipeline cold restart analysis and implement a continuing cold-restart evaluation program. Include periodic evaluation of the crude oil gel strength and other rheological model parameters; assessment of the impact of North Pole residuum on crude properties and restart; development of new analytical procedures for use with Alyeska's cold restart model; and assessment of the impact of ice at pipeline low points, crude oil heating, and possible presence of pipeline pigs. In addition, perform a cold restart analysis every 5 years.

10. Utilize the current curvature pig-monitoring program to monitor pipeline frost heave to ensure that reduced oil temperatures do not create an overstress condition in the buried pipe.

[1] Note that residual monitoring and neutralization of corrosion inhibitor and biocide chemicals would be required in Valdez before draining treated water into the BWT system.

11. Perform a detailed analysis of field instrument capabilities at low flows and of effects to the leak detection system from degraded field data and lower flow rates.

12. Conduct a probability analysis to determine a winter design shutdown duration and associated credible minimum ambient temperatures. Conduct a probability analysis to also determine design pipeline slowdown criteria. These criteria will be utilized as part of the design basis for low flow mitigation measures.

13. Supplement the Department of Revenue forecast for timing of low-flow related mitigation projects with the forecasting algorithm developed by the LoFIS team based on past throughput decline rates. Update the algorithm yearly.

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# Acronyms and Abbreviations

| | |
|---|---|
| ANS | Alaska North Slope |
| API | American Petroleum Institute |
| BPD | barrels per day |
| BPH | barrels per hour |
| Btu | British thermal unit |
| BWT | ballast water treatment |
| CFD | computational fluid dynamic |
| cP | centipoise |
| CV | check valve |
| DRA | drag reducing additive |
| DRAMA | DRA monitoring and analysis |
| DSC | differential scanning calorimetry |
| DSD | droplet size distribution |
| dw/o | dispersed water in oil |
| dyne/cm$^2$ | dyne per square centimeter |
| EOT | end of test |
| ft$^3$ | cubic foot |
| FTIR | Fourier transform infrared spectroscopy |
| g/cm$^3$ | grams per cubic centimeter |
| GC | gas chromatography |
| GPM | gallons per minute |
| GVEA | Golden Valley Electric Association |
| HAZID | Hazard Identification |
| HTGC | high temperature gas chromatography |
| Hz | hertz |
| IFT | interfacial tension |
| Kg/m$^3$ | kilograms per cubic meter |
| KHz | kilo-hertz |
| kPa | kilopascal |
| kV | kilovolts |
| LEFM | leading edge flow meter |
| LFL | lower flammability limit |
| LoFIS | Low Flow Impact Study |
| m/s | meters per second |

| | |
|---|---|
| MEL | mitigated event likelihood |
| MIC | microbial induced corrosion |
| mm | millimeter |
| MMBPD | million barrels per day |
| mN/m | millinewton per meter |
| N/m | Newton meter |
| NPR | North Pole Refineries |
| ºC | degrees Celsius |
| OCC | Operations Control Center |
| ºF | degrees Fahrenheit |
| Pa | Pascal |
| PD | positive displacement |
| PDL | pig data logger |
| PLHTM | pipeline hydraulic thermal model |
| ppt | parts per thousand |
| PRV | pressure reducing valve |
| PSD | particle size distribution |
| psi | pounds per square inch |
| psid | pressure differential |
| psig | pound force per square inch gauge |
| RGV | remotely controlled gate valve |
| RPM | revolutions per minute |
| RTD | resistance temperature detector |
| RVP | Reid vapor pressure |
| S&W | sediment and water |
| SIMDIS | simulated distillation |
| SOT | start of test |
| SRB | sulfate reducing bacteria |
| UFL | upper flammability limit |
| VMT | Valdez Marine Terminal |
| VPR | Valdez PetroStar Refinery |
| WAT | wax appearance temperature |
| WDT | wax dissolution temperature |
| WMT | water modeling tool |
| WPT | wax precipitation temperature |
| wt% | weight percent |

# 1. Project Overview

The Low Flow Impact Study (LoFIS) was commissioned to provide a better understanding of the issues associated with lower flow rates in the TAPS and to recommend measures to mitigate the operational impacts. As the flow rates in the Trans Alaska Pipeline System (TAPS) decline, the velocity of the crude oil decreases and the time required for the oil to transit from Pump Station 1 (PS01) to Valdez increases. The longer transit times cause the temperature of the crude oil to decline. The turbulence within the pipeline also decreases as the flow rates decline. Water and solids contained within the crude oil drop out within the pipeline as a result of the reduced turbulence at lower flow rates. The lower temperatures and reduced turbulence result in a number of different operational issues for the TAPS.

TAPS wintertime oil temperatures have declined from above 100 ºF in the late 1980s, when PS01throughputs were above 2.0 million barrels per day (MMBPD), to about 38 ºF in portions of the pipeline at today's flows of roughly 630,000 BPD (note that all references to throughput volumes represent volumes at PS01 unless otherwise indicated). At some point in the future pipeline oil temperatures are expected to drop below the freezing point of water as Alaska North Slope oil fields continue to mature and lower throughputs are expected.

## 1.1 TAPS Description

The TAPS is an 800-mile long, 48–inch-diameter pipeline built in the 1970s to move crude oil from Prudhoe Bay on Alaska's North Slope to the Marine Terminal in Valdez (VMT) on Prince William Sound (see Figure 1). The pipeline was originally designed to incorporate 12 active pump stations. Since peaking at roughly 2.0 MMBPD in the late 1980s, average throughputs have dropped to approximately 630,000 BPD. Active pumping is currently employed at 4 of the 12 original pump stations: PS01, PS03, PS04, and PS09. Relief tanks are provided at each of these stations as well as at PS05.

Flow enters the pipeline at PS01 from five metered sources and is delivered to two separate, metered refinery locations and the VMT. Refinery crude oil connections with residuum returns are at North Pole near Fairbanks and at PetroStar Refinery in Valdez (VPR). Oil is stored in fixed roof tanks at the VMT before being transferred to oil tankers via two loading berths. The VMT is equipped with ballast water tanks (BWTs) that are used for oily ballast water from the oil tankers. The ballast water is treated and then discharged into Valdez Arm.

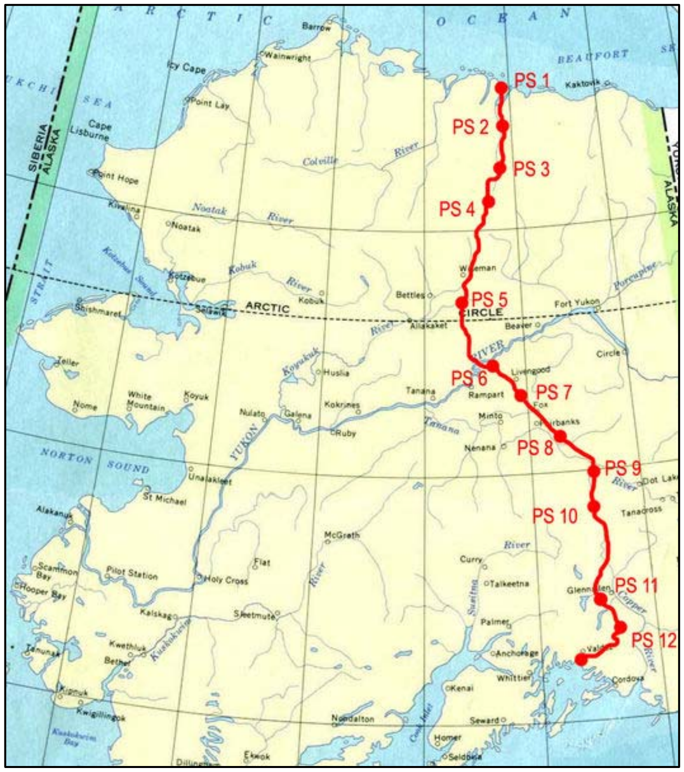



**Figure 1. Trans Alaska Pipeline System**

## 1.2 Low Flow Concerns and Issues

Pipeline flow began in July 1977, and by September 1977 crude flow in the pipeline was above 700,000 BPD. Flow volumes rapidly climbed over the next few years to peak at TAPS capacity of 2.0 MMBPD in 1988. Since then, TAPS flow volume has been dropping at a rate of about 5.4 percent yearly (see Figure 2).

As flow volumes in the pipeline decline, the velocity of the crude oil decreases and the time required for the oil to transit from PS01 on the North Slope to Valdez increases. The longer transit times result in the crude oil being exposed to ambient temperatures for longer periods. The longer residence time in the pipe along with a reduction in frictional heating causes the temperature of the crude oil to decline as flow rates are reduced. TAPS wintertime oil temperatures during normal steady state operations have declined from above 100 ºF in the late 1980s when flow rates peaked to about 38 ºF in portions of the pipeline at today's flow volumes (see Figure 3).

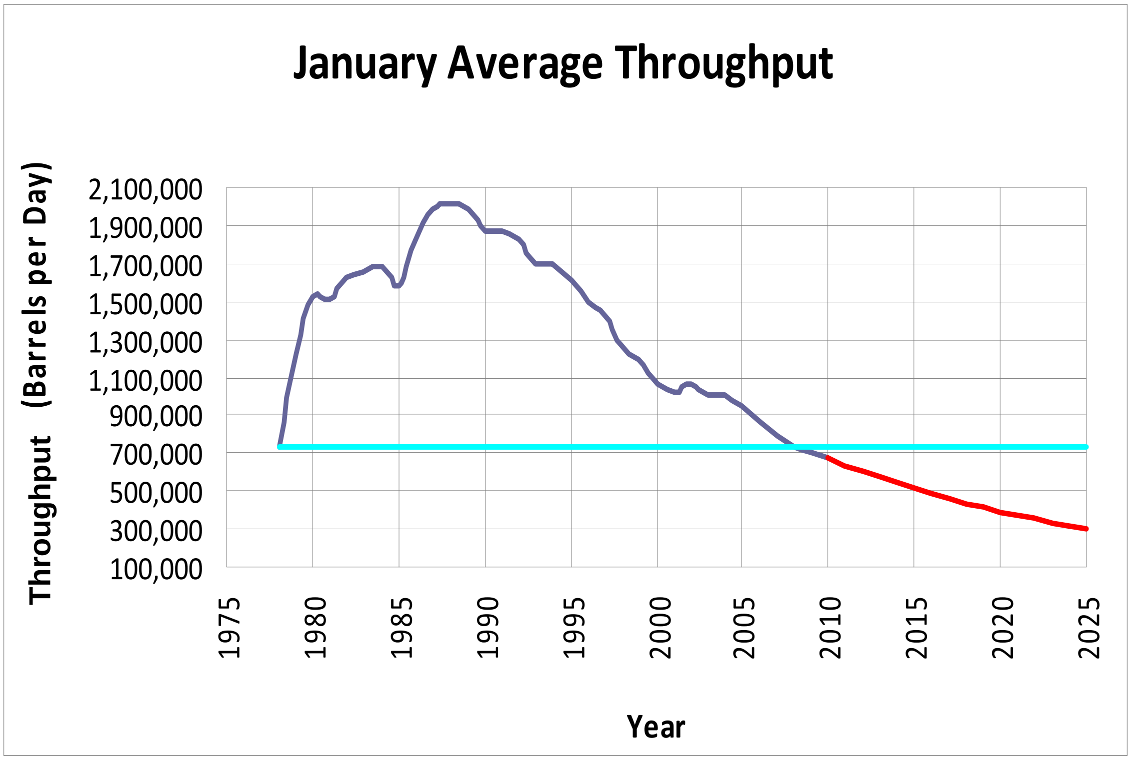



**Figure 2. Past and Anticipated TAPS Flow Volumes**

Note: Throughput projections are based on a 5.4% annual decline rate. (The blue line indicates actual January average throughput, and the red line indicates the projected throughput.)

Oil temperatures in the pipeline are also susceptible to additional temperature decreases due to slowdowns and shutdowns during normal operations. For example, when a partial interruption to North Slope oil field operations occurs and flow rates into the TAPS are reduced for a short time, temperatures in the pipeline decrease both during and after the temporary reduction in pipeline flow rates. The ongoing diminishing average annual flow volumes will further lower future oil temperatures.

Crude oil temperatures would be lower than shown in Figure 3 for the section of pipeline south of the North Pole Refineries (NPR) if not for the hot residuum (at a temperature of approximately 125 ºF) injected into the pipeline at the refinery. This heat source is equivalent to having a crude oil heater installed at this location. The VPR also supplies hot residuum, to a much lesser degree. Alyeska does not have control over these sources of heat.

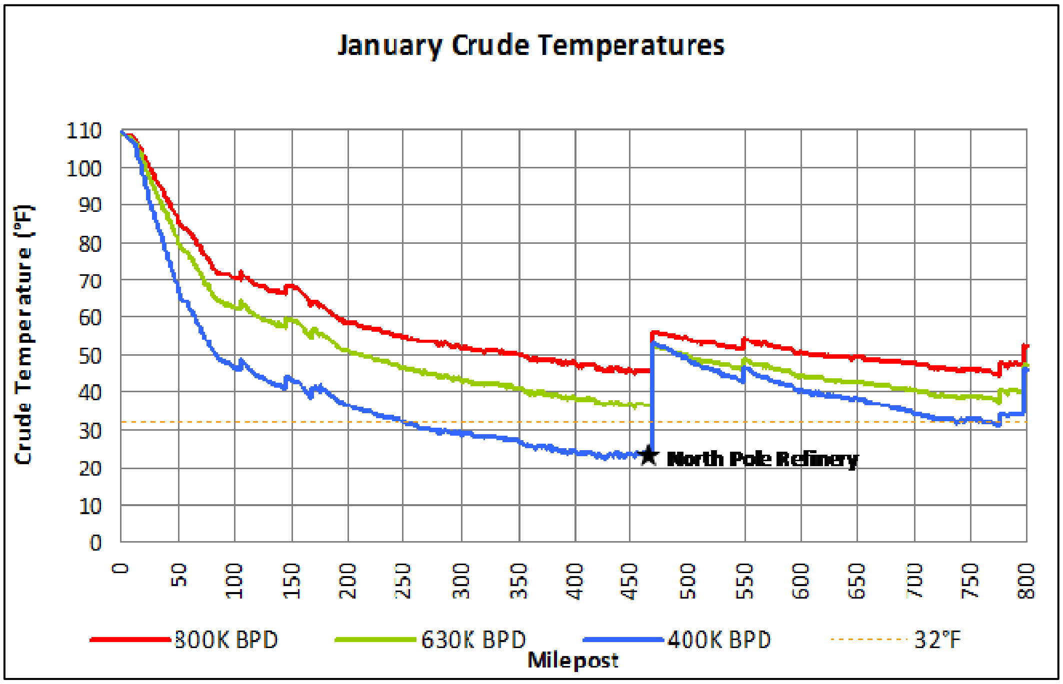



**Figure 3. TAPS Crude Oil Temperatures at Various Steady State Flow Volumes in January**

In addition, as flow volumes decline the turbulence within the pipeline decreases. At lower flow rates anticipated in the future, the reduced turbulence will cause water and solids contained within the crude oil to drop out and settle within the pipeline during flowing conditions.

Lower crude stream temperatures and reduced turbulence in the pipeline as flow volumes decline will cause operational issues. Although the TAPS has experienced temporary lower flow volumes during slowdowns and shutdowns during normal operations, long-term steady state winter operating conditions at flow volumes less than 600,000 BPD and associated operating issues have not been encountered during the history of the TAPS. (Note that the original TAPS designers only considered flow volumes down to 500,000 BPD and based design assumptions on dry Sadlerochit oil).

As TAPS flow rates decline under the rates previously experienced and progressively decline, operational uncertainty increases. Further, the routine temporary slowdowns in flow that occur on a regular basis will result in the TAPS experiencing lower flows rates and the associated issues sooner than anticipated.

### 1.2.1 Assumptions and Expected Operating Regime

LoFIS testing, modeling, and analysis assumed the following:

- TAPS throughput will decline at about 5.4 percent per year.
- PS01, PS03, PS04, and PS09 will be the only active pumping locations, and PS05 will remain as a relief facility.

Table 1 provides other base assumptions underlying LoFIS efforts.

**Table 1. Operating Assumptions – No External Heat Added**

| PS01 – NPM Flow Rate | PS1 – NPM Velocity | NPM to VPR Flow Rate | NPM to * VPR Velocity | VPR to ** VMT Flow Rate | VPR to VMT Velocity | Crude Oil Transit Time PS01 to VMT | Reynolds Number Min/Max |
|---|---|---|---|---|---|---|---|
| 600,000 BPD | 3.25 feet/sec | 565,000 BPD | 2.94 feet/sec | 553,000 BPD | 2.94 feet/sec | 15.5 Days | 5.48E+4 3.37E+5 |
| 500,000 BPD | 2.7 feet/sec | 465,000 BPD | 2.4 feet/sec | 453,000 BPD | 2.4 feet/sec | 18.7 Days | 3.85E+4 2.81E+5 |
| 400,000 BPD | 2.15 feet/sec | 365,000 BPD | 1.86 feet/sec | 353,000 BPD | 1.86 feet/sec | 23.5 Days | 2.53E+4 2.26E+5 |
| 300,000 BPD | 1.61 feet/sec | 265,000 BPD | 1.33 feet/sec | 253,000 BPD | 1.33 feet/sec | 31.8 Days | 1.45E+4 1.71E+5 |

Notes:

* North Pole Refinery return residuum is set at 90 °F for all flow rates.

** Valdez PetroStar Refinery return residuum is set at 131.7 °F for all flow rates.

NPM = North Pole Metering

VMT = Valdez Marine Terminal

VPR = Valdez PetroStar Refinery

## 1.3 Project Scope and Approach

The LoFIS was initiated to identify and understand operational constraints and physical problems that could result from future reduced flow volume in the TAPS. The study also provided recommendations for mitigation of low-flow related issues.

The LoFIS investigated the following issues associated with declining flow in the TAPS: low oil temperatures, reduced flow velocities, water transport and accumulation, ice formation, wax deposition and precipitation, and other TAPS operational impacts and phenomena.

The LoFIS comprised the following:

- A literature survey to identify physical models and existing validating evidence that address the phenomena that are expected to occur at decreasing throughput and temperatures. Section 1.3.1 provides an overview of survey efforts.
- A testing program consisting of analytical laboratory bench testing, static cell testing, flow loop testing, and TAPS operational and field testing. The testing program was structured to better understand the physical processes and to provide model validations and input for areas not addressed through literature or other sources. Section 1.3.2 provides an overview of the testing program.
- A simulation and modeling program that entailed developing tools used to support engineering analysis and evaluate and recommend mitigation measures. Additional studies and analyses were conducted to assess models and test evidence, develop integrated pipeline engineering simulation tools, evaluate limits to operation, and identify and rank low throughput mitigation efforts. These studies included the following:
  - An analysis of frost heave impacts to the pipeline to determine limits to differential pipe movement, identify areas that have a high potential for frost heave, and determine the throughput levels at which the initiation of frost heave would occur and when the limits of differential pipe movement would occur.
  - An analysis of the effect of cold oil temperatures on tank volatility through evaluation of vapor samples and volatility data taken from pump station crude oil tanks to determine volatility in vapor space related to temperature.
  - An analysis of water transport in the TAPS at current flow rates using pipeline water analyzer data to determine the behavior of water as it transits from PS01 to Valdez.
  - An analysis of water settlement in the TAPS at various water content levels utilizing the water-tracking tool to determine locations of water accumulation after a pipeline shutdown for various water contents. In addition, statistical analysis of crude oil water content was performed.
  - An analysis of Leading Edge Flow Meters (LEFMs) as a method of monitoring wax accumulations associated with pigging. The analysis determined the LEFM method is not viable because of the similarity between wax and crude oil

densities and the associated similarity in the signal velocities between the two mediums.

- An analysis of the properties of ice formed in static conditions.
- A study of wax deposition at various flow rates in the TAPS using test data and two different wax models to predict wax deposit thickness at various flow rates.
- A study of the effects of wax precipitation and agglomeration at various flow rates in the TAPS.
- An analysis of ice formation in the TAPS at low flow to predict ice formation rates for various mechanisms in both flowing and shutdown conditions.
- Several analyses of water transport and emulsion stability in the TAPS at various flow rates.

- A high-level hazard assessment (HAZID) to identify undesirable pipeline conditions associated with decreasing TAPS flow rates and to assess the potential consequences and likelihood of occurrence. Section 1.4 presents the approach and results of the HAZID.
- An analysis of mitigation options for low-flow issues identified through LoFIS work.

### 1.3.1 Overview of Literature Survey

The literature survey was one of the first tasks undertaken by the LoFIS team and included a review of existing papers, reports, and other research and test documentation available from the public domain via copyrighted materials, and as written applicable material obtained from the TAPS owner companies. The purpose of the survey was to determine the basis for analysis and testing required to understand and predict the consequences of the physical processes that become important at low crude oil flows and temperatures The literature survey was designed to identify low throughput equations and physical models, identify any existing data that validated these models, and make a preliminary assessment of processes that may impede TAPS operation at low flow rates. Processes considered in the literature survey included pipeline water transport, wax deposition, ice formation, and other physical processes that are important at low throughput. The survey included evaluating the following:

- Pipeline-scale computer simulators
- Water transport in pipelines

- Heat transfer and ice formation in pipelines
- Flow restriction and other impacts of ice and wax formation
- Wax formation in pipelines
- Heat transfer from the pipeline to the above- and belowground environments
- Freeze point suppressants, flow improvers, and pigging practices (preliminary evaluation)
- Computational tools that might be useful for low throughput analysis

### 1.3.2 Overview of Testing Program

The purpose of the testing program was to better understand issues associated with lower flows in the TAPS where other applicable research and testing were not available. The primary areas of interest were water-, ice-, and wax-related issues. Most testing was performed in a phased approach to first better understand the issues and available research identified through the literature survey.

Tests and analyses of available pipeline data were conducted before planning and designing major test equipment. Models were identified that could be validated with the testing results. In some cases, such as water transport, new models were developed. The general testing work consisted of laboratory bench testing, static cell testing, flow loop testing, and TAPS operational and field testing.

- Laboratory bench testing included testing water emulsion stability; crude oil, wax, and residuum properties; tank-water draw samples from the Valdez storage tanks; ice properties including freeze point and compressive, tensile, and shear strengths; and vapor samples from crude tanks along the TAPS. Testing results were used to provide input parameters and determine empirical coefficients for TAPS low throughput physical models.
- Static cell testing was performed in Valdez with samples of crude oil taken directly from the pipeline. Settlement rates were tested in static cells designed to accommodate pipeline pressure: a vertical cell, a V-shaped cell, and three cells that could be tilted at different angles to determine the effect of pipeline angle on water accumulation rates. The testing was conducted at different temperatures and water contents. A water droplet size distribution was taken using the Canty device at the start and end of each test. Water content was measured during the testing from

sample ports located along the test cells. The results from this testing were used to develop a static water settlement model.

- Flow loop testing was conducted using two 3-inch-diameter 90-foot flow loops constructed within a temperature-controlled building capable of being operated at temperatures from 104 ºF to -40 ºF. The flow loops were designed to incorporate horizontal, downhill, and uphill pipe sections. Instrumentation was included to provide the capability to monitor pressure and temperature at various locations as well as flow rates. For the flow loop utilized for water transport testing, sample locations were used to determine water content at the top and bottom of the flow loop. The flow loops included storage tanks and preparation tanks where test fluids were mixed prior to the flow loop testing. The system also had a shear pump that was used to create water droplets of a size observed in the TAPS. A data collection system was used to record flow loop data. One of the flow loops was designed primarily to study the impacts of low throughput on water transport, and the other flow loop was designed to primarily study wax deposition at low throughputs. Testing included the following:
  - Water behavior in crude oil in flowing conditions at various flow rates, temperatures, and water content.
  - Wax formation in flowing conditions using various percentages of residuum, crude oil, oil and pipe wall temperatures, and flow rates.
  - Ice formation in flowing conditions at various water content geometries and temperatures.
  - Ice bursting under various pressures and temperatures.
  - Restart pressures for gelled crude oil.

### 1.3.3 Overview of Simulation and Modeling Program

Through the literature survey and testing program, the LoFIS team identified existing models applicable to the TAPS and potential low-flow issues. The team validated the models using off-the-shelf modeling tools that had been previously developed and could be validated and tuned with the LoFIS test data. However, modeling tools were not available for a number of TAPS low flow issues and were then developed by the LoFIS team. The team also applied several different modeling approaches to the same issue to provide redundancy and in many cases a secondary validation of the modeling and analysis results.

The models were used to predict the impact of operating the TAPS at low throughput and serve as a basis for analyzing mitigation efforts needed to ensure safe operation of the pipeline in future years. Modeling efforts included the following :

- Thermal modeling at various pipeline flow rates under steady state conditions to predict future thermal profiles at lower flows. The purpose was to determine the expected TAPS temperature profiles at various flow rates. The thermal analysis was performed using a version of the pipeline hydraulic thermal model (PLHTM) configured for the LoFIS project. PLHTM is a steady state spreadsheet-based model. It performs a steady state hydraulic calculation for the pipeline and uses the same 2,634-point survey file database that is used for real-time pipeline modeling in the TAPS Operations Control Center (OCC). PLHTM calculates head and thermal gradients for the pipeline, addresses both above- and belowground heat transfer, incorporates the impacts of pump station operation on the temperature gradient, addresses crude off-take and residuum reinjection at refinery sites, and addresses slackline effects. The PLHTM was calibrated and tuned using several years of recorded TAPS SCADA data over a wide range of throughputs.
  - Thermal modeling was used to determine the TAPS throughput at which external heating or enhanced mainline pipe insulation is required, evaluate various heating and pipe insulation options, determine heating requirements for each option as a function of flow, and determine an operational safety factor to apply to the minimum temperature to include the effects of variations in pipeline flow and ambient air temperatures.
  - Thermal modeling was also used to understand geotechnical issues, i.e., frost heave, related to the thaw bulb surrounding belowground pipeline and potential for damage to the structural integrity of the pipeline.

- Wax modeling to predict future wax deposition rates at lower flow rates. This modeling was done using the PVTsim Version 19 Software from CALSEP A/S (DEPOWAX) and the WaxDep Software developed and owned by ExxonMobil - Upstream Research Center (XOM-URC). WaxDep is XOM-URC's in-house wax deposition software application. This application was developed and validated using single and multiphase flow loop data and field data. Wax deposition modeling is strongly influenced by the oil temperature and throughput, as well as by heat transfer characteristics between the oil and the ambient environment. Different modeling assumptions were required for the northern (PS01 to NPR off-take) and the southern (NPR off-take to VMT) pipeline sections of the TAPS. In addition, the

DEPOWAX and WaxDep models required different specific assumptions as part of their configurations.

- Water transport modeling to quantify the degree that water entrained in the oil will hold up (settle out of the oil) when throughputs decline and flow velocities become low. Models included the following:
  - Models that work from droplet coalescence, transport and migration, formation, and size limitation considerations.
  - A model that works from droplet and kinetic energy considerations.
  - An analysis tool that considers gravitational migration of the water during a pipeline shutdown with no transient modeling.
  - A model based on analysis of LoFIS laboratory, static cell, and flow loop test data combined with dimensionless fluid mechanical considerations.
  - A widely used commercial modeling tool designed to perform multiphase and multi-component fluid modeling at pipeline scale and configured to address the TAPS LoFIS considerations (OLGA).
  - A pipeline-scale modeling tool utilizing an energy-balance method to analyze the impacts of operating TAPS with water at low throughput and with pipeline pigging.
  - A tool designed to examine the water balance on the TAPS pipeline based on field measurements.

- Models specifically developed for the LoFIS project included:
  - A new oil-water slip relation developed to provide both water holdup and flow regime (bulk water or water dispersed as droplets) as a function of oil and water densities, bulk oil rate, pipeline diameter and angle of inclination, and water cut. This model was developed to evaluate the water dropout potential for the TAPS. The oil-water slip relation was then implemented into a transient pipeline scheme, capable of tracking pipeline transients such as introduction of off-spec water, shutdown/restart, and pigging operations.
  - An empirical model based on static cell and flow loop test data to provide predicted water settlement in static conditions and water holdup in flowing horizontal pipe sections.

– A water settlement and tracking model to determine specific areas of water accumulation along the pipeline after a pipeline shutdown. It was installed at the OCC. This model can be used as on online water analyzer data to track water as it traverses the pipeline and identifies areas of water accumulation after a shutdown. A detailed pipeline elevation profile is included in the model. It can be used as an engineering tool to evaluate the effects of different water contents and as a tool during a pipeline shutdown to determine areas of water accumulation given the actual water contents prior to the shutdown. This model does not have the capability to determine water settlement during flowing conditions and because of this, will only be valid for the current flow regime where the water stays entrained with the crude oil.

– Models to determine cool-down rates in TAPS aboveground pipeline sections during pipeline shutdowns.

– Models to determine ice formation rates for various ice formation mechanisms in flowing and shutdown conditions.

– Limited modeling to evaluate the pressure required to burst an ice plug.

## 1.4 Hazard Assessment

To assess the potential risk associated with operation of the TAPS at low flow rates, a hazard identification, or HAZID, was conducted. The HAZID was the product of structured group meetings conducted in October and December 2010. The process used consequence information supplied by the LoFIS along with historical event information, experiential knowledge of the group, and the Alyeska Risk Matrix to identify areas of risk exposure as throughput declines. Experts from the LoFIS presented information to the team, and the project supplied probable consequences at declining flow rates. The HAZID team included personnel with TAPS experience in engineering, operations, integrity management, maintenance, hydraulic performance, and safety systems.

The risks identified in the course of the HAZID process may not include all of the risks. While the HAZID team applied the best science and tools available and worked diligently to identify each and every significant risk associated with low flow, it is possible that not all such risks have been identified by the team.

### 1.4.1 Philosophy and Approach

It is important to note that risk determination of this type does not examine a proposed design or set of actions that are a basis of mitigation. In order to identify risk, the HAZID assumed that the TAPS is subject to the basic initiator of events, i.e., declining flow rates. Scenarios were then applied associated with the historic operation of the pipeline, such as normal operation, reduced flow, pigging, and pipeline shutdown.

The review was performed as a high-level hazard review using a facilitated team-based approach. A systematic brainstorming method was applied through which the team could:

- Identify potential hazard scenarios.
- Consider consequences of the hazards, including escalation to the worst-case event.
- Identify safeguards in place to provide hazard prevention or mitigation.
- Propose recommendations, as needed, to eliminate, prevent, control, or mitigate hazards.

The team initiated the review process by brainstorming possible initiating events that have the potential to result in a significant consequence to pipeline operations. A pre-determined set of initiating events was provided to the team at the start of the meeting; however, a focused effort was made to ensure that the team also provided input on any additional events for consideration.

For each initiating event, the team discussed the possible causes of the event and further evaluated the scenario to determine the potential consequences and possible ways in which the event may escalate. It was the intent of the team to remain focused on the identification of hazards, without being constrained by thinking "this cannot happen." The focus of the review was centered on identifying the hazard scenarios unique to the pipeline operations under low flow conditions, and more specifically, to each flow rate case.

The consequences of each scenario were assessed by assigning a severity rating based on the Alyeska Risk Assessment Procedure. Likelihood ratings were assigned using the Alyeska Frequency Criteria, also found in the Alyeska Risk Assessment Procedure. Two likelihood ratings were assigned for each scenario. The Mitigated Event Likelihood (MEL) was assigned based on the likelihood of the event under present-day operation, given the safeguards in place. The team then assigned a Predicted MEL, which was intended to reflect the likelihood of the hazard event occurring and leading to the consequence defined given the safeguards in place.

The team was then able to determine the final Predicted Risk Rank for each scenario using the Maximum Severity ranking and the associated Predicted MEL. Note that the risk ranking applied during the HAZID was intended to provide a qualitative risk ranking for purposes of organizing the findings of the study, but was not necessarily a quantitative assessment of the potential risk associated with operation at the given conditions.

Following the guidelines of the Alyeska Risk Assessment Procedure, the team generated recommendations for higher risk scenarios. Recommendations were also provided for other scenarios where necessary to ensure that hazards are appropriately defined and mitigated, regardless of the estimated risk.

#### *1.4.1.1 Hazard Identification, Description, and Throughput Relationship*

TAPS Low Flow Risk Assessment Rate Case Operating profiles were developed to provide a summary temperature profile for the TAPS at various rates indicating locations in the pipeline where the temperature is predicted to drop to 31 ºF, which is a general trigger point for the analysis below which there is a potential for water in the crude to begin forming ice. In addition, the HAZID team had access to detailed projections of temperature profiles at flow rates of 200,000 to 600,000 BPD for each milepost of the pipeline.

Steady state throughput and temperature are directly correlated. In developing and examining initiating events the team considered steady state operation and the resulting temperatures for flow rates of 600,000 BPD; 500,000 BPD; 400,000 BPD; and 300,000 BPD. For each of these flow rates the team also considered sensitivities such as reductions of 25 and 50 percent loss of heat from NPR, pigging, and pipeline shutdown.

Assessment scenarios were applied to the pipeline on a “nodal” basis. The pipeline was divided into analysis nodes of PS01 to PS02, PS03 to PS04, PS04 to NPR, and NPR to VMT. The exception is for the scenarios used to directly examine pigging. For those the pipeline was divided into the nodes of PS01 to PS04 and PS04 to VMT because those are the pig launching and receiving locations. Analysis nodes were also assigned to PS01, PS03, PS04, PS09, VMT Metering, VMT Tanker Loading, VMT Tankage, VMT Power/Vapor, and VMT Ballast Water Treatment (BWT).

## 1.4.2 Hazard Analysis Results Summary

Issues (consequences) were identified by the LoFIS, and the resulting hazards were identified for flow rates of 600,000 BPD; 500,000 BPD; 400,000 BPD; and 300,000 BPD, respectively.

Because the predicted temperature curve for the pipeline is always above 31 ºF, there are no identified risks for steady state flow of 600,000 BPD. All identified events for this flow rate are associated with initiating events that are outside the base steady state flow. These events include pipeline shutdowns and loss of NPR heat input.

As the flow rate base declines and more of the pipeline length is exposed to a steady state temperature of 31 ºF and below, consequences identified by the LoFIS, such as ice in the flowing condition, become more of a factor in the risks identified. Correspondingly, the risks identified with loss of NPR heat, shutdowns, and pigging become more widespread and potentially severe in the pipeline system as the steady state flow rate case declines. Generally, the flow rate case for 300,000 BPD contains all the risk associated with higher-rates case plus added risk.

### *1.4.2.1 Ice Formation Hazard Analysis*

Ice formation affected pipeline risk in two forms, as determined by the LoFIS work: risk produced with the pipeline in a flowing condition below 31 ºF, and risk produced by pipeline fluid cooling during a shutdown.

**Hazard from Ice in Operating Pipeline**

Based on the nature of ice formation identified in the LoFIS, the HAZID determined that ice crystals will form in the pipeline stream, while flowing, at temperatures below 31 ºF. The crystals can then combine with wax and add to the volume of debris pushed in front of a pig or, as seen in the flow loop tests, be deposited at locations such as valves. Ice deposits could then accumulate at valves and potentially interfere with valve action such as the sealing of CVs.

The team identified potential mitigations for this risk: heating to avoid the temperature drop causing the condition, insulating to mitigate the temperature drop, or adding freeze suppression to the system to lower the temperature at which the water freezing occurs. (Issues were also identified for the use of freeze suppressants such as impact to the refineries, incompatibility with some gasket materials, etc.)

Under the normal flow rate ranges examined, pipeline pump stations with required pumps for oil movement (PS03, PS04, and PS09) were not subjected to 31 ºF and below temperatures. However, the relief pump station, PS05, is subjected to freezing temperatures below a flow rate of 400,000 BPD, and PS09 is subjected to freezing temperatures at any flow rate if NPR heat input is lost.

**Hazard from Ice in Shutdown Pipeline**

Based on the nature of water settlement and ice formation identified in the LoFIS, the HAZID assumed that a series of time-dependent occurrences would take place associated with ice formation in the event of a shutdown.

- The closer to, or further below, the system is to 31 ºF, the sooner after shutdown the series of events would occur. However, for analysis purposes a uniform timeframe of occurrence was assumed, with effects beginning in the coolest portions of the pipeline at the time of shutdown.
- The progression of this freezing would take place under very cold, winter conditions (while the HAZID team applied historical experience to develop a qualitative likelihood of a shutdown in winter conditions).
- Water would settle within 24 hours and begin to freeze within 48 hours.

Shutdown periods of 48 hours and 10 days or more were examined.

Various potential effects of ice formation were assessed by the team, including the melting of the ice presenting a heat load to the system on startup; sloughing of ice from the pipe on startup and into the flow stream; and the effect of ice in the system on strainers, pumps, and pigging. Movement of a pig in the pipeline following an extended shutdown was identified as a particular concern because the pig cannot be stopped and can push considerable volumes of ice, ice slurry, or ice/wax slurry through the pipeline and into instrumentation connections, pumps, strainers, as well as refinery off-takes, mainline relief valve branches, and the backpressure control system in Valdez.

### *1.4.2.2 Corrosion Hazard Analysis*

Water holdup (dropout) is predicted in the pipeline at flow rates below 500,000 BPD. The HAZID assumed that the presence of free water would alter the corrosion rate historically evidenced and raise the likelihood of corrosion-related spills. A broad recommendation was made to determine the effect of free water on the pipeline system, investigate additional corrosion mitigation methods, and expand corrosion investigation and mitigation accordingly.

The team recognized the change in water behavior in the pipeline at lower flow rates as a potential high risk to the system. However, it was also recognized that little is known about effect of this change in water behavior, the required response, or the cost or the scope of effects to the pipeline system. Additional work is needed to quantify the effect to the system and associated risk.

### *1.4.2.3 Wax Deposition Hazard Analysis*

Increased wax deposition on the pipe wall was not considered a major hazard based on the information from the LoFIS. However, as temperatures decrease the percent volume of precipitated wax crystals increases significantly in the flowing stream. This was considered for potential adverse effects throughout the analysis. Note that because the HAZID was an analysis to identify risk to the system related to low flow and not an analysis of mitigation techniques, the effect of heating the crude stream on wax characteristics was not considered.

**Hazard from Wax Deposition and Precipitation in the Operating Pipeline**

Wax deposition was not considered to significantly increase with declining temperature. However, there were considerations associated with wax and cleaning pigs that affect the risk profile of the pipeline.

Even without increased wax deposition and corresponding increased frequency of cleaning pigs, the presence of pigs within the pipeline will increase with declining throughput rates. This is due to the slower fluid movement and thus longer time for a pig to transit the pipeline from PS01 to Valdez. The transit time through the pipeline increases from 15 days at 600,000 BPD to 30 days at 300,000 BPD. With the same frequency of running cleaning pigs, this results in twice as many pigs in the line and affects many low-flow related risks. For instance, during any extended pipeline shutdown at lower operating rates, more cleaning pigs in the line will push any ice, wax, or ice/wax slurry to more places where such materials can present a hazard.

Also, as throughput and corresponding operating temperatures decline, the larger volumes of entrained wax crystals in the flow stream must end up somewhere. These volumes have the potential to settle out during a pipeline shutdown and be pushed by a cleaning pig on restart, resulting in high volumes of wax potentially building up in front of the pig that would have to be managed as the pig is received or passes through a pump station. In general, the HAZID treated this larger volume of entrained wax as not having a substantial effect in the flowing conditions of normal operation, and it was considered to stay entrained. However, there was uncertainty in several areas, including whether wax could begin to build up and become harder with less occluded oil in front of a pig following a shutdown and how this may affect pump stations. In particular, it was considered a potential high risk for passing ice/wax mixtures through a pump station because the pump stations are not necessarily currently designed for this and no experience base exists from which to draw. The same applies to receiving pigs at the VMT that are subjected to pushing this type of debris. These concerns are elevated if there are multiple pigs in the line and if they are aggressive cleaning pigs.

**Tank Wax Settlement and Deposition**

Entrained wax is anticipated to increase as flow rates decline. This is expected to progressively increase the potential for wax settling in the crude tanks at the VMT, thereby resulting in potentially higher financial impacts for tank bottoms management and tank cleaning.

At flow rates into the VMT between 300,000 and 400,000 BPD, the wax loading is expected to overcome the capacity of the tank mixers and result in an inability to keep the wax suspended. This has implications for mixer redesign and replacement, and significant acceleration in tank bottom settlement.

**Pig Operability at Low Flow**

At the lower pipeline velocities associated with low flow, the current pig designs may be ineffective. Review and potential redesign of the pigging program is likely required. Significant "bypass" of fluid by the pig may be required to keep the large volumes of wax entrained in front of the pig. Note that analysis of the current scraper pig design indicates that the bypasses are significantly blocked within 100 miles of the pig launch site. This effect slows the movement velocity of the pig even more and results in a potential to block the pig and make the pigging ineffective, e.g., damage the pig, etc.

Also, there will be more and greater slackline areas (areas of downhill flow where the line is not packed with liquid) in the pipeline. The slackline is expected to increase at Atigun Pass and Thompson Pass, and appear at Isabel Pass. The Atigun Pass slackline will eventually extend past Chandalar Shelf. The pig tends to move through slackline at a high rate of speed, resulting in a greater potential for pig damage. This includes damage to instrument pigs with potential loss of data. Further, it will be more difficult to obtain corrosion data from instrumented pigs in areas that become typically slackline, resulting in higher cost and potential data gaps.

#### *1.4.2.4 Geotechnical Hazard Analysis*

At low flow rates approaching 300,000 BPD, temperatures in the pipeline will not be adequate to keep soil around the pipeline thawed. This could result in formation of ice lenses, and subsequent jacking and deformation of the pipe in susceptible areas. Such damage was assumed to have a financial effect in terms of rework, pipe replacement, cost of shutdown and bypass of piping, and greater inspection need. Also, the added potential for associated shutdown would place the system at greater risk in a low-flow situation.

#### *1.4.2.5 Cold Tank Volatility Analysis*

Cold temperature in relief tanks can result in lower volatility of the crude in the tank, resulting in a vapor space mixture that is not over-rich in hydrocarbon vapors. Under some circumstances, cold temperature in the tank can result in a relief tank with vapors in the explosive range. Although the tanks are designed for a very low probability for the presence of ignition internal to the tank, the vapors represent a large amount of confined energy lacking only a spark for ignition. To control any likelihood of an explosive mixture in the tanks, the tanks should be at or above a base temperature. Two locations, PS03 and PS09, currently do not have tank heaters. The temperatures of tanks at PS03 and PS09 are a function of the temperature of the crude that flows into the tanks, the residence time in the tanks, and the ambient temperature.

As the pipeline flow rate and corresponding temperature decrease, incidental flow to these tanks is less likely to maintain a temperature in the tanks to keep them above the explosive mixture. Flowing allowable amounts of oil into the tanks to keep them adequately warm will become impractical and result in air quality permit violations. The recommendation is to insulate and/or heat the tanks that are currently unheated to mitigate the risk.

### 1.4.3 Conclusions

The HAZID team identified recommendations for follow-up and assigned a Risk Rank to each. Several of the recommendations were assigned to multiple scenarios involving multiple Risk Ranks. In these cases, the recommendation takes on the priority of the highest ranked scenario.

The HAZID identified the following areas affected by lower flow in the pipeline in which risk is higher than in the previous flow history of the pipeline, changing the risk profile of the pipeline, and should be addressed:

1. With lower flow the temperature profile of the pipeline has changed and will continue to decrease. Without mitigation, increasing areas of the pipeline will operate, while flowing, at temperatures below the freezing point of entrained water in the pipeline.
2. At current rates, loss of heat from the NPR residuum at cold ambient temperatures will result in a condition downstream of the NPR of the pipeline operating below the freezing point of entrained water. This exposes PS09 and the VMT to the need to operate with possible ice slurry entering the facility, for which there is no current design basis.
3. At current and lower rates, extended reduction in pipeline rates will result in portions of the pipeline operating below the freezing point of entrained water.
4. The thermal profile associated with low flow means that a pipeline shutdown of significance places large sections of the pipeline closer to the freezing point of water than in historical operation.
5. With the current thermal profile, a reduction in PS01 heat in the winter will result in portions of the pipeline operating below the freezing point of entrained water.
6. Water dropout at rates below 500,000 BPD changes the exposure of the pipeline to internal corrosion.
7. Higher entrained wax at lower temperature associated with low flow affects pigging activities and presents greater risk of pig damage and adverse pipeline operation effects.
8. Pigs in the pipeline during a shutdown present a new operating regime; particularly on startup. There are many unknowns about the ability to push ice/wax slurry, and the design of the pump stations does not currently consider this operation.

In addition, four key findings were noted as a result of the HAZID:

- The hazard scenarios discussed during the course of the review were based on data produced by steady state temperature modeling for the pipeline. Currently there is no transient temperature modeling available to represent the potential impacts to the pipeline as a result of process upsets under low-flow conditions. A concern was noted that the lack of transient temperature data may affect the accuracy of the assumptions made during the review. A recommendation was made to validate the assumptions made during the review against a transient temperature model.

- The likelihood rankings applied for loss of NPR heat were based on the operating experience of the team for current operation and did not consider any potential impacts associated with low temperature operation under low flow conditions. It was noted that a delivery temperature to NPR of less than 32 ºF has the potential to lead to water entrainment to the crude tower, leading to a possible increased frequency of refinery shutdowns for an extended duration.

- For purposes of the HAZID, the review team was unable to cite a credible scenario for which the Producer operations would result in a supply temperature of less than 105 ºF. However, it was noted that Alyeska currently has no control over the crude temperature entering PS01. If the supply temperature were to drop below 105 ºF, potential exists for significant impacts to pipeline operations under low flow conditions. A recommendation was made to establish a clear minimum temperature limitation for delivery of Producer fluids to the line.

- There is sufficient rate turn-down with legacy pumping equipment at PS01 to operate to a rate of about 500,000 BPD. However, a degree of uncertainty is associated with the ability to operate this equipment at low flow rates for an extended period of time and the associated effect to reliability of the legacy pumping equipment. The team believes that, at a minimum, a station recycle loop should be considered for PS01 in the near future.

# 2. Major Low Flow Findings

Significant low flow issues identified through the LoFIS are as follow:

- Water Transport Mechanism Issues: Water is currently transported in the form of small droplets within the crude oil that do not interact with the steel pipe wall. This mode is expected to change when throughputs decrease below 500,000 BPD, and the water is transported as a separated layer at the bottom of the pipe.

- Ice Formation Risk: Operating TAPS below 32 ºF will maintain water droplets in supercooled form, i.e., below their freezing point without them forming ice crystals. The droplets will crystallize in the presence of a nucleation site around which an ice crystal structure can form. As a result, restrictions to the flow, such as partially opened CVs, the pump strainers, and the pipe wall at bends, provide nucleation sites for supercooled droplets to form ice. Ice also will form in the wax deposits on the pipe wall, where it can be collected and hardened with the wax by scraper pigs. In addition, water accumulation at pipeline low points under wintertime shutdown conditions may result in local accumulations of free water expected to form ice under no-flow conditions. Such ice accumulations may pose a high risk to TAPS operation.

- Wax Deposition Impacts: The rate of wax deposited on the pipe wall will decrease slightly as crude oil throughputs in the TAPS continue to decline. Regular pigging will continue to be required to clear the pipeline of deposits. In addition, increased wax particle fallout amounts during short pipeline shutdowns/slowdowns are likely because the pipeline oil carries more precipitated solid with colder oil temperatures. This may pose a problem for pigs that transit the pipeline after the shutdown. Note that increased precipitates may also impact normal pig operation at low flow.

- Enhanced Corrosion Concern: As flow rates decline, the water will begin to drop out and accumulate at pipeline low points. This is expected to start to occur at flow rates of approximately 500,000 BPD. The water accumulation will increase the potential for internal corrosion within the mainline pipe.

- Frost Heave: As the crude oil temperatures decline below freezing, the soils around buried pipe sections will freeze, and in certain soil conditions ice lenses will form that could cause differential upward movement of the pipe. Structural integrity issues with the pipe will occur if soil movement exceeds 12 inches.

- Tank Volatility: Total hydrocarbon contents within the pipeline breakout tank vapor space can be within the flammability range as a result of colder crude oil temperatures associated with reduced pipeline throughputs. The colder crude oil temperatures result in reduced hydrocarbon content in the vapor space, as well as slightly increased values for the vapor space upper flammability limit (UFL). The tank vapor space can fall within the flammable range in static conditions at temperatures below approximately 10 ºF.

- Pig Operability: Scraper pigs can be expected to have increased deposits of wax in their interior spaces because of generally colder oil and increased oil residence time for the oil bypassing the pig. Pigs operating in oil below the freezing point of water following a wintertime shutdown may also experience ice accumulations. If the pig bypasses plug or ice up, wax and ice deposits ahead of the pig will not be diluted by the bypass flow and may result in high-density plugs of wax and ice that could cause hydraulic impacts and problems at pump stations and terminal facilities. In addition, an increasing number of pigs will be required in the pipeline at a given time to maintain the current scraper pig intervals as velocities decline and pig transit times increase.

- Slackline Operation: As flow volume declines, the quantity, locations, and extent of slackline areas increase. The areas of slackline operation create challenges for instrument pig runs and data collection due to the high velocity of the instrumented pig while transiting slackline areas. Slackline areas also present issues during pipeline cold restart, because these pipe sections do not contain oil and can rapidly approach ambient conditions during a winter shutdown. These pipe sections are then exposed to thermal stresses when refilled with “warm” crude oil during restart.

- Cold Restart: The potential exists for high crude oil gel strengths, which impact the ability to perform a pipeline cold restart, due to increased percentages of refinery residuum in the southern end of the pipeline. Cold restart concerns will be exacerbated if the restart procedure and equipment encounter ice plugs that can form at low points.

- Leak Detection: The increased extent of slackline area at lower flow rates will reduce the sensitivity of the real-time leak detection system. Another leak detection issue is degraded field instrumentation data. At lower flow rates the proportion of data noise to flow rate increases, which can also retard leak detection capabilities. Lower flow volumes and colder temperatures also affect the field instrument performance. As field instrument data degrades, leak detection capabilities will be reduced and, in some situations, will cause the loss of leak detection in an area.

These issues are discussed in greater detail below.

### 2.1.1 Water Transport Mechanism Issues

Most TAPS water droplets will stay entrained in the oil flow above a critical threshold flow rate. The threshold flow rate is a function of oil and water properties, including water particle size, the characteristics of crude entering the TAPS, and the local pipe elevation gradient. The current flow rate is above the threshold rate, and the water is entrained in the crude oil as water droplets. Once flow volume declines below the critical threshold flow rate, larger water droplets will settle to the bottom of the pipe and tend to accumulate in low points. Testing at PS09 indicates that, at current flow rates, the concentration of water droplets and water content are slightly higher at the bottom of the pipe than at the top of the pipe. As flow volumes continue to decline, the amount of water that settles out will increase. When this occurs the oil will flow over the top of the accumulated water until the water is pushed out by the pig. Testing and modeling indicate that at flow rates below approximately 500,000 BPD, water will begin to separate from the flowing oil and hold up at pipeline low points during flowing conditions (see Figure 4 and Figure 5). The vertical axis depicted in Figure 4 indicates the water holdup at a given location along the pipeline. For example, a holdup of 0.5 represents a location where the pipe would be 50 percent full of water with the oil flowing over the top of the accumulated water.

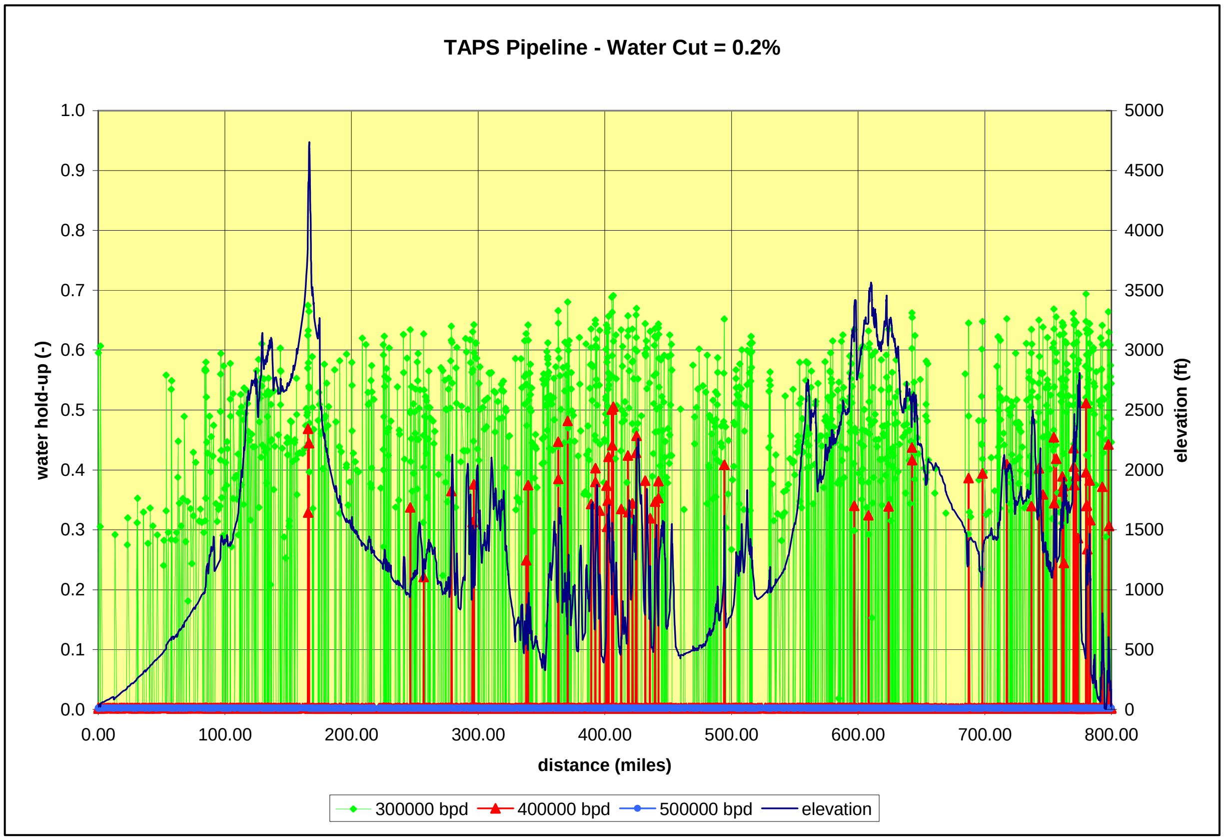
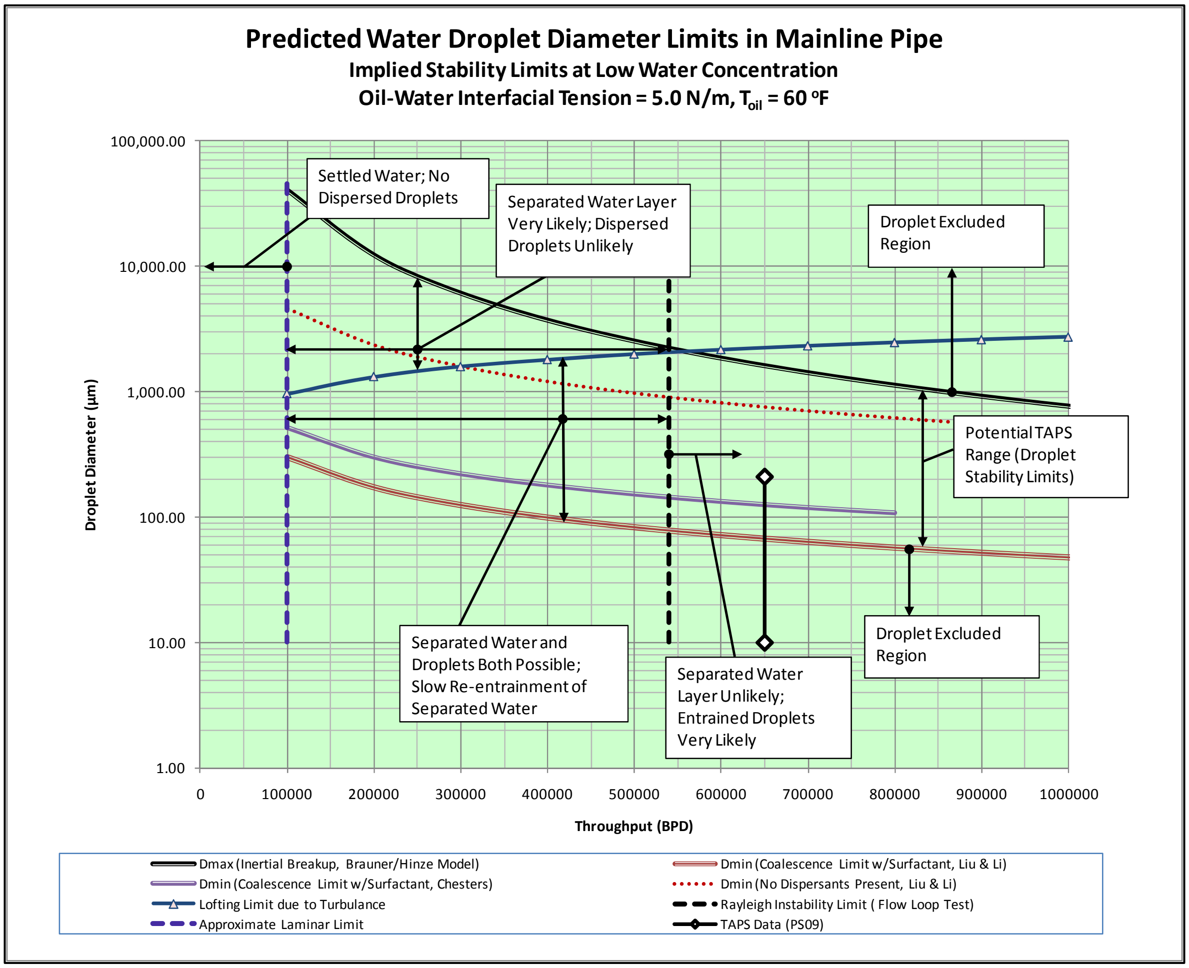



**Figure 4. Steady State Water Holdup at Various Throughputs**

As flow rates decline below approximately 500,000 BPD, the first pipeline low points to accumulate water will be those bounded by the highest inclination angles. As flow rates decline further, that water will accumulate at low points bounded by smaller angles. Water holdup will create the following issues:

- Internal pipeline corrosion.
- Water slugs generated by pigging that could freeze during a shutdown.
- Water slugs generated by pigging that could deposit water in various pipeline appurtenances and create corrosion.




- Water slugs generated by pigging that could affect refineries.

**Figure 5. Water Transport Phase Limits Based on Droplet Diameters**

The accumulated water will also be picked up by pigging operations, and could generate a significant slug of free water in front of the pig. At flow rates of 400,000 BPD the slug is estimated to be as much as 3,000 barrels, and at 300,000 BPD the slug is estimated to be as much as 7,000 barrels. It should be noted that the volume contained in 1 foot of 48-inch pipe is 2.2 barrels; pig-generated water slugs could occupy a significant length of pipe. The water slug, of unknown length, will contribute to the amount of water settled out during a shutdown and will freeze during an unexpected long wintertime shutdown or generate issues with the refineries as it passes through.

During pipeline shutdowns, water contained within the crude oil will settle and accumulate at pipeline low points. In aboveground and shallow buried belowground pipeline low points, the accumulated water could freeze during extended winter pipeline shutdowns.

### 2.1.2 Ice Formation Risk

The TAPS crude oil always contains some amount of water (as do all crude oils), and as pipeline temperatures decline below freezing ice will form in the pipeline and create operational risks. The pipeline was designed as a warm oil pipeline; the original designers did not consider issues/risks associated with operating the TAPS in a steady state below freezing levels. Depending on the crude stream temperature, ice formation in both flowing and shutdown conditions was found during the LoFIS testing program. The risks to pipeline operations related to ice formation during the winter months increase as pipeline flow rates decline, and the extent of pipeline segments operating at below freezing temperatures increases.

#### *2.1.2.1 Ice Formation in Flowing Conditions*

Ice formation in flowing conditions is a complex process and subject to a number of different ice formation modes (see Figure 6). Testing indicates that ice can form in flowing conditions at temperatures below 31 ºF. The depressed freezing point of the water contained in the TAPS is primarily due to the salt content of the water.

**Figure 6. Hard Ice Scraped from Flow Loop**

Note: Formed downstream of flow loop gate valve during flowing condition ice formation flow loop tests.

A significant mode of ice formation is the inertial deposition of ice when the cold crude with entrained supercooled water droplets flows around objects or corners such as at CVs, tees, partially opened valves, and strainers. The water droplets then freeze when they encounter these objects and form ice. Ice formed by this mode was observed in the flow loop testing and tends to be a hard ice because the impurities are swept away with the flow. Another significant mode of ice formation is the diffusion of water to the pipe wall to form ice. This ice forms as a deposit within the wax matrix. The ice formed in both of these mechanisms continues to build up from a continuous supply of water provided by the flowing oil stream.

Depending on how and where the ice forms, as well as the quantity, several potential operational issues can occur. The formation of ice will likely interfere with operating the valves, freeze instrument lines, freeze small fittings, block or partially block pump strainers, form an ice/wax slug in front of scraper pigs, and may create other operational issues. Thermal analysis indicates that the critical throughput at which crude oil temperatures during normal wintertime operation decline through the freezing point of fresh water is about 550,000 BPD during the winter months, provided the heat from the NPR residuum continues to be available. Absent the heat from the NPR residuum, pipeline temperature will drop below freezing at current flow volumes (approximate current annual average flow volume is 630,000 BPD). At very low flows potential exists for ice to form at aboveground low points and on upward-facing inclines due to water settlement.

#### *2.1.2.2 Ice Formation in Shutdown Conditions*

During pipeline shutdowns, entrained water will settle out of the crude and accumulate at pipeline low points and at closed gate and CVs. Shortly after the pipeline is restarted, water slugs are often observed flowing into Valdez. This is thought to result from the water accumulated at low points being re-entrained in the crude oil stream.

Testing of water settlement in static cells was performed as part of the LoFIS. At lower flow rates water held up in the pipeline low points is likely to accumulate in front of pipeline pigs. During a shutdown when the pig stops, the holdup water will also accumulate against the pig, at low points in the line, and at closed gate and CVs. Freezing is predicted to occur in aboveground and shallow buried belowground pipeline sections in as little as 48 to 72 hours following a shutdown, depending on the starting oil and ambient temperatures. The freezing is expected to occur at both the circumference of the pipe and as ice end caps at the water/oil interfaces (see Figure 7).

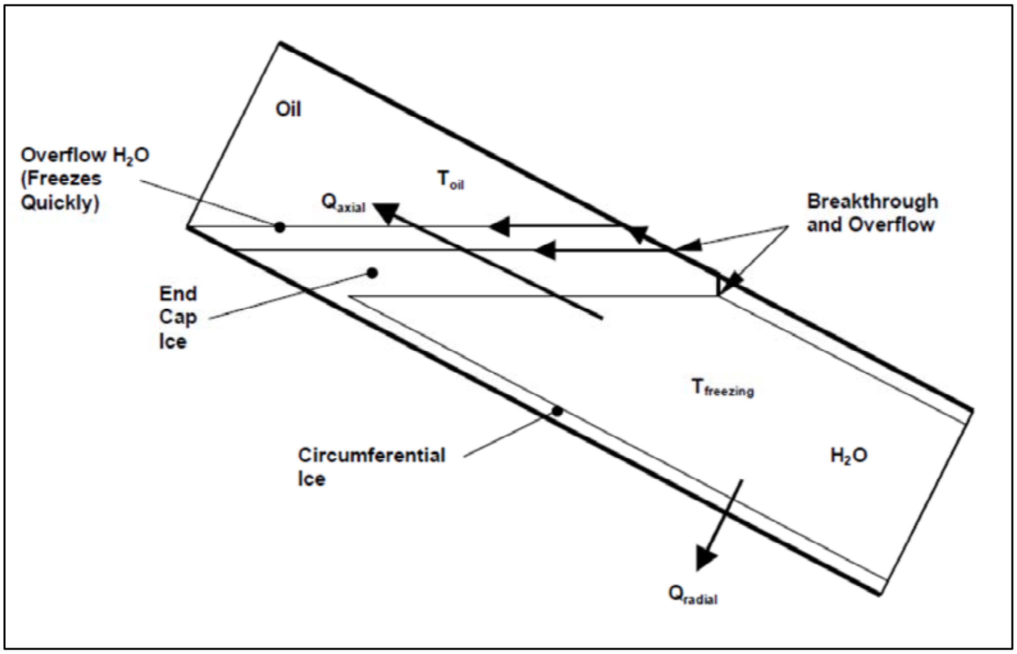



**Figure 7. Stationary Water Slug Ice Formation**

Resultant issues depend on the length of the winter shutdown and ambient temperatures and include:

- Pipeline blockage or partial blockage due to ice formation at pipeline low points, valve locations, and frozen water accumulated in front of a pipeline pig.
- Ice accumulation in front of a pig and blockage of strainers and/or relief valves when the pig arrives at a pump station after restarting the pipeline.
- Generation of significant pressures within the pipe caused by the formation of an ice plug from a pipeline low point completely full of water during a long-duration winter shutdown.
- Ice formation around closed remotely closed gate valves (RGVs) and CVs, hindering their operation during a restart and after the pipeline has restarted. Frozen closed CVs will prevent pipeline restart.

Pipeline areas of particular concern are those where water will accumulate over 50 percent of the pipe diameter during a pipeline shutdown. The number of areas that accumulate water greater than 50 percent of the pipe diameter depends on the water content of the crude oil and whether the CVs are closed or opened. Higher crude-oil water levels and closed CVs result in more critical areas of water accumulation. For example: for water content of 0.35 percent, the number of critical locations is 11, and for water content of 1 percent the number of critical locations is 73. If the CVs are opened, then the critical locations for water content of 0.35 percent decreases to five.

### 2.1.3 Wax Deposition Impacts

Crude oil solids (i.e., wax) exist within the TAPS at lower temperatures and flow rates as a result of deposition and precipitation. As long as the solids remain suspended or diffused within the crude oil stream, no operational impacts are identified. Wax can be deposited on the pipe wall and precipitate as particles in the flowing oil stream. Operational impacts begin to occur as excessive solids accumulate on the pipe wall or settle to the bottom of pipe.

#### *2.1.3.1 Wax Deposition on the Pipe Wall*

Deposition of wax on the pipe wall results from two different processes:

- Thermal gradient driven molecular diffusion of dissolved wax components to the inside of the pipe.
- Additional migration of waxes precipitated in the free stream into pipe wall deposits.

The primary mechanism for deposition of wax to the pipe wall is molecular diffusion. Extensive flow loop testing was done to determine wax deposition rates and validate several existing wax deposition models (see Figure 8 and Table 2). While the two models produced slightly different results, both models support the following conclusions:

- The total volume of wax deposited on the pipe wall will remain stable or decrease.
- Heating the crude will not significantly increase wax volumes deposited on the pipe wall.
- Current and future wax depositions on the pipe wall are not excessive by industry standards.

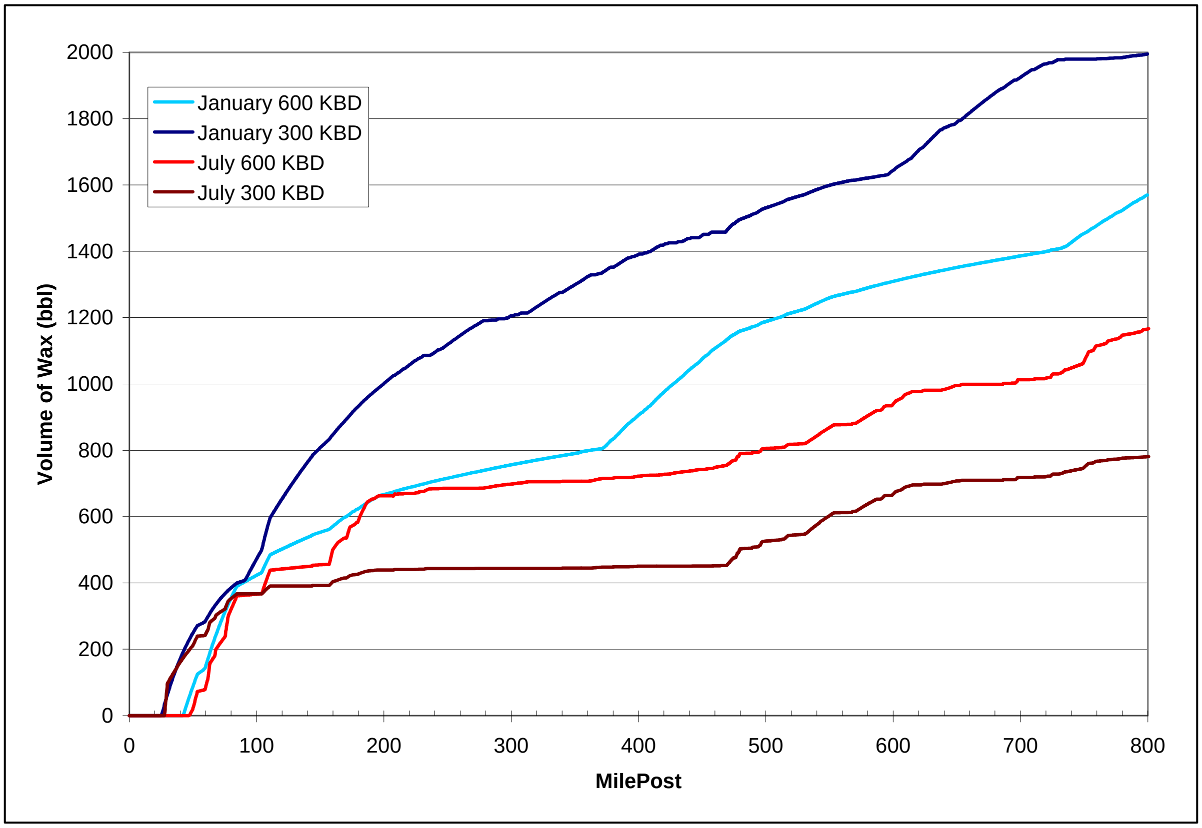



**Figure 8. Cumulative Wax Pipe Wall Deposit Volume Predicted by WaxDep**

Note: 14-day pigging interval.

**Table 2. Cumulative Wax Pipe Wall Deposit Volume Predicted by WaxDep and DEPOWAX**

| Predicted Cumulative Wax Deposited on the Pipe Wall | | |
|---|---|---|
| **Throughput (BPD)** | **WaxDep (barrels)** | **DEPOWAX (barrels)** |
| 600,000 | 1025 | 7110 |
| 300,000 w/o Crude Heating | 1209 | 1835 |
| 300,000 w/ Crude Heating | 1369 | 2505 |

Note: 14-day pigging interval.

No deposition occurs above the crude oil wax appearance temperature (WAT) of approximately 75 ºF, and deposition appears to decrease significantly as the crude oil temperature approaches the pipe wall temperature. This is because the most significant wax deposition mechanism is driven by the wall thermal gradient. As the crude oil cools toward the ambient temperature, the wall thermal gradient decreases significantly, and the wax deposition on the pipe wall slows down with it. As flow rates and crude oil temperatures decline, it is expected that the amount of wax deposited on the pipe wall will decrease over most of the pipeline. However, in the northern pipeline segment additional wax will be deposited on the pipe wall north of PS03 as more of the oil temperature in this pipe segment declines below the WAT.

Scraper pigs remove the deposits off the wall where the flowing oil can carry them through the pipeline. As flow rates decline below 350,000 BPD, the velocity of the oil may not be sufficient to keep the wax removed by the pig from the pipe wall suspended in front of the pig in a slurry form. If the wax settles as a deposit in front of the pig, a significant quantity of wax could form that could cause the pig to become stuck in the pipeline or create issues with clogging pump station strainers and pumps.

#### *2.1.3.2 Settlement*

When crude oil temperature falls below the value supporting the existence of a single liquid phase, wax precipitation forms solid wax particles, initially at nano-scale size, and as the temperature of the oil continues to drop, larger crystals (1 to 3 microns) form. As crude oil temperature continues to decline, enough solid particles are formed to affect the viscosity of the oil, creating non-Newtonian behavior, typically described as shear thinning with identifiable gel strength. In addition, wax particles can grow or agglomerate, resulting in particle sizes in excess of 100 microns. Wax particles of up to 180 microns were observed in the Valdez incoming crude oil with a significant volume of particles over 100 microns.

Problems related to wax agglomeration and settlement in TAPS at low flows include:

- Increased wax particle fallout amounts during pipeline shutdowns and at lower flow rates (see Figure 9). The pipeline oil carries more precipitated solids with the colder crude oil temperatures associated with lower flow rates. Larger wax particles are also likely created by refinery residuum injection (the addition of warm residuum into cold oil). Due to lower carrying velocities that occur during pipeline shutdowns and at lower flow rates, the suspended wax settles and accumulates at the bottom of the pipe. The future shear rates in the pipeline operating at 300,000 BPD will be less than the average shear rate currently provided by VMT tank mixers.

- Potential for problematic routine pigging operations due to increased amounts of settled wax solids in the pipeline. The settled wax is collected by scraper pigs, which “hardens” the wax ahead of the pig by de-oiling it, resulting in increased amounts of high-density solids pushed down the pipeline and impacting operation of filters, strainers, mainline pumps, valves, and pipeline instrumentation taps.

**Figure 9. Pipeline Wax Removed from PS04 Pig Trap, March 2010**

- Potential for problematic interaction of settled water and wax solids, creating enhanced corrosion. This results from the need to use less "aggressive pigs" to provide enhanced bypass flow through the pig to try and keep wax solids better fluidized in the flow, which in turn leaves more water and wax behind in the pipeline.
- Potential for high crude oil gel strengths, which impact the ability to perform a pipeline cold restart due to large plugs of high solid-wax content slurries ahead of trapped pigs, and large volumes of high water cut emulsions formed by interaction of settled water and wax.

### 2.1.4 Enhanced Corrosion Concern

Little internal corrosion has been observed in the mainline pipe, despite high levels of corrosion-causing bacteria detected throughout the entire TAPS. This is likely due to the water remaining entrained within the crude oil as droplets at current flow rates. As flow rates decline to lower levels in the future, the water that is currently entrained within the crude oil as droplets will begin to drop out and accumulate at low points bounded by high-angle pipeline sections. This is expected to start to occur at flow rates of approximately 500,000 BPD. As flow rates decline further, the water will accumulate at pipeline low points bounded by lower-angle pipeline sections. This will result in more areas of water accumulation and increase the potential for internal corrosion within the mainline pipe. When flow rates decline, the areas of water accumulation in the mainline pipe will have a higher potential for internal corrosion.

### 2.1.5 Frost Heave

In current TAPS operations, the pipeline temperature and the temperature of the soils immediately surrounding the buried pipeline are above freezing. As the crude oil temperatures decline below freezing, the soils around buried pipe sections will freeze, and in certain soil conditions ice lenses will form that could cause differential upward movement of the pipe. Structural integrity issues with the pipe will occur if the movement exceeds 12 inches. LoFIS studies indicate there are 33 areas totaling 9 miles with a high potential for frost heave under current operating conditions, which includes the heat from NPR residuum. Additional areas would be of concern if this heat was not available.

Initially the ice lenses would form as crude oil temperatures reached freezing levels during the winter months. The warmer summer temperatures would thaw the ice lenses, which would likely not accumulate to greater than 12 inches. However, at lower flow volumes the summer temperatures would not be warm enough to thaw the seasonally generated ice. The ice would continue to build from year to year. Frost heaves would start to accumulate from year to year when the annual average crude temperature reaches 32 ºF. This is predicted to occur under current operations, including refinery residuum temperatures, at a flow volume of approximately 350,000 BPD at PS01. The frost heave is predicted to reach the 12-inch limit at a flow volume of approximately 300,000 BPD at PS01.

### 2.1.6 Tank Volatility

LoFIS investigated issues related to low crude oil temperatures in the pipeline break-out tanks and found that actions must be taken by Alyeska to prevent the operation of those tanks with vapor space compositions in the flammable range—specifically total hydrocarbon contents above the lower flammability limit (LFL) and below the UFL. This condition is the result of colder crude oil temperatures associated with reduced pipeline throughputs. The reduced crude oil temperatures result in reduced hydrocarbon content in the vapor space, as well as reduced average hydrocarbon molecular weight and thereby slightly increased values for vapor space UFLs.

### 2.1.7 Pig Operability

The number of pigs in the pipeline increases dramatically at low flow (see Figure 10). Scraper and other pigs will operate in the future at much lower velocities. The pig typically moves at a velocity slightly less than the velocity of the crude oil as a result of the pig bypass flow. This is a net flow of oil through bypass openings in the pig.

Low flow impacts to pig operation may occur as the pig bypass flow rate is reduced (the bypass flow rate is proportional to the pipeline flow rate). The result of a reduced bypass flow rate will be an increasing amount of wax accumulation in front of the pig because less of the wax removed from the pipe wall will be swept away downstream of the pig. The impact of this will be a slug of oil in front of the pig that will be characterized by high viscosities and wax concentrations. The wax accumulations ahead of the pig will grow with time, and may then impact the operation of pipeline strainers, relief valves, mainline pumps, and flow meters.

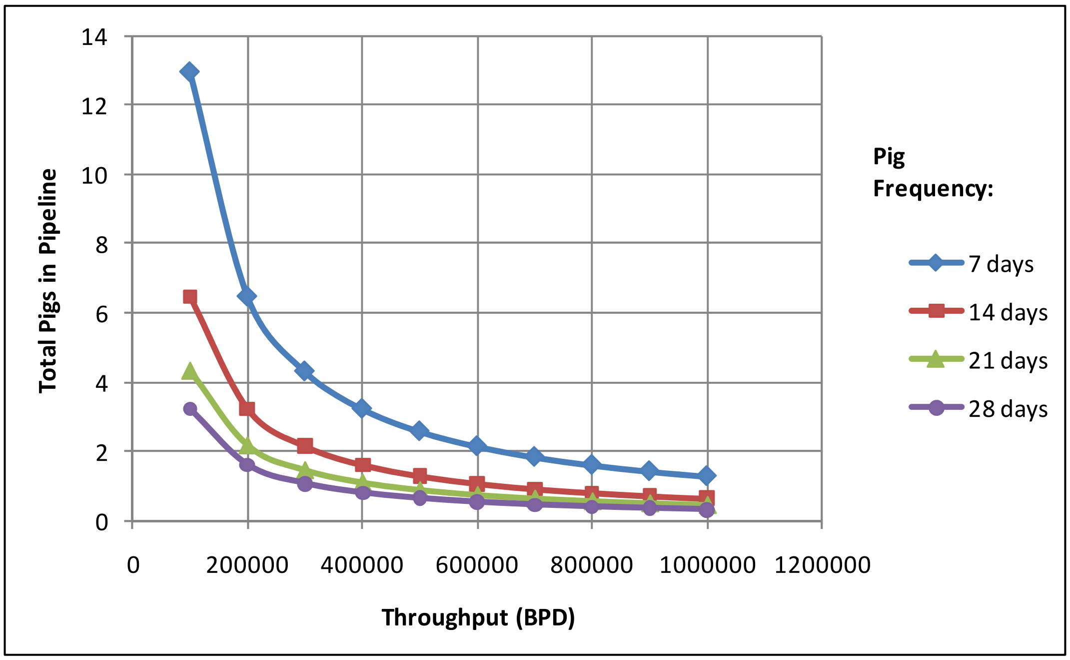



**Figure 10. Scraper Pigs in Pipeline at Low Flow**

Furthermore, if the bypass flow contains wax particulates or water droplets that are subject to settlement, the confined spaces inside the pig between the pig cups present ideal locations for such settlement because the pig surfaces are assumed to reduce turbulence that normally tends to entrain the particulates and droplets. Analysis indicates that the bypasses of the existing TAPS scraper pigs already plug rapidly with wax as the pigs move down the pipeline, which may increasingly be an issue as flow rates decline further.

For example, wax particulate volumes and agglomerated sizes are assumed to increase due to the continuing reduction in temperature. Under this assumption, the deposition of wax inside the scraper pigs may at least double as the throughput declines from 600,000 to 300,000 BPD. Even greater increases can be expected if crude oil temperatures decline further over this flow range, given that the amount of precipitated wax increases significantly as oil temperatures decline.

In addition, if the oil temperature drops below the freezing point of water, additional depositions of ice due the settlement of supercooled water droplets inside the pig can also be expected. Thus, significant additional deposits of both wax and ice are likely for pigs transiting the cold pipeline following an extended wintertime shutdown.

If these effects occur, additional plugging of the bypasses due to the large internal wax and/or ice deposits may occur. If complete plugging occurs, wax and/or ice deposits on the pipeline walls will not be diluted by the pig bypass flow. This will presumably have two impacts:

- The segment of pipe ahead of the pig will consist primarily of cold, high-viscosity wax and/or ice plugs that will present high hydraulic resistance to flow. The pipeline hydraulic operation may be affected.
- The wax/ice deposits ahead of the pig are likely to affect the operation of strainers, relief valves, mainline pumps, and flow meters.

### 2.1.8 Slackline Operation

The TAPS currently has several areas of slackline flow at locations descending from pipeline high points where the oil stream does not completely fill the pipeline cross-section. In these areas the hydraulic head gradient follows the pipeline elevation profile. As flow volume declines, the quantity, locations, and extent of slackline areas increases. In addition, slowdowns in throughput operations will increase the number of intermittent slack areas. Table 3 provides estimated miles of slackline areas at various flow volumes.

The areas of slackline operation create challenges for collecting instrument pig data due to the high velocity of the instrumented pig while transiting slackline areas. Also, the collapse of vapor bubbles at the slackline interface creates pressure pulses that have the potential to cause fatigue damage to the pipe at dent locations and aboveground pipe supports. The slackline sections do not contain crude oil during a pipeline shutdown and can rapidly approach ambient conditions. These pipe sections are then exposed to thermal stresses when refilled with “warm” crude oil during restart.

**Table 3. Estimated Miles of TAPS Slackline Areas at Various Flow Volumes**

| Location | Flow Volume (in BPD) | | | |
|---|---|---|---|---|
| | 600,000 | 500,000 | 400,000 | 300,000 |
| Atigun Pass | 1.4 | 2.4 | 3.3 | 3.5 |
| Isabel Pass | 0.8 | 4.8 | 7.2 | 10.1 |
| Thompson Pass | 0.4 | 0.4 | 0.4 | 0.4 |

Backpressure control valves were installed at Valdez in 1997 to raise the pipeline pressure between Valdez and Thompson Pass, and also raised the slackline interface to an elevation that reduced the pressure pulses created at the slackline interface. Vibrations from the slackline pressure pulses in the Atigun Pass area caused impacts to the aboveground pipe supports that required repair in 2010.

### 2.1.9 Cold Restart

During a pipeline shutdown, gel structure can form if the crude oil reaches a low enough temperature. To restart the pipeline, the gel structure is broken by applying pressure or reducing pressure at various points along the pipeline.

Potential issues related to lower flow rates are associated with the current cold restart plans.

- As flow rates decline the composition of the crude in the southern pipeline segment will have an increased percentage of residuum if NPR residuum continues at current rates. Because the residuum has higher gel strength than the crude oil, an increased percentage of residuum associated with lower flow rates will result in higher gel strengths in the southern pipeline segment (the pipeline segment south of the North Pole Metering Station) , which could require changes to the cold restart plan.

- During an extended shutdown water will accumulate in pipeline low points, and ice will likely form in the aboveground pipeline sections. The ice may create blockages or partial blockages that could impact pipeline restart plans. At lower flow rates the temperatures along the pipeline will be lower during normal operations. This will create a lower temperature at the start of a pipeline shutdown and result in ice forming sooner and the thickness of the ice to be greater during a given shutdown duration. The ice formation and lower operating crude oil temperatures may also require changes to the cold restart plan.

### 2.1.10 Leak Detection

The current TAPS primary leak detection system is a real-time model based on the principle of conservation of mass. The accuracy and reliability of the system are completely dependent on field instrument data that includes flow measurement devices, pressure, temperature, etc. Based on the field data, the leak detection system applies a computational fluid dynamics (CFD) model to obtain the net mass imbalance. Depending on the level of net mass imbalance a leak is either declared or not.

A significant low flow leak detection issue is the increased extent of slackline. Real-time leak detection system sensitivity levels are degraded in slackline areas. Because leak sensitivity is severely degraded, the leak detection system is limited on the size of a leak that can be detected (larger leaks must occur to be detected). The slackline issue also affects the time to detect a leak (increases it) and locate a leak (degrades it).

Another leak detection issue is degraded field instrumentation data. Data noise adversely affects the system's ability to detect leaks. It also adversely affects the reliability of leak detection. At lower flow rates the proportion of data noise to flow rate increases, which can retard leak detection capabilities. Lower flow volumes and colder temperatures also affect the field instrument performance. Instrument reliability may degrade as crude solids accumulate at pressure sensor sites and in flow measurement equipment. As field instrument data degrades, leak detection capabilities will be reduced and, in some situations, will cause the loss of leak detection in an area.

A recent evaluation of leak detection capability indicates that as the size of the leak to be detected decreases the capability of the system to detect the leak becomes less likely. Degraded leak detection capability presents risk in potential inability to meet regulatory requirements.

# 3. Mitigation Recommendations and Plan Forward

This section summarizes recommendations for mitigation action and presents an implementation plan. Major mitigation recommendations include the following:

- Capital improvements such as crude oil heating, insulation enhancement, and the installation of an additional pig trap.

- Changes to the entrance specifications that include eliminating water slugs and establishing a minimum TAPS entrance temperature.
- Changes to operating procedures to reduce low-flow related issues.
- The establishment of a crude oil and water-monitoring program.
- Further evaluation of several areas of uncertainty at very low flow rates, such as wax precipitation and pigging.

The timing for implementation of several of the near-term mitigations has become critical because of throughputs declining faster than anticipated over the last several years. Preliminary design of several mitigation measures has already begun. In addition to technical recommendations, organizational and staffing recommendations are included in this report to enable the organization to effectively implement recommendations and address low flow issues into the future.

As flow rates continue to decline, it will be important for Alyeska to continue to monitor and evaluate the issues described in this report and other potential issues that may not have been foreseen by the LoFIS team. Issues that have not been previously experienced by Alyeska will arise as throughputs continue to decline.

## 3.1 LoFIS Project Mitigation Recommendations

The HAZID and mitigation analyses provided options that will address near-term low throughput issues. Project Work requests (PWRs) have been developed for several of the mitigation options, and further analyses and development of several of the mitigation options are underway as separate projects.

The following provides conclusions and recommendations to address low flow issues. An implementation plan for recommended mitigations is presented in Section 3.2.

- Alyeska should implement facilities to heat the crude oil as required to maintain operating crude oil temperatures above 32 ºF plus some margin to address short-term throughput variations and upsets. Analysis indicates that the minimum temperature should be maintained at 36 ºF or higher, depending on subsequent risk analysis results, to allow sufficient margin for upsets and severe ambient temperatures. Maintaining this minimum temperature will eliminate the formation of ice inside the pipeline during normal operation. To achieve this:

   – If heat from the sources at North Pole cannot be relied upon, additional heat sources that are capable of duplicating the heat from the sources at North Pole may be required.
   – Implement crude oil heaters at locations that appear to be optimal in existing infrastructure and proximity to the locations that require the heat, and use crude heating facilities to mitigate large volumes of ice and wax amounts ahead of scraper pigs created by pipeline shutdowns and slow downs. Potential initial locations for added heat are PS03, PS04, PS05, PS09, and possibly PS07. (Note that if heating via the residuum returns at NPR cannot be maintained, then additional heating will be required at PS08, PS09, and/or PS07.) Recycle heating can be utilized at PS03, PS04, PS07, and PS09. Heat can be recovered from the turbine generators at PS03 and PS04. Fired heaters can be installed at PS05 and PS09.
   – Consider enhancing the insulation of the aboveground portions of the pipeline north of North Pole to minimize the cost of running heaters. This will reduce the amount of heat required to maintain the crude temperature above freezing. The added insulation will also reduce the amount of heat lost during pipeline shutdowns and extend the time before the crude oil gels and ice forms at pipeline low points. Note that during pipeline shutdowns the heat from point heating sources will not be available.
   – Establish a minimum crude temperature entering the TAPS of 105 ºF from fields on the North Slope.

- Develop a design basis for pipeline shutdown duration and pipeline slowdowns. Develop design minimum temperature to apply during these events.
- Implement procedures to reduce the risk of having a throughput interruption or slowdowns that will result in pipeline crude oil temperatures below the freezing point:
   – Maximize available VMT storage capacity during winter months to reduce potential for pipeline slowdown.
   – Investigate a winter wind loading restriction waiver for the TAPS marine terminal to reduce potential for pipeline slowdown during the winter months.
- Develop contingency procedures, practices, and facilities to minimize the potential formation of ice as a result of extended pipeline shutdowns and reduced

throughput in the winter months, and enhance Alyeska's ability to monitor low throughput water and ice formation. Include the following:

– Modify the current water specification of 0.35 percent to prohibit water slugs above 0.35 percent. Of particular importance during the winter months of November through March, this modification will limit the number of aboveground pipeline low points and shallow buried belowground pipeline low points where excessive water accumulates and make local mitigating response feasible. It will also reduce the amount of water contained in the crude oil stream.

– Install enhanced insulation at critical aboveground pipeline and shallow buried belowground low points to extend the time before ice starts to form during an extended pipeline shutdown. (Based on pipe cool-down temperature data collected during the recent January 2011 shutdown, additional analysis is required to better determine the time for water to accumulate at pipeline low points and the potential for the water to freeze in transit to the low points.)

– Procure contingency equipment to locally respond to water at pipeline low points during an extended pipeline shutdown. (Based on pipe cool-down temperature data collected during the recent January 2011 shutdown, additional analysis is required to better determine the time for water to accumulate at pipeline low points and the potential for the water to freeze in transit to the low points.)

– Maintain injection pumps, tanks, and equipment as well as a quantity of freeze suppressant for injection into the pipe at PS01 as a contingency to lower the freeze point to 20 ºF. This is only a short-term contingency measure to address pipeline slowdowns in the time period before heaters are operational. Use of freeze suppressants will require coordination with the NPR and PetroStar Valdez operations and work to ensure compatibility with the BWT process.

– Implement real-time monitoring and off-line simulation tools to track and forecast pipeline water, pipeline crude oil temperatures, and ice formation on a transient basis during normal operation at low throughput and during pipeline upsets. Models developed as part of the LoFIS will provide the basis for the simulation tools, which would be used to identify specific areas where water regularly accumulates between pig runs and to perform additional monitoring of internal corrosion at these areas of water holdup.

- Identify pump station contingency measures and equipment (such as heating equipment to melt ice) to enable the handling of ice and wax pushed into the pump station by pigs after an extended winter shutdown. The ability to handle such solids should be considered in the design of the heating facilities.
- Open CVs during extended winter shutdowns to minimize ice formation against CV clappers.
- After an extended winter shutdown, move pigs to locations where they can be held in place until throughput is restored and temperatures in the pipeline are above freezing. This will reduce the quantities of precipitated wax and ice pushed into facilities by the pig after an extended winter shutdown.

- Implement the following when flow rates decline to levels when water begins to hold up in flowing conditions (500,000 BPD). These measures will help to reduce the risk of internal pipeline corrosion resulting from increased water holdup in the pipeline at low flows:
  - Regular injection of corrosion inhibitor and biocide chemicals into the crude stream at PS01 and PS04. Residual monitoring and neutralization of the chemicals would be required in the VMT prior to draining treated water into the BWT system.
  - Regular pigging to sweep out accumulated water and wax in the pipeline. Pig designs require modification to optimize the removal of accumulated water. It will become critical to remove as much water as possible from the pipeline and minimize the water remaining after pig passage to reduce the accumulations of water in the pipeline and the potential for internal corrosion.
  - Change the water entrance specification to 0.2 percent at flow rates of 400,000 BPD and below to reduce resulting increased water holdup.
  - Periodically monitor water droplet size distributions at PS01 to determine any changes to the North Slope water separation process or chemical use that could impact water holdup predictions.
  - Utilize the water tracking tools described above to identify specific areas where water accumulates during flowing conditions and determine additional corrosion monitoring requirements for these areas.
  - Evaluate the viability of utilizing instrumented pigs for monitoring corrosion in slackline areas as the extent of these areas increases with lower flow rates. Also

consider reduced velocities and increased transit times for future instrument pig runs at lower flow rates.

- Perform the following to address continued or increased wax deposition:
  - Investigate the use of a pig washer to reduce the cost of pig cleaning and the cost of wax disposal as a hazardous waste.
  - At flow rates below 500,000 BPD conduct an analysis and consider an enhancement to the VMT tank mixers to reduce the accumulation of wax within mixing dead zones. These enhancements would include adding the capability to periodically swing selected mixers.
  - Install an additional pig receiver and launcher at PS09 or another suitable location, along with the capacity to handle ice and wax before the mainline units are impacted. The pig receiver should be installed in conjunction with crude oil heaters and solids handling equipment to enable the use of warm recycled crude to melt wax and ice solids, blending them back into the crude stream downstream of the pump station. The design of the pig receiver should consider the solids generated during an extended winter shutdown.
  - Develop and implement a continuing wax and crude oil solids monitoring program as outlined in Table 4.
  - Implement the following plan to ensure efficient continued use of pigs to clear the pipeline of wax and water during normal operation, and to clear the line of settled solids, water, and ice following a pipeline upset:
  - Establish a formal pigging program to evaluate water and wax issues and establish an optimal pigging frequency and design based on these issues. This program should include an annual review of the pigging program and recommend changes to pigging frequency and/or pig design.
  - Evaluate the viability of pigging at low velocities below 350,000 BPD. Evaluate pig design for lower velocities and higher precipitated wax volumes.
  - Evaluate the viability of pipeline pigging following a pipeline upset, including removal of any wax settled to bottom of the pipe. Perform hydraulic analysis to evaluate pigging if precipitated waxes form a slug downstream of the pig.
- Revisit Alyeska's previous pipeline cold restart analysis:

- Evaluate the crude oil gel strength rheological model parameters assuming various percentages of residuum in the oil.
- Develop new analytical procedures for use with Alyeska's new STARWACS cold restart model.
- Run a validated STARWACS model for various residuum percentages to determine the viability of the current restart plan. Include the formation of ice at pipeline low points, the impacts of crude oil heating, and possible presence of pipeline pigs in the analysis.
- Include annual monitoring of changes in gel strength and gelled crude oil rheological parameters in the crude oil monitoring program recommended above. In addition, perform cold restart analysis modeling every 5 years or to evaluate significant changes to crude oil composition. Use existing Alyeska cold restart models and rheological test methods if the new STARWACS model is not yet available.

- Implement the following items to maintain the vapor space within the crude oil breakout tanks above the UFL:
  - Maintain existing breakout tank heaters at PS04 and PS05, or install new heaters or insulation capable of maintaining a minimum tank temperature of 40 ºF. Install new heaters at PS03 and PS09 capable of the same requirements.
  - Utilize the tank mixers to the maximum extent possible during the winter months.
  - Utilize warm crude oil cycling as an interim measure until heaters are installed to maintain the PS03 and PS09 tanks above 20 ºF.
- Employ the current curvature pig-monitoring program to monitor pipeline frost heave to ensure that reduced oil temperatures do not create an overstress condition in the buried pipe.
- Analyze field instrument capabilities at low flow volumes and impacts that may occur due to degraded field data. Evaluate the accuracy of the existing leak detection system at lower flow rates.
  - Review temperature-monitoring devices for both flowing conditions and during pipeline shutdowns.

  - Perform a detailed analysis of the leak detection system capabilities at lower flow rates.

- Supplement the long-range planning forecast for timing of low-flow related mitigation projects with the forecasting algorithm developed by the LoFIS team based on past throughput decline rates. Update the algorithm annually. This recommendation will augment crude oil forecasts used for Alyeska's long range planning. The forecasts have generally predicted higher throughputs than have actually occurred.
- Continue the current program to evaluate and remediate the bottoms of pipe fittings to protect from freezing of water that accumulates in these fittings.

## 3.2 Plan Forward

This section provides an action plan for implementing mitigation recommendations, identifies several areas of uncertainty where additional testing and analysis are required, and recommends organization and staffing changes to enable the organization to effectively implement recommendations and address low flow issues into the future.

### 3.2.1 Mitigation Implementation is Critical

When the LoFIS began, the 2008 long-range plan indicated that the throughput in 2011 would be 785,000 BPD. The actual throughput in 2011 is approximately 630,000 BPD, much lower than anticipated in 2008. The timing for implementation of near-term mitigation measures has become critical.

Long-term steady state winter operating conditions at flow volumes less than 600,000 BPD and associated operating issues have not been encountered during the history of the TAPS. (Note that the original TAPS designers only considered flow volumes down to 500,000 BPD.) As the TAPS flow rates decline below rates previously experienced and progressively decline each year, operational uncertainty increases. As throughputs decline, issues related to lower flows in the TAPS will continue to develop and challenge Alyeska with managing technical issues and cost-effective operations. In particular, flow slowdowns now put total flow in the TAPS below 500,000 BPD. These slowdowns can persist for weeks, effectively creating pipeline conditions associated with low flow rates of concern.

The following summarizes implementation of the study recommendations.

### *3.2.1.1 Specification Change Implementation*

A number of specification change-related recommendations were made including changes to the water specification, establishing a minimum entrance temperature, and assuring heat is available from the refinery at North Pole.

Alyeska will recommend implementation of the changes to the entrance specifications to the TAPS Owners. Any changes to the entrance specifications are within the purview of the TAPS Owners.

Discussions are currently underway regarding the availability of heat from the NPR. Associated costs will be evaluated and a determination will be made if an additional heater is required south of the refinery.

Implementation of the specification change-related recommendations will be the responsibility of the Alyeska Director of Oil Movements. Implementation of the initial entrance specification changes and assurance of availability of heat from the NPR is recommended for 2011. Additional changes to the water specification will be required when flows reach 400,000 BPD, which is anticipated to occur in approximately 2018.

### *3.2.1.2 Operating Procedures Implementation*

The following recommendations for changes to operating procedures will be the responsibility of the Operations Engineering Team, with changes made to the procedures or new procedures developed by the end of 2011:

- Maximize the VMT storage capacity during the winter months.
- Raise critical CV clappers during an extended winter shutdown.
- Utilize the breakout tank mixers to the maximum extent possible.
- Utilize warm crude recycling to maintain heat in the breakout tanks while heaters are being installed.
- Inject freeze suppressant (for suppression to +20 ºF) at PS01 during flow slowdowns.
- Hold up pipeline pigs to the extent possible after an extended winter shutdown.

#### 3.2.1.3 Monitoring Implementation

The LoFIS utilized the current TAPS crude oil for testing, analysis, model validation, and recommendations. Changes to the crude oil characteristics or North Slope processing may change the timing of recommendations or require additional mitigation measures. These changes include those resulting from flow slowdowns where Producer crude oil deliveries to PS01 are affected, thereby providing changes to the TAPS mix crude oil leaving PS01. Recommendations for continued monitoring of crude oil characteristics, wax, crude oil solids, cold restart parameters, and water droplet sizes should be made regularly to ensure that low-flow related mitigations are effective and planned mitigation timing remains valid.

Monitoring activities related to low flow should be performed by the Operations Engineering Team. The models developed by the LoFIS can be utilized to evaluate changes to crude oil characteristics or other monitoring parameters. The existing crude oil and water-monitoring program should be supplemented to include the recommendations in Table 4.

**Table 4. LoFIS-recommended TAPS Monitoring Program for Low Flow Issues**

| No. | Monitoring Description | Related Low Flow Issue |
|---|---|---|
| 1 | Crude Oil Monitoring (Online IR-spectroscopy or Other) | |
| | Total n-Paraffin and/or Saturates | Pipeline Waxing, Pigging, Tank Solids |
| | Wax Precipitation Temperature (WPT) | Pipeline Waxing |
| | Total Wax Solids at Specified Temperature | Pipeline Waxing, Pigging, Tank Solids |
| | Gel Strength at Specified Temperature | Pipeline Cold Restart, Recovered Oil Viscosity |
| | Viscosity at Specified Temperature | Pumping Costs, Emulsion Behavior |
| | Interfacial Tension (IFT) at Specified Temp. | Emulsion Behavior |
| | Asphaltene wt%, Resin/Asphaltene Ratio | Emulsion Behavior, Pipeline and Tank Solids |
| | Average Water Content and Droplet Size | Emulsion Behavior |
| | Reid Vapor Pressure | Tank Vapor Generation - upper flammability limits (UFL) |

| No. | Monitoring Description | Related Low Flow Issue |
|---|---|---|
| 2 | Pig Monitoring | |
| | Pig Data Logger (PDL) Information (Accel., Vibration, dP) | Wax Deposit Character/Location & Pig Solids |
| | Pig Wax Composition by HTGC | Pipeline Solids Character (Hardness, etc.) |
| | DRAMA/PI Data for Slippage, Wax Thickness/Roughness | Wax Deposit Character/Location & Pig Solids |
| 3 | CANTY Monitoring of Pipeline Flow | |
| | Water Droplet Size Distribution (DSD) | Pipeline Water Fallout |
| | Wax Particle Size Distribution (PSD) and wt% Flowing Solid | Pipeline Wax Fallout |

Note: Existing TAPS online monitoring includes API, BS&W, and RVP/TVP.

#### *3.2.1.4 TAPS Capital Improvements Implementation*

A number of capital improvement mitigation projects were recommended and include crude oil heating, an additional pig trap, and other projects. A number of Project Work requests have already been developed for the near-term capital improvement projects, and in many cases a project team has been formed and work is underway. In all cases individual projects will implement the capital improvement mitigations. This work will be the responsibility of the Alyeska Project Management Team. The project management process will be employed to develop and implement these projects. Funding for the capital improvement projects will follow the Authorization for Expenditure (AFE) process.

### 3.2.2 Continuing Modeling Program

Several models have been developed and validated as part of the LoFIS and will be useful to TAPS engineers for future analysis of low-flow issues related to the TAPS and making predictions during pipeline slowdowns and shutdowns. These models should be enhanced with better user interfaces and a more robust code to enable long-term use by the engineers, and should be linked to online pipeline data and be readily available to the engineers. Models included are the transient water transport, the pipeline temperature, the pipeline cool down, the ice formation, and the wax deposition (commercial) models.

### 3.2.3 Areas Requiring Further Analysis

The following low-flow related issues will require further evaluation and analysis. In some cases additional testing will be required. In all of these areas the issues are generally longer-term at lower throughputs.

#### *3.2.3.1 Wax Precipitation*

The LoFIS included analysis and prediction of wax particle precipitation. However, testing to determine wax precipitation rates at various flow rates was not done. Wax particle size distributions were obtained at several locations along the TAPS, and large particle sizes were observed. Wax particle precipitation should be further evaluated for flow rates below 350,000 BPD before flow rates decline below 400,000 BPD, to include the following:

- Measurement of wax particle densities.
- Measurement of wax settlement rates.
- Measurement of wax particle sizes at North Pole Metering incoming stream.
- HTGC testing of pig wax samples for ratios of normal paraffins to branched and cyclic alkanes to ascertain any difference in solids formation mechanisms attributed to pig wax and VMT tank sludges. This will enable differentiating between precipitated wax and wax deposited on the pipe wall.
- Re-evaluation of settlement rates when test work is completed.

#### *3.2.3.2 Pigging at Low Velocities*

The crude oil velocity at 350,000 BPD may not be sufficient to keep the wax scraped from the pipe wall or precipitated wax suspended in the flow as slurry in front of the pig, which could allow large accumulation of wax in front of the pig and potential for the pig to become stuck in the pipeline. Pigging at flow rates below 350,000 BPD should be further investigated before flow rates reach 400,000 BPD. Such investigation may include evaluating pig designs that differ from the design currently being used (e.g., pig with center bypass) to address the issue of pig bypasses clogging with wax .

#### *3.2.3.3 Corrosion Inhibitor Chemicals*

Specific corrosion inhibitor chemicals were recommended along with an application methodology once flow rates decline below 500,000 BPD. Testing should be conducted to confirm the recommended chemicals and application methodologies prior to implementing the chemical treatment.

#### *3.2.3.4 Water Removal Pigs*

When flow rates decline below 500,000 BPD it will be important for the pigging operation to sweep out as much water as possible to minimize internal corrosion potential. The current pigs are designed to remove wax. The pig design should be further evaluated to optimize the removal of water and wax. Two different pig types may be required.

#### *3.2.3.5 VMT Tank Mixers*

An evaluation of the VMT tank mixers indicates that the horsepower is adequate to maintain the precipitated wax solids suspended. A re-evaluation should be conducted when flow rates reach 500,000 BPD to determine whether the mixers can be optimized by the capability to swing selected mixers to reduce wax accumulation in mixing dead zones.

#### *3.2.3.6 Cold Restart*

The effects of increased residuum percentages and the effects of crude oil heating on crude oil gel strengths should be further evaluated. This could be done in conjunction with the implementation of the new STARWACS cold restart model or, if necessary, with existing Alyeska test protocols and restart models.

#### *3.2.3.7 Water Settlement Rates*

During the January 2011 shutdown event, pipeline cool-down temperatures that were colder than expected along the bottom of the pipe were observed. The cold temperatures and slow water settlement rates may result in freezing of water during a winter pipeline shutdown before the water reaches a pipeline low point. Further analysis is warranted to better understand this issue.

#### *3.2.3.8 Properties of Ice Formed from an Oil/Water Emulsion*

Testing of ice properties was done for ice formed from pipeline free water. A portion of the settled water during a pipeline shutdown may remain as an oil/water emulsion. The properties of ice formation within this emulsion should be further investigated.

#### *3.2.3.9 Inhibition of Ice Formation*

Considering the operational challenges the formation of ice in the TAPS would create and the low water cut of TAPS crude oil, a study should be conducted to determine whether inhibition of ice is possible at lower flow rates.

#### *3.2.3.10 Design Basis*

A shutdown duration and slowdown design basis should be developed along with winter design temperatures that can be used for design of low-flow related facilities.