bp

By Fax and U.S. Mail

Steve Marshall
President, Alaska

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April 3, 2006

The Honorable John D. Dingell
Ranking Member, Committee on Energy and Commerce
United States House of Representatives
Washington, DC 20515
Fax: (202) 226-0371

The Honorable George Miller
Member, Committee on Resources
United States House of Representatives
Washington, DC 20515
Fax: (202) 225-5609

Gentlemen:

Thank you for the opportunity to respond to your letter dated March 24, 2006 and your questions related to the North Slope oil spill from the Prudhoe Bay Unit Western Operating Area oil transit line (WOA OTL). This letter responds to those questions. We also look forward to meeting your staffs during their visit to Alaska next week to answer questions and ultimately to provide you with a better understanding of the issues related to this spill.

I am deeply disappointed to have had a spill of this magnitude. We are committed to learning from the incident and will apply these learnings to other parts of the field operation, as well as sharing what we learn with others. As a first step in this process, and as discussed with members of your staffs, we are thoroughly investigating the circumstances related to the incident to help us ensure it won't happen again. The investigation team is being led by a senior BP leader from outside of Alaska and includes representatives of the Alaska Department of Environmental Conservation (ADEC) and the United Steelworkers Union.

Although the investigation is not yet complete, the information available to the team suggests that recent and aggressive internal corrosion is the likely cause of the leak. Over 2000 inspections of our other Greater Prudhoe Bay oil transit lines conducted since the spill have not detected accelerated corrosion in any other lines, or in the other segments of the WOA OTL. Although the leak detection system worked as designed and met ADEC regulations, we still experienced a substantial spill. The investigation report is anticipated shortly. Beyond the report, we are committed to making improvements to our overall leak detection and surveillance program and will discuss our analysis with the relevant state and federal agencies.

We have included two attachments to further respond to the questions and points raised in your March 24 letter. You will see that we have expanded our response beyond the information you requested to provide a more complete description of our corrosion program.

- Attachment 1 is a summary of BP Exploration (Alaska) Inc.'s (BPXA) corrosion monitoring and prevention program, which is reviewed every six months by ADEC. Based upon the data collected under our program, our corrosion technical specialists did not expect accelerated corrosion at this location because there was an established track record of low and manageable internal corrosion rates in this line.

- Attachment 2 contains our responses to the questions attached to your letter. The responses are based on our current understanding of the issues and the information that we have gathered to date.

On a forward basis, we have committed to several actions in response to the spill:

- We will clean up the spill to the highest standards that minimize damage to the environment.

- The WOA OTL segment from Gathering Center 2 (GC2) to Gathering Center 1 (GC1) will not be brought back into service until its integrity can be confirmed.

- We will smart pig the WOA OTL within three months of placing the segment of the WOA OTL that leaked back into service.

- We will inject corrosion inhibitor directly into the WOA OTL upon restart.

Please do not hesitate to contact me should you have any further questions.

Sincerely,

S. Marshall

Steve Marshall

cc with attachments:
The Honorable Joe Barton, Chairman
Committee on Energy and Commerce
Mr. Brigham McCown, Acting Administrator
Pipeline and Hazardous Material Safety Administration
U.S. Department of Transportation

ATTACHMENT 1

BP Exploration (Alaska) Inc. (BPXA) - Corrosion Monitoring and Prevention Program

Background

BPXA's crude oil production facilities are located on the North Slope of Alaska. Prudhoe Bay is the largest of the five Alaskan oil fields operated by BPXA and was discovered in 1968. Oil production from Prudhoe Bay commenced in 1977, and remained at a rate of 1,500,000 barrels per day until 1989. Since 1989 production has declined to a current rate of just under 500,000 barrels of oil per day.

Numerous facilities and equipment have been built over the past 30 years to produce, process and transport crude oil from Prudhoe Bay and the four other production units that are operated by BPXA. Table 1 is a summary of the major facilities and equipment that have been built to produce oil from Alaskan fields that BPXA operates

Table 1: BPXA Operated Facilities

2,000 wells
1,500 miles of pipelines (not including TAPS)
3,500 Pressure Vessels
1,500 Tanks
11 Major Separation Plants
2 Major Gas Treating Plants
3 Major Water Treatment Plants

The oil formations at Prudhoe Bay and other North Slope fields produce a mixture of oil, natural gas and water – these three components need to be separated before the oil can be delivered to the Trans Alaska Pipeline System. The associated natural gas contains carbon dioxide which dissolves in the water to form carbonic acid. This acid is corrosive to the carbon steel equipment, such as pipelines, and must be treated to mitigate its corrosive effects on the internal system components. The produced liquids may also entrain sand and rock particles which, at high velocity in the pipelines, can erode of the wall of the pipe. In addition, moisture on the outside of pipe from snow, rain, and condensation can cause external corrosion if they are allowed to contact the pipe.

Program Objectives and the "Fit for Service" Strategy

The objective of BPXA's corrosion monitoring and prevention program is twofold –

1. Control corrosion in all equipment, pipelines, vessels and tanks.
2. Provide assurance that the equipment is in good condition – meaning it is safe to operate and will not release fluids into the environment.

Equipment that is in the safe and environmental sound condition described in objective two above is also referred to as being "Fit for Service". BPXA has designed our corrosion monitoring and prevention program around a "Fit for Service" strategy that has four key elements –

1. Identification of corrosion mechanisms for various equipment and lines (internal, external, erosion).
2. Frequent monitoring of corrosion rates through various corrosion monitoring programs.
3. Periodic inspections to identify corrosion damage and pipeline wall thickness.
4. Mitigating the progress of corrosion.

Specific Processes and Procedures

Numerous processes and procedures are utilized to deliver the Fit for Service strategy. These processes and procedures are summarized below.

Corrosion Monitoring: A variety of techniques are used to monitor the corrosion rates, including the use of metal weight loss coupons at over 5,000 locations. These coupons are inserted into the fluid stream. After the coupons have been exposed to the stream for a set period, they are removed and analyzed to determine the coupon corrosion rate. In addition, BPXA has installed 100 electrical resistance corrosion probes that continuously monitor the corrosivity of the fluids. The data obtained from the corrosion coupons and probes are used to adjust corrosion inhibitor injection rates and to initiate other corrosion mitigation actions.

Corrosion Mitigation: A variety of methods are used to mitigate corrosion. The type of method used is dependent upon the type of corrosion most likely to occur at a given location. Corrosion caused by the mixing of carbon dioxide (CO_2) and water, forming carbonic acid, is the most common type of internal corrosion in BPXA's facilities. CO_2 or carbonic acid corrosion is typically controlled by injection of corrosion inhibitor chemicals into the production streams. BPXA currently injects over 2.5 million gallons of corrosion inhibitor annually.

Bacterial corrosion resulting from bacteria and bacterial byproducts can also result in internal corrosion. Bacterial corrosion is controlled by injection of a biocide chemical. Many corrosion inhibitors contain quaternary amines, which also have biocide chemical properties. Mechanical pigging of pipelines is also used to remove solids and water that may build up in low points in the pipelines over time.

External corrosion of pipelines is controlled by replacing wet insulation or degraded coating with dry, sealed material.

Inspection: BPXA has one of the largest inspection programs in the oil and gas industry and currently inspects over 100,000 individual locations every year, for both internal (60,000) and external (40,000) corrosion. North Slope pipelines are unique compared to most oil and gas operations, as North Slope pipelines have been built above ground to prevent thawing of the permafrost and to protect the tundra. Even in areas where the pipelines are below ground, such as at road or caribou crossings, the pipelines are cased (i.e. placed within another larger pipe). The above ground pipeline configuration is advantageous to the corrosion monitoring program as it allows for significantly easier access for inspection compared to a buried pipeline.

Below are the inspection programs used to identify specific forms of corrosion damage.

- Corrosion Rate Monitoring (CRM) programs repeat inspections at the same location, typically every 6 months, to look for loss of metal.
- Corrosion Under Insulation (CUI) programs are designed to detect external corrosion that can be hidden by the thermal insulation that is on the outside of the pipelines.
- Erosion Rate Monitoring (ERM) is conducted at locations that could be susceptible to erosion inside the pipe due to high velocities and fluid characteristics. ERM is typically performed at bends every 3 months.

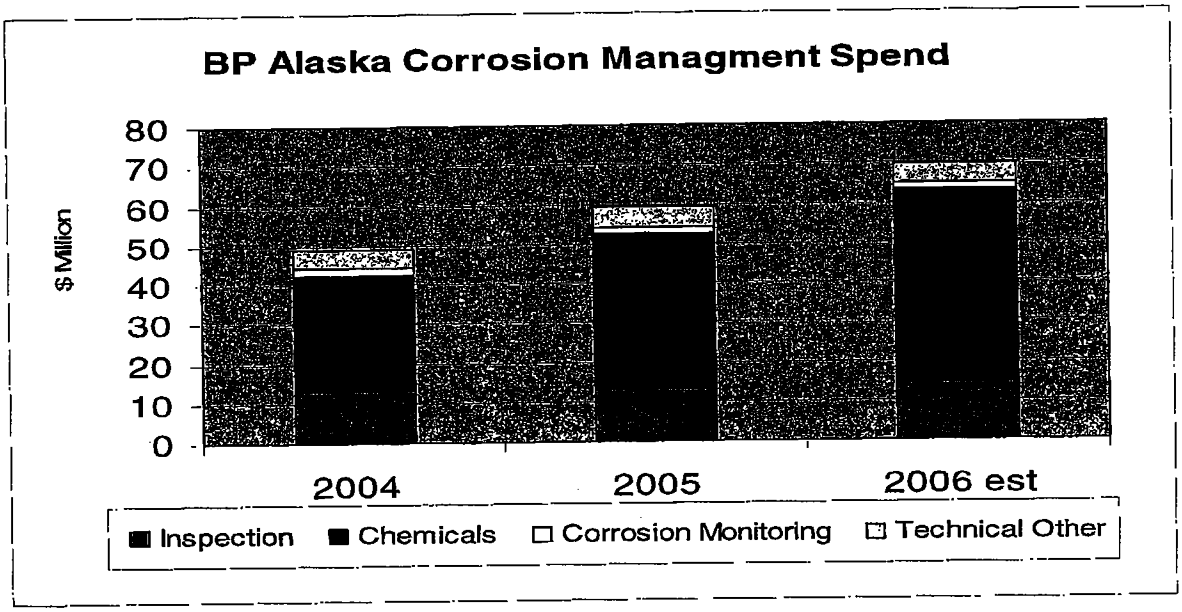
A variety of inspection techniques are used in the inspection programs described above. The techniques include **visual, ultrasonic, radiographic** and **magnetic flux** and each can be used to detect different types of damage. The basic technology in many of these techniques has also been built into devices which crawl, climb or travel along equipment to provide a "damage map" of large areas or all of a piece of equipment. For example, **smart pigs** can inspect the surface of an entire pipeline. Smart pigs and other automated techniques are helpful in identifying locations that should be more closely monitored using one of the point inspection methods, e.g visual, ultrasonic, radiographic. Smart pigs can also provide assurance that the spot inspections are truly representative of the pipeline condition. Again, the above-ground design of the North Slope pipelines makes it possible to monitor specific locations with potential damage with much greater frequency compared to buried pipelines.

Below is overall summary list of the various inspection and monitoring techniques, some which are mentioned above as well as additional items.

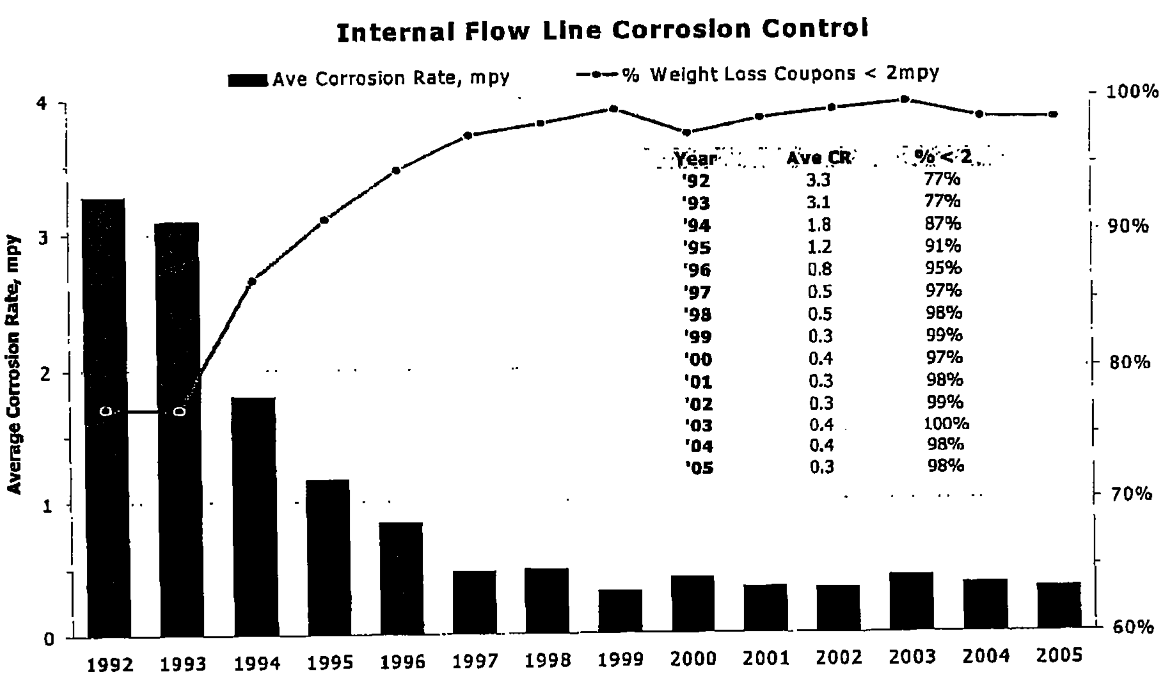
Inspection Techniques	Corrosion Monitoring Techniques
Radiography	Weight loss coupons
Tangential radiography	Electrical resistance probes
Ultrasonic	Galvanic probes
Guided wave	Linear polarization
Electro-magnetic pulse	
Magnetic flux smart-pig	

Corrosion Program Resources and Results

BPXA has been funding an ever more aggressive Corrosion, Inspection, Chemical (CIC) program to address the challenges posed by corrosion. Twenty-five BPXA engineers and technical specialists are teamed with an alliance of world leading suppliers of specialist services for inspection and chemicals. The 2006 annual budget for the program is $71 million, an increase of 15 percent from 2005, and 80% from 2001. The chart below illustrates the resource spend and commitment from 2004 through 2006.



Most important, a substantial improvement in control of internal corrosion in three phase flow lines (i.e. pipelines that transport oil, gas and water) has been seen over the past several years. The following graph illustrates the significant improvement in corrosion rates experienced since the early 1990s and the effective management of the corrosion rate over the past ten years. This plot shows the average corrosion rate on major production flow lines.



Year	Ave CR	%<2
'92	3.3	77%
'93	3.1	77%
'94	1.8	87%
'95	1.2	91%
'96	0.8	95%
'97	0.5	97%
'98	0.5	98%
'99	0.3	99%
'00	0.4	97%
'01	0.3	98%
'02	0.3	99%
'03	0.4	100%
'04	0.4	98%
'05	0.3	98%

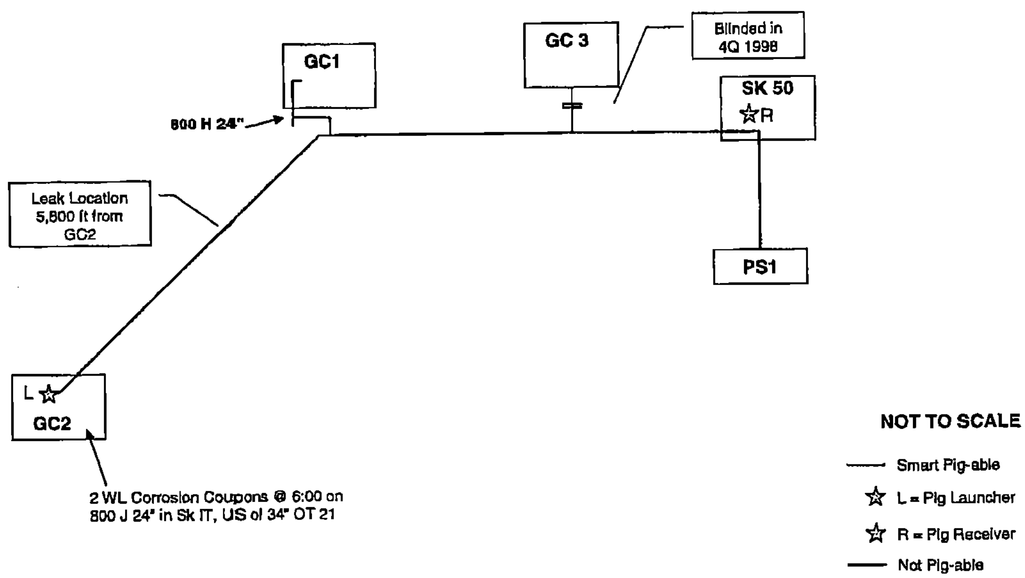
ATTACHMENT 2

Responses to Questions

1. Please provide a detailed schedule of all corrosion testing for the entire Oil Transit Line (OTL). For this effort, please delineate the type of testing used (e.g. visual, smart pigging, ultrasonic spot, etc.). Please also indicate where specifically any testing occurred.

The schematic below provides an illustration of the Prudhoe Bay Unit Western Operating Area Oil Transit Line (WOA OTL).

WOA Pipeline Schematic for Processed Sales Oil



The tables below provide detail on the corrosion monitoring and inspection programs applied to the WOA OTL from August 1998 (after the WOA OTL was last inspected using a smart pig) through February 2006.

Table I

WOA OTL Distribution of Inspections (August 1998 – February 2006)

Geographic Area	External Inspection	Internal Inspection	Cased Pipe Inspection
GC2 to GC1	85	149	10
GC1 to GC3	29	112	1
GC3 to Skid 50	77	127	13
*Skid 50 Bypass	10	491	-
Skid 50 to PS1	60	60	-

*Note: The bypass segment at Skid 50 was decommissioned in 2003

Table II
WOA OTL Inspection Program (August 1998 – February 2006)

Year	Nondestructive Test Method	No. of Inspections	Purpose of Assessment
1998	Ultrasonic Testing	29	Internal Corrosion
1998	Walking Speed Survey	1	Visual Mechanical Integrity Deficiencies
1999	Tangential Radiography	35	External Corrosion
1999	Ultrasonic Testing	134	External Corrosion
1999	Ultrasonic Testing	62	Internal Corrosion
2000	Electro-magnetic Testing	2	Cased Pipe Inspection/External Corrosion
2000	Guided Wave Inspection	1	Cased Pipe Inspection/Internal & External Corrosion
2000	Ultrasonic Testing	17	External Corrosion
2000	Ultrasonic Testing	246	Internal Corrosion
2001	Electro-magnetic Testing	2	Cased Pipe Inspection/External Corrosion
2001	Ultrasonic Testing	11	External Corrosion
2001	Radiographic Inspection	1	External Corrosion
2001	Ultrasonic Testing	263	Internal Corrosion
2002	Ultrasonic Testing	130	Internal Corrosion
2003	Tangential Radiography	2	External Corrosion
2003	Guided Wave Inspection	13	Cased Pipe Inspection/Internal & External Corrosion
2003	Ultrasonic Testing	21	External Corrosion
2003	Ultrasonic Testing	62	Internal Corrosion
2003	Walking Speed Survey	1	Visual Mechanical Integrity Deficiencies
2004	Tangential Radiography	40	External Corrosion
2004	Guided Wave Inspection	5	Cased Pipe Inspection/Internal & External Corrosion
2004	Ultrasonic Testing	40	Internal Corrosion
2005	Guided Wave Inspection	1	Cased Pipe Inspection/Internal & External Corrosion
2005	Ultrasonic Testing	107	Internal Corrosion

A further description of the various inspection and tests performed on the WOA OTL is summarized below.

(a) **Smart Pig** – The WOA OTL was inspected using a magnetic flux smart pig in 1990 and 1998. The line is scheduled to be inspected using a smart pig again during 2006. The "pig-able" section of the line from Gathering Center 2 ("GC-2") to Skid 50 ("SK 50") adjacent to Pump Station 1 of the Trans Alaska Pipeline was inspected.

(b) **Ultrasonic (UT) Inspections** – BPXA completed 1,122 individual UT inspections at both fixed and variable locations on the WOA OTL between July 23, 1998 (the date of the last smart pig run) and February 2006. "Fixed locations" are known damage sites where recurring inspections are performed to monitor corrosion growth. "Variable locations" are new locations added to discover potential areas of new corrosion. Table I above shows which section of the GPB OTL was inspected between August 1998 and February 2006. Table II shows the number of inspections between August 1998 and February 2006 relative to the geographic segment of pipeline. In addition, from March 2, 2006 through March 28, 2006, BPXA has completed over 2,000 inspections on the WOA OTL alone.

Exhibit A is an aerial overview of the WOA OTL with detailed inspection locations.

(c) **Guided Wave Inspections** – BPXA completed 20 guided wave inspections on the WOA OTL between August 1998 and February 2006. Table II shows the number of inspections and the year when they occurred. The guided wave inspections occurred at the road and caribou crossings along the WOA OTL.

Exhibit B is an aerial overview of the WOA OTL with crossing locations specified where the guided wave inspections were conducted. Guided wave inspections had been conducted at all of the road and caribou crossing locations from GC-2 to GC-1 with the exception of crossing R-1 at GC-2.

(d) **Weight Loss Coupons** – Coupon monitoring points are located on the WOA OTL within the Gathering Center 1 (GC1) and Gathering Center 2 (GC2) facilities. GC2 is located upstream of the failure point and GC1 is located downstream of the failure point. The coupons are analyzed every three months.

(e) **Electrical Resistance (ER) Probe** – ER Probes are located on the WOA OTL at both Gathering Center 2 and Gathering Center 1. Both ER probes are read and analyzed weekly.

(f) **Electromagnetic Pulse** – BPXA completed 4 electromagnetic pulse inspections on the WOA OTL between August 1998 and February 2006. Table II shows the number of inspections and the year when they occurred. The inspections occurred in the cased pipe sections of the WOA OTL (road or caribou crossings). The caribou crossing at the spill location had been inspected using the electromagnetic pulse method.

(g) **Tangential Radiography** - BPXA completed 77 tangential radiography inspections on the WOA OTL between August 1998 and February 2006. Table II shows the number of inspections and the year when they occurred.

(h) **Walking Speed Survey** – The WOA OTL was last examined with a Walking Speed Survey (WSS) in 2003 in locations that are accessible by foot. The WSS for the WOA OTL consists of a visual examination of the pipeline, supports and related components to identify mechanical integrity deficiencies.

2. Please indicate whether BP had any specific warning(s) that the OTL faced significant corrosion issues from within the company or through outside engineers or consultants. If so, did any reports or consultations predict problems in the low-lying caribou crossings? If so, please describe those reports or consultations.

BPXA is not presently aware of any specific warning that the WOA OTL faced a high risk of leaking due to accelerated internal corrosion at this location though we are continuing to check our monitoring data. The corrosion coupon data reviewed to date has indicated corrosion rates well below the BPXA standard target of 0.002 inches per year ("2 mils per year" or "2 mpy"). Corrosion coupon data have been demonstrated to be an effective way of measuring internal corrosion rates.

Similarly, annual ultrasonic (UT) inspection data showed manageable corrosion rates. There was some evidence of an increased internal corrosion rate in September 2005. In response, additional inspection points were added to the monitoring list and the inspection frequency was doubled. A smart pig run was scheduled for 2006.

BPXA was aware of the potential for external corrosion in low-lying caribou crossings, such as the type of external corrosion that caused the spill from the Y-36 three-phase flow line in 2003. BPXA undertook a number of actions after the Y-36 spill, including visual inspection of all caribou crossings, in order to make repairs at any locations that held accumulations of water – as was the case with Y-36.

The potential of external corrosion in cased pipe segments is being addressed in the inspection program by the use of smart pigging and long-range inspection techniques. These inspection techniques include electro-magnetic and guided-wave inspections. Only a small fraction of cross country pipelines are inaccessible to direct inspection methodologies such as visual, radiographic or ultrasonic inspection.

While cased pipe segments are often associated with dips in the pipelines not all dips are associated with cased segments. There is nothing about the casing itself that creates an environment for internal corrosion to occur and, certainly, the approximate 100 ft of piping inside the casing is often in a similar condition as the piping outside of the casing. As a result, assessment of internal corrosion in cased pipe segments can be inferred through examination of the piping outside of the casings.

BPXA's corrosion program and results are reviewed by ADEC on an annual basis.

3. If the OTL had not been smart pigged since 1998 (as reports claim), please indicate why it was not deemed prudent by BP to apply technology with greater frequency to such a strategic line.

The WOA OTL's above ground construction allows for more frequent and precise point inspections and monitoring when compared to a smart pig inspection. Frequent point inspections of areas with known corrosion using ultrasonic and other methods have been found to be a more effective method to monitor and adjust the corrosion prevention program thereby reducing the need for frequent smart pig runs.

Smart pigs do provide a comprehensive view on the condition of a pipeline. The results from smart pig runs are used to determine areas with potential damage that require recurring follow-up using UT and other point inspection technologies. The WOA OTL monitoring and inspection program followed this approach using the results from the two earlier smart pig inspections in 1990 and 1998, and the various point inspections, e.g. UT, guided wave.

The next smart pig inspection had been planned for 2006.

4. Please specify where ultrasonic tests were taken on the failed line prior to the leak, and where those tests were taken relative to the failed section. In particular, was the failed section tested prior to the leak? If not, why not? Also, does BP believe that a test measuring tolerances in one section of the OTL to be representative of tolerances for the entire line? Please explain.

As noted in the response to Question One, UT testing was done at a variety of fixed and variable locations prior to the leak since 1998.

Conventional UT was not taken at the leak location because it was in a buried crossing. The crossing had been tested using guided wave technology both prior to and post leak at the leak location. Guided wave technology provides a volumetric assessment of pipe-wall condition more suitable for broad areas of external corrosion metal loss rather than internal pitting. While the technique may have detected the corrosion pitting on the internal surface, guided wave technique does not provide quantitative information with exact measure of wall loss. The guided wave technique is used to screen for anomalies, monitor for active corrosion and where active corrosion is determined, corrective action is taken.

The 1998 smart pig did show 9% wall loss at the location of the leak. This wall loss occurred after 20 years of operation including the period when no formal inhibition programs were in place. The remaining 91% of wall thickness was judged to be more than sufficient to ensure integrity between the smart pigging runs.

As part of our corrosion monitoring program, 37 locations on the WOA OTL were re-examined with ultrasonic testing to assess pipe condition and corrosion rate between August 12, 2005 and September 9, 2005.

- 7 locations showed increasing corrosion damage with inspection intervals ranging from approximately 2 to 8 years and corrosion rates ranging from 9 to 32 mpy. (mpy equals 0.001 inch per year, or mil per year.) The severest corrosion penetration recorded was a pipe wall thickness 0.140 inches compared to the nominal pipe wall thickness of 0.380 inches.
- 30 locations showed no increased damage with inspection intervals ranging from approximately 1 to 10 years. The corrosion rates for these locations were zero and the severest corrosion penetration recorded was a pipe wall thickness of 0.180 inches compared to a nominal pipe wall thickness of 0.380 inches.

In October 2005, five of the same locations inspected between August and September were re-examined. None of the locations showed any increase in damage from the prior inspection one to two months earlier.

The nearest upstream and downstream locations to the leak site that were inspected in 2005 were approximately 4,600 feet upstream and 1,200 feet downstream. Neither of these locations showed any increase in corrosion in the 2005 survey.

Measurements in one location may be representative of other locations depending on the mechanism of damage. If the mechanism is understood, it is possible to identify the locations of highest risk and rely on measurements taken at those locations to be indicative of worst case corrosion rates. This is the basis for BPXA's risk based inspection. BPXA believes the six month spot inspection schedule for March 2006 would have detected the accelerated corrosion downstream of the leak location, which would likely have alerted BPXA to the possibility of accelerated corrosion within the caribou crossing.

5. It has been reported to us that the line in question, while having a low water cut, also has a very low flow rate and this essentially makes the OTL a giant "oil-water separator." We are advised that results in the settlement of solids in the underlying layer of stagnant water. Is this the case? If so, what are or were implications of this?

The flow in the WOA OTL has a low water cut because it carries sales quality crude. Although the flow rate has dropped to one-quarter of the peak rate, the velocity in this line has always been low. There is potential for internal corrosion along the bottom of the line as water or solids drop out or through microbiologically induced corrosion (MIC). Prior to this spill these risks were mitigated in two ways:

1. There are several stages of separation (oil, water and gas) with the final separator pressure at approximately 15 psig. This essentially removes all of the corrosive carbon dioxide gas and the majority of the solids.
2. Any water present in the oil should contain corrosion inhibitor carried over from treatment upstream. The presence of corrosion inhibitor would reduce any residual carbon dioxide corrosion rate to an acceptable level (<2 mpy). These corrosion inhibitors typically inhibit microbiological growth as well.

These mitigating measures were effective in mitigating internal corrosion for many years.

It should be noted that BPXA had an indication prior to the spill that something caused a reduction in the carry over of corrosion inhibitor in the water in this particular section of the WOA OTL, although we did not believe it to be a matter of serious concern. The investigation is still ongoing but there are two leading theories at this time: the inhibitor was absorbed onto the fine sand and/or the corrosion inhibitor effectiveness was reduced because of a reaction with an emulsion breaker used in the production facility to reduce the amount of water and flour silts in the oil transit line. To mitigate this effect, BPXA will directly inject corrosion inhibitor into the WOA OTL when GC2 restarts.

6. Were significant amounts of solids known to be present in the bottom of the line prior to the leak, particularly at the caribou crossings where the pipeline dips? Have significant amounts of sludge been found at the caribou crossings since examining the pipeline post leak? If solids were known, what concern(s) would this pose to the line? Also, if solids were deemed a concern, would a maintenance pig have been able to remove them and by removing them, would this in any way have made the line less likely to fail?

Records from the 1998 pigging program did not show an unusual presence of sediment in the WOA OTL. BPXA has no indication of the amount of sediment that might be present in the line at this time. We are currently researching methods which could be used to identify sediment in the line.

In the last one to two years BPXA Operations have seen an increase in fine sediment production (so called flour sands) into GC2 from the production of "viscous" oil. It may be possible that some portion of these sediments carried over into the oil transit line. If sediments do carry over, the main risk of corrosion would be from under-deposit or bacterial corrosion. It should be noted, however, that these same sediments should have carried through to the WOA OTL downstream of GC1. That portion of the WOA OTL does not appear to have experienced the same accelerated corrosion as did the segment from GC2 to GC1.

The risk from sediments has been discussed in Question Five. If sediments were believed to be a concern, a maintenance pigging program would be appropriate to remove them.

7. Please explain why the leak detection system on the OTL line failed to detect the leak and what changes will be made to leak detection systems on this and all of the BP North Slope lines.

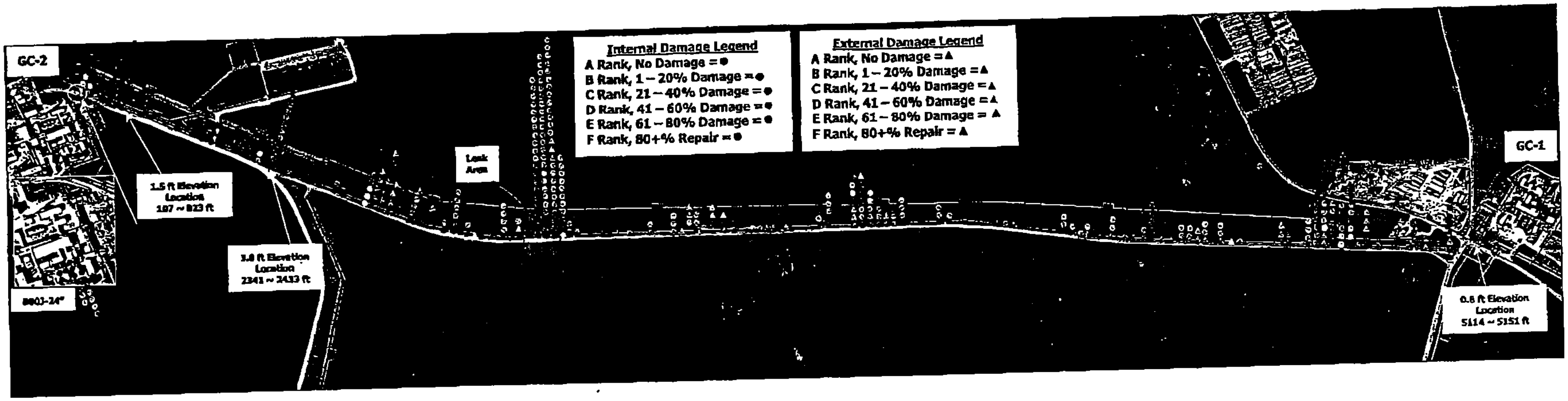
The leak detection system was demonstrated to meet the State of Alaska regulatory requirement of being able to detect a 1% leak over a 24 hour period. The joint BPXA and ADEC investigation team concluded the estimated leak rate was likely below the 1% threshold. Twice per day drive-by inspections are also completed by personnel trained in spill reporting. The leak occurred during winter conditions and went undetected because it was on the outboard side of a pipe rack from the road and was under drifted snow.

BPXA is analyzing ways to improve the overall leak detection and surveillance program on the WOA OTL and will provide a comprehensive review of possible improvements to ADEC and DOT in the coming months.

NOTE: We would like to take this opportunity to provide more information about the spill volume.

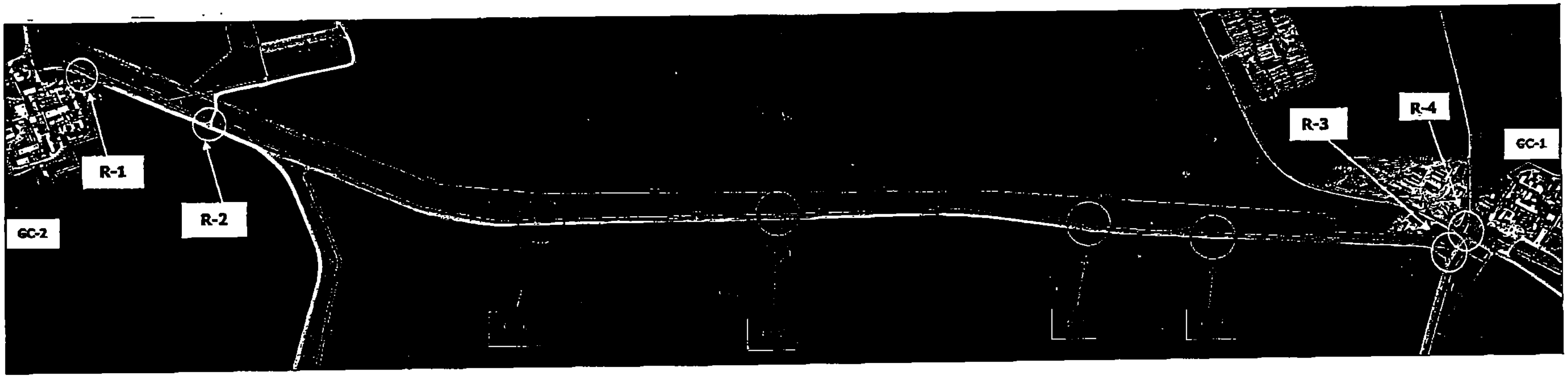
When the spill was discovered, production was immediately shut in without incident in an effort to minimize further impact. The Unified Command, which led the spill response and consists of the U.S. Environmental Protection Agency, ADEC, the North Slope Borough, and BPXA, estimated the spill volume on March 9 to be 4800 barrels +/- 33%, for a range of 3200 to 6400 barrels (134,783 to 267,500 gallons). Unfortunately, the lower figure (3200 barrels) was inadvertently dropped from the Unified Command's press release dated March 10. For a few days BPXA and the Unified Command reported the estimated spill volume to be 200,000 to 267,500 gallons. This was not accurate and we regret any confusion this may have caused. We do not anticipate that the spill volume estimate will be revised until a final number is determined at the end of the clean up.

Exhibit A



Aerial overview of the WOA OTL from GC2 to GC1 with the locations of the inspection points.

Exhibit B



Aerial overview of the WOA OTL from GC2 to GC1 with the locations of the caribou crossings (C-Crossing Number) and road crossing (R-Crossing Number).