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BY HAND DELIVERY

The Honorable Senator Lisa Murkowski
United States Senate
Washington, DC 20510-0202

Dear Senator Murkowski:

I appreciate the time you and your staff took to meet with me on December 17 and I hope your holiday season was restful and joyful.

I am writing to follow up on our discussions and to respond to your December 9, 2009 letter regarding the Lisburne L3 pipeline leak. We have now finalized our investigation and better understand the events that led up to the incident and the critical factors we believe led to the incident. We have identified corrective actions to help minimize risks of reoccurrence.

The leak was discovered on November 29, 2009 at approximately 3 a.m. within the Lisburne field in an 18-inch flow line that carries unprocessed oil, gas, and produced water from several drill sites to the Lisburne Production Center (LPC). The rough preliminary estimate of the spill volume, using surveying techniques, was 45,822 gallons/1,091 barrels of liquids. With the exception of summer tundra rehabilitation, site cleanup is now complete. One of the goals of the site cleanup was to recover the oil from the site to provide an accurate volume of the oil that was released. Just this past Friday, January 22, 2009, ADEC agreed with BPXA's third-party consulting firm that the total volume of oil recovered from the site was approximately 13,500 gallons/322 barrels. BPXA is still working with ADEC to get agreement on the final oil volume when considering potential evaporation and the percentage of oil that remains entrained in the soil and vegetation that was removed and stockpiled from the site. However, our view today is that the preliminary estimate was substantially high.

The 18-inch flow line has been in operation since 1985, when it was commissioned to deliver production from Lisburne drill site L3. At this same time, a 24-inch pipeline was commissioned to deliver production from Lisburne drill sites L4 and L5. For approximately 10 years both the 18-inch and the 24-inch pipelines carried dedicated production from those individual drill sites. However, as the Niakuk field to the northeast of Lisburne was brought into production, a production optimization study was done and the decision was made to "loop" the lines together into a common transportation system. What this did was to create a single pipeline system that allowed the production from the three Lisburne drill sites and the Niakuk field to flow into either the 18-inch flow line or the 24-inch flow line. Looping the lines in this manner reduces backpressure in the individual pipelines and decreases oil slugging events. The system has operated in this looped configuration since that time. The two critical factors that led to the overpressure rupture of the pipeline were this looped configuration in combination with inadequate temperature monitoring locations.

To ensure a thorough response to your December 9 letter, I have extracted your questions and provided responses for each.

<u>Responses to Questions</u>

1. *Did BP Exploration (Alaska) Inc. (BPXA) know that the line was not flowing prior to the incident? What were the events leading to the incident?*

On November 14, 2009, LPC operators noticed a change in process conditions at the production facility. They suspected a decrease in temperatures in one of the production lines. After various tests, they determined that the 18-inch pipeline was not flowing and that the line had ice blockages close to both ends of the pipeline. LPC staff met and began developing a thawing plan in accordance with the BPXA Safe Handling of Hydrates Procedure. A draft temporary line thawing plan was completed on November 22, 2009, and presented to the operations team leader for review.

During the winter of 2007-08, LPC had discovered an ice plug in the 14 inch flow line coming from L2 to LPC. This line had previously been de-oiled and shut in. When it was being restarted on December 27, 2007, an ice blockage attributed to a leaking valve was discovered. A thawing plan was prepared, but an extensive effort to thaw the pipe and return it to service was unsuccessful. After a thorough risk assessment, the decision was made to leave the line frozen in place until the summer of 2008. That line was returned to service without incident on June 7, 2008. Because of that recent unsuccessful experience at the facility in trying to thaw a similar line and the known risks of damaging a pipeline during thawing operations, the North Area Manager asked LPC staff to complete a risk assessment of other options when they presented their draft thawing plan to him on November 26, 2009. Several days later a Lisburne Drill Site Operator discovered the spill during one of his periodic visual inspections of the pipeline system.

As part of the investigation, historical temperature data from the two pipelines was analyzed. When graphed and compared against ambient temperatures, it shows that flow in the 18-inch line started to slow in late May 2009 and stopped altogether in June. The condition existed for some time prior to that time, but it was unknown for three primary reasons. First, unlike common carrier pipelines that transport fully processed crude oil, three-phase flow lines usually do not contain flow measuring devices such as meters. Second, because of the looped condition of the two pipelines the production flow rates from the three Lisburne drill sites and Niakuk was not impacted because the entirety of the flow from these drills sites continued to flow through the 24-inch line to the LPC – essentially, the path of least resistance. Finally, temperature monitoring devices are used on three-phase pipelines to indirectly help monitor continued flow, but in this instance they were physically located on the pipelines at a location inside the production facility and not outside. As a result, the freezing temperatures of the fluids inside the pipeline went unrecognized until November 14.

2. *If BPXA personnel knew the line was not flowing at normal rates, could BPXA have taken steps to evacuate the oil and water from the line?*

On November 14, when the condition was discovered in the pipeline, the operators tried bleeding down the pressure in the line, only to find that the line was frozen very close to both ends of the 16,431 foot long pipeline. In order to minimize the chance for leaks to the tundra, the pipeline section had been designed with no valves, bleed locations, or any other ports that could have been used for fluid removal.

The response to Question 1 discusses how LPC staff was following our standard operating procedure for thawing frozen pipelines when the event occurred.

3. *How long did it take to discover the leak after it occurred?*

LPC drill site operators and North Slope Security conduct visual surveillance on three-phase pipelines with frequent drive-by inspections. An Operator discovered the spill on November 29, 2009 around 3 a.m. while driving on the road next to the pipeline as part of his normal operational rounds check. The last inspection of the pipeline prior to that time occurred around 6 hours earlier, at approximately 9 p.m. on November 28, 2009, when security personnel drove by that area and reported no evidence of a leak.

4. *Why are there no spill detection devices on this line? Are there other lines with no spill detection systems?*

Oil transmission pipelines that carry fully processed crude oil have meters that accurately measure oil movement. These oil transmission lines also use those meters as part of their leak detection systems. However, as mentioned above, multi-phase production flow lines typically do not have either metering or leak detection systems. Leak detection for three-phase pipelines is commonly provided through visual drive-by inspection of the lines, daily checks of each well's production rate, and by monitoring flow through low-temperature alarms and pressure alarms.

5. *What assurances can BPXA give that this type of occurrence will not happen again on another line?*

Immediately after the incident we took steps to manage the potential risk from similar occurrences on other lines on the North Slope by completing an inventory of all looped pipelines in our operations to ensure we knew all locations with similar risks. We also check each well line and flow line on a daily basis, weather permitting. In addition, we have identified three recommendations and 12 specific action items to help ensure a similar event will not happen again, including the following three actions, which have already been initiated in some manner. First, we evaluated the location of the temperature sensors of the other looped lines to ensure they were located outside the facility. Second, we have initiated an engineering assessment of all looped lines and will implement all corrective actions based on the results of that assessment. Third, we will be reviewing and updating all Process Hazard Assessment (PHA) worksheets to specifically include line freezing and potential rupture as a hazard scenario. These and the other action items we have identified are designed to address the root causes of the incident and will be implemented across all locations.

6. *Are ice plugs a common problem, and specifically on underground low pressure lines on the Slope? Information on past issues with ice plugs and logistical issues involved in dealing with ice plugs.*

BPXA operates a single, approximately one mile long section of underground, low-pressure, three-phase pipeline. This pipeline is buried in the Prudhoe Bay Seawater Treatment Plant Causeway and has not experienced any ice plug issues. It is not a looped line. Since it is embedded in a manmade causeway (not in the permafrost), the underground location actually assists with freezing prevention by creating a thaw bulb that keeps the fluids warm during periods of cessation in pipeline flow.

For the remainder of the piping, the basic installation design for pipeline systems on the North Slope is above-ground piping on spans raised three or more feet above the ground. There are occurrences of low-pressure, three-phase pipelines dipping underground for road or caribou crossings, but these locations are comparatively few across the field. In these circumstances, the line is usually installed inside a protective casing within the underground crossing, and ice plugs are not an issue.

BPXA has operated in Alaska for over 50 years and has a high level of respect for the harsh arctic environment on the North Slope of Alaska. We have dozens of procedures specifically designed to help ensure that wells, well lines, flow lines, and production operations are managed with cold freezing temperatures in mind. That said, while ice plugs or hydrates are not a common occurrence, we can expect them to occur from time to time. Most occur in well piping and smaller diameter process piping. The majority of ice or hydrate blockages are safely and effectively resolved. The risk of ice or hydrates is usually associated with ice/hydrate plug movement, often during the thawing procedure. There have been cases when the mass and velocity of the ice/hydrate plug movement has resulted in visible movement of the piping system in which they are contained. In rare instances, the forces generated by the movement of an ice/hydrate plug have resulted in physical damage to piping or valves. Because of these risks, when we discover a frozen line, we have a detailed Safe Handling of Hydrates Procedure that must be followed.

The procedure allows operators to initiate mitigation activities through the injection of hot fluids or heating of the pipe surface using hot air or electrical resistance, but only if specific safety conditions are met. Mitigation can only occur if we have the ability to monitor and manage pressure changes throughout the mitigation attempt. If mitigation fails, or we do not have the confidence that we can safely manage the potential pressures associated with mitigation, the procedure requires that the pipe remain frozen in place and monitored until it can be slowly thawed by warming summer temperatures. In this instance, as discussed in the response to Question 1 above, we had developed the thawing plan and were conducting a risk assessment at the time the leak occurred.

As we discussed in our December meeting, a pipeline freezing incident did occur at Prudhoe Bay in 2001 involving a looped line running from D-Pad to Gathering Center One. The investigation into the D-Pad incident highlighted the importance of monitoring flow conditions independently on all lines in a looped line configuration. Unfortunately, the event occurred just months after BPXA took over as operator of the Lisburne field from ARCO Alaska and the lessons learned from the D-Pad incident were not effectively transferred to this looped line at Lisburne. Several of the corrective actions identified in response to the November incident support our goal of more fully embedding lessons learned across all North Slope operations.

I hope the responses above answer your questions. I look forward to meeting with you again to discuss our progress and actions. If you have additional questions, please do not hesitate to call me.

Sincerely,

John Mingé