STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL & GAS

SARAH PALIN, GOVERNOR

550 WEST 7TH AVENUE, SUITE 800
ANCHORAGE, ALASKA 99501-3560
PHONE: (907) 269-8800
FAX: (907) 269-8938

June 5, 2007

The Honorable Bart Stupak, Chairman
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Stupak:

On May 16, 2007 I testified on behalf of the State of Alaska at the hearing entitled "2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" This letter responds to the following questions asked by yourself and by Rep. Inslee:

1. What did BP tell the Alaska Department of Environmental Conservation (ADEC) in order to justify its request that ADEC waive the pigging requirement in the May 29, 2002 Compliance Order By Consent (COBC)?

2. Why did ADEC agree to waive the pigging requirement?

In support of my responses, several relevant documents are provided for your reference. Some of these documents have only recently been received by the State of Alaska, and help significantly to clarify the events in question. With the exception of the documents identified with the prefix "BPXA-ADEC" and the excerpts from the "Commitment to Corrosion Monitoring Reports," it is my understanding that all of the attached documents have previously been received by the Subcommittee.

In response to the first question, the short answer is that BP told ADEC that testing indicated its original report regarding solids in the oil transit lines (OTLs) was incorrect, and that only minimal sediment existed. BP then told ADEC that it had made facility modifications which would allow it to pig the OTLs at any time in the future.

The state's previous response on this issue is captured in the October 16, 2006 letter from ADEC Commissioner Kurt Fredriksson to Chairman Barton providing information on the COBC. The requirement that BP pig the pipeline segments was included in the COBC as a result of BP's earlier report that solids had been discovered in the OTLs that could interfere with tests of the leak detection system. However, in August 2002, after the COBC was entered into, BP notified ADEC that flow meter testing indicated that in fact only minimal sediment existed. This information sets forth BP's position that its earlier sediment estimates had been incorrect such that pigging the OTLs as a prerequisite to testing the leak detection system was no longer necessary. The attached August 9, 2002 letter from Gary Campbell to Lydia Miner, and Ms. Miner's August 14, 2002 response further support this conclusion. The October 13, 2002 letter from Kevin Gaynor on this issue includes as attachments additional internal BP documents attempting to reconcile BP's original representations to ADEC and BP's subsequent retraction of its statements regarding sediment levels following additional ultrasonic testing. Last, BP's October 2002 internal timeline summarizes events relating to the leak detection requirements, and draws from internal BP e-mail discussing this issue.

The "Billie Garde Report," in particular pages 16-22, sheds additional light on BP's inconclusive determination regarding whether sediment existed in the OTLs. Importantly, none of the correspondence or data underlying the debate was shared with ADEC or any other Alaska agency until recently. The Garde Report also does not address the fact that ADEC was ultimately told that only minimal sediment existed in the OTLs.

Finally, I draw your attention to key statements in several of the "Commitment to Corrosion Monitoring" reports submitted by BP each year pursuant to the Charter Agreement. (The full reports are available at the following website: http://www.dec.state.ak.us/spar/ipp/nscharter.htm .) These reports focused on well lines and flow lines, only reporting on the OTLs by exception, and then only briefly. However, the reports for 2002, 2003, and 2004 did specifically address the issue of pigging the OTLs. In those reports, BP informed the state that "periodic maintenance pigging" was part of its corrosion mitigation plan for "export oil" lines, i.e., the OTLs. We now know that no maintenance pigging had been done on the Western Operating Area OTLs since 1998, and on the Eastern Operating Area OTLs since 1990. However, since BP informed ADEC in Mr. Campbell's August 9, 2002 letter that it had made modifications which would allow it to pig the OTLs at any time in the future without further facility modifications, and subsequently stated that periodic maintenance pigging was in fact being performed on the OTLs, ADEC had no reason to believe that sediment build-up was an ongoing problem on those lines. This answers your second question.

Thank you for the opportunity to provide additional information in response to your questions, and for the opportunity to appear before the Subcommittee.

Sincerely,

Jonne Slemons
Petroleum Systems Integrity Office Coordinator

Enclosures:

- Compliance Order By Consent, Consent Order No. 02-138-10
- October 16, 2006 Fredriksson/ADEC Letter to Hon. Joe Barton
- August 9, 2002 Campbell Letter to L. Miner/ADEC
- August 14, 2002 Miner/ADEC Letter to G. Campbell
- November 26, 2002 Conrad letter to C. Leonard/ADEC
- March 25, 2003 Bronson Letter to J. Mach/ADEC
- April 3, 2003 Hutmacher/ADEC Letter to J. Fritts
- October 13, 2006 Gaynor Letter to Snowdon, Knauer
- February 13, 2002 Phillips Letter to M. Barnes
- January 31, 2002 Conrad Letter to C. Leonard/ADEC, with attachments
- October 19, 2002 Campbell E-mail to Phillips, Blankenship, Conrad
- September 16, 2002 Jacobsen E-mail to Phillips, with attachments

Enclosures, cont:

November 18, 2002 Phillips Letter to M. Barnes
October 1, 2001 Campbell Letter to R. Watkins, with attachments
“Redacted Interim Report of Investigation” by Garde and Clifford
“GPB Leak Detection Summary 10-13-2002”
October 18, 2002 Bruchie E-mail to Neill
Excerpt, “Commitment to Corrosion Monitoring, Year 2002”
Excerpt, “Commitment to Corrosion Monitoring, Year 2003”
Excerpt, “Commitment to Corrosion Monitoring, Year 2004”

cc (w/enclosures):
The Honorable Sarah Palin, Governor, State of Alaska
The Honorable Ted Stevens, Senator, U.S. Senate
The Honorable Lisa Murkowski, Senator, U.S. Senate
The Honorable Don Young, Representative, U.S. House of Representatives
Vice Admiral Thomas J. Barrett, USCG (Ret.), Deputy Secretary, U.S. Department of Transportation
Stacey Gerard, Chief of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation
Commissioner Thomas Irwin, Alaska Department of Natural Resources
John Katz, Director, Alaska Governor’s Office, Washington, D.C.

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
OFFICE OF THE COMMISSIONER

FRANK H. MURKOWSKI, GOVERNOR

410 Willoughby Ave., Ste 303
Post Office Box 111800
Juneau, AK 99811-1800
PHONE: (907) 465-5066
FAX: (907) 465-5070
http://www.dec.state.ak.us

October 16, 2006

The Honorable Joe Barton
Chairman, Committtee on Energy and Commerce
U.S. House of Representatives
Washington DC 20515-6115

Dear Chairman Barton:

The October 6, 2006, letter from the Committee on Energy and Commerce includes several questions regarding the May 2002 Compliance Order by Consent (COBC), No. 02-138-10, between the Alaska Department of Environmental Conservation (ADEC) and BP Exploration (BP). While the Committee's questions are primarily directed to BP, it is appropriate that I address why the COBC was not included in my testimony before your Committee on September 7, 2006. I also want to provide the Committee information regarding ADEC's actions to enforce the COBC. My response to each question follows.

Why wasn't the COBC mentioned in the September 7, 2006 testimony?

The Committee's invitation to testify stated that the hearing was entitled, "BP's Pipeline Spills at Prudhoe Bay: What Went Wrong?" The failure to control internal pipeline corrosion before pipeline wall failure is what went wrong. The purpose of the May 2002 COBC was to correct BP's past leak detection violations. ADEC ordered BP to demonstrate compliance with the State of Alaska's leak detection requirements. Pipeline corrosion was not an issue addressed in the COBC. The COBC was not mentioned in the State's testimony because it did not appear relevant to what went wrong with BP's recent pipeline spills.

What actions did ADEC take to enforce the COBC?

As described in the COBC, on April 30, 2001, BP had "discovered settled solids in some pipeline segments" that could interfere with the leak detection system. As a result, the COBC required BP to "determine the sediment levels in EOA and WOA pipelines," and pig the pipeline segments to "evaluate and establish the leak detection system compliance."

On August 9, 2002, BP notified ADEC that "as a result of flow meter testing which indicated that there is minimal sediment in the pipeline at the proposed meter installation point. Accordingly, we do not have a need to pig the line at this time and expect the flow meter to function as designed once installed" (enclosure 1). In that letter, BP requested ADEC concurrence that the pigging requirement in the COBC was not necessary.

Based on the information provided by BP that sediment levels would not interfere with the leak detection system, ADEC concurred with BP on August 14, 2002, that the pigging requirement could be eliminated (enclosure 2). Following leak detection tests that verified compliance with Alaska's leak detection requirements, ADEC closed the COBC on April 3, 2003 (enclosure 3). As provided in the COBC, BP also paid the State of Alaska $300,000 for failing to comply with the State's leak detection requirements.

I appreciate the opportunity to respond to the Committee's questions and would be pleased to provide further detail should you need it. Thank you.

Sincerely,

Kurt Fredriksson
Commissioner

Enclosures:

August 9, 2002 BP letter to ADEC
August 14, 2002 ADEC letter to BP
April 3, 2003 ADEC letter to BP

cc (w/enclosures):

The Honorable Frank H. Murkowski, Governor, State of Alaska
The Honorable Ted Stevens, Senator, U.S. Senate
The Honorable Lisa Murkowski, Senator, U.S. Senate
The Honorable Don Young, Representative, U.S. House of Representatives
The Honorable Alberto R. Gonzales, Attorney General, Department of Justice
Vice Admiral Thomas J. Barrett, USCG (Ret.), Administrator,
Pipeline and Hazardous Materials Safety Administration
John Katz, Director of State/Federal Relations and Special Counsel,
Office of the Governor

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

August 9, 2002

GPB
305.80.577

Ms. Lydia Miner
Alaska Department of Environmental Conservation
555 Cordova Street
Anchorage, Alaska 99501

RE: In the Matter of: State of Alaska, Department of Environmental Conservation Consent Order Number 02-138-10, Compliance Order by Consent Monthly Status Report, July 2002

Dear Ms. Miner:

Enclosed is BP Exploration (Alaska) Inc.'s monthly status report pursuant to the captioned compliance order by consent. Please note that the project is on track for year-end 2002 delivery.

Table 1 is a summary of status against the milestones included in the COBC. The elimination of one of the milestones; i.e. to "Pig EOA pipeline from FS-1 launcher to Skid 50", is as a result of flow meter testing which indicated that there is minimal sediment in the pipeline at the proposed meter installation point. Accordingly, we do not have a need to pig the line at this time and expect the flow meter to function as designed once installed. We have already completed the installation of the pigging equipment at Skid 50; therefore we have the ability to perform pigging operations at any time in the future without further facility modifications.

Since the pigging operations were included as milestones in the COBC, we request ADEC provide concurrence with our technical justification for not performing the pigging.

Based on the meeting between BP, ADEC, and the office of the State Attorney General, BP will be drafting test protocols for the system pipeline segments to be reviewed by ADEC, and the legal representatives will be meeting to discuss issues around the 1% leak detection criteria and the associated Best Available Technology (BAT) requirements as provided in the COBC.

If you have any questions or need additional information associated with this report, please do not hesitate to call me directly at 564-4275 or Nick Glover at 564-5511.

Respectfully,

FOR

Gary R.B. Campbell
GPB, HSE Manager
Attachment

cc: W. Hutmacher, ADEC
C. Leonard, Office of State Attorney General
N. Glover, BPXA

In the Matter of: State of Alaska, Department of Environmental Conservation Consent Order Number 02-138-10, Compliance Order by Consent

Table 1: Status of Tasks and Milestones per the COBC

COBC Task	Due Date	July Status Report
Determine sediment levels in EOA and WOA pipelines at Skid 50	03/31/02	All GPB crude oil transmission pipelines have been inspected for sediment and no appreciable sediment build-up was found with the exception of the Flow Station 2 segment. **Task Complete.**
Modify EOA pig receiver at Skid 50	03/31/02	The modification of the EOA pig receiver at Skid 50 has been completed. **Task Complete.**
Pig EOA pipeline from FS-1 launcher to Skid 50.	06/30/02	The lack of appreciable sediment build-up in the EOA crude oil transmission pipeline segments, Flow Station 2 excepted, has eliminated the immediate operational need to conduct pigging operations for the purpose of utilizing ultrasonic clamp-on meters. The Flow Station 2 segment was analysed and the low velocity condition made routine pigging of this segment impractical. Installation of a new turbine meter and associated piping appears to be a better option over a strap-on meter for the Flow Station 2 segment. The turbine meter-run, will be reduced diameter piping, providing increased velocity and greater accuracy, while minimizing the potential for future sediment build-up. The installation of this turbine meter at the end of the Flow Station 2 segment does not add to the gravel footprint or pose any additional environmental risk as there is an existing module with a sump and gas detection system available for meter installation. **Task Eliminated**
Pig WOA pipeline segments if necessary.	09/30/02	The lack of appreciable sediment build-up in the WOA segments of the GPB crude oil transmission pipelines has eliminated the immediate operational need to conduct pigging operations for the purpose of utilizing ultrasonic clamp-on meters. **Task Eliminated.**
Test and select flow meters at EOA pipeline, Skid 50 if necessary.	09/30/02	Testing and evaluation of additional flow meters has been completed. Meters have been ordered and should be delivered in September 2002. **Task Complete.**
Complete WOA crude oil flow smoothing modifications.	12/31/02	Crude oil flow smoothing modifications will be conducted, as necessary, to demonstrate compliance with the pipeline leak detection regulations. **Task Ongoing.**
Install and test meters on all pipelines.	12/31/02	Activity anticipated beginning in September 2002.
Evaluate and establish leak detection system compliance.	12/31/02	Activity anticipated beginning once all additional meters are installed and tested.

TONY KNOWLES, GOVERNOR
555 West Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.state.ak.us/dec

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS AND PIPELINE PROGRAM
Exploration Production and Refineries

FILE COPY

August 14, 2002

File No: 305.80.5079

Mr. Gary Campbell
BP Exploration (Alaska), Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Dear Mr. Campbell:

Subject: June and July 2002 Status Reports of Compliance Order by Consent (COBC) for BP Exploration (Alaska), Inc. (BPXA) Greater Prudhoe Bay

The Alaska Department of Environmental Conservation (DEC) has reviewed your letters dated July 15 and August 9, 2002. Upon review of the "Status Report" tables, and after meeting with you on August 6, 2002, we concur with the "completed" status of the following COBC remedial measures:

- Determine sediment levels in EOA and WOA pipelines at Skid 50;
- Modify EPA pig receiver at Skid 50;
- Test and select flow meters at EOA pipeline, Skid 50 if necessary.

We also agree that the following tasks can be eliminated:
- Pigging the EPA pipeline from FS-1 launcher to Skid 50;
- Pigging the WOA pipeline segments if necessary.

If you have any questions, please contact me at 269-7680.

Sincerely,

Lydia Miner

Lydia Miner
Section Manager

Enclosures: June and July Status Report Tables

cc: Bill Hutmacher, IP&PP Manager, ADEC
Nick Glover, BPXA
Cam Leonard, Alaska Dept. of Law

In the Matter of: State of Alaska, Department of Environmental Conservation
Consent Order Number 02-138-10, Compliance Order by Consent

COBC Task	Due Date	June Status Report
Determine sediment levels in EOA and WOA pipelines at Skid 50	03/31/02	All GPB crude oil transmission pipelines have been inspected for sediment and no appreciable sediment build-up was found with the exception of the Flow Station 2 segment. **Task Complete.**
Modify EOA pig receiver at Skid 50	03/31/02	The modification of the EOA pig receiver at Skid 50 has been completed. **Task Complete.**
Pig EOA pipeline from FS-1 launcher to Skid 50.	06/30/02	The lack of appreciable sediment build-up in the EOA crude oil transmission pipeline segments, Flow Station 2 excepted, has eliminated the immediate operational need to conduct pigging operations for the purpose of utilizing ultrasonic clamp-on meters. The Flow Station 2 segment was analysed and the low velocity condition made routine pigging of this segment impractical. Installation of a new turbine meter and associated piping appears to be a better option over a strap-on meter for the Flow Station 2 segment. The turbine meter-run, will be reduced diameter piping, providing increased velocity and greater accuracy, while minimizing the potential for future sediment build-up. The installation of this turbine meter at the end of the Flow Station 2 segment does not add to the gravel footprint or pose any additional environmental risk as there is an existing module with a sump and gas detection system available for meter installation. **Task Eliminated**
Pig WOA pipeline segments if necessary.	09/30/02	The lack of appreciable sediment build-up in the WOA segments of the GPB crude oil transmission pipelines has eliminated the immediate operational need to conduct pigging operations for the purpose of utilizing ultrasonic clamp-on meters. **Task Eliminated.**
Test and select flow meters at EOA pipeline, Skid 50 if necessary.	09/30/02	Testing and evaluation of additional flow meters has been completed. Meters have been ordered and should be delivered in September 2002. **Task Complete.**
Complete WOA crude oil flow smoothing modifications.	12/31/02	Crude oil flow smoothing modifications will be conducted, as necessary, to demonstrate compliance with the pipeline leak detection regulations. **Task Ongoing.**
Install and test meters on all pipelines.	12/31/02	Activity anticipated beginning in September 2002.
Evaluate and establish leak detection system compliance.	12/31/02	Activity anticipated beginning once all additional meters are installed and tested.

In the Matter of: State of Alaska, Department of Environmental Conservation Consent Order Number 02-138-10, Compliance Order by Consent

Table 1: Status of Tasks and Milestones per the COBC

COBC Task	Due Date	July Status Report
Determine sediment levels in EOA and WOA pipelines at Skid 50	03/31/02	All GPB crude oil transmission pipelines have been inspected for sediment and no appreciable sediment build-up was found with the exception of the Flow Station 2 segment. **Task Complete.**
Modify EOA pig receiver at Skid 50	03/31/02	The modification of the EOA pig receiver at Skid 50 has been completed. **Task Complete.**
Pig EOA pipeline from FS-1 launcher to Skid 50.	06/30/02	The lack of appreciable sediment build-up in the EOA crude oil transmission pipeline segments, Flow Station 2 excepted, has eliminated the immediate operational need to conduct pigging operations for the purpose of utilizing ultrasonic clamp-on meters. The Flow Station 2 segment was analysed and the low velocity condition made routine pigging of this segment impractical. Installation of a new turbine meter and associated piping appears to be a better option over a strap-on meter for the Flow Station 2 segment. The turbine meter-run, will be reduced diameter piping, providing increased velocity and greater accuracy, while minimizing the potential for future sediment build-up. The installation of this turbine meter at the end of the Flow Station 2 segment does not add to the gravel footprint or pose any additional environmental risk as there is an existing module with a sump and gas detection system available for meter installation. **Task Eliminated**
Pig WOA pipeline segments if necessary.	09/30/02	The lack of appreciable sediment build-up in the WOA segments of the GPB crude oil transmission pipelines has eliminated the immediate operational need to conduct pigging operations for the purpose of utilizing ultrasonic clamp-on meters. **Task Eliminated.**
Test and select flow meters at EOA pipeline, Skid 50 if necessary.	09/30/02	Testing and evaluation of additional flow meters has been completed. Meters have been ordered and should be delivered in September 2002. **Task Complete.**
Complete WOA crude oil flow smoothing modifications.	12/31/02	Crude oil flow smoothing modifications will be conducted, as necessary, to demonstrate compliance with the pipeline leak detection regulations. **Task Ongoing.**
Install and test meters on all pipelines.	12/31/02	Activity anticipated beginning in September 2002.
Evaluate and establish leak detection system compliance.	12/31/02	Activity anticipated beginning once all additional meters are installed and tested.

bp

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

VIA FACSIMILE NO. (907) 451-2846
AND DHL OVERNIGHT SERVICE NO. 8547062451

November 26, 2002

RECEIVED NOV 26 2002

Mr. Cameron Leonard
State of Alaska
Department of Law
Office of the Attorney General
100 Cushman Street, Suite 400
Fairbanks, Alaska 99701

RE: In the Matter of: State of Alaska, Department of Environmental Conservation v. BP Exploration (Alaska) Inc., Consent Order No. 02-138-10, Compliance Order by Consent

Dear Mr. Leonard:

This letter states BP Exploration (Alaska) Inc.'s ("BPXA") opinion that it will satisfy the best available technology ("BAT") requirement in the captioned compliance order by consent ("COBC") when it verifies that the Greater Prudhoe Bay Unit crude oil transmission pipeline ("Pipeline") leak detection system satisfies the requirement in 18 AAC 75.055(a)(1). (A copy of the COBC is attached as Attachment "A".) Here is a brief discussion of this matter.

I. COBC BAT Requirement

In COBC section III counts I and III, the Alaska Department of Environmental Conservation ("ADEC") contends that BPXA failed to comply with its 1999 oil discharge prevention and contingency plan ("1999 C-Plan") requirement to submit a Pipeline leak detection system that meets the BAT requirement in 18 AAC 75.425(e)(4)(A)(iv) and, accordingly, failed to operate in compliance with the 1999 C-Plan. In COBC Section III counts II and IV, ADEC contends that BPXA will continue to operate out of compliance with the 1999 C-Plan until BPXA verifies that its proposed Pipeline leak detection system satisfies the requirement in 18 AAC 75.055(a) consistent with 18 AAC 75.425(e)(4)(A)(iv). COBC section IV paragraph 23 provides in relevant part:

> [i]n order to address the violations outlined in Counts I-IV of Section III of the Order, the Respondent agrees to complete all outstanding action items to verify that the leak detection system for the FACILITY satisfies both the 1% leak detection requirement in 18 AAC 75.055(a), as applied to each pipeline segment, and the BAT requirement of 18 AAC 75.425(e)(4)(A)(iv)....

18 AAC 75.425(E)(4)(A)(iv) requires oil discharge prevention and contingency plans to provide for the use of BAT in accordance with 18 AAC 75.445(k). 18 AAC 75.445(k)(3) prescribes BAT for crude oil transmission pipelines.

II. ADEC Approval of Pipeline Leak Detection System BAT

By letter dated April 29, 2002, ADEC approved the "Greater Prudhoe Bay, North Slope, Alaska, Oil Discharge Prevention and Contingency Plan dated October 21, 2001 with revisions through March 21, 2002" ("2002 C-Plan"). (A copy of the April 29th letter is attached as Attachment "B".) Section 4.7 of the 2002 C-Plan (entitled "Leak Detection for Crude Oil Transmission Pipelines [18 AAC 75.425(e)(4)(A)(iv)]") provides in relevant part:

> [i]n conclusion, a detailed BAT review, presented in Table 4-4, demonstrates that MBLPC [mass balance line pack compensation] leak detection system combined with a visual surveillance program is BAT, and is the most appropriate system for the GPB [Greater Prudhoe Bay]...crude oil transmission pipelines....

(Brackets supplied.) Accordingly on April 29th, ADEC approved BAT for the Pipeline leak detection system under 18 AAC 75.425(e)(4)(A)(iv). (Copies of C-Plan, Section 4.7 and Table 4-4 are attached as Attachments "C" and "D", respectively.)

III. Conclusion

Based on the above discussion BPXA submits that when BPXA verifies the Pipeline leak detection system satisfies the requirement in 18 AAC 75.055(a)(1), it will also satisfy the COBC BAT requirement.

Please call me if you have questions concerning this letter (907-564-5425).

Sincerely,

Jeffrey C. Conrad

Jeffrey C. Conrad
Senior Counsel

Attachments

cc: W. Hutmacher, ADEC w/ attachments
L. Miner, ADEC w/ attachments

bp

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

March 25, 2003

Gr. Prudhoe Bay 565.10.5079

RECEIVED
MAR 27 2003
ADEC COMMISSIONER'S OFFICE

Mr. Jeff Mach
Oil and Gas Coordinator
Department of Environmental Conservation
410 Willoughby, Suite 303
Juneau, AK 99801-1795

Re: BPXA's Request for Termination of Consent Order No. 02-138-10, Compliance Order by Consent Regarding Greater Prudhoe Bay Unit Crude Oil Transmission Pipeline Leak Detection System Contingency Plan Requirement

Dear Mr. Mach:

Request for Termination

By way of this letter and its attachments, BP Exploration (Alaska) Inc. (BPXA) requests the Alaska Department of Environmental Conservation (ADEC) to provide BPXA written termination of consent order No. 02-138-10, compliance order by consent (COBC) regarding Greater Prudhoe Bay Unit (GPBU) crude oil transmission pipeline leak detection system oil discharge prevention and contingency plan as provided in Sections item 43 c, "Termination." BPXA has established compliance for all of the issues outlined in Counts I to IV of Section III of the COBC, and has complied with the provisions for terminating the COBC.

Tests to Evaluate Compliance

BPXA submits that its testing at GPBU in December 2002 met the final task of the COBC. The final task, found in item 23, stipulates that BPXA will evaluate and establish the GPBU leak detection systems' compliance with ADEC crude oil transmission pipeline system requirements by December 31, 2002. On each of six crude oil transmission pipeline segments, the testing demonstrated an alarm following a simulated crude oil leak volume of less than one percent of the daily pipeline segment throughput volume. BPXA used two methods to simulate crude oil leaks: the crude oil draw method; and the meter biasing test method.

Comparison of the results of the crude oil draw test method and the meter biasing test method showed that the methods are not significantly different.

Results that Establish Compliance

Immediately following the tests, BPXA sent the ADEC Industry Pipeline and Preparedness Program staff a letter transmitting the results. The December 23, 2002 letter and its attachments met the December 31, 2002, COBC deadline specified in item 23. The test results in that letter's attachments showed that the leak detection system on each of the six oil transmission pipeline segments signaled a leak volume of less than one percent of the daily throughput volume. BPXA maintains that the December data verify that the GPBU leak detection systems satisfy the requirement in 18 AAC 75.055(a) consistent with 18 AAC 425(e)(4)(A)(iv) as stipulated in Section III, Count IV of the COBC. The test procedures and results are summarized by Dave Bruchie and Mike Bronson in Attachment 1 to this letter.

Earlier Tasks

A series of earlier BPXA reports to ADEC outlined fulfillment of the other seven tasks in COBC Section IV, item 23 before year-end 2002.

Maintaining Compliance

Attachment 2 describes how BPXA envisions maintaining the crude oil transmission pipeline leak detection system capabilities at GPBU. The leak detection system will be adapted to declining oil throughput rates and to facility re-designs in order to remain compliant with the applicable regulations and the oil discharge prevention and contingency plan.

Sincerely,

Mike Bronson

Mike Bronson
Crisis Management Coordinator

cc: Cameron Leonard, Office of the Alaska Attorney General
Bill Hutmacher, Alaska Department of Environmental Conservation
Lydia Miner, Alaska Department of Environmental Conservation

Attachments:

1 Leak Detection System Tests at Greater Prudhoe Bay Unit
2 Maintaining Leak Detection Capabilities on GPBU Crude Oil Transmission Pipelines Covered by COBC

ATTACHMENT 1 (TO MARCH 25, 2003, BPXA-TO-ADEC LETTER)

LEAK DETECTION SYSTEM TESTS AT GREATER PRUDHOE BAY UNIT

Introduction

Six sales crude oil transmission pipeline segments' leak detection systems in the Greater Prudhoe Bay Unit (GPBU) were tested in December 2002. The tests were conducted under the terms of Alaska Department of Environmental Conservation (ADEC) Consent Order number 02-138-10, compliance order by consent (COBC). The methods and results are summarized in this report.

Methods

Leak Detection Systems

Crude oil leak detection distinguishes a signal associated with a crude oil leak from normal pipeline background variations in a reliable way. In effect, data regarding a change in crude oil flow that is visible to the meters are processed and integrated in the leak detection system's accumulators, thereby initiating an alarm in a timely manner.

Process variations come from normal swings in crude oil flow, composition, temperature, and pressure. In order to reliably detect one percent crude oil flow leaks, it is important that meter balance variations under normal (non-leaking) conditions are approximately 0.5 percent. This provides a 2 to 1 margin between leaks and normal variations, or "noise," and ensures that false alarms are infrequent. Achieving a balance between sensitive detection and few false alarms requires application of high accuracy crude oil flow meters and calibration of the meter system.

GPBU's the leak detection system consists of the meters in each segment of the facility's sales crude oil transmission pipeline, the meters between pipe segments where the segments are connected, the Pump Station 1 (PS1) meters, a data acquisition system, and the Ed Farmer and Associates (EFA) computer program that analyzes data and generates alarms.

Ed Farmer and Associates' MassPack leak detection system analyzes crude oil flow measurements from meters on each segment and accumulates estimated leak volume data over periods of one minute, one hour, one day, and 30 days. For the volumes simulated in the tests, the daily accumulator was expected to detect the leaks.

One Percent Criterion

The daily accumulator alarm thresholds were set for approximately 0.5 percent of the year 2005 nominal segment crude oil flow rates, levels expected to detect crude oil leaks of less than one percent of the 2005 nominal daily segment crude oil throughput. The simulated leaks were expected to be detected in about 10 to 18 hours, depending on the operating conditions.

Because pipeline crude oil flows are expected to continue to decline in coming years, the nominal flow rate on which the one percent regulatory criterion is calculated will decline as well. To establish crude oil leak detection performance for the future, the expected flow rate values for the year 2005 were used in establishing the one percent testing criterion. The expected flow rates in each segment are shown in Table 1.

Table 1. Expected Crude Oil Flow Rates (thousands of barrels per day)

Year	GC2/GC1	GC1/Skid50	Skid50/PS1	FS3/Skid50	FS1/FS3	FS2/FS1
2003	115	205	500	223	132	50
2004	102	184	455	204	121	46
2005	88	163	411	184	109	41

General Procedure

The general testing procedure for the segments is summarized as follows:

1. The pipeline segment crude oil flow rates were verified as in the "normal" range for 24 hours preceding the test. The existing distributed control system (DCS) trending package was used to view the trends.

2. The crude oil draw monitoring equipment was set up with tanks to receive the drawn oil and with existing meters, or stand-alone meters.

3. The leak simulation was started and recorded.
4. The simulated leak was limited to periods less than 24 hours.
5. The leak detection alarm time was recorded. The leak volume and rate data were recorded.
6. The leak volume and rate were verified as falling within the procedure's test threshold limits.
7. Before subsequent tests, the leak detection system data integrator was unwound for at least 24 hours, to minimize the previous test's effect on the next test.

Fluid Draw Method

The segments GC-2 to GC-1 and FS-2 to FS-1 used the fluid draw method to simulate leaks. Crude oil was drawn from the segment to an existing tank or to crude oil processing equipment. The simulated leak was controlled manually and measured using a micromotion coriolis meter or transmission type ultrasonic flow meter, or by measuring the liquid level in a tank. The test ended when a simulated leak was detected. The simulated leak volume was then calculated from the records of the leak flow, the flow meter internal totalizer, or changes in tank level. Trends of system flows and leak accumulation signals for the previous 24 hours also were available for comparison.

GC2 to GC1

An ultrasonic crude oil flow meter was recently added downstream of the crude oil bank meters associated with the GC2 to GC1 segment. The leak was simulated by drawing oil through the Skid 33 crude oil drain line to Skid 4. To protect the drain line from Skid 33 to Skid 4, the drain line pressure was limited to no more than 50 psi by modifying the pneumatic inlet valve to the sphere launcher (SDV-503) closed by a temporary pressure switch. A HART handheld monitor was connected to the temporary leak meter to read oil flow rate at the control valve.

FS2 to FS1

The leak was simulated through a drain upstream of the meter at the FS1 end of the line in the pig trap module. The drained crude oil was recycled into FS1. A at 545 barrels based on the expected 109,000-barrel daily throughput in 2005 as planned. The technicians realized this after the accumulated leak volume had passed the expected alarm point. They let the test continue at the simulated 1,090 barrels per day leak rate until the alarm was tripped at the higher level. Even with the higher trip level, the alarm tripped in less than 18 hours. A more realistic time to alarm, if the alarm set point had been the lower and based on the predicted 2005 throughput, would have been 13 hours.

The meters involved in the tests were calibrated and inspected as appropriate and according to standard operating procedures in the preventive maintenance program. Flow meters on pipeline segments were balanced by trending procedures. Ultrasonic meters were inspected. The coriolis micromotion meter was calibrated at a gravimetric prover.

Comparison of the results of the crude oil draw method and the meter biasing method showed that the two tests are not significantly different. Each method involved a similar amount of time to alarm.

Results

The results of the GPBU tests are listed in Table 2. The times to alarm ranged from 13 hours to 18 hours following simulated crude oil leaks that ranged from 0.5 percent to 0.7 percent of the expected daily throughput volumes.

Table 2. Results of Leak Detection System Tests on Six GPBU Crude Oil Transmission Pipelines, December 2002

Pipeline Segment Description	Throughput in 2005 (barrels oil per day)	Simulated Leak Rate (barrels oil per day)	Draw Volume (barrels)	Time to Detect from Start of Draw (hours)	Simulation Method and Type of Meter
GC-2 to GC-1 34 inches; 16,000 LF	88,000	880*	469	12.8	Oil draw; 2 ultrasonics
GC-1 to Skid 50 34 inches; 25,000 LF	163,000	1,630	1,190	17.5	Bias meter; 3 ultrasonics
FS-2 to FS-1 30 inches; 16,000 LF	41,000	410*	250	14.6	Oil draw; 4 turbine meters 4 positive displacement
FS-1 to FS-3 34 inches; 18,000 LF	109,000	1,090	800	17.6	Bias meter; 1 ultrasonic 4 turbine meters
FS-3 to Skid 50 34 inches; 7,000 LF	184,000	1,840	1,178	15.4	Bias meter; 3 turbine and 2 ultrasonic meters
Skid 50 to PS1 34 inches; 1,500 LF	411,000	4,110	2,163	12.6	Bias meter; 2 turbine and 2 ultrasonic meters

* The manually controlled draw volumes were less than 3 percent greater than the targeted rate in the table.

ATTACHMENT 2 (TO MARCH 25, 2003, LETTER TO ADEC)

MAINTAINING LEAK DETECTION SYSTEM CAPABILITIES ON GREATER PRUDHOE BAY UNIT CRUDE OIL TRANSMISSION PIPELINES COVERED BY CONSENT ORDER NO. 02-138-10, COMPLIANCE ORDER BY CONSENT

Crude Oil Leak Detection System

The Greater Prudhoe Bay Unit (GPBU) crude oil transmission pipeline leak detection system covered by consent order no. 02-138-10, compliance order by consent (COBC) comprises the following major components:

- Crude oil flow meters,
- Data acquisition system that collects data from crude oil flow meters, reads and writes data to an analysis program,
- Ed Farmer and Associates' MassPack crude oil leak detection software, and
- SetCim operator consoles for alarms and status at GPBU's Eastern Offtake Center (EOC).

Data move from the turbine and ultrasonic meters by means of flow computers and data converters to data accumulators. BP Exploration (Alaska) Inc. (BPXA) uses the Ed Farmer and Associates crude oil leak detection program to analyze the data and generate alarms. The data then are displayed at the operators' consoles, to show alarms and status. At Prudhoe's EOC, operators monitor and respond to the alarms.

Segments

In addition, the network of crude oil transmission pipelines is organized into six individual segments for crude oil leak detection purposes. Figure 1 illustrates the segments.

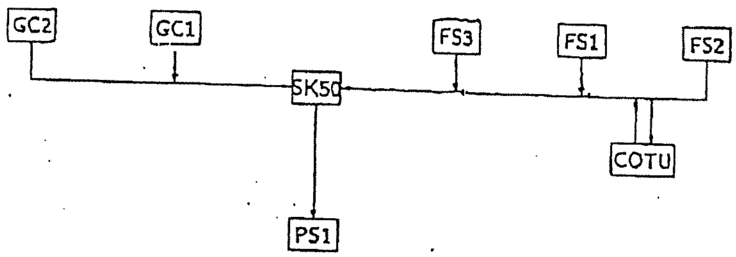


Figure 1: Prudhoe Bay Leak Detection System Segments

The EOC display monitors the pipeline segments. The most important information on the screen is the current estimated crude oil leak volume for the most recent minute, most recent hour and most recent day for each segment.

The monthly crude oil leak data accumulator is used to monitor crude oil leak detection system performance and to tune the system meter factors. The daily accumulator updates more quickly than the monthly accumulator and can detect crude oil leaks below 1 percent of the daily crude oil throughput volume. The hourly leak accumulator is useful for detecting larger leaks (e.g., more than 3 percent of normal segment crude oil flow rate). The minute accumulator is too sensitive for reliable crude oil leak detection.

Crude oil leak detection is based on crude oil flow rate measurements throughout the crude oil transmission pipeline system. Measurements are made by existing turbine meters and ultrasonic flow meters. Data also are collected from the oil bank orifice meters at GC1 and GC2, although they are not the primary crude oil leak detection meters. In addition, although BPXA does not maintain the crude oil flow meters at Pump Station 1 (PS1), the company does maintain data acquisition hardware that collects crude oil flow rate data from PS1. BPXA routinely works with Alyeska Pipeline Service Company to maintain meter accuracy at PS1. Figure 2 illustrates the positions of meters in the crude oil leak detection system.

Turbine Meters

Turbine meter crude oil flows are calculated using Daniels 2500 and 2233 series flow computers using actual crude oil volume (gross) flow rates. Crude oil flow rate data are read from flow computers over the network with a Lantronix terminal server. The data are maintained by the Automation group. BPXA will be upgrading the 2233 flow computers to 2500 series units in the future.

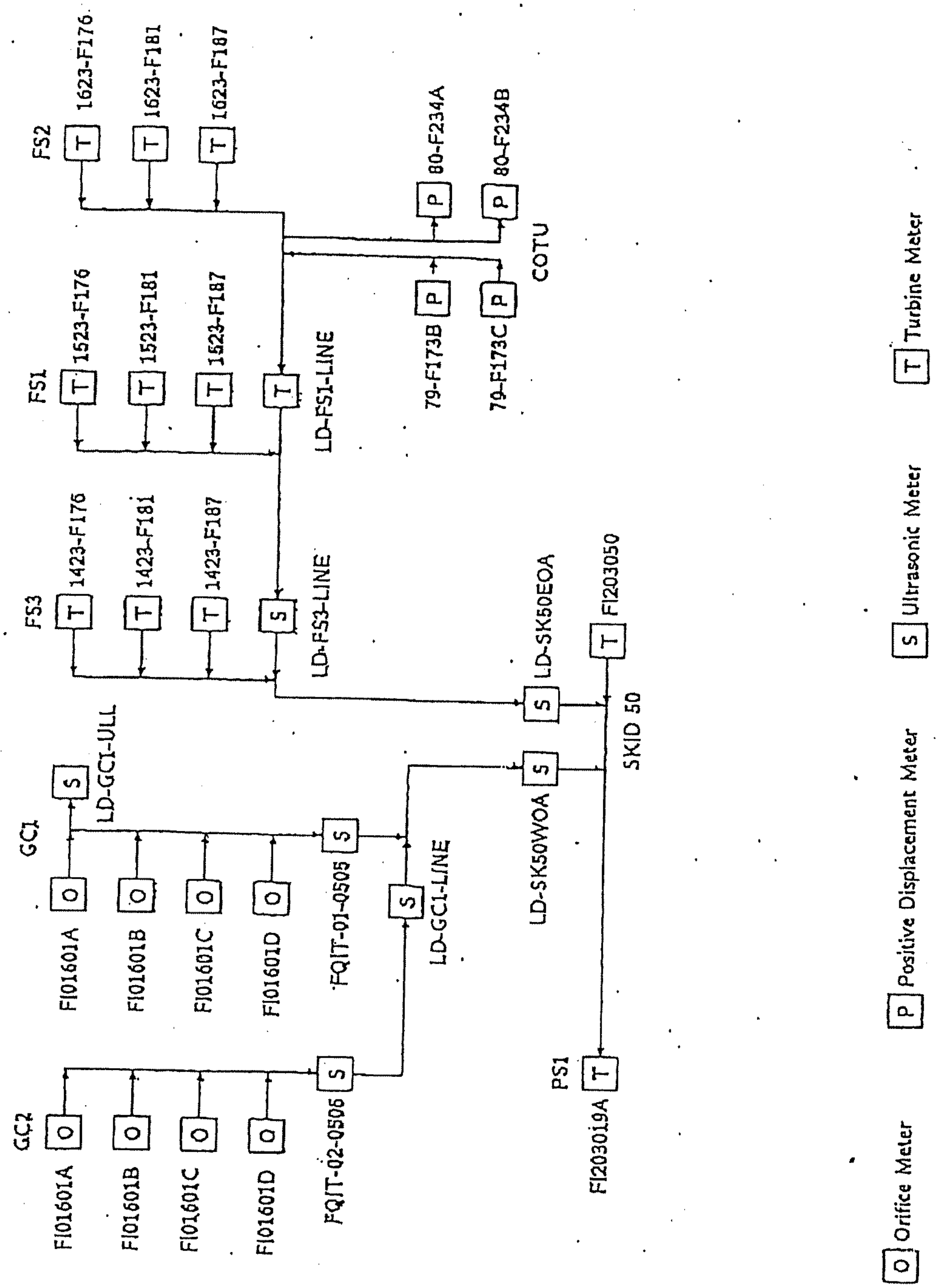


Figure 2: Prudhoe Bay Leak Detection System Meters

Ultrasonic Flow Meters

Ultrasonic crude oil flow meters at segment junctions, especially at outside junctions, are installed without making more holes in the pipeline system, minimizing the chances of causing a crude oil leak. They are installed at junctions and outside GC1 and GC2 as alternatives to the existing orifice meters. The ultrasonic meters have the advantage of being downstream of the control valves, crude oil coolers and sample points.

The ultrasonic meters are 4-channel (8 transducer) Controlotron 1010 DV special units. They average the crude oil flow measured by each of the four channels.

The analog flow rate output from these meters is sent to Opto22 Ethernet I/O units. In addition, the Controlotron serial port is wired to the process network via the Lantronix terminal server for access to diagnostics.

Orifice Flow Meters

Crude oil bank orifice meters are wired to the leak detection system at GC1 and GC2. They can be used as alternates to the ultrasonic flow meters on the crude oil pipelines from these facilities. They are upstream of the bank third stage separator level control valve, the crude oil coolers and the water cut analyzer. Consequently, they require regular corrections to calculate pipeline crude oil volumes. Because BPXA plans to use meters giving the best performances, the ultrasonic flow meters rather than orifice meters are currently used for crude oil leak detection.

Data Acquisition System

The data acquisition system collects field data from transmitters and flow computers over the process network, packages them for the Ed Farmer and Associates leak analysis programs and collects their output for display. These data are made available for display through operators' consoles. The data acquisition system comprises field I/O devices (Opto22 Ethernet I/O, Lantronix/Schneider ModBus and serial terminal servers), and programs on the LeakNet computer in the GPBU Automation shop.

The data acquisition system is built around a shared memory organized as a set of ModBus registers (like some PLCs), and the various programs that read and write data to this memory. A program on the LeakNet computer controls each section of the data acquisition system. The data acquisition system has five sections, as follows:

- A ModBus server to let SetCim read and write the shared memory,
- Analog data collection using Opto22 Ethernet I/O,
- Interface to Daniels flow computers,
- Interface to Allen Bradley PLC at Skid 50, and
- Interface to and from the EFA crude oil leak detection programs.

The Daniels 2500 series flow computer makes internal data available over a serial port using the ModBus protocol. Schneider and Lantronix ModBus/IP terminal servers connect to the Daniels ModBus over the process network. The Daniels Collect program on the LeakNet computer polls the flow computer for data every one to two seconds, and stores the data in the LeakNet computers shared memory for use by the operators' consoles and the crude oil leak detection software.

Calibration and Maintenance Procedures

Calibration and maintenance procedures are in place for the crude oil transmission pipeline leak detection systems that were recently tested at GPBU. The written procedures address documentation, response to crude oil leak detection alarms, and provide a system manual and reference material to aid the Leak Detection System Administrator (LDSA).

The LDSA is the main contact administering the transmission pipeline leak detection procedures. The LDSA trains operators and maintenance technicians regarding the leak detection system and authorizes changes in the leak detection computer programs. Currently, the Flow Measurement Engineer maintains that position.

Using the accumulation of pipeline crude oil flow measurement data, the LDSA will continue to oversee maintenance and improvements in the crude oil leak detection system. For example, the preventive maintenance program includes quarterly instrument checks and calibration of the crude oil leak detection flow meters. In addition, the LDSA examines false alarms to minimize their recurrence and coordinates leak detection tests.

Assuring the GPBU Crude Oil Transmission Pipeline Leak Detection System Covered by the COBC into the Future

BPXA has anticipated several critical elements for maintaining the GPBU crude oil transmission pipeline leak detection system capabilities into the future.

Testing

Functional or software testing will be performed after hardware or software changes that may affect system reliability. Software or functional tests results will be stored in document control. A minimum of the two most current test results will be stored. Trend data, alarm history, and DCS printer data may be stored with the test results. The LDSA will be responsible for documenting and storing the information.

As BPXA monitors and tunes up the system, transient signals are sometimes seen. In some instances they cause false alarms. Technicians work to track down transient signals to reduce the false alarms and to increase system resolution.

For example, on the Skid 50 to PS1 segment, Alyeska will simplify the signal processing hardware at PS1, modifying how it converts and sends data to BPXA. The simplification will reduce the pipeline fluid "noise" and increase crude oil leak detection precision.

Furthermore, API 1130 and 1155 will be considered for guidance to support reliable crude oil leak detection capabilities.

Declines of Crude Oil Flow Rates

BPXA recognizes that anticipated crude oil transmission pipeline flow rate declines will affect the crude oil leak detection system. Under the coordination of the LDSA, calibration and modifications will be made to maintain each segment's capability to detect crude oil leaks. As crude oil flows decline by approximately 50 percent, BPXA expects to re-examine the meters' suitability.

Facility Re-Designs

Furthermore, major re-designs of GPBU facilities may affect the crude oil transmission pipelines and their leak detection system. The re-designs will take into account the necessity to maintain crude oil leak detection capabilities. To further that goal, the Health Safety and Environment Department will have a role in the re-designs to ensure that crude oil leak detection system integrity is maintained.

Crude oil leak detection system "Management of Change" procedures will be followed before commencement of projects that may have an affect on the crude oil leak detection system and potentially increase false alarms.

ADEC ANCHORAGE 002

#3

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration Production & Refineries

FRANK H. MURKOWSKI, GOVERNOR
555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.state.ak.us/dec

FILE COPY

April 3, 2003

File No. 305.80.5079

Mr. Jack Fritts
Greater Prudhoe Bay Unit Operations Manager
BP Exploration (Alaska), Inc.
P. O. Box 196612
Anchorage, AK 99519-6612

Dear Mr. Fritts:

Re: Closure of Compliance Order by Consent (COBC) No. 02-138-10; BP Exploration (Alaska) Inc., Greater Prudhoe Bay; ADEC Plan No. 014-CP-5079.

On March 26, 2003, the Alaska Department of Environmental Conservation (DEC) received BPXA's letter requesting termination of this compliance order by consent (COBC) regarding the crude oil transmission pipeline leak detection system for Greater Prudhoe Bay.

Your letter included a description of the leak detection system tests conducted in December 2002 and the results of these tests that establish compliance with the standard established in Alaska regulation 18 AAC 75.055(a)(1). The system in place at Greater Prudhoe Bay detected a simulated discharge smaller than 1% of the current daily throughput at the six pipeline segments tested. The letter also included a description of maintaining these leak detection capabilities.

With this submittal, BPXA's obligations under the COBC have been completed, and DEC is closing the COBC. If you have any questions, please contact DEC at the number listed above or me at 269-3054.

Sincerely,

Bill Hutmacher

Bill Hutmacher
Program Manager

cc: Larry Dietrick, ADEC
Lydia Miner, ADEC
Cam Leonard, Dept. of Law
Gary Campbell, BPXA
Mike Bronson, BPXA
Jeff Conrad, BPXA

CATS Complaint No 2002-138

In the Matter of: State of Alaska, Department of Environmental Conservation
Consent Order Number 02-138-10, Compliance Order by Consent

Table 1: Status of Tasks and Milestones per the COBC

COBC Task	Due Date	July Status Report
Determine sediment levels in EOA and WOA pipelines at Skid 50	03/31/02	All GPB crude oil transmission pipelines have been inspected for sediment and no appreciable sediment build-up was found with the exception of the Flow Station 2 segment. **Task Complete.**
Modify EOA pig receiver at Skid 50	03/31/02	The modification of the EOA pig receiver at Skid 50 has been completed. **Task Complete.**
Pig EOA pipeline from FS-1 launcher to Skid 50.	06/30/02	The lack of appreciable sediment build-up in the EOA crude oil transmission pipeline segments, Flow Station 2 excepted, has eliminated the immediate operational need to conduct pigging operations for the purpose of utilizing ultrasonic clamp-on meters. The Flow Station 2 segment was analysed and the low velocity condition made routine pigging of this segment impractical. Installation of a new turbine meter and associated piping appears to be a better option over a strap-on meter for the Flow Station 2 segment. The turbine meter-run, will be reduced diameter piping, providing increased velocity and greater accuracy, while minimizing the potential for future sediment build-up. The installation of this turbine meter at the end of the Flow Station 2 segment does not add to the gravel footprint or pose any additional environmental risk as there is an existing module with a sump and gas detection system available for meter installation. **Task Eliminated**
Pig WOA pipeline segments if necessary.	09/30/02	The lack of appreciable sediment build-up in the WOA segments of the GPB crude oil transmission pipelines has eliminated the immediate operational need to conduct pigging operations for the purpose of utilizing ultrasonic clamp-on meters. **Task Eliminated.**
Test and select flow meters at EOA pipeline, Skid 50 if necessary.	09/30/02	Testing and evaluation of additional flow meters has been completed. Meters have been ordered and should be delivered in September 2002. **Task Complete.**
Complete WOA crude oil flow smoothing modifications.	12/31/02	Crude oil flow smoothing modifications will be conducted, as necessary, to demonstrate compliance with the pipeline leak detection regulations. **Task Ongoing.**
Install and test meters on all pipelines.	12/31/02	Activity anticipated beginning in September 2002.
Evaluate and establish leak detection system compliance.	12/31/02	Activity anticipated beginning once all additional meters are installed and tested.

KF, DE, LD, FILE

Vinson&Elkins

Kevin A. Gaynor kgaynor@velaw.com
Tel 202.639.6688 Fax 202.879.8888

October 13, 2006

Andrew Snowdon, Counsel
Committee on Energy and Commerce
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, DC 20515

RECEIVED
OCT 19 2006
ADEC COMMISSIONER'S OFFICE

Christopher Knauer, Investigator
Committee on Energy and Commerce
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, DC 20515

Re: BP Exploration (Alaska), Inc. (BPXA)

Dear Gentlemen:

Enclosed please find some additional responsive documents regarding the Pipeline Leak Detection COBC, which were located after Bob Malone's letter of October 10, 2006 was sent. BPXA is continuing to search its files and we will send any additional responsive documents that are located.

Please note that there are attorney-client privileged documents among these and prior document productions we have made to the Committee. We understand that it is the position of the Committee that privileged documents need to be produced. While BP does not waive any privileges it has over any documents, it is nonetheless providing them to the Committee. As we have discussed with you in the past, documents that BPXA has provided and continues to provide to the Committee could implicate the personnel privacy interests of BPXA employees and BPXA requests that you inform BPXA and give it an opportunity to be heard prior to any release of documents to the public.

V&E

Please call me if you have any questions. Thank you for the many courtesies you have extended to BPXA and the professionalism you have displayed in handling material provided to the Committee.

Very truly yours,

Kevin A. Gaynor

Enclosures

V&E

cc: The Honorable Ted Stevens, Senator (w/ enclosures)
U.S. Senate

The Honorable Lisa Murkowski, Senator (w/ enclosures)
U.S. Senate

The Honorable Don Young, Member (w/ enclosures)
U.S. Senate

Mr. Kurt Fredriksson, Commissioner (w/ enclosures) ✓
Alaska Department of Environmental Conservation

Vice Admiral Thomas J. Barrett, USCG (Ret.), Administrator (w/ enclosures)
Pipeline and Hazardous Materials Safety Administration

Stacey Gerard, Acting Assistant Administrator, Chief Safety Officer (w/ enclosures)
Pipeline and Hazardous Materials Safety Administration

Ted Willke, Acting Associate Administrator (w/ enclosures)
Pipeline and Hazardous Materials Safety Administration

bp

BPXA LAW DEPT

WHC	ICC	RMJ	JHC	SJS	GDB
KJW					

FEB 13 2002

File:

Copy:

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

February 13, 2002

BY FAX AND U.S. MAIL

Ms. Mary Frances Barnes
United States District Court
District of Alaska
Probation and Pretrial Services Office
Federal Building
222 West 7th Avenue #48
Anchorage, AK 99513-7562

RE: Mr. Hamel's correspondence dated January 30, 2002 regarding pipeline leak detection

Dear Ms. Barnes:

I would like to respond to the issues raised by Charles Hamel in his January 30, 2002 letter to Robert Malone, on which you were copied. That letter addressed BPXA's handling of the leak detection requirements for crude oil transmission lines and field integrity testing of the C-82 valve. Regarding the C-82 valve, my letter of January 15 addresses this issue in detail. This valve was replaced on February 5, and we plan to bench test it in the presence of the valve manufacturer to learn more about its condition, as well as how to improve our testing and maintenance programs. The remainder of this letter addresses leak detection requirements.

Effective in 1997, the Alaska Department of Environmental Conservation (ADEC) revised the definition of crude oil transmission pipelines, which resulted in the application of Alaska's pipeline leak detection and Best Available Technology (BAT) regulations to the sales oil pipelines within Prudhoe Bay. The leak detection regulation, 18 AAC 75.055(a)(1), states: "if technically feasible, the [pipeline should have the] continuous capability to detect a daily discharge equal to not more than one percent of daily throughput." The BAT regulation, 18 AAC 75.425(e)(4)(A)(iv), requires the proposed pipeline leak detection system to utilize the Best Available Technology consistent with applicable criteria in 18 AAC 75.445(k)(3).

Subsection (k)(3) of 18 AAC 75.445 contains eight criteria by which to assess whether the BAT requirement is met: whether the technology is the best in use in similar situations and is available for use by BPXA, whether the technology is transferable to BPXA's operations, whether it is reasonable to believe that the technology will provide increased spill prevention or other environmental benefits, the cost to BPXA, the age and condition of technology currently in use, whether the technology is compatible with existing operations, the practical feasibility of utilizing the technology, and whether any environmental impacts associated with the technology offset any anticipated environmental benefit.

Thus, it is a subjective assessment that determines what leak detection equipment is required to comply with the regulations. Compliance depends upon the particular circumstances specific to each regulated pipeline. Each of the six pipeline segments in Prudhoe Bay presents a unique set of conditions that must be addressed and verified independently by field-testing.

Since 1997, ADEC and BPXA have been working together to determine, given the eight BAT criteria, the extent to which the regulations require the technical retrofitting of Prudhoe Bay pipelines and facilities that were designed, constructed and commissioned in the 1970s and early 1980s consistent with the regulations and industry standards then applicable. ADEC and BPXA agreed upon a timeline for BPXA to submit technical proposals, purchase and install leak detection equipment, function test the system, and refine system performance, among other things. By the end of 2000, BPXA had installed a new pipeline leak detection system that we believed would fully comply with the regulations.

Regarding the Lisburne pipeline segment, field-testing has proved that the leak detection system installed in 2000 meets the regulatory requirements. However, regarding the remaining five pipeline segments, it became clear in December of 2000 that ADEC and BPXA were interpreting the application of the regulation to pipeline segments differently. ADEC's interpretation would require modifications to certain pipeline segments and facilities. Having discussed a number of technical alternatives with ADEC, on January 31, 2001, BPXA submitted a proposal based on ADEC's interpretation for installing and testing additional meters to evaluate potential improvements to the performance of the leak detection system for each segment.

During planning sessions regarding the meter installations, a new technical challenge emerged: the accuracy of the additional meters would be affected by the sediment build-up in the pipelines that has occurred over time. Given the present configuration of the facilities on the eastern half of the field, it is not likely that the sediment in certain segments can be removed until retrofits are completed. Once the additional meters are tested and installed, optimization of the leak detection system could require the management of the flow in each segment and extensive fine-tuning of the complex leak detection algorithms used by the leak detection software. It is possible that ADEC and BPXA could ultimately agree that compliance with the strictest interpretation of the regulation is not feasible for certain pipeline segments. In this event, BPXA, in coordination with ADEC, would request a regulatory waiver for these segments. We continue to work closely with ADEC staff on the coordination of the remaining test program activities.

Given these challenges, the timeline for compliance was revised with ADEC's concurrence from time to time. The last agreed timeline required BPXA to function test all segments of the leak detection system by December 31, 2001. Although BPXA function tested the Lisburne segment prior to this date, we determined that it would not be possible to complete all of the required testing by December 31, 2001.

We approached ADEC and the Alaska Attorney General in mid-December to develop a Compliance Order by Consent (COBC) to establish a new installation and testing schedule.

As you may know, COBCs are authorized by the legislature and are a standard way to allow regulated companies to continue working with an agency to resolve compliance issues in the midst of regulatory uncertainty (AS 46.03.020 and AS 46.03.850). We are currently negotiating a COBC that would commit BPXA to complete certain activities by certain dates. (See attached). We understand that the Attorney General will maintain that BPXA went out of compliance in December 2000, when BPXA received the letter from ADEC regarding the application of the regulation to individual pipeline segments. Any fines that may be assessed would likely be calculated based upon this date.

In closing, please note that these six pipeline segments have operated well since field startup and have never leaked. And please be assured that the pipeline segments at issue already had a leak detection system in place before they became subject to the regulations in 1997 – thus, the segments have not lacked a leak detection system as Mr. Hamel implies. That system, which still exists today, consists of low pressure alarm systems, road access to all crude oil transmission pipeline segments, and visual surveillance by trained security (twice daily) and operations personnel. In 1999, an aerial surveillance component was added which is used when visual surveillance cannot be accomplished due to weather or snow conditions. The aerial surveillance uses the Forward Looking Infra-Red (FLIR) camera system. Finally, in 2000, the aforementioned upgrades were completed, which include flow measurement alarm systems that are currently operational and provide an additional level of monitoring, although there is no way to quantify its effectiveness until the testing program is complete.

I hope this information is sufficient to satisfy any concerns you may have regarding these issues. Please do not hesitate to contact me if you have any questions or if you require any additional information. My response to Mr. Hamel's second letter of January 30, 2002 regarding fire and gas detection system issues will follow shortly.

Sincerely,

Chris J. Phillips

Chris J. Phillips
Vice President, BPX(A)

Cc: w/ Attach:

John Katz, Office of the Governor of the State of Alaska
Commissioner Michele Brown, Alaska Department of Environmental Conservation
Cameron Leonard, Assistant Attorney General
Ridgway Hall, Esq.
Carol Dinkins, Esq.

Bc: w/Attach:

Steve Marshall
Neil McCleary
George Blankenship
Gordon Birrell
Ross Klie
Gary Campbell
Mark Merrill
Nick Glover
Ronnie Chappell
Jeff Conrad
Rosy Jacobsen

bp

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

January 31, 2002

VIA FACSIMILE NO. (907) 451-2846
AND DHL OVERNIGHT SERVICE NO. 8526262161

Mr. Cameron Leonard
Assistant Attorney General
100 Cushman Street, Suite 400
Fairbanks, Alaska 99701

RE: Draft COBC Addressing Possible BPXA Violations of ADEC Leak Detection Requirements at Greater Prudhoe Bay Unit

Dear Mr. Leonard:

On January 11, 2002, the Alaska Department of Environmental Conservation ("ADEC") and BP Exploration (Alaska) Inc. ("BPXA") met to discuss BPXA's request for a compliance order by consent ("COBC") to address possible BPXA violations of 18 AAC 75.055 and 18 AAC 75.425 ("Requirements") at BPXA's Greater Prudhoe Bay Unit. ADEC agreed to draft a COBC for BPXA's review. You requested that BPXA provide the following information: 1. the period of possible violations, 2. the estimated economic benefit to BPXA from the possible violations, and 3. the remedial activities and time frames needed to become compliant with the Requirements as interpreted by ADEC. Here are BPXA's responses.

I. Period of Possible Violations

BPXA submits that prior to December 7, 2000 it was compliant with the BPXA eastern operating area and western operating area oil discharge prevention and contingency plans (condition 8 in each plan) which gave BPXA additional time to meet the Requirements. It is arguable that ADEC's December 7, 2000 letter to BPXA disapproving its proposed pipeline leak detection system terminated these extensions. BPXA has since submitted a revised pipeline leak detection system proposal to ADEC, and has completed several of the remedial activities needed to verify compliance with the Requirements.

II. Economic Benefit from Possible Violations

BPXA submits that the economic benefit associated with the possible violations is arguably the interest on a dollar amount equal to the costs BPXA will incur to complete activities necessary to verify compliance with the Requirements. The interest should accrue separately for each activity beginning upon the effective date of the COBC until the activity is complete. A list of complete activities, activities that remain outstanding and estimated activity costs follow:

	ACTIVITY		ESTIMATED COST
1.	Identifying pipelines (See attachment "A".)		$ 0M
2.	Identifying meter locations on pipelines (See attachment "A".)		$ 0M
3.	Activities pre-meter installation and testing		
	- Determining pipeline sediment levels	$ 10M	
	- Modifying Skid 50	$150M	
	- Pigging pipelines (EOA)	$ 200M	
	- Pigging pipelines (WOA)	$ 125M	
	- Selecting meters for pipelines	$ 50M	
	- Completing Lisburne crude flow smoothing modifications	$ 0M	
	- Completing other crude flow smoothing modifications	$ 150M	$ 685M
4.	Installing meters on all pipelines		$ 231M
5.	Testing meters on all pipelines		$ 25M
6.	Verifying leak detection system meets Requirements		$ 5M
		TOTAL ESTIMATED COSTS	$ 946M

The time frames for completing these activities are listed in Attachment "B".

III. Remedial Activities/Time Frames

See Attachment "B".

Please call me if you have questions concerning this letter (907-564-5425).

Sincerely,

Jeffrey C. Conrad
Senior Counsel

Attachment

cc: J. Mach, ADEC

ATTACHMENT "B"

REMEDIAL ACTIVITIES TO EVALUATE COMPLIANCE WITH 18 AAC 75.055(a)(1) AND 18 AAC 75.425

1. Verify ability to accurately measure the daily throughput for each pipeline.

- Identify pipelines. (Done. The GPBU crude oil transmission pipeline system includes 5 pipelines. See attachment "A".)
- Identify meter locations on pipelines. (Done. The attached map identifies each meter location. See attachment "A".)
- Activities pre-meter installation and testing:
  - Determine sediment levels in both the eastern operating area ("EOA") and the western operating area ("WOA") pipelines at Skid 50. (BPXA estimates it will complete this activity by 1Q 2002.)
  - If sediment is present, the following activities are necessary:
    - Modify the EOA pig receiver at Skid 50. (BPXA estimates it will complete this activity by 1Q 2002.)
    - Pig the 34" EOA pipeline from the FS-1 pig launcher to Skid 50. (BPXA estimates it will complete this activity by 2Q 2002.)
    - If necessary, pig the WOA pipeline segments. (BPXA estimates it will complete this activity by 3Q 2002.)
  - Test clamp-on-meter on EOA pipeline at Skid 50 to determine repeatability with existing meters at the flow stations. (BPXA estimates it will complete this activity by 2Q 2002.)
  - If necessary, test other meter technology at EOA Skid 50. (BPXA estimates it will complete this activity by 3Q 2002.)
  - Select meters to be used for leak detection. (BPXA estimates it will complete this activity by 3Q 2002.)
- Install meters on all pipelines. (BPXA estimates it will complete meter installation by 4 Q 2002.)
- Complete Lisburne crude oil flow smoothing modifications. (Done.)
- Complete WOA crude oil flow smoothing modifications
  - Tune existing controls to optimize the oil train vessels. (BPXA estimates it will complete this activity by 4Q 2002.)
  - If necessary, upgrade level control valves to the inlet separators. (BPXA estimates it will complete this activity by 4Q 2002.)
  - If necessary, reprogram or upgrade gathering center automation. (BPXA estimates it will complete this activity by 4Q 2002)
- Test meters on all pipelines. (BPXA estimates it will complete meter testing by by 4Q 2002.)

2. Evaluate leak detection systems' compliance with 18 AAC 75.055(a)(1) and 18 AAC 75.425 on all pipelines.

– Test each pipeline to evaluate whether the leak detection system can detect a leak of 1% of daily crude oil throughput (i.e. the leak detection system must detect the leak [at the moment] the volume of crude oil lost from the pipeline equals 1% of the daily crude oil throughput for the pipeline or sooner if required by 18 AAC 75.425. (BPXA estimates it will complete leak detection evaluation by 4Q 2002.)

Conrad, Jeffrey C

F.1c

From: Campbell, Gary RB
Sent: Saturday, October 19, 2002 7:48 AM
To: Phillips, Chris J; Blankenship, George R; Conrad, Jeffrey C
Cc: Neill, David H; Bruchie, James (Dave) D; GPB, Ops Mgr
Subject: Leak Detection

Chris, et al,

David Neill and Dave Bruchie have provided additional information to summarize the circumstances regarding the pipeline sediment at GPB to verify what testing was done on the crude oil transmission pipeline at GPB that showed sediment, and why in 2002 we did not need to pig the lines; i.e. one of the reasons we requested the COBC and extended the Leak Detection installation deadline to Dec 31, 2002.

In the spring of 2001, Ultra-sonic (U/S) strap-on meters were tested on the crude oil line at FS-2 to test the accuracy of the meters given the expected low flow rates in the line. During the testing, it became evident the FS-2 line where it intersects with the FS-1 line had significant sediment buildup (about 1/3 of the bottom of the pipe). This was determined while setting up the ultrasonic transit time meter, and rotating the meter transducers around the perimeter of the pipe, and watching the signal attenuation. In order for the meter to function accurately as the flow rates change, we require a clean pipe. With sediment in the line, the meter is non linear. Based on the finding at the FS-2/FS-1 intersection, we assumed at the time, that there was significant sediment buildup along all the EOA pipeline segments all the way to Skid 50. At that time we began making piping and pig receiver modifications at Skid 50 to allow us to pig the FS-1/Skid 50 piping. The velocity in the FS-2 segment was <0.5 ft/sec making pigging impossible.

At the FS-2/FS-1 intersection, there is a pig launcher/receiver module where the pipeline diameter changes from 30" to 34". This module has a gas detection system and hydrocarbon sump system and was suitable to install a reduced diameter turbine meter run. In looking at alternate locations for meter installation for testing, the alternative of installing a turbine meter at FS-2 was discussed with the Operations Manager who recommended looking at the Turbine meter because:

1) we could install a reduced size meter run, sized to match the current flow rates from FS-2 (lowest in the field by a factor of 2), rather than an insert turbine meter (on full diameter line pipe) or ultrasonic meter operating at less than 0.6 ft./sec (near the low end of the reliable operating range for these meters) in the main line pipe.
2) with a turbine meter in the reduced size meter run, we would not need to pig the lines, provided other sections of the line selected for ultrasonic meters did not have sediment.
3) the turbine meter could be installed in an existing building with gas detection to detect leaks at flanges and a sump to handle liquids during maintenance

This was deemed the best metering solution for the FS-2 segment as the reduced diameter meter piping would increase the flow velocity, thereby eliminating the possibility of sediment buildup in the meter run.

In early 2002, subsequent ultrasonic meter testing at the FS-1/FS-3 intersection and the Skid 50 intersection showed no sediment buildup at those locations. At these locations with clean pipe and flow velocities well above 1 ft/sec we expect the ultrasonic transit meter to perform well. Also these intersections are out in the open over tundra, so the non-intrusive design of the ultrasonic clamp-on meters posed no potential leak source. During this time we tested several manufacturers brands of ultrasonic transit time meters to find the one that worked best. We also tested WOA locations at the GC-2/GC-1 intersection and the WOA Skid 50 intersection and found those areas free of sediment.

Based on the information we had in 2001, a decision was made to inform the agency that we had detected the sediment at FS-2, and that we would not have time to design, obtain the financial approvals internally and with partners required to install pigging equipment, pig the lines, purchase and install meters, and have a witness test by ADEC before the December 31, 2001 deadline. We therefore initiated discussions on a COBC.

I was incorrect in stating that we moved the meters to avoid the sediment at FS-2. In fact, we installed a turbine meter in a reduced size meter run to avoid pigging because of the inherent risks involved with the low velocity flow. We did pick optimum locations for the ultrasonic meters; in straight run sections of pipe to insure good flow profile, and completely covering the pipe segments. these locations were found free of sediment. Pipeline elevation (to avoid pipeline low spots with possible sediment build-up) was not a consideration for meter location. We do not know how much, or where sediment may be present in the pipelines. One of the advantages of the ultrasonic meters is we can move them fairly easily if necessary should we experience sediment build-up or for other reasons. We also have the pigging facilities installed and available should we need them in the future.

Gary R B Campbell
GPB, HSE Manager
Anchorage: 564-4275
GPB: 659-8462

Brewster, Monica P

From: Jacobsen, Rosanne M
Sent: Monday, September 16, 2002 6:37 PM
To: Phillips, Chris J
Cc: Brewster, Monica P
Subject: the info you wanted re pipeline leak detection?

Hi Chris -- I've been looking for the documents that you asked Monica for last Friday -- I seem to recall a "chronology" of events re GPB's actions re pipeline leak detection, but haven't run across it yet -- either electronically or in my paper files. Now I'm not sure that it ever existed!

The only thing I found are attachments to this e-mail:

FW: Leak Detection Information...

Also stumbled across a very "drafty" version of an issue card:

Pipeline leak detection issue ...

Are any of these documents what you were looking for?? Rosy

GPB Specific Leak Detection Discussion Points

- The regulatory deadline for compliance with the current leak detection regulatory requirements associated with crude oil transmission pipelines was January 1, 1997.
- ADEC extended GPB* additional time to comply to allow for additional engineering for the pre-existing facility.
- January 29, 1999, ADEC issued conditions of approval for the renewal of the GPB plans requiring a leak detection submittal on or before August 31, 1999.
- BPXA and Phillips submitted the required proposals on August 30, 1999.
- Submittals initiated a series of discussions on leak detection systems, leak detection BAT's and regulatory interpretation of compliance requirements.
- On December 7, 2000 ADEC found the leak detection proposal (most recently modified and resubmitted on October 19, 2000) insufficient and required a revised proposal be submitted by January 31, 2001.
- On January 31, 2001, BPXA submitted a revised leak detection system and system-testing proposal concurring with the Departments interpretation of segment level detection requirements. This submittal established December 31, 2001 as the deadline for functional performance testing of the GPB system.
- BPXA has conducted 2 functional fluid draw tests on the Lisburne crude oil transmission pipeline. The first test highlighted areas for functional improvement and the second test (improvements in place) demonstrated the ability to detect a leak of <1% on that segment of pipeline.
- BPXA is working closely with ADEC staff to:
    - field test additional alternative sensing systems,
    - smooth GPB flow conditions,
    - investigate alternative metering concepts,
    - improve the overall performance of the leak detection system, and
    - field verify the optimum performance of the system.
- BPXA recognized that work would not be complete by December 31, 2001 and has requested a COBC to demonstrate compliance until all leak detection work is complete.

* GPB represents both the EOA and the WOA

Crude Oil Transmission Pipeline Leak Detection Information

Regulatory Information

- Prior to 1997 leak detection requirements did not apply to EOA or WOA
- ADEC revised the "crude oil transmission pipeline" definition to include non-DOT regulated sales oil pipelines (EOA and WOA).
- The leak detection regulations refer to a leak detection system which industry interpreted as applicable to commingled crude oil transmission pipelines. Examples are Kuparuk/MPU, Endicott/Badami, and GPB.
- By December 2000 a BPXA legal review concurred with the ADEC interpretation of the regulation and efforts to resolve compliance concerns were initiated.

System Information

- All pipelines have conventional low pressure and flow rate alarm systems to provide a primary means of leak detection.
- All North Slope leak detection systems define and utilize Ed Farmer Associates (EFA) proprietary leak detection software as Best Available Technology (BAT). EFA offers a system either mass balance (Mass Pack) detection or pressure wave (Pressure Point Analysis, PPA) detection. BPXA has installed both systems on all pipelines. Some pipelines (Endicott, Badami, Northstar) have additional leak detection systems installed as well.
- BPXA used vender performance information (<0.15%) in the presentation of our BAT assessment for leak detection systems. Failure to meet these claims has created tension between ADEC and BPXA.
- ADEC has recognized the limitations of some facilities to meet regulatory requirements and is willing to issue waivers as long as BPXA demonstrates that all reasonable options have been considered and that the system is optimized to the maximum extent possible.

Performance Information

- Field-testing of the systems has failed to meet vendor claims. Vendor claims are dependant on a steady state, low noise pipeline environment that does not exist on the North Slope.
- Mass Pack has been proven to meet the regulatory requirement to detect leaks of less than 1% of daily throughput (0.4% at Endicott).
- PPA has failed to meet regulatory requirements.
- The vendor has communicated directly with ADEC to defend his product and has stated that BPXA needs to upgrade metering, optimize flow conditions and/or install shipping tanks to buffer the noise.

Field Specific Leak Detection Information

<u>MPU</u>

Background -	The MPU leak detection system was originally installed as a component of the Kuparuk sales oil line leak detection system. No historical issues from ADEC on segment definition or non-compliance.
Status -	The recognition of a segment detectability requirement initiated the purchase and installation of new instrumentation and upgraded software. A testing program has been submitted to ADEC and testing will be conducted over the next couple of months. Initial testing scheduled for mid-January were cancelled due to software problems with the EFA system. ADEC will witness testing.
Issues -	None
Outcome -	Anticipate compliance with leak detection requirements.

<u>Northstar</u>

Background -	The Northstar leak detection system was subject to tremendous scrutiny during the permitting and planning approval activities. Sub-sea pipeline issues centered on our ability to detect leaks. An untested gas sieve detection system (LEOS) was installed to satisfy concerns that a chronic leak below conventional detection limits could go unnoticed for months under the solid ice cover during the winter season.
Status -	Northstar is working closely with ADEC in the development of testing protocols. Ed Farmer is currently on site assisting facility personnel with the final adjustments of the system. ADEC will witness functional tests of the EFA leak detection system in the next few days. Northstar will coordinate similar testing activities with ADEC to validate the efficacy of the LEOS system.
Issues -	Extensive surveillance programs may be required if LEOS fails to perform as anticipated.
Outcome -	Anticipate compliance with leak detection requirements. Optimistic but not overly confident of LEOS performance testing.

<u>Endicott</u>

Background -	The leak detection system for Endicott was originally submitted as a combined system with the Badami pipeline. The existing plans were approved with information supporting this position. Field-testing of the system in 2000 and 2001 verified that Endicott can meet the regulatory requirement but the low flow regime at Badami cannot.
Status -	Endicott is continuing to work with ADEC to verify that the system has been optimized. A test program is in place.
Issues -	None
Outcome -	Anticipate compliance with leak detection requirements.

Badami

Background - The Badami leak detection system was originally installed as a component of the Endicott sales oil pipeline leak detection system. No meter was installed at the Badami/Endicott junction to allow segregation of flow. Field-testing has indicated that Badami cannot meet regulatory requirement with the existing system.

Status - Badami is working with ADEC and has proposed the installation of a turbine insertion meter at the Endicott tie-in. Installation is planned for this year and additional field-testing will be performed to validate system performance.

Issues - The low flow rates (1500 bopd) present a unique challenge to instrument sensitivity. The 1% requirement equates to less that 2 quarts of oil per minute. This may not be achievable.

Outcome - Anticipate ADEC issuance of a waiver of leak detection requirements.

Lisburne

Background - The Lisburne leak detection system was installed in 2000 as a stand-alone leak detection system. Initial field-testing failed to demonstrate compliance with regulatory requirements. Ed Farmer and Lisburne personnel worked to smooth out the flow at the facilities and fine-tune the software to match the operating conditions. Additional testing proved the system meets the regulatory requirements.

Status - Lisburne personnel are working with ADEC to determine if additional verification testing is required.

Issues - None

Outcome - Anticipate compliance with leak detection requirements.

<u>EOA/WOA</u>

Background - In 2000 the EOA and WOA sales oil pipelines were connected into a single line entering Pump Station 1 (PS1). This was done to optimize PS1 meter performance in light of reduced flow rates. The leak detection system was installed late in 2000 under the premise that segment detection was not required by the regulations.

The quality of metering at the GCs has been a subject of concern by ADEC. The GCs use orifice plates to meter shipping while the Flow Stations use turbine meters to record flow. BPXA was able to quell the concern by demonstrating that while orifice meters have less accuracy than turbine meters, the canceling error effect with meters placed in series provides the needed accuracy to support the leak detection system. The GCs have 4 meters in series.

Status - BPXA has worked closely with ADEC to investigate potential options to provide the level of pipeline segment detectability required by the regulations. A testing program is in place. To cover the recognized non-compliance BPXA is currently negotiating a COBC to define the required activities and schedule for completion.

Issues - A range of options have been discussed with ADEC. These include installation of turbine meters at the GCs ($10MM+), shipping tanks at production centers ($30MM+), and turbine meters at segment junctions ($5MM+). Cost is a consideration in the BAT analysis but there is not much sympathy for a field producing 600k bopd. The installation of additional tanks and the pipeline turbine meters pose an increased environmental risk with the introduction of new potential spill sources and an increased environmental impact associated with the required expansion of the gravel footprint to support installation.

Outcome - Compliance with leak detection requirements is theoretically achievable but has not been proven. A waiver from ADEC may be required to relieve one or more pipeline segments from the regulatory requirement.

PIPELINE LEAK DETECTION

Issue: You've been out of compliance with state pipeline leak detection requirements for years and are dishonestly trying to further delay compliance by entering into a Compliance Order.

Position: Compliance with all laws and regulations is very important to me. In this situation, compliance with the law is somewhat subjective because it depends on the feasibility of applying new technology to our pipelines. We have been working with ADEC since 1997 to determine what kind of leak detection system is appropriate for our pipelines, and that work is continuing. We installed a new leak detection system in late 2000, and our last deadline for testing the system was on December 31, 2001. Due to several technical challenges and regulatory uncertainty, we need more time to complete this work.

Because compliance is so important, we have begun negotiating a compliance order with the Alaska Attorney General. Compliance orders are authorized by the legislature and are a standard way to allow companies to continue working with an agency to resolve compliance issues in the midst of regulatory uncertainty. The Compliance order will require BPXA to take certain actions by certain dates, and will likely include a fine.

Supporting facts/evidence/analogies:

Regs first began to apply to sales oil pipelines in 1997

Only six pipeline segment are regulated: FS-2 to FS-1; FS-1 to FS-3; FS-3 to PS-1; GC-1 to PS-1; GC-2 to PS-1; and GC-3 to FS-3

The regs are subjective – and are subject to an analysis of the cost to BPXA, the feasibility of applying the new technology, etc.

NOTE: it would be hard to defend the position that "we did everything we could" because BPXA apparently could/should have done more sooner

The six segments have always been covered by some form of leak detection system: low pressure and flow measurement alarm systems, visual surveillance by road, and aerial surveillance. Since late 2000, the new leak detection software and implementation has provided an additional level of assurance.

The Attorney General has not yet determined when BPXA may first have been out of compliance, but it could be as early as 12/00, when BPXA received a letter from ADEC finalizing the definition of daily throughput. BPXA then knew for sure its position on the definition wasn't right. The first date of non-compliance could also be 1/1/02, when BPXA could not meet the last agreed timeline. The worst case would be non-compliance since 1997, when the regs became effective.

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

November 18, 2002

BY COURIER

Ms. Mary Frances Barnes
United States District Court
District of Alaska
Probation and Pretrial Services Office
Federal Building
222 West 7th Avenue #48
Anchorage, AK 99513-7562

Re: Answers to follow-up questions from October 16, 2002 meeting with BPXA

Dear Ms. Barnes:

We have received your letter dated October 25, 2002, which poses nine questions. The first part of this letter addresses questions one through five, on the subject of Pipeline Leak Detection, and the second part of this letter responds to questions six through nine regarding the reporting of NO_x emissions and summarizes our October 16 discussion of these matters.

Pipeline Leak Detection

Q1 The Compliance Order by Consent states that in December 2000, Alaska Department of Environmental Conservation ("ADEC") determined that BP Exploration (Alaska) Inc. ("BPXA") proposed Leak Detection System did not meet the 1% standard or the Best Available Techniques (BAT) requirement. What Leak Detection System was proposed to ADEC for use on transmission pipelines which ADEC determined to be inadequate?

A1 BPXA proposed a combination mass balance line pack compensation ("MBLPC") system and pressure point analysis ("PPA") system as the leak detection system ("Leak Detection System") for the Greater Prudhoe Bay Unit ("GPBU") crude oil transmission pipeline system ("Pipeline").

The proposed MBLPC system would use existing turbine meters at the three flow stations on the east side of GPBU to measure crude oil flow from these facilities into the Pipeline and utilize existing orifice meters at the two gathering centers on the west side of GPBU to measure crude oil flow from these facilities into the

BPXA-CEC00001661

Pipeline. An existing custody transfer meter at Pump Station 1 would measure crude oil flow out of the Pipeline.

The proposed PPA system would use existing pressure sensors to measure pressure differentials along the Pipeline. The flow and pressure data would be input into a proprietary software system. The Leak Detection System in conjunction with a visual surveillance program could continuously detect a leak of 1% from the Pipeline and provide flow verification every 24 hours.

Q2 What reason did ADEC give to BPXA for the agency conclusion that the Leak Detection System did not meet the BAT requirement or the 1% standard?

A2 In the December 7, 2000 Harvey-to-McCleary letter ("December 7 Letter"), ADEC noted that BPXA's October 19, 2000 proposal did not include a BAT review as required by 18 AAC 75.425(e)(4). ADEC stated, "BPXA must perform a specific BAT analysis on all elements of the proposed leak detection system. The analysis must demonstrate that the selected technologies are the most appropriate for the EOA/WOA pipeline system as outlined in the referenced BAT regulations". (See December 7 Letter, page 6. A copy of the December 7 Letter is attached as Attachment "A".)

In the December 7 Letter, ADEC concluded that the proposed Leak Detection System could not meet the requirement to detect a daily discharge equal to not more than 1% of daily crude oil throughput. ADEC stated "[c]ompliance with the one percent daily throughput requirement of 18 AAC 75.055(a)(1) must be determined for each pipeline segment based upon the current throughput for individual segments of the system. BPXA's analysis incorrectly uses the combined flow into Alyeska's Pump Station 1 as the basis for assessing leak detection accuracy. The Department has determined that the proposed system's leak detection threshold for individual pipeline segments would exceed one percent". (See Attachment "A," page 1.)

BPXA did not agree with ADEC's conclusion and continued to work with ADEC to clarify the interpretation of the regulation.

Q3 When was it first communicated to BPXA by an ADEC employee that the proposed Leak Detection System did not meet the BAT requirement or 1% standard?

A3 On the date BPXA received the December 7 Letter. (See Attachment "A".)

Q4 What is the industry standard for the Leak Detection System on transmission pipeline systems?

A4 There is no single industry standard for leak detection systems on crude oil transmission pipeline systems. The American Petroleum Institute states "...[pipeline] leak detection can be accomplished by a variety of techniques such as: aerial/ground line patrol; third party reports; inspections by company staff; sensors; supervisory control and data acquisition ("SCADA") monitoring of line conditions by pipeline controllers; and software based monitoring". (See "Computational Pipeline Monitoring", API Publication 1130, First Edition, October 1995, page 1 ("API 1130").) The best leak detection system for a particular pipeline depends upon numerous factors. (See API 1130, section 4.2 and "Evaluation Methodology for Software Based Leak Detection Systems, API Publication 1155, First Edition, February 1995 ("API 1155"), chapter 3. Copies of API 1130 and API 1155 are attached as Attachment "B".)

Q5 What is the industry standard for Leak Detection Systems which require detection of 1% loss of product? What is the industry standard for the BAT on Leak Detection Systems of this type (requiring the detection of 1% of loss of product)?

A5 We reviewed the pipeline leak detection requirements in other states and did not locate another state requirement to detect a daily discharge equal to not more than 1% of daily crude oil throughput. Similarly, we did not locate industry standards for a leak detection system that requires detection of a daily discharge of not more than 1% of daily crude oil throughput or for a best available technology requirement on such a leak detection system.

NO_x Emissions Reporting

Reading your questions revealed that we had not done a very good job of explaining the NO_x issue when we met with you, Tim Burgess and Deborah Smith on October 16, which we regret. Rather than answer your questions directly, we will lay out for you the issues surrounding our NO_x disclosure and thereafter will address specific questions at the end of our letter. When we meet on November 20, there should be ample opportunity for us to further clarify the NO_x situation, as necessary.

At Greater Prudhoe Bay, each of our major facilities has ADEC air permits that provide operational limits for NO_x (NO and NO_2) releases from major fuel-burning equipment (primarily turbines, heaters and larger stationary diesel engines). Included in these regulated releases are those from the combustion of pilot and purge gas used to maintain our safety flare systems.

NO_x releases from emergency flaring events and from mobile, portable equipment that operates on a temporary basis within the field do not require a permit. NO and NO_2 are listed pollutants under CERCLA with a threshold reporting quantity of 10 pounds. An

EPA regulation (40 CFR 302.8) provides that releases of NO_x that do not require a permit must be reported under CERCLA if a 10 pound threshold is exceeded.

CERCLA allows releases that are either continuous or intermittent but predictable in quantity and rate to be reported under a single report called a "continuous release report." Accordingly, BPXA filed a continuous release report for NO_x, estimating a daily release of approximately 78,000 lbs of NO_x for upset flaring and portable equipment, including fire response equipment. This is the report that BPXA referred to in its October 16, 2002 presentation.

In contrast to the level of NO_x emitted by our normal operations, the release of NO_x that resulted from the A-22 fire was de minimus, some 70 pounds, or approximately one tenth of one percent of the maximum estimated daily release pre-reported to the EPA. BPXA did not identify spurious NO_x releases from fires in the continuous release report and thus should have separately reported this incident. This release was overlooked by the advisors who perform spill reporting on the North Slope because they were not aware of the full duration of the fire and viewed the release as a natural gas release that is exempt from reporting under CERCLA. Even though the EPA was aware of the fire at the time, we overlooked that fact that NO_x was emitted, from which unintentional release arose a separate reporting requirement. It wasn't until the incident was reviewed by Jeff Conrad, whom you met on October 16th, that the need to separately report was determined.

On October 8th, BPXA determined, using conservative estimation methods, that more than 10 pounds each of NO and NO_2 could have been released, which exceeded the accidental release Reportable Quantity ("RQ") under CERCLA for each substance. On that same day, BPXA reported the releases to the National Response Center ("NRC") and ADEC. On October 29, 2002, BPXA filed a Voluntary Disclosure of Violation of 40 CFR Parts 302 and 355 at Greater Prudhoe Bay (see Attachment "C") in accordance with EPA's Voluntary Disclosure Policy and the United States Department of Justice Factors. Such reports are contemplated in Section IV.D.2 of the Plea Agreement.

To avoid similar incidents of overlooking such a reporting requirement in the future, BPXA will develop a checklist on CERCLA reporting for emergency response advisors to alert them to consider the potential for reports such as this. In addition the North Slope release reporting procedure will be amended to alert personnel regarding release notification requirements relating to NO_x.

Against this background, following are the answers to the specific questions you asked.

Q6. Which agency provided the permit referenced by BPXA in the October 16, 2002 presentation?

A6. As noted earlier, the use of the term "permit" is a misnomer. BPXA is required to report releases of listed pollutants, including NO and NO_2, that exceed the respective RQ for each pollutant pursuant to CERCLA reporting regulations. Reduced reporting is allowed for certain releases that are continuous, or intermittent but predictable, in quantity and rate. To qualify for reduced reporting, a company must provide certain initial and follow-up notifications. BPXA made such notifications for NO and NO_2 to EPA Region 10. After these notifications are made, individual releases that meet these criteria need not be reported. Thus, BPXA is not required to report NO_x releases that exceed the RQ if they are subject to reduced reporting and are covered in our original notification. However, BPXA is required to report NO_x releases that exceed the RQ if they are not subject to reduced reporting. Any such reports must be made to the NRC, ADEC, and the Local and State Emergency Planning Committees.

[illegible] DOES NOT INCLUDE A "CONTINUOUS RELEASE" REDUCED REPORTING REQUIREMENT. EVERY UNPERMITTED RELEASE MUST BE REPORTED TO ADEC

Q7. Is BPXA required to report NO_x emissions to the environment in ADEC situation reports? ?

A7. No, ADEC, not BPXA, prepares situation reports. The previous answer addresses when ADEC must be notified.

Q8a. What does the BPXA permit state regarding the level of NO_x emissions which do not have to be reported?

A8a. As described above, NO_x emissions may be governed under ADEC permits, or if outside the scope of the ADEC permit, then NO_x releases are governed under federal and state reporting requirements.

Regarding emissions governed under CERCLA, BPXA's current notification to EPA for Greater Prudhoe Bay states that the maximum estimated NO_x release is 78,018 pounds total of NO and NO_2 per 24 hours. The A-22 NO_x emission was estimated to be approximately 70 pounds. NO_x releases under 10 pounds in any one day period are not reportable under CERCLA.

? At facilities governed by ADEC permits (17 total at Greater Prudhoe Bay), there is no requirement to report NO_x emissions. Rather, specific permit limits involve surrogates such as equipment type, emissions control equipment, fuel specifications, or hours of operation that are used to limit emissions of NO_x.

Q8b. What facilities are permitted?

A8b. BPXA's CERCLA notification covers every [illegible] facility within Greater Prudhoe Bay and includes well pads such as A pad, where the A-22 well is located.

ADEC-permitted facilities at Greater Prudhoe Bay are:

Flow Station 1 (FS-1)	Central Power Station (CPS)
Flow Station 2 (FS-2)	Seawater Treatment Plant (STP)
Flow Station 3 (FS-3)	Seawater Injection Plant East (SIPE)
Gathering Center 1 (GC-1)	Crude Oil Topping Unit (COTU)
Gathering Center 2 (GC-2)	Prudhoe Bay Operations Center/ Main Construction Camp (PBOC/ MCC)
Gathering Center 3 (GC-3)	Base Operations Center (BOC)
Lisburne Production Center (LPC)	Hot Water Plant (HWP)
Central Gas Facility (CGF)	Grind & Inject (G&I)
Central Compression Plant (CCP)	

Q9. What is the level of NO_x emissions released to the environment over the past year and to date? Which facilities are covered by the permit?

A9. For the most current calendar year available (2001), NO_x emissions governed under the CERCLA release notification totaled 16,237,824 pounds. Permitted NO_x emissions totaled 63,304,380 pounds. Thus, the sum of NO_x emissions for 2001 is 79,542,204 pounds.

We trust this addresses your questions, and hope you and the children are continuing to recover from the automobile accident. We especially appreciate your carrying through with our meeting immediately after having been involved in such a distressing event. We look forward to meeting with you again on November 20.

Sincerely,

Chris J. Phillips

Chris J. Phillips
Vice President, BPX(A)

Enclosures as stated

Cc : Timothy Burgess, Office of the U.S. Attorney, District of Alaska
Deborah Smith, Office of the Assistant U.S. Attorney, District of Alaska
Ridgway Hall, Crowell & Moring
Carol Dinkins, Vinson & Elkins

3c w/o encl:

Rosy Jacobsen
Jeff Conrad
Karen West
Bill Colbert
Janet Platt
Gary Campbell
George Blankenship
Neil McCleary

bp

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

October 1, 2001

Eng YE'01
Pg, Order Q1/02
Test (M) Q1/02
Purch/Inst Q2/02
Test+Run Q3/02.

Mr. Robert Watkins
Alaska Department of Environmental Conservation
Industry Preparedness and Response Program
555 Cordova Street
Anchorage, Alaska 99501

Re: BPXA - Prudhoe Bay Leak Detection Update

Dear Mr. Watkins:

BPXA is providing you an update on the work completed and currently planned on the Leak Detection System at Greater Prudhoe Bay; and, to request a meeting to review this information and the proposed way forward to complete the work necessary to fulfill ADEC commitments and to ensure BPXA is in compliance with Regulations. We are proposing two options; 1) Update the BAT information and present the Leak Detection results currently available and agree on conditions for a waiver on the 1% threshold, or, 2) enter a COBC to provide legal protection while the work is completed on the leak detection system in 2002.

Background:

The January 1, 1997 regulatory deadline for demonstration of less than 1% leak detection capability for EOA/WOA crude oil pipelines consistent with Alaska Oil Pollution Prevention requirements has, through a series of agreements between ADEC and BPXA been extended to December 31, 2001. There have been differences in opinion on the technical feasibility of retrofitting a facility designed, constructed and commissioned in the 1970's and early 1980's consistent with the regulations and industry standards then applicable. A complicating factor in the establishment of Best Available Technology (BAT) is the technical feasibility of working with a pipeline system originally sized for large flow rates, with the surge capacity at the Pump Station 1 end. Some individual segments are now flowing at rates well less than 1 ft./sec, resulting in sediment buildup, which inhibits accuracy of ultrasonic, and insertion turbine meters. The low flow rates are below the manufacturer's recommended cut-off for insertion turbine meters. Work completed to date on testing leak detection systems has yielded an increased understanding of the capabilities and the restrictions of the various Leak Detection systems being promoted within the industry as BAT; particularly when applied to older facilities operating below design capacity.

Status Summary:

Attached is a full status of the 12 actions agreed at the April 30 meeting. The time line originally presented has not been met due in most part to the discovery of solids in the crude oil pipelines, in particular in the Eastern Operating Area segments, making the use of strap-on ultrasonic flow meters impractical. This situation was not contemplated in the original planning and time line prepared by BPXA and reviewed and agreed by ADEC. This has caused a delay in the full feasibility testing of the meters to achieve segment leak detection; however, the attached test data completed to date is very encouraging suggesting that we are close to having an overall system detection accurate to 1% of hourly accumulator data (at present rates, 200 bbl/hr). The following summarizes the test results to date.

Lisburne

The testing summary is that mass balance at Lisburne is working within the 1% fairly consistently. Occasional plant upsets, resulting in oil rate swings are still causing us some problems. See attached spreadsheet covering the time period Aug. 28 – Sept. 9. On Sept. 9 11:53 – 12:15, and 17:11 – 20:28 we experienced plant upsets resulting in hourly accumulator readings exceeding 1%.

Prudhoe Bay

Overall Mass balance for the entire Prudhoe Bay network is repeatable within 1% most of the time. The main problem is flow fluctuations from the WOA Gathering Center's. Now that we are getting consistently good data across the network, the next step is to try and tune the oil train level controls to optimize existing vessel capacities. Segment leak detection is still giving us problems. We have tested ultrasonic strap-on meters on the Eastern Operating Area, Flow Station-2 – Flow Station-1 section. This line is 30"diameter and the flow velocity is well under 1ft/sec. Due to the low velocities, we suspect significant buildup of sediment and paraffins in the line. Ultrasonic meter accuracy is dependent on a clean straight pipe. Regarding the EOA lines, we lost the ability to pig when the oil lines were combined into a single pipe between Skid 50 and the PS-1 metering skid.

We are progressing with the engineering and purchase of the materials to enable pigging the pipelines and to prepare the likely pipeline areas where meters will be installed by stripping the insulation and pulling communication wires. We would like to test several brands of meters before we commit to a certain brand however this is not achievable with the December 31, 2001 deadline.

In summary, BPXA requests a meeting to review this status and to discuss the needs of ADEC and the feasibilities of the options available. Please contact Gary Campbell 564-4275 at your earliest convenience to coordinate this meeting.

Respectfully,

Gary Campbell

Gary R B Campbell
GPB HSE Manager

Attachments:

Attachments:

PBU Leak Detection Status Report Sept. 27, 2001
PBU Leak Detection Results
Lisburne Leak Detection Results
VECO Memo; Use of Storage/Surge Tanks at the GC's
Procedure to test Mass Pack

cc: Susan Harvey, ADEC
Sig Colbert, ADEC
Len Seymour, BPXA
Nick Glover, BPXA
David Neill, BPXA

Prudhoe Bay Unit Leak Detection Status Report
September 27, 2001.

Timeline for additional leak detection system work: Rev 1 9/27/01

1. ADEC Review of Existing EFA Leak Detection System at LPC and Prudhoe - Tour and review of these systems with the North Slope Instrument Engineer. Timeline: February 12-18, 2001 or any subsequent alternating week. - DONE

   yes

2. Best Available Technology (BAT) Analysis - BAT Analysis due to ADEC outlining BP review that the current EFA system is in fact the best available technology, once additional meters are installed. This will address the proposed segmented detection system discussed here. Timeline: March 1, 2001. - DONE

   yes

3. Prove Principle - Test Case, install Panametrics or Controlotron external ultrasonic meter downstream of existing Flow Station turbine meters to insure accurate flow measurement at various flow conditions. Compare to 0.5% accuracy facility meter data to prove technology works.
   Original Timeline: Late April/Early May, 2001.

   NO

   <<<9/27/01 Update In the April/May timeframe we tested strap-on ultrasonic meters in FS-2 downstream of existing turbine meters. We were unable to get a good test because of turbulence. Insulation was removed from piping outside near the FS-1 pig module for subsequent testing. Both Controlotron, and Panametrics meters were tested. It became evident that significant sediment buildup in the pipe caused poor readings.

   We feel this is still the best location to test an ultrasonic strap-on meter.
   1) Low velocity out of FS-2 represents the most difficult case to design for.
   2) We have already implemented flow-smoothing algorithms at FS2 so the flow rate steady.
   3) We have very accurate meters to compare against.
   4) The only way to get good results from the ultrasonic meters is to have clean straight pipe. At the test location we have several hundred feet of straight pipe upstream. Any other flow meter for this service would have similar requirements.
   5) This is where we would mount a meter for this pipe segment.

   At this time the EOA lines are not piggable due to recent modifications to Skid 50.
   >>>

   Preliminary engineering to modify Skid 50 is under way. The plan is try to assess how much of the sediment in the pipeline is solids. Pigging, will result in solids collection in the meter skid strainers at PS-1. We are trying to determine the operational, and manpower impacts of a pigging operation to see if it is feasible.

The plan is to proceed with installing wiring and site preparations, for addition of meters to allow segment leak detection. Once we able to commence testing and recommend a meter, we can proceed with ordering.

A. Engineering complete and long lead items on site for Skid 50 modifications. Timeline: December 31, 2001
B. Complete pigging of EOA crude sales lines. The timeline for this pigging may be dependent on ambient conditions, or operational issues at the PS-1 metering skid. Timeline: ?
C. Resume testing of ultrasonic meters. Timeline: Immediately after pigging is completed

4. Complete Lisburne crude smoothing modifications. Level control modifications on treater flash drum and crude oil surge drum should minimize slugging leaving facility. ADEC is invited to visit LPC with the controls engineer making these modifications. Original Timeline: April 15, 2001.

Yes

Network communication problems are solved. Lisburne MBLPC system working within 1% except during periods of extreme process upsets.
At this time we feel we have a pretty reliable Mass Balance leak detection system for the Lisburne Line. Concentrating on the GC-1 & GC-2 flow smoothing is our priority.

5. Demonstration of System Capability (Lisburne) - Functional test of Lisburne leak detection system. Timeline: April 30, 2001. Lisburne MBLPC system was successfully tested in house. We are prepared to invite DEC to witness another test at their convenience to be co-coordinated with the North Slop Controls Engineer and LPC Operations. See attached testing plan.

Yes

6. Compare Other Vendor Meters - Gather data and ensure most reliable and accurate meter is selected. Timeline: April 30, 2001. We still want to evaluate ultrasonic meters on piping we think is clean. We may test an insertion turbine meter (via 3" hot tap) if the ultrasonic meters don't meet expectations. <<<However the velocities on the FS-2 and GC-2 segments are less than the manufacturers minimum for accurate metering. This type meter may not be BAT for that location.

NO

7. Optimize Meter Locations - Work with EFA to ensure new meter locations will produce best available technology line segmentation and leak detection. Timeline: May 15, 2001. We believe we have identified the best locations for additional meters.

Yes

8. Evaluate surge tank installation for GC crude smoothing. Timeline: May 30, 2001.

NO

Contracted VECO engineering to evaluate addition of surge tanks at the GC's. In preliminary discussions with VECO, they recommended against tanks based on vapor recovery, leak potential, operational problems, added facility footprint. The decision was made to look at automation upgrades to existing oil train controls as a possible option. See attached memo from VECO regarding our flow smoothing options.

9. Develop Installation Package for New Meters - Original Timeline: May 31, 2001. We are proceeding with site preparation, and pulling wires to these locations. We are pre-investing in adequate wiring and hardware will be suitable for any type of meter. Timeline: December 31, 2001

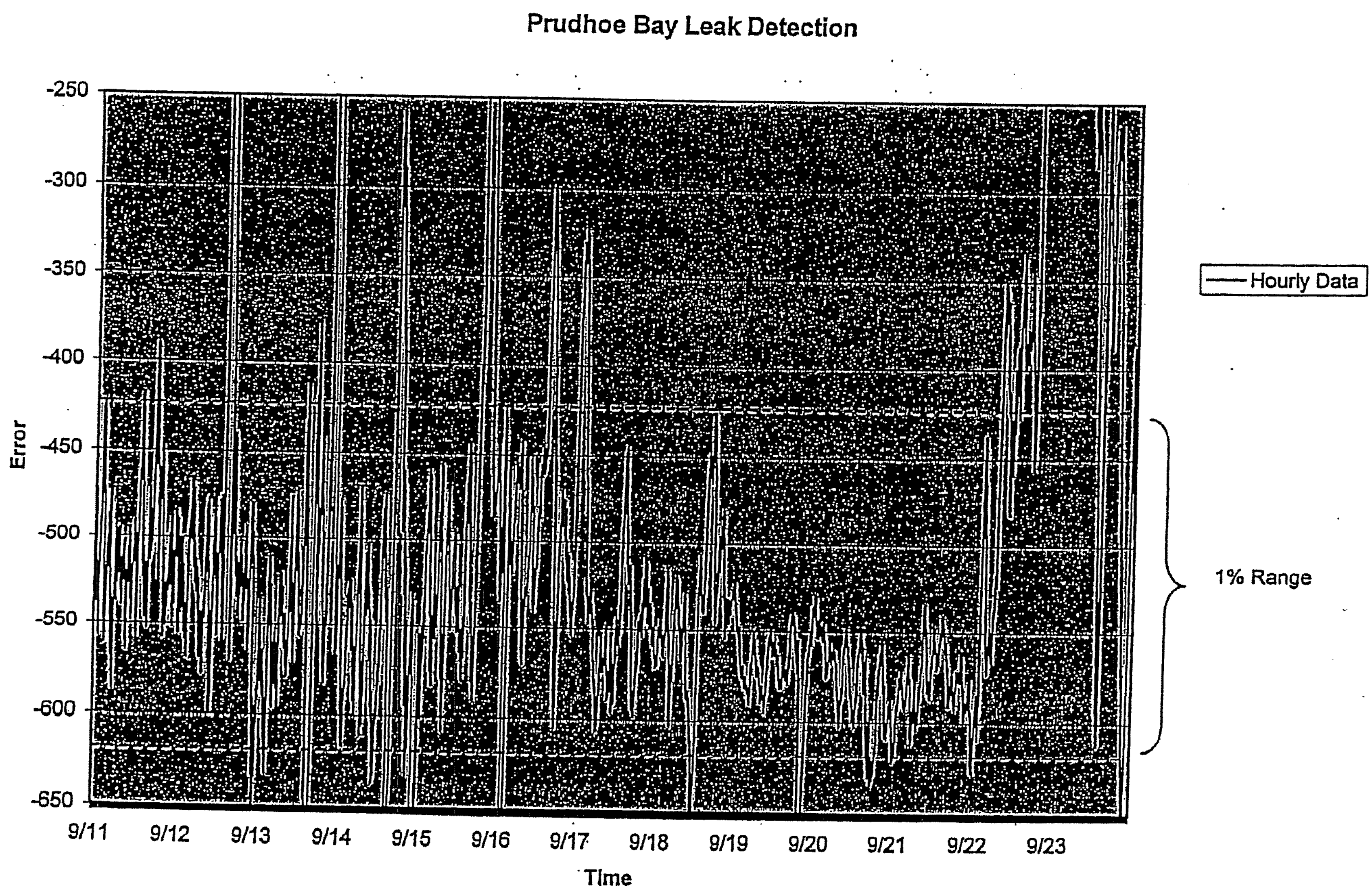
10. Retrofit Pipeline Segments - Install new meters and meter housing, integrate data acquisition with EFA leak detection system, ensure adequate power is available. Original Timeline: October 31, 2001.

    When testing is complete, and we are ready to order, meter lead times are usually 8 - 10 weeks. We would proceed with installation and hook up immediately.

11. Complete Prudhoe crude smoothing modifications, in particular the GC's. Level control modifications on the crude surge drums should minimize slugging leaving the facilities. ADEC is invited to visit the GC's with the controls engineer working these modifications. Original timeline December 15, 2001.

    We are now working on tuning at the GC's. We expect to thoroughly evaluate the capabilities of the existing GC controls, and make recommendations. Timeline: December 31, 2001

12. Demonstration of System Capability (Prudhoe Bay) - Functional test of Prudhoe Bay leak detection system. Original timeline: December 31, 2001. New Timeline: ?


Prudhoe Bay Leak Detection
-250
-300
-350
-400
-450
-500
-550
-600
-650
Error
9/11
9/12
9/13
9/14
9/15
9/16
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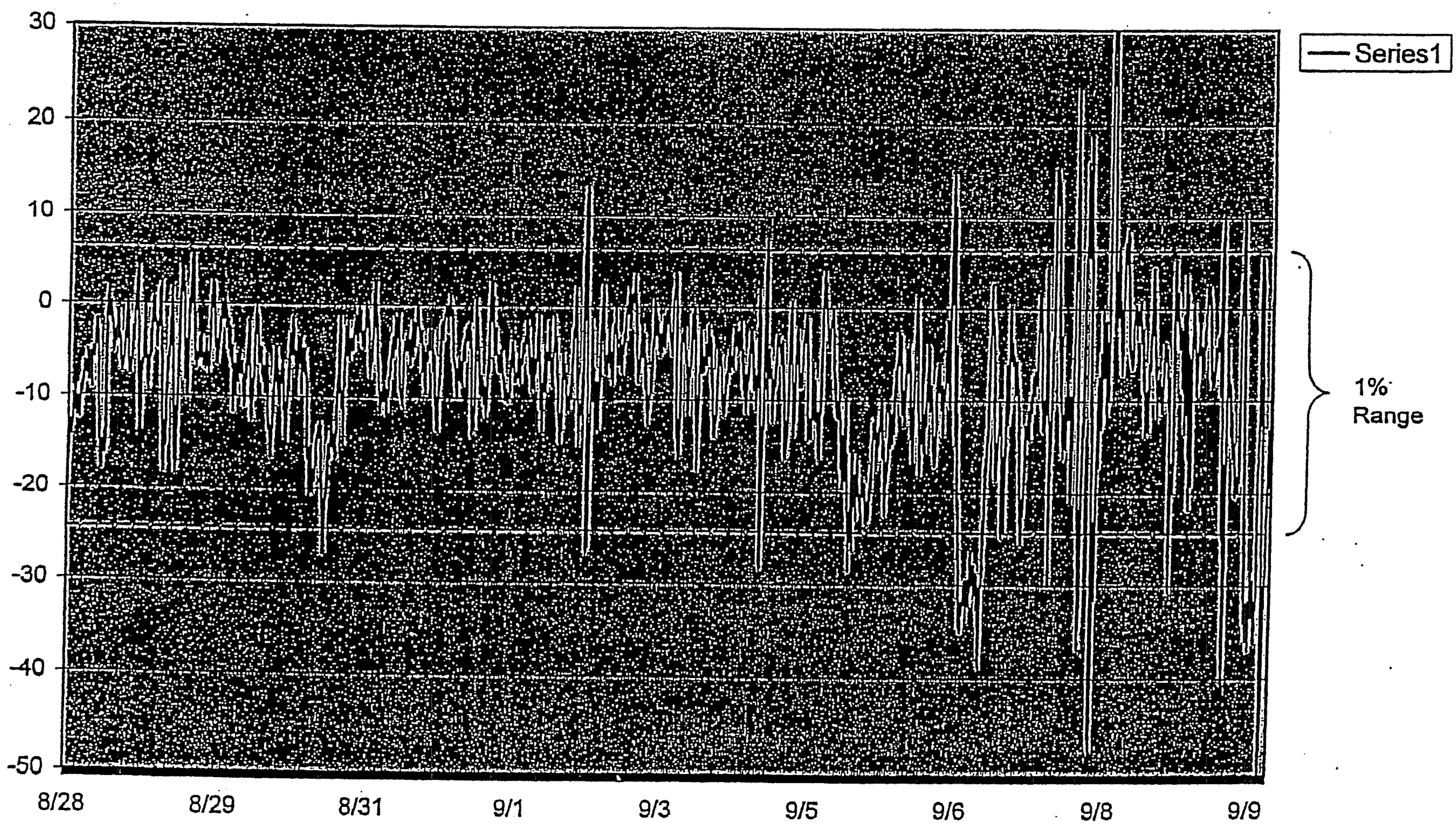
9/18
9/19
9/20
9/21
9/22
9/23
Time
Hourly Data
1% Range

Lisburne Leak Detection



MEMORANDUM

TO: Dave Neill, BP Alaska

Subject: USE OF STORAGE / SURGE TANKS AT THE GATHERING CENTERS

From: Stephen Preston

Date: September 28, 2001

PROBLEM

1 The oil sales lines between the Gathering Centers / Flow Stations and Pump Station One (Trans Alaskan Pipeline System – TAPS) must be monitored for leaks on a continuous basis.

2 Currently leak detection is accomplished by flow / mass balance. Fluctuating flow rates from the GC's are affecting meter function and accuracy.

3 Pressure Point Analysis (PPA) has been proposed as possible best available technology (BAT), but it requires pressure (i.e. flow) stability to function.

4 The Eastern Operating Area (Flow Stations – FS's) has sufficient surge capacity and automation, in the oil separation trains to allow controller tuning to achieve the required flow (and, therefore, pressure) stability.

5 The Western Operating Area (Gathering Centers – GC's) is not currently configured to achieve the necessary flow stability.

OPTIONS CONSIDERED

To achieve flow stability in the Gathering Centers, two primary options were considered. These are:

1 Control Modification.

This involves converting the oil separation trains from level control to cascading flow control, allowing each vessel in the oil system to absorb a portion of the flow swings. This will result in stable (i.e. relatively constant) flow from each facility, provided sufficient volume is available in the oil vessels.

2 Tankage (surge capacity) Addition.

This entails adding low pressure tankage at the "back end" of each GC to provide sufficient storage capacity to absorb the flow swings and provide for stable flow to TAPS. This includes additional compression for the evolved gas, and a significant rerouting of the oil train piping to enable existing pumps to be utilized.

DISCUSSION

Control modification is the best option for the following reasons:

1 Reliability

2 Environmental Impact

3 Schedule

4 Production Impact, and

5 Cost

RELIABILITY

Option 1 has little impact on the reliability of the existing Gathering Centers. It does not add any equipment, merely new controls that can use existing vessel nozzles and bridles. It will improve monitoring of the process since it will replace the outdated pneumatic system with a new, more flexible, electronic system. Electronic control provides the added benefit of easy adaptation to changes in production profiles.

Option 2 adds a significant amount of new equipment. This includes Vapor Recovery Compression, Tankage, control valves and piping. Overall system reliability will, therefore, decrease. This will lead to additional shutdowns and upsets during normal operation.

ENVIRONMENTAL IMPACT

Adding equipment to the Gathering Center will increase the number of leak sources, potentially increase the amount of fugitive emissions (on failure of the Vapor Recovery system), and will require secondary containment. Given the lack of gravel pad space at the Gathering Centers, the addition of pad footprint, in an already environmentally sensitive area, is likely. Option 1 has no additional environmental impact since no new equipment is added. The increased process flexibility, provided by DCS control, will potentially reduce the number of flow induced upsets (shutdowns) experienced by the Gathering Centers. This will result in fewer flare events, and a reduced spill risk.

SCHEDULE

Depending on compressor deliveries, that can run 12 – 18 months, Option 2 will take at least 18 - 24 months, to design and install. Option 1, however, can be installed in less than half the time. This will allow flow smoothing modifications to be initiated faster.

PRODUCTION IMPACT

A partial or complete shutdown of each Gathering Center is required to add tankage to the oil production system. Since Prudhoe Bay is currently gas compression limited by the CGF / CCP plants, this "lost" production cannot be recovered in the short term. Option 1 can be accomplished with minimal interruption of normal production operations. The instrumentation can probably be added without a shutdown, and the bulk of the modification will be software.

COST

The instrumentation option will entail significantly less cost than adding tankage and its associated compression equipment. The difference can be an order of magnitude ($1 million versus $10 million) per GC.

Procedure to test Mass Pack Leak Detection system:

Preparation:
1) Install spare micromotion on drain lines from oil sales line to sump in 4920.

2) Verify test flow meter signal reaches Bailey and is trendable

4) Set flow control valve for test:
Find a convenient throttlable drain valve, and set it for a flow rate of about 35bbl/hr (0.6 bbl/minute) record position, or flag and block in.

5) Arrange to have a local operator at the blowcase during the test

Testing:

1) Review test procedure with board operator and local operator.

2) Start recording leak flow, and leak detection accumulators

3) Establish flow through the blow case to the flare liquid knockout drum, record start time.

4) When leak alarm is recorded at the control panel
record time, terminate test.

5) if there is a plant upset requiring the local operator to leave,
block in the oil drain, record time. The test will have to be rerun.

Ending the test:

1) Block in the drain.

2) Empty the blowcase

3) Save all recorded data.

If the test is stopped early for any reason, wait at least one hour before restarting the test, to let the leak system hourly accumulator reset.

BPXA 10/01/01

Redacted Interim
Report of Investigation

Failure To Disclose COBC Documents To Congressional Subcommittee And Other Issues

Prepared on Behalf of
BP America, Inc.

By:

Billie Pirner Garde
John M. Clifford
Clifford & Garde, LLP
1707 L Street, NW
Suite 500
Washington, DC 20036
(202) 289-8990

Table of Contents (Redacted Report)

BPXA-CEC00018338

Interim Report of Investigation (Redacted)

Introduction

In October 2006, it was discovered that a Compliance Order By Consent (COBC)[1] had not been provided to the Oversight and Investigations Subcommittee (O&I) of the House Energy and Commerce Committee, prior to the September 7, 2006 Congressional Hearing. The Subcommittee staff requested BP America, Inc. (BPA) to conduct an internal investigation into certain matters surrounding the failure to provide the document and preparation for the hearings.[2]

The President of BPA, Robert A. Malone, retained Billie Pirner Garde, of the law firm of Clifford & Garde, LLP (Clifford & Garde), as a consultant for the purpose of conducting an investigation into a number of issues related to the COBC. In addition, Mr. Malone requested the assistance of John Clifford, also of Clifford & Garde, in the investigation.

This Report of Investigation provides the interim results of that investigation.[3]

I. Terms of Reference

Mr. Malone assigned corporate responsibility for the investigation to Rick Cape, the BPA Vice President for Compliance and Ethics. The scope of the investigation was defined in a formal Terms of Reference document. The investigation was to reach a determination of the extent to which issues represented in the 2002 COBC, No. 02-138-10, between the State of Alaska Department of Environmental Conservation (ADEC) and BP Exploration Alaska (BPXA) were considered and included in the preparation for the September 7, 2006 hearing before the Oversight and Investigations Subcommittee of the House Energy and Commerce Committee (the Hearing). To the extent that COBC

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[1] This is the Compliance Order by Consent, No. 02-138-10, between the State of Alaska and BP Exploration Alaska. The COBC was executed in May, 2002 and was closed April 3, 2003. (Exhibit 1)

[2] By letter dated October 6, 2006 Congress requested answers to four questions concerning BPA's knowledge of the COBC. BPA answered the questions in its letter of October 20, 2006. See October 6, 2006 letter from Chairman Barton, Ranking Member Dingell, Chairman Whitfield and Ranking Member Stupak to Mssrs. Kurt Fredriksson and Robert A. Malone (Exhibit 2) and October 20, 2006 response from Bob Malone (Exhibit 3). O&I Committee Staff then gave BPA the opportunity to investigate and report back to it on three topics: What the Company knew about the existence of sediment in the North Slope oil transit lines, prior to the spills in March and August, 2006; whether the COBC was identified and considered in preparation for the Hearing; and, if not, why not.

[3] As of April 30, 2007 the document collection, review and production had not been completed by BPXA It was the determination of the investigators that the report should not be finalized before completing the document review and analysis, and any interviews that may be required as a result. Therefore, this interim report reflects the facts, findings and conclusions as of the date of this report.

issues[4] were not considered or included in the preparation for the Hearing, the investigation was to determine the causes of the failure by BPXA to include the COBC issues.

In order to fully complete the investigation, the investigators were to review the processes for document research and production and for preparation of testimony for the Hearing, and to make recommendations to management regarding the Hearing preparation processes during the investigation, since management's involvement with the Subcommittee is ongoing.

II. Investigation Responsibilities and Process

Ms. Garde and Mr. Clifford conducted the investigation of all concerns jointly, although primary responsibility for the development of the issues regarding the knowledge and consideration of potential sediment in the Oil Transit Lines (OTLs) fell to Mr. Clifford and primary responsibility for the development of the COBC disclosure and assessment of the 2006 Hearing preparation process fell to Ms. Garde.

The investigation was based upon interviews of people with personal and/or institutional knowledge of the relevant facts, and a review of documents. The documents relevant to the time frame and subject matters of the investigation were retrieved primarily through a comprehensive database established by the law firm of Vinson & Elkins,[5] supplemented by materials obtained through the investigation and interview process of both BPA and BPXA employees. Beyond the review of documentary evidence and various hearing transcripts, the investigators interviewed individuals with relevant knowledge, and reviewed other interviews of those involved with the BPXA corrosion program and sediment issues, as well as those involved in the 2006 Congressional investigation and Hearing preparation process. Interviews were conducted both in person and, on occasion, by telephone.

BPA and BPXA personnel provided complete cooperation with the investigation. The investigation supporting materials are maintained in the law offices of Clifford & Garde, and are available to the Company upon request.

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[4] The term "COBC issues" is defined in the Terms of Reference to mean the existence of the COBC, the identification or knowledge of sediments in the pipelines, the decisions regarding the "pigging" of the lines, the identification of any program weaknesses in the corrosion control program, the budget issues impacting the corrosion control program and leak detection system, and/or personnel related issues that may have had an impact on pipeline integrity.

[5] Documents made available to Clifford & Garde for this investigation were compiled through the Vinson & Elkins database prepared in response to the April 26, 2006 U.S. Department of Justice (DOJ) and the Alaska Department of Environmental Conservation (ADEC) subpoenas. The documents were provided after a number of refinements to the initial collection of hundreds of thousands of documents, isolated using issue codes and word searches, then again refined by V&E lawyers to identify relevant and responsive documents. As of this writing, the database search is incomplete.

III. Executive Summary

The investigation addressed three primary areas of concern: first, the issues surrounding the knowledge by BPXA of sediments in the OTLs; second, whether the "COBC documents" were considered in the development of responses to Congressional questions, and if not, why not; and, third, a review of the Hearing preparation processes with any recommendations for future hearing preparation activities.

The investigation reached the following conclusions:

1. Knowledge of Sediment in the Oil Transit Lines and Any Actions Taken To Respond to Sediments

Issue:

What did BPXA know about the amount of sediments in the OTLs, when did it know that information, and what did it do about that knowledge?

Conclusion:

BPXA did not actually know the amount of sediments in the OTLs until it pigged the lines in July (EOA) and November (WOA), 2006. However, in September 2001, an Instrument/Controls (I/C) engineer interpreted the results of flow meter tests as indicating that there was significant sediment at some places in both of the OTLs, especially in the FS-2 segment in the EOA. He presented his concern to the Chemical, Inspection and Corrosion (CIC) Manager; a CIC Integrity Analyst responded. Based on his past experience with a similar concern in 1998 and the minimal sediments resulting from pigging, he concluded that it was unlikely that more than minimal quantities of sediments existed in the lines. No one conducted testing or examination of the lines to attempt to determine the amount of sediments in the lines between 2001 and the 2006.

The investigation did not identify any evidence that the CIC group engineers or any other CIC staff held or asserted a concern that sediment build up would lead to a corrosion leak, beyond the fall 2001 Email conversations referenced within this Report.

As of April 30, 2007 the investigation is not yet complete into the question of whether the OTL lines would have been pigged, as part of a robust corrosion management system, if CIC had not been attempting to contain costs. The answer to this question should be resolved upon review of the remaining documents. The investigation has revealed budget pressures on the CIC which had an impact on the program and its staff. The documents reviewed indicated that there was an ongoing attempt by the CIC department to obtain additional funding to "optimize," in any way it could, the existing corrosion control programs. At this point, it is unknown whether "optimization" would have included pigging.

2. **The Consideration of the COBC Documents in Preparation for the Congressional Hearings**

Issues:

Were the COBC and related documents considered in the preparation for the September 7, 2006 Congressional Hearing?

Conclusion:

The COBC and related documents were not considered in connection with the preparation for the September 7, 2006 Congressional Hearing. The Congressional Hearing preparation process, though intended to be comprehensive and transparent, relied primarily upon individuals who did not have personal historical knowledge of the COBC. While there were people with knowledge of its existence, the preparation process did not ensure that such knowledge was fully incorporated into the Hearing and testimony preparations and briefings. This result was neither directed by BP management personnel nor understood to be a consequence of the process followed.

The direction from the new President of BPA was for candid and transparent disclosure of all requested and relevant information. The expectation from the President of BPXA was that all relevant and responsive information be provided to the Committee and utilized in preparation for his testimony. Nonetheless, the COBC and related materials were not disclosed and not included in the preparation process for the Hearing.

3. **To the Extent that COBC Issues Were Not Considered or Included in the Preparation for the Hearing, the Investigation is to Determine the Causes of the Failure by BP Exploration Alaska to Include the COBC Issues, and Other Process Research and Production Issues, and to Make Recommendations**

Issue:

(a) To the extent that COBC issues were not considered or included in preparing for the Hearing, the investigation is to determine the causes of the failure by BPXA to include the COBC issues;

(b) *The investigation was also to review the process for document research and production and for preparation of testimony for the Hearing; and*

(c) To make recommendations to management regarding the Hearing preparation processes during the investigation, since management's involvement with the Subcommittee is ongoing.

Conclusion and Recommendations:

(a) The COBC and other relevant information available to the BPXA organization was not provided to staff or to the Subcommittee, or considered by BPXA or BPA in preparation for the September, 2006 Congressional Hearings. This was because the information either was not identified as responsive and included in Hearing preparation materials at all, or, if identified, not accessed by the people preparing for the Hearings and/or providing the responses to Congress.

(b) The investigation did not identify any intentional actions to obfuscate the issues from Congress or to withhold documents of interest to the Subcommittee staff's inquiries. However, documents were available for hearing preparation that were not relied upon or utilized in framing the testimony and preparation of witnesses, and other information was available that had it been accessed and reviewed would have provided additional information to provide to Congress about the events surrounding the Prudhoe Bay issues.

(c) As to this issue, we were asked to provide recommendations on the process to ensure further Congressional inquiries were responded to in a manner that provides assurance for accuracy and completeness. Those recommendations are:

- BPXA should institute clear policy expectations for transparency and complete candor in all dealings with Congress and other stakeholders;
- BPXA should, as a matter of routine practice, seek out the best and most accurate information from those with institutional knowledge in the subject matter at issue, and not solely rely upon computerized data base searches or other mechanized means to identify responsive materials;
- BPXA should remove any bias toward compartmentalization, or "siloing" of information which, in part, we found contributed to this situation; and,
- BPXA should ensure that important projects, such as responding to Congressional requests for information, are managed by persons with personal or first-hand knowledge of the events at issue.

IV. Findings and Conclusions

A. Background

In order to ensure appropriate context surrounding the issues and events discussed in this Report, and to appreciate the impact of the many changes on the North Slope during the relevant time frame, we have included background relevant to the issues and organization.

1. The History of the Oil Transit Lines (OTLs)

The largest oilfield in North America, Greater Prudhoe Bay (GPB) on the North Slope of Alaska, is divided into the Eastern Operating Area ("EOA") and the Western Operating Area ("WOA"). BPXA has operated the WOA since 1985 and the EOA since July 2000. Prior to that time, ARCO Alaska Inc., now known as ConocoPhillips Alaska, Inc., had operated the EOA.

The EOA and WOA are similar fields with similar but not identical facilities. Each side of the field has three production facilities – known as Gathering Centers in the WOA and Flow Stations in the EOA. The raw fluids from over 1,000 wells in Prudhoe Bay flow through well lines to commingling stations, where the 3 phase fluids[6] are piped via flow lines to one of these six production facilities for processing.[7] These production facilities then process the full well stream fluids into gas, water, and sales quality crude.[8] (The exception to this is GC-3, which only partially processes the oil prior to sending it to FS-3 for final processing.) Once processed, the crude oil enters the large diameter (30-inch and 34-inch), relatively short (three to five miles), above ground oil transit pipelines (OTLs) that carry final sales quality crude oil to Skid 50. There, the EOA and WOA oil streams are joined, Natural Gas Liquids are blended in, and the combined fluids are sent to Pump Station 1 of the Trans-Alaska Pipeline System (TAPS).

Besides differences in nomenclature, the following are some of the relevant distinctions between the fields. The WOA OTL was designed as a single entity, a 34-

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[6] Besides oil, the fluids entering the production centers via flow lines are corrosive, as they contain water, natural gas and carbon dioxide. *FS-2 Oil Transit Line Spill Incident Investigation Report,* January 31, 2007 ("FS-2 Report").

[7] As the GPB field ages, changes occur in the systems necessary to extract the oil from the oil reservoir. Crude oil flowing from the reservoir contains water and gas which must be separated from the flow stream at the processing centers, in order to establish sales quality crude for delivery to the Trans Alaska Pipeline System (TAPS). The water that is separated from the flow stream is referred to as "produced water." Produced water and gas are pressurized and injected back into the reservoir. Injection of produced water and gas benefits the maintenance of the reservoir geometry and assists in establishing the hydraulic conditions necessary to force the crude oil stream up through the well head.

[8] "Sales quality" crude has been processed to the point that it contains less than 0.35% basic sediment and water (BSW), on average. Put another way, sales quality oil is at least 99.65% "pure." (Interview of [*name redacted, M-5*]).

inch pipeline with a single pig launcher and receiver. The EOA OTL was designed and built as two distinct segments, each with its own pig launching and receiving facilities. The segment from FS-2 to FS-1 is a 30-inch line, while the segment from FS-1 to Skid 50 is a 34-inch line. Also, BPXA had considerably more experience operating the WOA, 21 years, versus only 6 years operating the EOA.

2. The Installation of a Leak Detection System

On May 14, 1992, the Alaska Department of Environmental Conservation (ADEC) promulgated 18 AAC 75.055, Leak Detection, Monitoring and Operating Requirements for Crude Oil Transmission Pipelines. The regulation, requiring compliance with a 1% daily throughput standard for leak detection and with a Best Available Technology (BAT) requirement, was broadened by ADEC in 1997 to include the OTLs. On December 7, 2000, ADEC informed BPXA that the 1% standard applied to each pipeline segment, rather than field-wide. Thereafter, ADEC required BPXA to submit a leak detection proposal for GPB, which met the 1% standard and employed BAT, by January 31, 2001. BPXA agreed to verify its compliance within 2001.

3. The Roles of the CIC and I/C Departments

Beginning June 1, 2001 and continuing through the relevant period, the CIC (Chemical, Inspection and Corrosion) group and the I/C (Instrument/Controls) engineers were located in the "Shared Services Technical Business Unit," a business unit led by [*name redacted, M-1*]. Five managers reported directly to [*name redacted, M-1*], including [*name redacted, M-2*], the North Slope Services Manager and [*name redacted, M-3*], Shared Services Engineering & Production Management. The Corrosion Manager, [*name redacted, M-4*], directed CIC activities and reported to [*name redacted, M-2*]. The I/C engineers reported to [*name redacted, E-1*], the Facilities Engineering team lead, who reported to [*name redacted, M-3*].

Then and now, CIC manages a program to control corrosion at the GPB oilfield. The program has three fundamental missions: monitoring (including coupon-pulling and electrical resistance), chemical mitigation, and inspections, including non-destructive examinations (NDE). CIC's inspections are primarily intended to measure the integrity of piping and other equipment, so as to identify equipment needing repair or replacement.

The CIC Manager was [*name redacted, M-4*], a BP employee. Despite a (reportedly) aggressive management style, [*name redacted, M-4*] was widely respected for his expertise in the field of corrosion management. After his departure, CIC was restructured. [*Name redacted, M-5*] became CIC Team Leader (Anchorage) in July, 2005.

The focus of I/C is "process" instrumentation. I/C engineers have never been part of the CIC organization. Inspecting piping for corrosion and identifying potential leaks is a duty of CIC, not I/C. In 2001-2002, I/C had the responsibility to select, test and install a leak detection system that would comply with Alaska regulations.

An organization chart for both groups is included as an Exhibit to this Report.[9]

4. The Investigations of CIC Issues

a. CIC Department Issues From 1999 to 2004

At least since 1999, there have been personnel and contractor issues within the CIC organization. The issues involved a number of concerns regarding alleged misconduct within the contractor organization. These issues were reviewed and investigated, some by internal and some by external avenues, and have resulted in a number of contract and personnel related actions. Based on information we reviewed, none of the issues involved employees or contractors who claimed to have identified a concern about sediment in the lines, the failure to "pig" the lines, or a concern about internal corrosion on the OTLs.

b. HSE 1838 and the "Hotline" Investigation

In March 2003, a BP employee raised a concern to the Health, Safety and Environment committee (an HSE concern), that is a concern regarding some aspect of BP operations impacting the health, safety or environment in Greater Prudhoe Bay WOA. The committee is a joint labor-management committee to address such concerns. The issue, HSE-1838, was raised by a BP employee on behalf of a contract employee in the CIC group, alleging harassment and retaliation for reporting an HSE-related concern. Although the concern did not involve sediments, corrosion or the OTLs, it did involve that reducing the coupon pull staff could have an impact on corrosion rates. However, it did involve management actions within CIC regarding cost cutting and the management style of BP's CIC Program Manager, [*name redacted, M-4*].[10] HSE 1838 was then raised by workers to [*name redacted, BP-2*] who undertook an investigation of the issue. The conclusions of the investigation were that [*name redacted, M-4's*] behaviors had caused some degree of fear of retaliation and created a "chilling effect," such that BPXA management needed to take additional actions to ensure its policies and expectations were understood by the contractor work force and [*name redacted, M-4*]. [*Name redacted, BP-2*] also recommended coaching [*name redacted, M-4*] with respect to his management and communication styles. The findings were orally reported to [*name redacted, VP-2*], GPB Performance Unit Leader and [*name redacted, M-6*], GPB Field Manager in June, 2003 and confirmed with written recommendations, including that [*name redacted, M-4*] style, if left unchecked, would have adverse impacts on the program.

In June 2003 [*name redacted, M-4*] scope of responsibility was increased to include Fire & Gas and the Valve Shop.

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[9] See, Organization Chart for relevant time frame, (Exhibit 4).

[10] HSE Concern 1838 was provided to the Subcommittee in response to its request in September, 2006.

c. Vinson & Elkins Report

In March, 2004, additional allegations regarding the behavior of [*name redacted, M-4*] (similar to HSE 1838 but with different details) were supplied to the EPA's Region 10 Office of Suspension and Debarment and the U.S. District Court's Anchorage Office of Probation and Pretrial Services, which asked that BPXA look into the issues. BPXA retained the law firm of Vinson and Elkins (V&E) to investigate, and V&E issued a Report in October, 2004. (The Report was produced to the Subcommittee in connection with the September, 2006 Hearing.) The Report substantiated concerns regarding the existence of a "chilling effect" as a result of [*name redacted, M-4*] management style, but did not substantiate retaliation, falsification of records or coupon data, or that BP had "bad" pipe in service or that [*name redacted, M-4*] was intentionally hiding areas of corrosion. V&E also recommended a number of actions regarding [*name redacted, M-4*], and contract management issues, as well as education of the CIC employees regarding the corrosion program. Finally, it recommended a "focused review of the corrosion program data system (MIMR)" and supporting processes.[11]

[*Name redacted, M-4*] was transferred to Houston, Texas, effective January, 2005.

5. The April 2005 Baxter Report (Baxter I)

In November-December, 2004, John Baxter, BP Group's Director of Engineering, led a team of specialists (external to BPXA but internal to BP) to assess the integrity of the Corrosion Management System (CMS) at Greater Prudhoe Bay. The audit was conducted in November-December 2004. The team's Report, issued in April 2005, concluded that while the CMS did not have an immediate technical problem, the extent, complexity and aging state of the pipeline created the potential for leaks. The team's recommendations included updating the corrosion strategy to align the corrosion and inspection practices across both sides of the field; updating the budget process for CIC as the drive to maintain flat lifting costs had put undue pressure on the group; promptly replacing the departing manager and senior engineer; and conducting a technical review of the extensive corrosion inspection and monitoring program. The Report did not consider issues of sediment in the OTLs or elsewhere in the system.[12]

6. The March 2006 Spill

On March 2, 2006 BP workers discovered that oil was leaking from the Oil Transit Line (OTL) between GC-2 and GC-1 in the Western Operating Area (WOA) at

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[11] See, Vinson & Elkins Report for BPXA Concerning Allegations Of Workplace Harassment From Raising HSE Issues And Corrosion Data Falsification, October 20, 2004. ATTORNEY-CLIENT PRIVILEGED DOCUMENT. The report was provided to the subcommittee in response to its request in September 2006.

[12] *Internal Audit, BPXA Corrosion Management System, Technical Review, Final Report*, April, 2005 (Baxter Report I). The report was provided to the subcommittee in response to its request in September 2006.

GPB. The leak was first detected by smell; it did not register on the leak detection system (LDS). Almost immediately, BP employees and contractors began the processes of finding the location of the leak, sealing it and conducting environmental remediation. Shortly thereafter, additional BP employees and state and federal investigators began to converge on the area, seeking to determine the cause of the leak, and whether the LDS had worked as designed.

Suspicion about the performance of the LDS was quickly reduced, as it was determined that the rate of the leak was less than 1% of the throughput of the pipeline segment. The LDS had worked as designed and as required by regulations. Interest in determining the cause of the leak continued unabated.[13]

The leak occurred at a "caribou crossing" -- a section of the pipeline that is cased and buried to provide a crossover for migrating caribou. Given its location, external corrosion was suspected as the cause of the leak.[14] Within a few days after the spill was discovered, however, internal corrosion was identified as the cause of a quarter inch hole in the bottom of the pipeline.

Once internal corrosion was established as the source of the leak, investigators and regulators focused on issues relating to sediment[15] in the OTL as well as the lines' history of maintenance pigging and "smart" pigging.[16] On March 10, BPXA promised its State regulators that it would pig all the oil transit lines. Its promises were incorporated in a Department of Transportation Corrective Action Order issued on March 15, 2006. The CAO mandated pigging and directed BPXA to report on the extent of sediments in the lines.

7. The March 24, 2006 Congressional Inquiry Letter and BPXA's Response

Congress recognized the potential significance of issues relating to sediment and pigging and posed questions to BPXA. In a letter dated March 24, 2006, Congressmen John Dingell and George Miller asked BPXA's President, Steve Marshall, to answer seven questions about the OTLs; two of them related to sediment in the lines. Question 5 asked whether the low flow rate in the OTL resulted in the settlement of solids in water at the bottom of the pipe, and what implications that would have. Question 6 asked whether

[13] Interview of [*name redacted, A-1*].

[14] External corrosion is a common threat to the integrity of buried, cased lines, as the environment presents an opportunity for moisture to collect and maintain contact with the outside surface of the pipe. See, *GC-2 Transit Line Incident Investigation Report*, April 14, 2006, ("GC-2 Report"). Produced at September 7, 2006 hearing.

[15] In this Report, we are using the word "sediment" to include not only sand but also "sludge," "scale" and other materials that might accumulate in the pipe, although they are not the same.

[16] Maintenance pigging is a mechanical method of cleaning sediment and water from pipelines. Smart pigging is a method of using mechanical devices to internally examine the integrity of pipelines.

significant amounts of solids were known to be present in the bottom of the line, the concerns that would be presented by solids, and whether maintenance pigging would have been effective to remove solids and preserve the integrity of the line.[17]

On April 3, 2006, BPXA responded as to conditions on the WOA, where the spill had occurred. It explained that while the dropping out of water and solids presented the potential for internal corrosion, in the past it had mitigated this concern by removing corrosive carbon dioxide gas from the oil and by adding corrosion inhibitor, which until recently had carried over from upstream injections. As to the amount and effect of sediment in the line, BPXA said that no "unusual presence" had been found in the 1998 pigging, it had "no indication" of how much sediment was currently in the line, but removal by maintenance pigging was appropriate if sediments were a concern.[18]

Throughout the Spring and Summer of 2006, interested stakeholders, including the Congress and the Department of Transportation (DOT), continued to press the company for an accurate statement of the amount and location of the sediment in the OTLs. On several occasions, the Company provided preliminary estimates, which turned out to be incorrect. Thus, in May BPXA estimated that there were 9 to 12 inches of sludge in parts of the EOA, but reported sharply lower estimates in June. The Company's inability to respond on this point was a source of frustration for its stakeholders, including Congress and DOT.[19]

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[17] See March 24, 2006 letter from Congressmen Dingell and Miller to Steve Marshall (Exhibit 5).

[18] The full response to Question 6 is as follows:

> Records from the 1998 pigging program did not show an unusual presence of solids in the WOA OTL. BPXA has no indication of the amount of solids that might be present in the line at this time. We are currently researching methods which could be used to identify solids in the line.
>
> In the last one to two years BPXA Operations have seen an increase in fine solids production (so called flour sands) into GC2 from the production of "viscous" oil. It may be possible that some portion of these solids carried over into the oil transit line. If solids do carry over, the main risk of corrosion would be from under-deposit or bacterial corrosion. It should be noted, however, that these same solids 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 solids has been discussed in Question Five. If solids were believed to be a concern, a maintenance pigging program would be appropriate to remove them.
> (Exhibit 6)

[19] See, e.g., the July 26, 2006 letter from the Administrator, PHMSA, DOT, responding to Congressman Dingell's letter of June 15.

8. The April 26, 2006 DOJ Subpoena

On April 26, 2006 the U.S. Attorney in Alaska issued a subpoena duces tecum to BPXA in connection with its ongoing investigation of the GC-2 spill. The subpoena is relevant to this investigation, only because it requested documents that could have led to the identification of the COBC earlier than occurred, and its content was known to some people working on both projects.

9. The GC-2 Incident Investigation Report and June 2006 Baxter Report (Baxter II)

Immediately after the March spill, BPXA dispatched an Incident Investigation Team to determine the facts and circumstances surrounding the incident, review applications of management systems and compile a Report.[20] This team was not tasked with conducting a root cause analysis, and its Report did not identify the cause of the corrosion which led to the leak.[21]

Shortly thereafter, BP Legal asked John Baxter, the BP Group Director of Engineering to lead another team in reviewing technology issues related to the incident. Their Report (Baxter II) was delivered on June 7, 2006.[22] It noted that the likelihood of corrosion in oil transit lines is generally agreed to be low, given the carryover of chemical inhibitors and the specifications for BS&W. However, it also concluded that in the case of the OT-21 line (the OTL from GC-2 to GC-1), viscous oil (produced since 2002) and "flour" sands had caused "upsets" at GC-2, with resulting out of specification crude being released. In other words, the changes in the content of the oil entering GC-2 created the potential for oil with a high sediment and water content to be delivered to the line. The Report concluded that this presented the opportunity for water and solids to settle in the bottom of the OTL.

BPXA responded to the changed circumstances by working to regulate the output of GC-2 and to maximize the effectiveness of chemical treatments, but it did not conduct regular maintenance pigging to remove whatever sediment and water might have accumulated in low spots on the lines, nor did it focus on the possible corrosive effects of static water and sediment at the bottom of the pipe.[23]

The Report's findings included identifying the organization's need to follow a Management of Change process to cope with changing circumstances, and the observation that CIC's status as a leader in corrosion management had the potential for

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[20] *GC-2 Transit Line Incident Investigation Report*, April 14, 2006, ("GC-2 Report"). The report was provided to the subcommittee in response to its request in September 2006.

[21] Interview of [*named redacted, A-1*].

[22] *Alaska Transit Pipeline Technology Review*, June 7, 2006.

[23] Id., pages 3-4.

creating a "silo effect" where little time is spent considering other best practices and strategies. The Report warned that the existing inspection and leak detection regime would not necessarily minimize the likelihood of another significant spill.[24]

10. The August 6, 2006 Spill

BPXA was required to conduct cleaning and smart pigging of the EOA OTL, pursuant to Item 7 of the CAO (entered by DOT on March 15, 2006). BPXA began cleaning the EOA line during the week of July 3 and completed cleaning the 30-inch segment from FS-2 to FS-1 on July 20. It smart pigged the FS-1 to Skid 50 section on July 21, 2006. On August 4, 2006 BPXA received the preliminary report from the smart pig vendor. It indicated 16 significant anomalies clustered in 12 areas, but did not identify specific locations. When the locations were identified the next day, the CIC North Slope Team Leader dispatched crews to validate the data. On August 6, 2006 BPXA initiated the shut down of the EOA lines, after discovering two locations where the remaining wall thickness was only 0.03 inch and 0.04 inch, and three locations with active leaks.[25]

11. Congressional Investigation and the September 7, 2006 Hearing

Following the August, 2006 spill, Congress' interest in BPXA's knowledge of sediments in the OTLs intensified, which was conveyed to the Company during congressional staff visits to Prudhoe Bay, discussions with representatives in BP's Washington, D.C. office, and more formal requests for documents. On August 11, O&I Subcommittee staff notified BPA of a Hearing scheduled for September 7, 2006. In an August 31, 2006 letter to Bob Malone, the O&I Subcommittee formally requested the production of additional items, including "all records and communications relating to discussions about sludge/sediment, pigging, and/or corrosion on [the OTLs] (primary focus on the period from January 2006 to the present)."[26]

On September 7, 2006 a hearing was held before the Subcommittee on Oversight and Investigations of the House Energy and Commerce Committee. Two other congressional hearings were held over the next few weeks.[27] Testimony was provided by President of BPXA Steve Marshall and President of BP America Bob Malone. During the Subcommittee hearing Mr. Marshall was asked a series of questions regarding the status, maintenance, degrading and corrosion of the OTLs, including when BP was first aware of sediments in the OTLs and the level of knowledge or concern about the corrosion on the OTLs.

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[24] Id.

[25] FS-2 Report.

[26] See August 31, 2006 letter from Congressmen Barton, Dingell, Whitfield and Stupak to Bob Malone. (Exhibit 7).

[27] September 12, 2006 Hearing of the U.S. Senate Energy and Natual Resources Committee and the September 13, 2006 Hearing before the House Transportation and Infrastructure Committee.

Following the Congressional hearings, additional requests for information were received and responses developed.[28]

12. The Post-Hearing Discovery of the COBC Documents

Approximately one month after the Hearings, the Staff obtained a copy of a Compliance Order By Consent (COBC), an executed, official agreement that had been entered between the State of Alaska and BPXA, in May, 2002. The document included BPXA's representation that it had discovered "settled solids in some [OTL] pipeline segments," which prevented the company from complying with State regulations governing its leak detection system (LDS). The COBC also detailed tasks which BPXA committed to complete, including determining the sediment levels in the EOA and WOA pipelines at Skid 50, modifying the pig receiver at Skid 50, pigging the EOA line from FS-1 to Skid 50 and pigging the WOA line if necessary.

B. BPXA's Knowledge of Sediments in the OTLs and Any Actions Taken as a Result

1. The Historical Results of Pigging

The WOA OTLs had been cleaned and smart pigged in 1990.[29] Beginning in 1995, some members of BPXA's CIC group recommended pigging the WOA oil transit line.[30] A thermograph showed 3-6 inches of solids at a location on the OT-21 line, but this could not be confirmed with ultrasonic (UT) examination.[31] A robust discussion followed, in which the data supporting pigging was debated and the possible downsides, including plugging the strainers at TAPS and the risk of getting a pig stuck were considered.[32] Eventually, the Company committed to running a cleaning pig, which was conducted in 1998.[33] It resulted in the recovery of only 2 to 3 cubic yards of solids from the WOA oil transit line.[34] The subsequent smart pig run detected some wall loss, but it was below the levels set to assess fitness for service.[35]

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[28] See October 24, 2006 letter.

[29] See, July 22-29, 1990 pigging records.

[30] November 7, 1995 Email from [*name redacted, BP-3*] to PBU CIC, Re: Maint. Pigging of Oil Transit.

[31] Ibid.

[32] November 11, 1995 Email from PBU CIC to [*name redacted, BP-3*], Re: Maint. Pigging of Oil Transit.

[33] April 4, 1998 Email from Pigging Operators to CIC, and surrounding documents.

[34] Ibid.

[35] *Report by Pipeline Integrity International*, 9-30-98.

Documents that BP reviewed after the March 2006 GC-2 spill show that ARCO operated cleaning pigs in the EOA oil transit lines in 1990 and 1991. The 30" line from FS-2 to FS-1 was "found to be very clean" after caliper pigging on September 9, 1990.[36] The 34" line from FS-1 to Skid 50 was caliper pigged on September 23, 1990. The results indicated a 1/8" build-up of calcium carbonate scale downstream from the FS-3 tie line.[37] The EOA lines were cleaned again in September 1991 to prepare for smart pigging. The lines were then smart pigged, but the resulting data was later rejected by ARCO, as it conflicted with known information about the lines.[38] Apparently, ARCO did not make any further efforts to smart pig the EOA lines.[39]

2. The Results of Pigging After the GC-2 Spill

The pigging conducted after the GC-2 spill provided direct evidence that there had been sediments in all of the OTLs.[40] Cleaning of the first segment, FS-2 to FS-1, began on July 4, 2006. "Estimates of the amount of solids removed from the FS-2 to FS-1 cleaning were about 270 bbls."[41]

The FS-1 to Skid 50 segment on the EOA was pigged between September 30 and October 18, 2006.[42] Prior to cleaning, it was estimated that ~366 bbls of pigging solids (sand, scale and sludge) would be raised, based on gamma scan inspections.[43] Afterwards, the estimated recovery was 238 bbls, based on spin-out analysis, and 83 bbls were estimated, using APSC analysis.[44]

The GC-1 to Skid 50 segment on the WOA was pigged between November 1 and 12th, 2006. Prior to cleaning, it was estimated that ~208 barrels of pigging solids (sand, scale and sludge) would be raised, based on gamma scan inspections performed October 11-12, 2006.[45] After pigging, the estimated recovery based on spin-out analysis was 22 bbls, and 8 bbls were estimated as recovered, using APSC analysis.[46]

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[36] Appendix D to FS-2 Report.

[37] Ibid.

[38] Ibid.

[39] FS-2 Report.

[40] Ibid.

[41] Ibid.

[42] Ibid.

[43] The gamma scan (GR) estimates were intended to provide rough estimates since it is recognized that the method is not highly accurate for this purpose. (Explanatory comment provided by [*name redacted, BP-4*].)

[44] "WOA/EOA Progressive Cleaning" undated slide presentation.

[45] Ibid.

The actual, processed results of the combined product from the FS-1 and GC-1 segments was 32 bbls of sediment recovered.[47] The following chart[48] presents the pigging returns.

OTL Pigging Returns Volume Reconciliation

(in Bbls)

Segment	LF	Pipe Dia	Gamma Scan Estimate May 2006	Gamma Scan Estimate Aug 2006	Gamma Scan Estimate Oct 2006	BP Measured Returned Solids @ Skid 50	Alyeska Measured Returned Solids @ Skid 50
EOA OTL - FS2 to FS1	15,794	30	140	N/A	N/A	N/A	N/A
EOA OTL - FS1 to Skid 50	25,996	34	115	638	N/A	236	83
WOA OTL - GC1 to Skid 50	25,301	34	417	417	208	22	8
Totals						258	91

3. The Consideration of Sediments and the Feasibility of Pigging in 2001-2002

In December, 2000, BPXA was attempting to implement a new leak detection system on the OTLs, as required by ADEC regulations. The I/C group had responsibility for meeting regulatory requirements and was facing a firm deadline for compliance of December 31, 2001.[49] On December 29, 2000, an I/C engineer, [*name redacted, E-3*], sent an email within his group discussing the logistics of compliance. He proposed that BPXA smart pig the transit lines as part of the leak detection modification effort. Specifically, the email suggests that pigging is a preferable option because:

> "[t]he most likely leak scenario would be a pin hole leak due to external corrosion. No meter based leak detection system would be able to detect such a leak. Smart pigging the sales line would

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[46] Ibid.

[47] "Alyeska Pipeline BPXA Pigging TAPS Bypass Project, Agency Coordination Meeting," slide presentation, January 10, 2007.

[48] Chart supplied by [*name redacted, BP-4*].

[49] December 7, 2000 letter from ADEC, S. Harvey to N. McCleary, Re: BPXA Proposal for Leak Detection.

be a good way to assess external corrosion. This may be an idea that ADEC would accept."[50]

His manager, [*name redacted, E-4*], promised to raise the issue in a meeting and get back with "next steps." His second level supervisor, [*name redacted, M-3*] (the Shared Services Engineering and Projects Manager), also responded, asking if [*name redacted, E-3*] had proposed a WAG estimate, in the event that BPXA had to comply with ADEC's interpretation of the regulation.[51]

On January 7, 2001, [*name redacted, M-4*], the head of CIC asked [*name redacted, IA-1*], an integrity analyst, whether BPXA could "... smart pig both the EOA and WOA oil sales line? If there are issues, what are they?" [*Named redacted, M-4*] explained his belief that smart pigging would be "considerably cheaper" than installing meters to comply with ADEC's 1% leak detection standard. The next day, [*name redacted, IA-1*] responded "We could likely Smart Pig each of these lines but not without [a] considerable amount of work." He further noted that "WOA has seen quite a bit of internal and a fair amount of external damage. Internal is small pit networks @ 6:00 azimuth.....my thoughts are that the oil sales line has continued to degrade very slowly" and that the EOA has "done little or nothing for inspection of the sales line."[52]

By May of 2001, [*name redacted, M-4*] was pressing for funding in an effort to maintain CIC's smart pigging program, which he viewed as an integral part of the overall corrosion management strategy, at least for the lines bringing oil from the wells to the processing centers (*e.g.*, flowlines) and for the produced water lines (returning water from the processing centers to the field). The documents reviewed to date indicate that there was no pending request for funding to smart pig the OTL's. However, CIC was having to address severe financial restrictions -- what CIC's North Slope Team Leader called "bloodbath numbers." [*Name redacted, M-4*] raised his concern to his manager, [*name redacted, M-2*], the North Slope Service Manager and continued to press his case for funding to place the Corrosion Under Insulation (CUI) Mitigation and Detection, as well as smart pigging, into the summer.[53] Ultimately the smart-pigging/CUI fell off the list for that year's budget. Upon completion of the investigation, we will update whether CIC sought funding for pigging the OTL's or discussed or considered such activities as part of its business projected for compliance and safety.

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[50] December 29, 2000 Email strings from [*name redacted, E-3*] to [*name redacted, M-3*] and [*name redacted, E-4*], Re: PBU leak detection.

[51] Ibid.

[52] January 7, 2001 Email string from [*name redacted, M-4*] to [*name redacted, IA-1*], Re: Smart Pigging the Oil Sales Lines.

[53] May 14, 2001 Email from [*name redacted, BP-6*] to [*name redacted, M-4*], Re: CIC Group Team Leader Meeting, and surrounding strings, including May 26, 2001 Emails from [*name redacted, M-4*] to [*name redacted, BP-7*], Re: GPB Repair Cause History 1996-2001, and surrounding strings.

Needing to meet ADEC's interpretation of the regulation, the I/C group decided to use a strap-on ultrasonic metering system, which required clean pipe to get an accurate reading of flow.[54] While testing different meters in April-May 2001,[55] they experienced difficulty and were unable to get a reading at a point on FS-2 near its juncture with FS-1.[56] As the following communications illustrate, the I/C group interpreted the metering problems to indicate a significant build-up of sediment in the line -- an opinion not shared by the relevant members of the CIC group:

August 16, 2001. In an email to operators on the pigging crew and engineers at CIC, [*name redacted, BP-8*] asked whether the WOA OTL had been pigged since 1998 and what would be involved if maintenance pigging was necessary. [*Name redacted, BP-8*] explained that members of the I/C team were setting up a leak detection system that required a clean line, "...but their indications are that it is half full of sludge."[57]

September 6, 2001. An I/C engineer, [*name redacted, E-3*], wrote to the head of CIC, [*name redacted, M-4*], explaining the context of the meter testing, the problem encountered and his concern:

> "I am working on installing a leak detection system on the Prudhoe sales oil transmission pipelines. We have recently been experimenting with a strap-on ultrasonic meter on the FS-2 segment near the FS-1 pigging module. While testing the meter, it became evident that significant sediment has built up in the piping. In order to obtain optimum meter accuracy, we need a clean pipe. I discussed this with [*name redacted, E-4*], and we felt it was prudent to pig EOA lines regardless of the meter issue.
>
> Have we done any UT or RT on this piping recently? Considering the modifications to Skid 50, what would it take to pig these lines and how soon could we schedule it? We are obviously concerned about corrosion, and the possibility of a leak on one of the oil lines."[58]

[*Name redacted, M-4*] read this email, and forwarded it to [*name redacted, IA-1*] for response.

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[54] September 6, 2001 Email from [*name redacted, E-3*] to [*name redacted, M-4*], Re: Sales oil pipeline pigging (Exhibit 9).

[55] September 27, 2001 PBU Leak Detection Status Report, rev 1.

[56] October 1, 2001 letter from BPXA G. Campbell to ADEC R. Watkins Re: BPXA-Prudhoe Bay Leak Detection Update.

[57] August 16, 2001 Email from [*name redacted, BP-8*] to PBU, pigging Operators Re: Pigging of OT-PST line (Exhibit 8).

[58] Exhibit 9.

September 7, 2001. [*Name redacted, IA-1*], the integrity analyst from CIC responded. He described the results of recent UT corrosion testing of the EOA line, which showed "minor internal corrosion damage...around ~20% of wall thickness." He explained that the pigging capabilities had been removed when the east and west lines were combined at Skid 50, so the equipment would have to be restored before the line could be pigged. The writer stated his belief that the EOA line had never been pigged and that there was " likely to be a light layer of frac and formation sand lying on the bottom of the line, a bit heavier at lower points prior to upward bends." He explained that NDE (non-destructive examination) tools were of little help in measuring solids in the line. Finally, based on the results from the earlier cleaning runs on the WOA, he assumed there was a light layer of solids on the bottom ¼ of the pipe.[59]

The discussion between the two teams about *sediments* ended there, on Friday, September 7, 2001. Even in the context of the severe budgetary pressures described in the emails, the lack of follow up to this discussion and topic from the materials we reviewed is striking. Why would concerns about sediments, so articulately expressed by the instrumentation engineer, and so thoughtfully responded to by the integrity analyst -- both responsible, competent and respected members of the BPXA team -- disappear without further analysis or consideration?[60] We concluded that, whether right or wrong, neither considered the risk significant enough to pursue.

In interviews, [*name redacted, IA-1*] and [*name redacted, E-3*] explained the reasons for their conclusions. [*Name redacted, IA-1*] was skeptical of [*name redacted, E-3's*] belief that significant sediments were responsible for the testing problems.[61] Not only did he know from experience how difficult it was to find or measure solids when using equipment designed for the purpose, but he understood that I/C was not using such tools.[62] [*Name redacted, IA-1*] identified several reasons why one might fail to get a reading from ultrasonic meters, including misplacement of the meters, the volume of oil in the line, air or water in the line, and solids.[63] Also, [*name redacted, IA-1*] and CIC gave less weight to the concern because it was coming from individuals who were not

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[59] Exhibit 10. Note that [*name redacted, IA-1's*] response was forwarded to CIC Field Integrity Ops.

[60] While from this distance it may seem abrupt and surprising, we are mindful of the need to consider the facts in their historical context. In this case, it is fair to recall the disruptive effect of the terrorist attacks on the United States just four days later, on September 11, 2001, and the impact that event had on the focus of individuals and organizations throughout the weeks and months that followed. No one told us that they were distracted and forgot about the issues; indeed we are sure that they were not forgotten. But to erase that event from the context of this inquiry would be disingenuous.

[61] Interview of [*name redacted, IA-1*].

[62] Ibid.

[63] Ibid.

corrosion engineers.[64] For his part, [*name redacted, E-3*] was persuaded that sediment had interfered with the testing. By rotating the meters, the vendors determined that there was sediment in the bottom third of the pipe.[65] [*Name redacted, E-3*] concluded it was sediment, rather than scale, because FS-2 produces a lot of water and the sands tend to fall out at low velocities.[66]

We did not find evidence that the corrosion engineers were reluctant to pursue this issue of sediments because of concern about potential adverse consequences for doing so. For I/C, its conclusion that there was sediment was incorporated almost immediately into its strategy for complying with Alaska Regulations.

Notwithstanding a recognition of the aging pipelines and concerns about CUI, internal pitting and wall loss, CIC did not view the results of the flow meter testing or other observations as a cause for immediate concern, for several reasons, including:

- It believed the corrosion risk continued to be low in lines carrying "sales quality" oil;[67]
- Scant sediments had been recovered by pigging the WOA lines in 1990 and 1998;[68]
- It assumed that the historical trend regarding sedimentation was continuing and that the amounts deposited would be the same on both sides of the field;
- CIC regarded even the best available NDE technologies to be unreliable for purposes of sediment, thus the results of flow meter testing were not persuasive;[69]
- It believed that any corrosion risk posed by sediments was successfully controlled through its aggressive program of chemical inhibition, which appeared to be confirmed by the results of corrosion monitoring.[70]

None of the documents or witness statements in this investigation has supported or suggested that CIC regarded the evidence of sediment in the OTLs as a cause for concern from the standpoint of corrosion control. It is unquestionably true that CIC did not alter its practices or strategy in any way, on account of the evidence of sediment and/or concern about corrosion presented by I/C.

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[64] Ibid.

[65] Interview of [*name redacted, E-3*].

[66] Ibid.

[67] Ibid.

[68] Ibid.; Exhibit 9.

[69] Interview of [*name redacted, IA-1*].

[70] Ibid.

4. The Recognition that Sediments Prevented Compliance with Leak Detection Regulations

We found no evidence of any follow-up verification of the results of meter testing described above, or of any formal determination by anyone at BPXA as to whether and to what extent there were sediments in the EOA lines, until after the GC-2 leak.

The I/C group was persuaded that the new leak detection system could not be compliant with regulations until the line was pigged, therefore [*name redacted, E-4*] agreed that [*name redacted, E-3*]. Although [*name redacted, E-3*] thought "we barely have enough funds within the overrun limit in the original AFE to do this preliminary work," BPXA wanted to demonstrate to ADEC that it was making a reasonable effort to satisfy the leak detection requirement.[71] At the same time, [*name redacted, E-3*] believed that running cleaning and smart pigs would have practical value in the interest of integrity, and the State would be appeased to know that there was no significant corrosion issue. Thus he favored cleaning the lines and proceeding with ultrasonic meters, rather than using a small turbine meter in the FS-2 segment.[72]

With the December 31, 2001 deadline fast approaching, BPXA acted to inform the State of its sediment problem and to agree on a way forward.[73] In an October 1st letter, and a December 3rd meeting, I/C presented its position to ADEC, which was amenable to entering a COBC, under the circumstances.[74] On December 4, I/C requested the assistance of Legal to negotiate the COBC,[75] and on December 14, requested authorization to expend the funds needed to carry out its obligations under the Agreement.[76] BPXA made the commitments and took the actions necessary to comply with the regulations, accepting I/C's assessment that sediments were interfering with testing leak detection meters in the OTLs, at least in the EOA.[77] A review of the documentary record of the Company's conduct and statements confirm this belief. The following examples are offered:

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[71] October 11, 2001 Email from [*name redacted, E-3*] to [*name redacted, BP-10*], Re: Oil Sales Line.

[72] November 12-13 Email string, from [*name redacted, BP-11*] to [*name redacted, E-3*], Re: Leak Detection and Pipe Pigging.

[73] Interview of [*name redacted, E-3*]; see also October 19, 2002 Email from [*name redacted, BP-9*] to [*name redacted, M-1*] et al., Re: Leak Detection (Exhibit 15).

[74] December 4, 2001 Email from [*name redacted, BP-9*] to [*name redacted, A-2*] Re: ADEC COBC on Leak Detection (Exhibit 11).

[75] Ibid.

[76] December 14, 2001 Authorization for Expenditure, AFE # 4N0420.2 (Exhibit 12).

[77] December 30, 2002 letter from ADEC B. Hutmacher to G. Campbell, Re: COBC for BPXA ADEC No. 014-CP-5079.

- On February 13, 2002 the Vice President of BPXA, [*name redacted, M-1*], wrote to Ms. Barnes, the Company's Probation Officer. He advised her that "the sediment build-up in the pipelines that has occurred over time" was delaying the metering project.[78]

- On May 14, 2002 the GPBU Operations Manager, Jack Fritts, executed the COBC on behalf of BPXA. In paragraph 16, the COBC stated that BPXA had discovered settled solids in some pipeline segments, which had to be cleaned to permit testing of the LDS meters. He attested as to his authority to enter agreements for and to legally bind BPXA.[79]

- For a meeting with the Department of Justice on October 16, 2002 BPXA representatives prepared a slide presentation entitled "Events Leading to GPBU Pipeline Leak Detection COBC."[80] One slide explained that "sediment buildup in some of the pipeline segments prevented BPXA from meeting the December 31, 2001 deadline."[81]

Throughout the period of the COBC, the Company was mindful of its obligation to perform the various obligations imposed thereby, and to do so in a timely fashion.[82] As a result, all of the obligations were completed to ADEC's satisfaction and the system was successfully tested before the end of the year.[83]

5. The Actions Related to Sediments After Closure of the COBC

BPXA's compliance with the terms of the COBC was recognized on December 30, 2002, and ADEC officially closed the COBC on April 3, 2003.[84] Thereafter, interest in the subject of sediment in the OTLs evaporated.

After reviewing thousands of pages of documents, including the CIC Annual Corrosion Management Reports, and numerous interviews, we found no evidence that sediment in the oil transit lines was a matter of serious concern within BPXA, during the three years following the termination of the COBC. The voluminous annual reports of

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78 February 13, 2002 letter from BPXA C. Phillips to M.F. Barnes, Re: Mr. Hamel's correspondence dated January 30, 2002 regarding pipeline leak detection, (Exhibit 13).

79 See Exhibit 1.

80 October 16, 2002 presentation, "Events Leading to GPBU Pipeline Leak Detection COBC," (Exhibit 14).

81 Ibid.

82 August through December, 2002 Email string regarding pipeline leak detection status.

83 Exhibit 16.

84 April 3, 2003 letter from ADEC B. Hutmacher to BPXA J. Fritts (Exhibit 17).

the CIC group, which detailed BPXA's successful anti-corrosion efforts and its leadership in the development and improvement of chemical inhibitors, are silent on this subject.[85] The I/C group appears to have lost interest in the issue of sediment, as soon as it demonstrated the performance of the LDS to ADEC's satisfaction.[86] The corrosion engineers and analysts, while busy with the department challenges, including the ongoing budget battle, did not identify the OTLs as a high priority issue requiring attention.

6. The Effect of Budget Issues on the Corrosion Program

Budget and funding issues are addressed in two different ways on the North Slope. First, BPXA as operator has an annual budget to operate and maintain the field, referred to as the Operator budget. This budget, and any supplemental requests, are approved by the Working Interest Owners (WIOs) or co-owners, and provides department funds for normal operations and maintenance costs, repairs, engineering and well work, etc., as part of the annual operating budget. Capital Expenditures ("CAPEX") are specially allocated funds for major repairs (over $100,000.00) and studies, new facilities or construction, well and rig work, and anything "downhole," or other non-routine capital investments. These expenditures are submitted by BPXA to the Working Interest Owners through an Authorization for Expenditure ("AFE") process.

The CIC annual budget was reviewed and approved as part of the budget cycle process, and was subject – as were the budgets of other departments – to the internal BP "budget challenge." Also, as the budget was spent over the year, the CIC budget would be reviewed to determine whether there were items that could be deferred or cut in order to keep the overall budget in line with approved expenditures. Following a smart pigging campaign in 2000-2001, the CIC "pigging" budget was considered as part of the annual operating budget. A review of the impact of budget on the expenditures and funding is not yet complete.

This budget process, and its impact on the CIC department, has been the subject of criticism and concern. For example, as John Baxter, BP Group Chief Engineer, stated in the April, 2005 report:

> "Currently, the budget is set up-front with a flat lifting cost strategy, with corrosion management activities then developed around this budget allocation. This strategy to maintain flat lifting costs is driving behaviours counterproductive to ensuring integrity and the delivery of an effective corrosion management system. A more effective and efficient process would be to derive the set of activities required to deliver a robust corrosion management system over the

[85] See, Annual reports for years 2003-2005.

[86] We reviewed the entire documentary record compiled through the V&E search and found no mention of sediment by the I/C group subsequent to the closing of the COBC.

> longer term, and thereafter set the budget based on these activities."[87]

Budget pressures and the budget challenge process impacted internal CIC decisions. Email communications reviewed from the 2001 to 2005 timeframes indicate that budget considerations were a factor in CIC management decisions and actions, although this investigation did not probe the impact of the budget generally. Rather, it focused – and continues to focus – on whether budget considerations resulted in a decision not to pig the OTL lines.

Request for funding through the AFE process is also applicable to the determination of whether budget impacted decisions on pigging the OTL lines. Thus, for example, when the I/C group needed to reestablish the pig receiver at Skid 50 in 2001-2002, [*name redacted, E-3*] requested and obtained funding through the AFE process. Again, in June 2003, a request for funding was submitted to the Working Interest Owners (WIO) as AFE 4N0492, seeking $2.5 million to do the preliminary engineering and planning for the installation of pig launchers.[88] According to an Email from [*name redacted, BP-14*], both ExxonMobil and ConocoPhillips had rejected the 2003 AFE, and ExxonMobil saw it as "the tip of the iceberg" and wanted to understand how it fit within the greater corrosion mitigation/management program.[89] Our investigation has not yet determined whether the AFE was, in fact, ever intended to seek funding for pigging the OTL lines. The attachment to the AFE, the "Pigging Facility Priority Listing" does not identify the OTL lines. However, we intend to examine the evidence on this point so as to provide a reliable answer.

Finally, the budget process impacted people within the department in a number of ways – including morale, increased frustration, and a sense of pessimism about the ability to deliver on the expectations for the department. E-mail communications identified from the 2001 – 2005 time frame portray a bleak picture of employees trying to do their job against, what they saw as increasing odds. For example, [*name redacted, IA-1*], the Corrosion Integrity Analyst stated in a 2005 e-mail to [*name redacted, TL-1*], CIC Team Leader, in response to a request for:

> "Reliable funding and resources is yo-yo, accurate scheduling activities is joke, and predicting line lifts or impacts is even further out of the real (sic) of reality. We are sitting on a backlog or over 1,000 locations with CUI

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[87] Baxter I, at page 4.

[88] AFE 4N0492, submitted by BPXA, requested funding to "install permanent pig launching and receiving facilities on selected lines across the GPB." The proposed facilities were to be concentrated on the historic EOA production common lines and transit sales lines. The description of the maintenance pigging was to optimize the corrosion control program and "....also eliminate flow restrictions present from sediment and fouling with the pipelines." Pigging facility installations were identified for FS-1, FS-2 and FS-3, and associated drill sites. The AFE was rejected by the WIO, and requested to be withdrawn by BPXA.

[89] January 29, 2003 Email from [*name redacted, BP-14*] to GPB, Business Lead.

and there a dozen road-crossings that need to be dug up and we have a huge infrastructure that is hanging-on with no margin for error. Without margin we are not in a position for long-term detail planning, it is difficult enough just reacting to keep product inside the pipe. ***Same story, can't do effective planning overnight after 20 years of minimalist resources and maintenance (which doesn't seem to be keeping pace with the current lofty ideas)."

His interview and the Email itself confirm that [*name redacted, IA-1*] was committed to ensuring integrity within his department. Indeed, the Email ends with [*name redacted, IA-1*] commitment:

> "However, I will not run/sacrifice an inspection strategy and program with limited resources based on the conveyance of maintenance and/or operation impact. That, in my opinion, is negligent."[90]

7. The Way in Which BPXA Dealt With Evidence of Sediment, Before the Spill

As the foregoing demonstrates, I/C was sufficiently persuaded that sediment in the OTLs was interfering with its leak detection system, so that it went to great lengths to obtain regulatory approval and to devise a solution to the problem. CIC was aware of I/C's analysis, but CIC saw no need to modify its corrosion management program and insist on pigging as necessary.[91] While the CIC group did not consider the evidence from I/C to be particularly compelling,[92] it made no extraordinary effort of its own to test or disprove I/C's interpretation.[93] Instead, the CIC team relied upon its management to fight the budget battle,[94] and it continued with its monitoring program, confident it would identify leaks before they occurred.[95]

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[90] April 10, 2005 Email from [*name redacted, IA-1*] to NSU CIC TL RE: CIC MR-Capex AFE Tracker 2006; interview with [*name redacted, IA-1*].

[91] Interview of [*name redacted, IA-1*].

[92] Ibid.

[93] Ibid.

[94] April 15, 2004 Email from [*name redacted, M-4*] to [*name redacted, IA-1*] and [*name redacted, BP-7*], Re: Cost Challenge Feedback. In 2004, [*name redacted, M-4*] laid out his strategy for Field Cost Management (FCM), "therefore what we really need to look for is some options for removing costs from 2004 which have little or no material impact on the 2004 program…."; April 16, 2004 "… I do not propose to roll over and give up the money, therefore we will be making any cuts look as unpalatable as possible without appearing to be obstructionist -- tough game!"

[95] Email traffic throughout 2000-2005 confirms frustrations, indeed at times anger at the impact of budget constraints and challenges on the CIC program. See for example April 10, 2005 email from [*name redacted, IA-1*] to CIC Team Lead Re: CIC-MR-Cape AFE Tracker 2006.

In short, although seeking funding for pigging of the flowlines, CIC was convinced that historical trends of low sedimentation would not only continue but would apply across the field. Trusting the results of its own UT scans, which indicated minimal wall loss, CIC concluded that the risk of corrosion in the flow lines continued to be low.[96] While CIC was well aware of the dangers posed by deposits of sediment and water, particularly in slow flowing areas that are essentially "uphill,"[97] it believed that it was able to continue to manage the risk of corrosion through its program of chemical inhibition, and that it would be able to detect any changes in the rate of corrosion by continuing to monitor the locations that it deemed to be at highest risk.[98]

8. The Knowledge of the Amount of Sediments or the Risk Presented, After the Spill

We saw no evidence that BPXA identified increasing sediment in the OTLs as cause for imminent concern, from the standpoint of corrosion control, prior to the March spill. Shortly after the March, 2006 spill, while the actual mechanism of the corrosion at GC-2 was unknown, [*name redacted, VP-2*], BPXA's Vice President, expressed doubt that sediment was to blame. According to an article in "Petroleum News," she speculated that sediment was probably not the problem, because there were about two inches of solids in the bottom of the EOA line, but it had not been found to be corroded.[99]

C. The Consideration of the COBC Documents in Connection With the Preparation for the September 7, 2006 Congressional Hearing

The Compliance Order By Consent (COBC) and related documents were not considered in connection with the preparation for the September 7, 2006 Congressional Hearing. The Hearing preparation process, though intended to be comprehensive, complete and transparent, failed to identify the COBC. Thus, BPXA did not consider its import to the Congressional inquiries. The Congressional hearing preparation process in August-September relied primarily upon individuals who did not have personal historical knowledge of the 2001-2002 underlying events leading to the COBC, or the COBC itself.

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96 Undated PowerPoint presentation, "BPXA Maintenance Pigging Program" (Exhibit 18).

97 November 7, 1995 Email from [*name redacted, BP-3*] to PBU CIC.

98 See April 3 letter (Exhibit 6), answer to question 4:

> 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.

99 "Petroleum News," May 14, 2006. www.petroleumnews.com/pnarchpop/060514-17.html.

To the extent that there were individuals with knowledge of its existence, the preparation process did not ensure that such knowledge was fully incorporated into the responses to Congressional inquiries or Hearing preparations.

We did not find any evidence that this result was directed by BPA or BPXA management personnel, nor understood to be a consequence of the Hearing preparation process, until this investigation.[100] Indeed, the direction from the new President of BPA was for candid and transparent disclosure of all requested and relevant information. In addition, the expectation from the then President of BPXA was that all relevant and responsive information be provided to the Committee and utilized in preparation for his testimony. The COBC was already a public document. Nonetheless, the COBC and related materials were not included in the preparation process for the Hearing and not disclosed to Congress before the Hearing.[101]

1. The Identification of the COBC

Approximately one month after the September, 2006 Congressional Hearings, the Subcommittee Staff obtained a copy of the COBC, an executed, official agreement that had been entered between the State of Alaska and BPXA, in May, 2002. The COBC included the Company's representations - first formally made in October, 2001 - that it had discovered "settled solids in some [OTL] pipeline segments," which prevented the Company from complying with State regulations governing its leak detection system (LDS) by the required time frame, December 31, 2001.[102]

The COBC also detailed tasks which BPXA committed to complete, including determining the sediment levels in the EOA and WOA pipelines at Skid 50, modifying the pig receiver at Skid 50, pigging the EOA line from FS-1 to Skid 50 and pigging the WOA line if necessary.

[100] As stated above, it is important to note that the preparation for the September 7, 2006 hearings took place in a compressed time frame with less than a month between the second spill, the partial shutdown of the field and its restoration, the initiation and continuation of several investigations, extensive press coverage, an Alaskan state legislative hearing, and the press of daily business on the BPXA business unit.

[101] The relevance of the 2001-2002 COBC documents to the 2006 Congressional investigations and Hearings is not in dispute. BPXA individuals interviewed during the course of this investigation all recognize that it was relevant to the Committee's work and responsive to its requests. In other words, with the exception of one person who did not have contemporaneous knowledge of the COBC, everyone agreed that the documents were responsive and had they reviewed them, or recalled them, would have made sure that they were produced, and that the information about the COBC was included in the Hearing preparations.

[102] As described above, discussions between ADEC and BPXA regarding an acceptable Leak Detection System began in the 1990's when ADEC revised the definition of crude oil transmission pipelines, which resulted in the application of Alaska's pipeline leak detection regulations to the sales oil pipelines in Prudhoe Bay.

2. The History of Communications Regarding the COBC

The communication between ADEC and BPXA regarding its plans on how it was going to meet the regulatory requirement span from late 1990's through the execution of the COBC in May, 2002, to its formal closure in April, 2003.

A review of the COBC correspondence, internal memoranda, and e-mail traffic reveals that virtually all of the formal communication documents refer to or discuss the existence of sediment in the lines as the basis for the need for BPXA to receive an extension in order to prepare the lines to be pigged, to pig the lines, and to then install the leak detection system. (Examples of the correspondence have been cited herein, and a full listing is maintained within the files in support of this investigation report.)

3. The March 6, 2006 Spill and the Initial Collection of the COBC Documents

When he learned of the March 6, 2006 spill, BPXA's environmental attorney [*name redacted, A-1]*, was concerned that the leak had not been identified by the LDS and assumed that a failure of the LDS would be a significant concern to ADEC.[103] While he had recently assumed his position in the company's legal department and was not employed by BPXA when the COBC was an ongoing issue,[104] he had a general recollection of a compliance order regarding the LDS on the Greater Prudhoe Bay field. He asked two paralegals in the BPXA legal office pull together whatever information could be located about the COBC so he could take it with him to the North Slope.[105]

Another attorney in the BPXA legal department, [*name redacted, A-3]*, also had some concern that the COBC documents and other compliance agreements, along with correspondence with government regulators, would become relevant to the inquiry and/or response to the spill.[106] On March 13, 2006 she also requested that a paralegal collect the COBC and related documents.[107] The paralegals, with help from others, did so.

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[103] Interview of [*name redacted, A-1]*.

[104] [*Name redacted, A-1*] came to work for BPXA in the fall of 2004, and eventually replaced [*name redacted, A-2*], when [*name redacted, A-2*] was transferred to Houston, Texas in July, 2005. [*Name redacted, A-2*] had primary legal responsibility for the leak detection COBC, from October 2001 through its closure in April, 2003.

[105] See, March 6, 2006 e-mail to [*name redacted, "BP-15"*] and [*name redacted, BP-16]* from [*name redacted, A-1*] re: Prudhoe Bay C-Plan Compliance Order by Consent Records/Files. (Exhibit 19).

[106] Interview of [*name redacted, A-3*].

[107] March 13, 2006 e-mail string from [*name redacted, A-3*] to [*name redacted, BP-15*] and [*name redacted, BP-17]* and various responses, Re: Correspondence re BPXA's leak detection system. (Exhibit 20).

By March 20, 2006 the COBC documents were collected, along with numerous other relevant documents, and placed in a separate 4-inch, 3-ring, white binder in *[name redacted, A-3]* office. The binder is a chronologically arranged collection of documents beginning in 2001, including seventeen documents dealing with the leak detection COBC. It is labeled "Government Keepers Correspondence re Corrosion and Leak Detection 2001- Forward" and is identified here as the "Government Keepers Binder."[108] [*Name redacted, A-3*] explained that the purpose of the collection of the materials was to ensure that there was consistency among BPXA's regulatory representations.[109] The white binder remained in [*name redacted, A-3*] office throughout the entirety of the spill response, subsequent investigations, preparation for responses to Congressional inquiries, and later Congressional Hearing preparations.

4. The Failure to Recognize the Significance of COBC Materials to Congressional Inquiry

[*Name redacted, A-1*] informed us that soon after he arrived on the North Slope in response to the March, 2006 spill he was advised by a representative from ADEC that the leak detection system was no longer considered a concern in the investigation, and therefore the leak detection COBC was not an issue.[110] Accordingly, [*name redacted, A-1*] did not pay any further attention to the COBC documents. Significantly, he stated he did not read the COBC documents either before or after his Slope visit, or at any other time in connection with responses to congressional inquiries or the Hearing preparation process, because he did not believe they were any longer relevant to the inquiry.[111]

On March 24, 2006 Congressmen Dingell and Miller wrote to Steve Marshall, BPXA President, posing a number of questions regarding the March 6, 2006 spill and BPXA operations. Relevant to this investigation are questions five and six. The responsibility for preparing the response was designated by [*name redacted, P-2*] to [*name redacted, FM-1*], GPB Field Manager. [*Name redacted, FM-1*] chose [*name redacted, "BP-18]* to be the single point of accountability for the response, with [*name redacted, A-3*] as his legal tag. [*Name redacted, BP-18*] and [*name redacted, A-3*] then enlisted assistance from a wide variety of people with expertise in their areas of responsibility to draft replies to the questions and/or to review the draft answers. As a member of the Legal team with responsibility for dealing with the State regulators, [*name redacted, A-1's*] review was sought in connection with the response to the Congressional letter. Because he had never read the COBC, however, he was unable to "connect the dots" between the historical information about sediments set forth in the COBC, the ongoing congressional investigation and interest in that subject, and later hearing preparation.

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108 A duplicate copy of the binder is included with the investigation supporting materials.

109 Interview of *[name redacted, A-3]*.

110 Interview of *[name redacted, A-1]*.

111 Ibid.

[*Name redacted, A-3*] stated that she was quite deliberate about ensuring that the information collected was correct, reviewed by all persons with knowledge, and consistent with other regulatory representations. In her personal GC-2 "to do" list, she identified as the first item on the list to "[m]ake sure every investigation team member agrees [with] final version of report."[112] In a March 30, 2006 e-mail to those assembled to assist with the Congressional response, she stated:

> <u>As you know, it is important for every word to be accurate, every thought to be complete and not susceptible to misinterpretation</u> (to the extent we can). I hope you will be able to get others' input into this document before it goes final. (Daren, Sandy H., Richard W., Jeff Feldman, Andrew?, others?) Randal and Brad will take over the legal review from here…." (Emphasis added).

[*Name redacted, A-3*] continued with the legal support to the Congressional investigation assignment until early May, 2006. We did not identify any evidence that she "connected the dots" between the COBC documentation that she had collected and its relevance to the ongoing Congressional inquiry into the GC-2 spill. From May to July, 2006, [*name redacted, A-3*] was assigned to work on the Kuparak Field issues, and thus was not actively involved in the Hearing preparation.[113]

After the August 2006 spill, [*name redacted, A-3*] was assigned to the crisis response for about a week, and then returned to work on Commercial issues for a brief period of time, until again reassigned to the Hearing preparation process on approximately August 20, 2006, with the responsibility as the "legal tag" assisting [*name redacted, VP-3*] on a number of issues. She did not recall reviewing the COBC or related materials in connection with assisting in preparing that response to the Congressional request for information.[114]

In fact, while many of the COBC documents had been identified, pulled together and collected into one place and available for review, it appears that no one read them or, to the extent that the documents were reviewed, no one recognized the significance of the references to sediments having been identified in the lines in 2001.

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[112] [*Name redacted, A-3*] GC-2 "To Do" List, March 28, 2006.

[113] Interview of [*name redacted, A-3*].

[114] At different points in time, including late April, 2006, [*name redacted, A-3*] and one or more paralegals went through the documents in the Government Keepers Binder and attached "stickies" identifying certain terms on various documents, including "leak detection," "corrosion" and "pigging." (When interviewed, [*name redacted, A-3*] explained that she used "yellow" stickies and "pink" was used by paralegals.) A copy of the December 30, 2002 letter from B. Hutmacher to G. Campbell (Exhibit 16 to this Report), bears a yellow sticky with the handwritten notation "pigging." (As she was packing up files from her office during the last week of September [*name redacted, A-3*] found another copy of this letter and presented it to [*name redacted, A-7*]).

5. The Commonality of Individuals with Relevant Knowledge

There was some commonality of individuals who were familiar with the COBC and the events leading up to the COBC, and those involved in hearing preparations. Many of those with common knowledge were lawyers, including [*name redacted, A-3*], [*name redacted, A-1*] (whose knowledge was acquired after the 2001-2002 events themselves) and [*name redacted, A-4*], along with [*name redacted, A-5]* and [*name redacted, P-2]*.[115] Like [*name redacted, P-2]*, [*name redacted, P-1*] was copied on a number of e-mails regarding the announcement about the COBC and related fine. During 2001-2002 he was the Regional President, Western United States, of BP Amoco, plc, with some responsibility for government relations between BPXA and Congressional offices, thus he received a copy of the announcement in May-June, 2002.[116]

In addition to the common knowledge of some BPXA personnel between the COBC and congressional inquiries, there was also relevant knowledge about the COBC that was developed by counsel following the receipt of the April 26, 2006 Department of Justice Grand Jury Subpoena. The subpoena generated an elaborate process to search and find all relevant and responsive documents and materials, which included the documents responsive to questions about the LDS.[117] However, the people working on that data collection process were quite removed from the hearing preparation activities. We did not find any evidence that the Congressional request for information on the "sediment issue" was appreciated by those involved in the document collection and data base process (other than the attorneys from V&E, as discussed in part D.3 below).

6. The Lack of Communications within the BPXA Business Unit and Legal Department

We found that during the events that followed the March 2006 spill and continuing through the Congressional hearings in the fall of 2006 there was a lack of communication within the BPXA legal department itself, and between the legal department and the rest of the business unit. Seventeen of the COBC documents had been assembled within a single notebook, referred to as the "Government Keepers" notebook, which was located in [*name redacted, A-3's*] office, and was readily available.

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115 [*Name redacted, P-2's*] involvement with the COBC was quite limited. Since he arrived in the fall of 2001, he was not personally familiar with the facts leading to the negotiation and execution of the agreement itself. He was aware of the announcement of the agreement and the compliance requirements. We found no evidence of more than superficial involvement by [*name redacted, P-2*] in February, 2002 when BPXA wrote to the U.S. Probation Officer about the COBC, and at the October, 2002 meeting with the U.S. Attorney, the federal court appointed monitor, the EPA Debarment officer, and the US Probation Officer. During his interview, he didn't recall anything about sediments being a factor in the COBC. Interview of [*name redacted, P-2*].

116 May 29, 2002 e-mail from [*name redacted, BP-20*] to [*name redacted, A-5*], et.al., Re: Fine to Generate Press Coverage In Alaska. The e-mail contains "talking points" that mention the discovery of sediments in the line as the reason for the delay in installing the LDS.

117 April 26, 2006, Grand Jury Subpoena, question 7.

It had been reviewed at least in part by [*name redacted, A-3*], who tabbed significant items, including some referencing sediment in the lines. However, the notebook was apparently forgotten or ignored and its contents were not reviewed by attorneys in the legal department, to determine if the material was responsive to Congressional requests for information.[118]

While we did not find any evidence of intent to disregard any relevant information, the activities associated with the spills, investigations and inquiries seemed to have overwhelmed the BPXA legal department. There was a poor transfer of the substantial body of historical information known to [*name redacted, A-3*] to others, both within the legal department and the business unit itself, at the time that she was transferred to other assignments. There does not appear to have been anyone who was given the local assignment to coordinate and monitor the numerous congressional staff requests, or to take over the detailed "to do" lists where [*name redacted, A-3*] left off. Had the Legal Department done so, many of the questions posed and projects started may have resulted in the identification of the COBC and its connection to the response to the GC-2 spill and subsequent events. In short, the department appears to have been engulfed with responsibilities.

7. The Vinson & Elkins Database (COBC Search)

Another avenue that provided an opportunity to identify the COBC documents was the V&E database. As stated above, the COBC was eventually collected in response to the April 26, 2006 DOJ subpoena, question number 7, regarding the leak detection system. But the database was not designed or executed to collect documents responsive to the Congressional Staff questions of the moment. Notwithstanding a strong bias toward relying on the document database, its usefulness to the preparation process for the congressional investigation and hearing was limited.

A comprehensive review of the collection and availability of Leak Detection COBC documents was prepared by V&E for BPXA, and made available to us for this investigation. It concluded that although the V&E database had been under construction for months, documents were not actually loaded and available for review until August 24, 2006. The search parameters employed by V&E did, in theory, look for documents that discussed the build up of sediments in the line, but not the leak detection system. Also, the document "custodians" whose materials were prioritized for review, did not include those who would have had the COBC in their files.

V&E determined that they did not load any copies of the COBC into the database until September 1, 2006 and those copies were not reviewed for any comments or observations about "sediments" in the line. According to the V&E review, the "nexus between sediments, pigging, and the leak detection system had simply not been raised by

[118] Interviews of [*name redacted, A-7*] and [*name redacted, A-1*]; The "Government Keepers" notebook was also reviewed by V&E in the course of its document collection activities.

that date.[119] Thus, although the V&E database was a source of documentary information, it was not effectively operating at the time of the Congressional requests for information in the Spring and Summer of 2006, and only of marginal effectiveness in preparation for the Hearings themselves during the Fall of 2006.

8. The Failure to Access BPXA Personnel with Personal Knowledge of the COBC

Even though there were various BPXA employees who had been involved in the COBC, had knowledge of its provisions and cause, and would have had knowledge about the existence of sediments in the lines we did not find any evidence of a general distribution of the congressional inquiry questions. Hence, the BPXA employee population in the CIC department and/or in Instrumentation and Controls were never given the opportunity to provide this relevant information.

In short, while the responses to the March, 2006 spill were somewhat disjointed by the Business Unit, and missed the relevance of the COBC documents and the discussion of sediments within these documents, the process was flawed by the failure to push questions from Congress to those most knowledgeable in the business unit with the answers. Therefore, as responses were being prepared to important congressional questions in late March and early April, 2006, and the specter of a criminal probe began to loom imminent, the business unit began isolating the response activities to a smaller group of employees and the legal team.[120] While this is understandable in terms of litigation strategy, it appears that there was a lack of appreciation of the risk that isolating the process to protect and control the legal defense could result in the loss of the institutional knowledge necessary to fully inform the response to inquiries from other stakeholders, including Congress. This situation worsened after the second spill.

9. The Reasons that the COBC and Related Documents were not Disclosed

We did not find that anyone attempted to conceal the COBC and related materials from Congress. Considering that the COBC was a public document that had been the subject of some notable controversy, a lengthy public dialogue between ADEC and BPXA, and substantial press coverage just three years before, and thus known to many people, only an individual afflicted with remarkable hubris could believe that the COBC could be concealed. Indeed, such an attempt would have been impossible, given the public nature of the COBC and related documents. We also did not find an appreciation of the relevance of the COBC events and documents to the Congressional inquiries about

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[119] January 5, 2007 Memorandum from V&E Counsel [*name redacted, A-4*] and [*name redacted, A-6*] to BPXA [*name redacted, A-7*] and [*name redacted, BP-21*].

[120] Notes of [*name redacted, A-3*] re: April 7, 2006 telecon meeting among staff lawyers, outside counsel, BPXA personnel [*named redacted, P-2*], [*named redacted, VP-2*], [*name redacted, BP-22*], [*named redacted, A-5*], and [*name redacted, BP-23*].

BPXA's historical knowledge or belief about sediments in the lines in 2001 among those working on the Congressional responses in 2006.[121]

We did find that the Congressional response/Hearing preparation process itself was strategically and tactically driven, as well as informed, by individuals who had little, or no, knowledge of the COBC and almost none of its factual foundation. Specifically, neither of the individuals charged with drafting the factual portion of the response to the initial March 24, 2006 Congressional letter had been present during the COBC related events of 2001-2002. The lawyers who were involved in reviewing the responses had not read the COBC documents as part of their own preparations, and both had abandoned any interest in the COBC as relevant to the new issues.[122]

Finally, the primary "fact check" person that BPXA was relying upon in Washington, D.C. during the final days leading up to the hearing to review its Congressional testimony regarding the corrosion program, had not been employed by BPXA before 2005, was not familiar with the COBC and had never read it until he was interviewed in the course of this investigation.

Conclusion

We did not find any evidence that the failure to provide the information was knowing, intentional or deliberately considered by any BPA or BPXA personnel. The COBC itself and the documents surrounding it were relevant to the Committee's investigation, responsive to its requests for information, and available to individuals who were preparing for the Congressional Hearing. However, as described in this Report, the COBC, and COBC-related documents, were not considered or included in preparation for

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[121] On or about September 29, 2006 [*name redacted, A-3*] wrote an e-mail to BPXA's Managing Attorney [*name redacted, A-7*], that she had "stumbled" on a COBC related document, i.e., the December 30, 2002 letter from ADEC confirming that BPXA had complied with the remedial measures and did not need to pig the lines. [*Name redacted, A-7*] was unfamiliar with the COBC since the events that surrounded its issuance and closure had occurred several years prior to his arrival as Managing Attorney. Upon review, [*name redacted, A-7*] thought that the "discovery" of the information was a good thing for BPXA, as the document that he reviewed, lifting the pigging requirement, implied that there were no sediments in the lines and validated the decision not to pig. [*Name redacted, A-7*] directed that all documents relating to the COBC be retrieved and the staff did so. He was still unaware that 17 of the COBC documents were readily available in the Government Keepers Binder, down the hall from his office. None of the paralegals were aware of the issues surrounding the COBC or asked about their knowledge of documents responsive to the request.

[122] [*Name redacted, A-7*], BPXA's Managing Attorney, and [*name redacted, A-8*], BPA's Assistant General Counsel - Upstream, both commented that they were quite prepared and equipped to deal with litigation based requests for information, and were in fact in the middle of a DOJ investigation that requested substantial documentation. However, neither had been involved in a Congressional Hearing preparation process before and thus found the open-ended questions and requests for information difficult to manage. Thus, they deferred to the Washington, D.C. based Government Affairs office and related outside consultants and lawyers to respond to the inquiries. This investigation did not interview outside consultants.

the September 7, 2006 Congressional Hearing or the following Congressional Hearings in September and October, 2006.

D. The Hearing Preparation Process Issues

The overriding issue stemming from the failure to disclose the COBC is not, of course, about the failure to produce a single document or even several documents. Rather it is about the failure of BPXA to answer fundamental questions of the Congressional inquiry regarding knowledge of sediments in the OTLs and to provide information in response to the Congressional requests for information and the influence that information may have had on its work.

The investigation did not find any knowing or willful actions taken to prevent disclosure of information to the Subcommittee Staff by any BPXA or BPA employees. However, the investigation found that there was a lack of accountability by BPXA leadership to ensuring that information provided to the Congressional staff was complete, and based on the collective knowledge of the institution. The investigation also found that relevant information had been gathered by the Vinson & Elkins law firm that, if reviewed by BPXA witnesses and provided to the Committee, would have provided important information to assist in the Congressional Hearing preparation process.

1. The Congressional Requests for Information Regarding Sediments and Solids

By way of background, the Congressional Staff requested information about the knowledge and existence of sediments in the line, beginning shortly after the first spill and continuing through the Hearing and afterwards. The sediment request was first identified in the March 24, 2006 letter from Congressmen Dingell and Miller to Steve Marshall;[123] and continued through the Hearings and beyond. BPA's Washington, D.C. Director of Federal Affairs, [*name redacted, D-1*], stated during his interview that the Staff asked questions about sediments and sludge in virtually every meeting and conversation he had with them.[124] His recollection is confirmed by his notes of the Congressional Staff trip to the North Slope in April, 2006 and again in his August 21-25, 2006 list of questions identifying a concern about knowledge of sediments.[125] On August 25, 2006, [*name redacted, VP-3*], the new BPXA Vice President of Compliance[126] posed

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[123] See, Exhibit 5.

[124] Interview with [*name redacted, D-1*].

[125] [*Name redacted, D-1's*] notes of the August 21-25, 2006 trip record a list of ten extremely detailed questions, including questions regarding BP's awareness of a "sludge problem," pigging, employee concerns about corrosion, and budget issues.

[126] [*Name redacted, VP-3's*] first day on the job was August 3, 2006, and her primary counterpart in Alaska, [*name redacted, BP-24*], had only been there since late June. Neither of them had personal knowledge of the history of BPXA, the employee concerns issues, or other factors to respond to questions or challenge responses sufficiently to ensure accuracy or completeness.

the Congressional Staff questions about sludge to the Washington, D.C. and several BPXA employees. The August 25, 2006 questions, including "What we knew about sludge and when," were also copied to [*name redacted, A-1*] and [*name redacted, BP-4*] back in Alaska.[127]

On August 29, 2006 a meeting was held between the Congressional Staff and BP's Vice-President of Federal and International Affairs, [*name redacted, VP-4*], and [*name redacted, D-1*], along with BPXA's [*name redacted, VP-3*] and [*name redacted, A-7*], and BPA's Associate General Counsel, [*name redacted, A-9*] and attorney [*name redacted, A-10*]. Several of the attendees made notes and generated requests for information as a result of the meeting.[128] The requests about knowledge of sediments in the lines, along with other issues, are included in the various notes and lists. The questions were almost immediately conveyed back to the BPXA staff, which continued to work on collecting information.

The BPXA personnel in Alaska understood the sediment question to be limited to what the organization knew about solids after the March, 2006 spill.[129] Primary work was done on the responses by [*name redacted, BP-4*], Maintenance and Reliability Manager, BPXA, and substantial information was provided to [*name redacted, VP-3*] about what was known about solids and sludge after the March 6, 2006 spill.[130]

Information that had been collected and analyzed by [*name redacted, BP-4*] was forwarded to the BPXA staff in Washington, D.C. on September 5, 2006. The information from [*name redacted, BP-4*] came into the BPXA Hearing preparation process in the days immediately before the Hearing.[131] However, it appears that [*name redacted, BP-4*] and [*name redacted, BP-25*] interpreted the questions to determine what BPXA knew about sludge in the lines after the GC-2 spill, not about historic knowledge of sludge.

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[127] August 25, 2006 e-mail from [*name redacted, VP-3*] to [*name redacted, VP-4*], et al., Re: Immediate Needs – ASAP.

[128] August 29, 2006 e-mail from [*name redacted, A-7*] to [*name redacted, A-3*] et al., Re: Requests from meeting with staffers; August 30, 2006 e-mail from [*name redacted, VP-4*] to [*name redacted, BP-29*], et al.; and August 30, 2006 e-mail from [*name redacted, VP-3*] to [*name redacted, A-7*], et al., Re: questions from meeting today.

[129] See, August 31, 2006 letter from Chairman Joe Barton, et.al. to Robet Malone, requesting, among other things, "...(1) all records and communications relating to discussions about sludge/sediment, pigging, and/or corrosion on BP's Prudhoe Bay transmission lines (*primary focus on the period from January 2006 to the present.*) (emphasis added)

[130] September 5, 2006 e-mail from [*name redacted, BP-4*] to [*name redacted, VP-2*], et al., cc'd to [*name redacted, VP-3*], et al., Re: Solids Timeline.

[131] Interview with [*name redacted, BP-4*].

[*Named redacted, D-1*] again received additional clarifying questions from the Staff on August 30, 2006, conveyed by Mr. Chris Knauer of the Subcommittee, seeking information on "what did we know about sediments in the line."[132] These questions were also sent to a long list of people who were involved in the Hearing preparation process. However, none of those people had personal knowledge of the COBC documents, except for [*name redacted, A-3*], who by then had left Washington, D.C. for personal reasons.

Finally, our investigation uncovered a Congressional Hearing Document Request List generated in the DC office that identified and tracked information being requested by the Congressional Staff in the final days leading up to the hearing. This document contains the question, among others, about "what we knew about sludge and when?"

As of the latest version of the list we obtained, the 9/03/06 4:00 PM version, the status of the working response was:

> *STILL DETERMINING THE ANSWER TO THIS (and it'll take months)*
>
> *Representative sample of what we know now is in the DOT correspondence and e-mails*
>
> *[Name redacted, BP-19] and [name redacted, BP-13] has asked [name redacted, BP-4] for his internal documents and letters to Alyeska*
>
> *V&E can do search as well of the records they have collected (See V&E e-mail).*[133]

Document collection and information retrieval was underway during the days and weeks before the hearing. As described above, that process was relying heavily on the V&E database which was not yet fully functional, and on the assistance of people who were not personally involved with the CIC department during the time frame in question.

Thus, notwithstanding all of the Congressional requests, the instructions and expectations of the BPA and BPXA Presidents, the actions by V&E to upload and prioritize its search engine capability to support the hearing, and the good faith attempts by many employees to gather information to provide to the Subcommittee staff, the company failed to identify documents as responsive to the request. Thus, BPXA missed the opportunity to have discovered a critical link to be able to answer the Congressional inquiries about sediments in the line.

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[132] Interview of [*name redacted, D-1*].

[133] See, September 3, 2006, 4:00 PM Congressional Hearing Document Request List, Updated 9/3/06 4:00 P.M.

2. The Lack of Personal Knowledge

As stated above, in those cases where there was commonality between the two projects, both the Congressional Hearing preparation and knowledge of the COBC and related discussions regarding the sediments from the 2001 time frame, the Hearing preparation process did not provide adequate assurance that answers were complete and accurate, and based on all available knowledge of the Business Unit.

The BPXA staff lawyers, except for *[named redacted, A-1]* and *[named redacted, A-3]*, were generally new to the issue and did not have personal knowledge of the facts from 2001. *[Named redacted, A-1]* did not personally participate in the Hearing preparation process, but was included in the review of relevant facts. He had not read the COBC in reaction to the March, 2006 spill. He simply did not realize the sediments issue was addressed in the COBC documents.[134]

[Name redacted, A-3] had been personally involved in COBC-related matters as part of her assignment during the 2002 time frame.[135] She had read through the COBC and related documents, as is evident from the addition of the "sticky" notes to the COBC binder.[136] However, *[name redacted, A-3]* was not the primary lead on preparing the September, 2006 Congressional responses. Neither *[name redacted, A-3]* nor *[name redacted, A-1]* state that they had reviewed the materials that Vinson & Elkins had identified as potentially relevant and responsive to the Hearing preparation process.

[Name redacted, A-3] stated that she had a minor part to play in the hearing preparations. She was brought in to the actual Hearing preparation at the last minute, having spent several months in another department. She viewed her responsibilities as limited to assisting in the preparation of *[name redacted, P-2's]* testimony. However, her responsibilities were described more substantially in an August 8, 2006 e-mail from *[name redacted A-9]* identifying *[name redacted, A-3]* as the "legal tag" on GPB Operations, and again in the August 24, 2006 e-mail assignment of *[name redacted, M-5]* and *[name redacted, BP-4]*, along with *[name redacted, A-3]* to respond to the question of "[w]hat we knew about sludge and when."[137]

3. The Vinson & Elkins Document Collection Process

As described above, participants in the hearing preparations shared a mistaken reliance on the document review and information gathering being performed by V&E in connection with the governmental investigations, to provide comprehensive factual

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[134] Interviews of *[name redacted, A-1]*.

[135] See, COBC related documents.

[136] See, "Government Keepers Notebook;" and Interview of *[name redacted, A-3]*.

[137] August 24, 2006 e-mail from *[name redacted, A-9]* to *[name redacted, BP-27]*.

information for the Hearing preparation process. The electronic database, document analysis and identification process was, at best, in its infancy at that time.

In recognition of this, several V&E lawyers in Houston did a manual search of documents and pull together materials about a number of issues, including budget, sediment, pigging and the 2004 V&E investigation into allegations of retaliation issues within the CIC department. There were no documents about the COBC, or any documents directly related to the COBC in the compiled materials, although some of the sediment discussion e-mails were included. The documents were collected in the Houston offices of V&E, and provided to attorneys in nine different segments over the weekend before the hearing. The first section of the materials were delivered to [*name redacted, A-4*], on August 31, 2006 in preparation for a briefing of [*name redacted, P-1*] and other lawyers at the BP Westlake facilities later that day. [138] According to [*name redacted, A-4*], and others, the only use of any of the materials during the briefing of [*name redacted, P-1*], was in relation to other issues that were developing with respect to the hearing, i.e., the V&E Report of the CIC department.

Over the Labor Day weekend there were eight other supplements provided to a small group of attorneys, including [*name redacted, A-4*] and two other V&E lawyers, [*name redacted, A-11*], [*name redacted, P-2's*] personal counsel, [*name redacted, A-3*], and [*name redacted, A-7*]. By Monday, September 4, 2006, [*name redacted, A-6*] had printed and delivered to the Washington, D.C. office, "three or four" complete set of the materials. He believes these were distributed to BPXA attorneys [*name redacted, A-3*] and [*name redacted, A-7*], along with [*name redacted, BP-11*].[139] (The materials at issues were identified in the Alaska offices of [*name redacted, A-7*] during this investigation.)

During the final days of hearing preparations, the primary V&E lawyer responsible for the database did provide a proposal for ensuring factual accuracy of the most current information by BPXA employees. On September 2, 2006 V&E lawyer [*name redacted, A-6*] suggested that "[f]or e-mails and other internal communications about sediments/sludge, corrosion or pigging in 2006" that a number of people be asked to provide e-mails that they recall on this topic. That list included "[*name redacted, IA-1*], [*name redacted, M-5*], [*name redacted, M-2*], [*name redacted, VP-2*], [*name redacted, BP-4*], [*name redacted, FM-1*], [*name redacted, BP-25*], [*name redacted, BP-6*], [*name redacted, TL-1*], [*name redacted, BP-28*], and the other Nalco people working in BP's office in Anchorage and on the North Slope, [*name redacted, BP-29*]." The e-mail was forwarded to all the relevant BP attorneys on the same day. We found no evidence that this suggestion was adopted or action taken as a result to incorporate the institutional knowledge of that group of people into the final search for documents, or any expanded role in preparing or reviewing testimony.

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138 Interviews of [*name redacted, A-4*].

139 Interview of [*name redacted, A-6*] and [*name redacted, A-4*].

Unfortunately, by the time the materials were delivered to the BP office, the preparation teams were deeply engrossed in addressing and responding to emerging issues in connection with reports and information that the committee had requested pursuant to an August 31, 2006 letter. No one with responsibility for responding to the Congressional requests for documents either were aware of the materials, or reviewed them with a consideration of whether the materials were responsive to the pending requests for information. Nor was the information reviewed, considered, or relied upon by those staff members, consultants or lawyers responsible for drafting the testimony, ensuring its completeness, or preparing witnesses. The documents were not provided to either the President of BPA or the President of BPXA for their review before their testimony, nor were either of them briefed on the collected materials.

4. The Preparation of Steve Marshall Subcommittee Testimony

The written Congressional Testimony of Steve Marshall did not include discussion about sediments in the OTLs. His testimony was based primarily on the testimony he had provided to the Alaska State Legislature on August 18, 2006. That testimony had been written, in Alaska, by consultants and lawyers in the business unit. This investigation did not pursue the development of that testimony, but the Alaska testimony provided the framework for the subsequent Congressional testimony developed in Washington, D.C. The testimony prepared in Alaska was not, and could not, have been informed by the compilation of documents identified through the V&E document collection and search, since as described above, it was not searchable by that time.

Steve Marshall's Washington, D.C. testimony was written, or re-written, mainly by [*name redacted, VP-3*] and the other lawyers and consultants, many of whom were new to BPXA or outside counsel and/or consultants. They relied upon the BPXA interface, [*name redacted, VP-3*], who was also new to her Alaska assignment, to verify the facts. The BPXA team included [*name redacted, P-2's*] personal attorney, who was given access to the materials compiled by V&E.

There is no evidence that Steve Marshall reviewed the materials. He stated that he relied on the legal and support team, including his personal lawyer, the consultants, and [*name redacted, M-5*] of BPXA to ensure the testimony was accurate and complete.[140] One of the V&E lawyers familiar with the compiled materials did sit in on a portion of the Steve Marshall hearing preparation, and on occasion made observations or comments about the development of the testimony, but did not provide the documents to Steve Marshall.[141]

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[140] Interview of [*name redacted, P-2*].

[141] Ibid.

5. The Preparation of Bob Malone's Subcommittee Testimony

The Congressional testimony of Bob Malone did not include any discussion about knowledge about sediments in the OTLs. Mr. Malone's initial testimony was prepared primarily out of the BPA Washington, D.C. office, with input coordinated by [*name redacted, BP-27*].[142] The Malone testimony was also, in part, informed by the Alaska testimony of Steve Marshall and related talking points.[143] Ultimately, Mr. Malone wrote his own Congressional testimony based on information available to him at the time.[144] However, neither [*name redacted, BP-27*] nor anyone else on the Hearing testimony preparation team were aware of the V&E compiled materials, or accessed them during the preparation process. While V&E obviously was aware of the compilation, they were not involved in drafting Mr. Malone's testimony or verifying its accuracy. [145]

6. The Lack of Coordination

Finally, there was a lack of coordination involved in the Congressional Hearing preparation process, with two different Hearing preparation teams and two different sets of lawyers. One team was dedicated to the preparation of the events regarding the two spills and the decision to shut down the Prudhoe Bay following the August spill, principally the BPXA team. The other team was focused on other BP issues and the commitments and decisions about future action. There were also substantial distractions to the process, as the Congressional Staff was requesting, and the legal and business teams were considering the disclosure, arranging for disclosure, and then considering the implications of disclosure of a number of significant internal reports and documents.[146] These factors, along with the lack of a written document request, and the compressed time frame available to prepare for the Hearing itself complicated the preparation process and led to a less than optimum Hearing preparation and document disclosure process.

Conclusion and Recommendations:

The COBC and other relevant information available to the BPXA organization was not provided to Congressional Committee Staff or to the Committee, or considered by BPXA or BPA in preparation for the September, 2006 Congressional Hearings. This

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142 Interview of [*name redacted, BP-27*].

143 August 15, 2006 e-mail from [*name redacted, BP-30*] to [*name redacted, P-1*], et al., regarding the Alaska state legislature testimony.

144 Interview of [*name redacted, P-1*].

145 Interview of [*name redacted, A-4*], [*name redacted, A-6*], and [*name redacted, P-1*].

146 Congressional letter regarding 2004 V&E *Report for BPXA Concerning Allegations of Workplace Harassment From Raising HSE Issues and Corrosion Data Falsification*; 2005 *Internal Audit, BPXA Corrosion Management System Technical Review* (Baxter I); 2006 *Alaska Transit Pipeline Technology Review* (Baxter II); and 2002 *Corrosion Monitoring of Non-Common Carrier, North Slope Pipelines: Technical Analysis of BPXA Commitment to Corrosion Monitoring Year 2000 For Greater Prudhoe Bay, Endicott, Badami and Milne Point* (Coffman Report).

was because the information either was not identified as responsive and included in Hearing preparation materials at all, or, if identified, was not accessed by the people preparing for the Hearings and/or providing the responses to Congress.

As to this issue, we were asked to provide recommendations on the process to ensure further Congressional inquiries were responded to in a manner that provides assurance for accuracy and completeness. Those recommendations are:

- BPXA should institute clear policy expectations for transparency and complete candor in all dealings with Congress and other stakeholders;

- BPXA should, as a matter of routine practice, seek out the best and most accurate information from those with institutional knowledge in the subject matter at issue;

- BPXA should remove any bias toward compartmentalization, or "siloing" of information which, in part, we found contributed to this situation;

- BPXA should ensure that important projects, such as responding to Congressional requests for information, are managed by persons with personal or first-hand knowledge of the events at issue.

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GPB Leak Detection Summary 10-13-2002

Background:

- The regulatory change requiring pipeline leak detection for crude oil transmission pipelines at Greater Prudhoe Bay was introduced in April 1997.
- ADEC extended GPB (all areas, including the facilities purchased from ARCO) additional time to comply to allow for additional engineering analysis on how current leak detection technologies could best work for the existing facility design.
- On January 29, 1999 ADEC issued conditions of approval for the renewal of the GPB Contingency Plans (C Plan) requiring a leak detection proposal on or before August 31, 1999.
- Submittals stimulated a series of discussions on leak detection systems, leak detection technologies and regulatory interpretations of what constitutes compliance.
- On December 7, 2000 ADEC found the leak detection proposal insufficient and required a revised proposal be submitted by January 31, 2001.
- On January 31, 2001, BPXA submitted a revised leak detection system and testing proposal recognizing the Departments' interpretation of pipeline segment level detection requirements. This submittal established December 31, 2001 as the deadline for functional performance testing of the GPB leak detection system.
- BPXA has conducted several functional fluid draw tests on the Lisburne crude oil transmission pipeline segment and has demonstrated the ability to detect a leak of less than 1% on that segment of pipeline.
- BPXA recognized that work would not be complete on the other pipeline segments by year-end, 2001 due to sediment build up in the pipeline and BP asked ADEC to enter into a COBC to provide legal compliance until all leak detection testing and Best Availability Technology (BAT) analysis could be completed to satisfy state regulations.
- The key milestones of the COBC are as follows, with Status as of October 1, 2002:
  - Determine sediment levels in EOA and WOA pipelines at Skid 50. by 03/31/02 - Completed
  - Modify EOA pig receiver at Skid 50; BY 03/30/03 - Completed
  - Pig EOA pipeline from FS-1 launcher to Skid 50. by 06/30/02 - Task Eliminated; Approved by State
  - Pig WOA pipeline segments if necessary; By 09/30/02 Task Eliminated; Approved by State
  - Test and select flow meters at EOA pipeline, Skid 50 if necessary. 09/30/02 - Completed
  - Complete WOA crude oil flow smoothing modifications. By 12/31/02 Work in Progress
  - Install and test meters on all pipelines. By 12/31/02 Work in Progress
  - Evaluate and establish leak detection system compliance. By 12/31/02 Work in Progress

Greater Prudhoe Bay Leak Detection Operations – Current

- GPB has maintained a SCADA / DCS (Supervisory Control And Data Acquisition and Data Control System)
  - Pipeline measurement of flow rates, pressures and temperatures can detect leaks in pipelines with alarm for the Control room operator
- EFA leak detection Computer software system is in place to detect leaks and provide audible alarm to Operators
- Regular Security (twice daily) surveillance of pipelines
- Aerial surveillance of pipelines with Forward Looking Infra-Red (FLIR) is available if with Security cannot access the pipeline roads; inclement weather
- Drill Site and Facility Operators observations during daily field operations
- Corrosion Inspection & Chemical (CIC) Group
  - Walk certain pipelines; not easily accessible by road
  - Maintain Pipeline Discrepancy Report with Security support
- Anyone can call to report an anomaly that may represent a small leak or spill

Greater Prudhoe Bay Leak Detection Operations – Proposed

- In addition to the Current Leak Detection Systems;
  - Additional line segment meters are being installed to measure volume inlet against volume outlet of the pipeline segments (Ed Farmer; Mass Balance Line Pack Compensation) MASSPACK
  - Ed Farmer; Pressure Point Analysis (PPA) will also be installed as an auxiliary to the MBLPC. However, due to resident hydraulic noise in the shipping system, PPA is not expected to reduce the threshold of MBLPC leak detection system performance. PPA will however offer a redundant system to detect significant leaks from the GPB crude oil transmission pipelines

From: James David Bruchie [dave@alaska.net]
Sent: Friday, October 18, 2002 9:49 PM
To: Neill, David H
Cc: Campbell, Gary RB; Dave Bruchie (E-mail); GPB, SSEP Controls Engr
Subject: Re: FW: Please Edit

my comments are enclosed in <<>>

Dave Bruchie

On Fri, 18 Oct 2002, Neill, David H wrote:

> Gary,
>
> I gave a shot at editing your document. You might want to work my
> comments into the letter. Also, I thought your October 8, 2002 letter
> to Lydia Miner with the attached Table 1 "Status of Tasks and Milestones per the COBC"
> explained the FS-2 segment issues very well.
>
> Dave
>
>
> David Neill
> Instrument/Controls Engineer
> neilldh@bp.com
> (907)564-4292 Office
>
>
> -----Original Message-----
> From: Campbell, Gary RB
> Sent: Thursday, October 17, 2002 7:21 PM
> To: Neill, David H; Bruchie, James (Dave) D
> Subject: Please Edit
>
> Dave, David,
>
> Can you please edit to state the facts please: I spoke at the meeting
> on Wednesday with State AG and Court Appointed Monitor and said we
> moved the meters to high points of pipe elevation to avoid sediment;
> when I should have said that technically we used a turbine meter to
> manage in the sediment without pigging. I need to know if it is fair
> to say that the locations of the U/S meters are not at lower elevation
> points on teh pipeline that potentially may have sediment build-up. I
> need to know the possible suite of answers as I expect we will be asked to document our
official response.
> I would like to have a response to Chris Phillips early next week.
>
>
>
> To:
>
> I have researched the circumstances regarding the pipeline sediment at
> GPB to verify what testing was done on the crude oil transmission
> pipelines at GPB that showed sediment, and why in 2002 we did not need
> to pig the lines i.e. one of the reasons we requested the COBC and
> extended the Leak Detection installation deadline to Dec 31, 2002.
>

> <<During spring of 2001>>, Ultra-sonic (U/S) strap-on meters
were tested on the
> crude oil line at FS-2 to test the accuracy of the meters given the
> expected low flow rates in the line.
>
> During the testing, it became evident the FS-2 line where it
> intersects with the FS-1 line had significant sediment buildup. This
> was determined while setting up the ultrasonic transit time meter, and
> rotating the meter transducers around the perimeter of the pipe, and watching the signal
> attenuation. In order for the meter to function accurately as the flow
> rates change, we require a clean pipe. With sediment in the line, the
> meter <<remove "repeatability">> is non linear.
>
> Based on our finding at the FS-2/FS-1 intersection, we assumed at the
> time, that there was significant sediment buildup along all the EOA
> pipeline segments all the way to Skid 50. At that time we began
> making piping and pig receiver modifications at Skid 50 to allow us to
> pig the FS-1/Skid 50 piping.
>
> The velocity in the FS-2 segment was <0.5 ft/sec making pigging impossible.
> At the FS-2/FS-1 intersection, there is a pig launcher/receiver module
> where the pipeline diameter changes from 30" to 34". This module has
> a gas detection system and hydrocarbon sump system and was suitable to
> install a reduced diameter turbine meter run. This was deemed the
> best metering solution for the FS-2 segment as the reduced diameter
> meter piping would increase the flow velocity, thereby eliminating the
> possibility of sediment buildup in the meter run.
>
> A decision was made to inform the agency that we had detected the
> sediment and that we would not have time to install pigging equipment,
> pig the lines, install meters and have a witness test by ADEC before
> the December 31, 2001 deadline. We therefore initiated discussions on a COBC.
>
> During the discussions on the COBC, four of the milestones included were:
> 1) Determine sediment levels in EOA and WOA pipelines at Skid 50 by
> 03/31/02 - Completed
> 2) Modify EOA pig receiver at Skid 50 by 03/30/03 - Complete
> 3) Pig EOA pipeline from FS-1 launcher to Skid 50 by 06/30/02 -
> Task Eliminated; Approved by State
> 4) Pig WOA pipeline segments if necessary by 09/30/02 - Task
> Eliminated; Approved by State
>
> In early 2002, subsequent ultrasonic meter testing at the FS-1/FS-3
> intersection and the Skid 50 intersection showed no sediment buildup
> at those locations. At these locations with clean pipe and flow
> velocities well above 1 ft/sec we expect the ultrasonic transit meter to perform well.
> Also these intersections are out in the open over tundra, so the
> non-intrusive design of the ultrasonic clamp-on meters posed no
> potential leak source. During this time we tested several
> manufacturers brands of ultrasonic transit time meters to find the one
> that worked best. We also tested WOA locations at the GC-2/GC-1
> intersection and the WOA Skid 50 intersection and found those areas
> free of sedimemt. << actually there
might be a small amount of sediment at the very bottom of at least one location, I believe
it was the EOA pipe at skid 50. Based on slightly reduced signal strength during the
survey runs I estimated less than 0.5 inch of sediment based on the extent of the
attenuation, The attenuation might have been due to other causes>>
> In looking at alternate locations for meter installation for testing,
> the alternative of installing a turbine meter at FS-2 was discussed
> with the Operations Manager who recommended looking at a turbine meter because:
1) <<we could install a reduced size meter run, sized to match the current
flow rates from FS2 (lowest in the field by a factor of 2), rather than
an insert turbine meter or ultrasonic meter operating at less than
0.6 ft/sec (near the low end of the reliable operating range for these
meters) in the main line pipe.

2) with a turbine meter we would not need to pig the lines, provided other sections of the line selected for ultrasonic meters did not have sediment.
3) The turbine meter could be installed in an existing building with gas detection to detect leaks at flanges and a sump to handle liquids during maintenance>>
> As a result we proceeded to:
> 1) install a turbine meter with smaller diameter meter run piping at
> the
> FS-2/FS-1 intersection. FS-3 (still has sediment, but not needed to
pig)<<i'm not sure if it was FS3 or east side of SK50, but I estimated less than 0.5 inch deep based on the location of the slightly higher attenuation of ultrasonic signal.
> 2) Use ultrasonic clamp-on meters at all of the remaining pipeline
> segment intersections. install the other ultrasonic meters at optimum
> points on the pipeline (to avoid potential of sediment) << The
> location were picked
with more of a eye to getting a fully developed flow profile and completely covering the pipe segments than avoiding sediment. In fact the line meter at GC1 is at a low point. We could have avoided that by going several hundred yards upstream, but that would have left that part of the
GC2-GC1 line on the wrong side of the meter. One of the advantages of the ultrasonic meters is we can move them fairly easily if necessary.>>
> 3) keep the pigging facilities in place to be able to pig the lines
> should sediment build up at the ultrasonic meter locations in the
> future
>
> Technically I was incorrect in stating that we moved the meters to
> avoid the sediment. In fact, we installed a turbine meter to avoid
> pigging because of the inherent risks of pigging. We did pick optimum
> locations for the ultrasonic meters (in straight run sections of pipe
> to insure good flow profile << I expanded on this above >>) that we
> installed, and we have
the pigging facilities installed and
> available should we need them in the future.
>
> Gary R B Campbell
> GPB, HSE Manager
> Anchorage: 564-4275
> GPB: 659-8462
>

Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring

Year 2002

Prepared by

Corrosion, Inspection and Chemicals (CIC) Group
BP Exploration (Alaska) Inc.

March 2003

Table B.13 Corrosion Management System Implementation by Equip Type and Service

Service	Equipment Type	Monitoring Technique	Inspection Program	Mitigation Program
Oil	Flow line	▪ ER Probes ▪ WLC ▪ Process Monitoring	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ CI Injection ▪ Mixture Velocities ▪ Periodic Maintenance Pigging ▪ Operational Controls
	Well line	▪ WLC ▪ Process Monitoring	▪ CRM ▪ ERM ▪ FIP ▪ CIP ▪ CUI	▪ CI Injection ▪ Mixture Velocities ▪ Mixture Velocities ▪ Operational Controls
Produced Water	Flow line	▪ WLC	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ CI Injection* ▪ CI Carry Over ▪ Periodic Maintenance Pigging ▪ Mixture Velocities ▪ Operational Controls
	Well line	▪ WLC	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ CI Injection* ▪ CI Carry Over ▪ Mixture Velocities ▪ Operational Controls
Seawater	Flow line	▪ WLC ▪ Galvanic Probes ▪ Dissolved 0_2 ▪ Microbiological Activity	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ Biocide Treatment ▪ 0_2 Scavenger ▪ Periodic Maintenance Pigging ▪ Operational Controls
	Well line	▪ WLC ▪ Microbiological Activity	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ Biocide Treatment ▪ Periodic Maintenance Pigging ▪ Operational Controls
Export oil	Flow line	▪ WLC ▪ ER Probes	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ CI Carry Over ▪ Mixture Velocities ▪ Operational Controls ▪ Periodic Maintenance Pigging

* No CI injection for FS-2 PW

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Service	Equipment Type	Monitoring Technique	Inspection Program	Mitigation Program*
Oil	Flow line	ER Probes WLC Process Monitoring	CRM FIP CIP CUI	CI Injection Mixture Velocities Periodic Maintenance Pigging Operational Controls
	Well line	WLC Process Monitoring	CRM ERM FIP CIP CUI	CI Injection Mixture Velocities Mixture Velocities Operational Controls
Produced Water	Flow line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Periodic Maintenance Pigging Mixture Velocities Operational Controls
	Well line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Mixture Velocities Operational Controls
Seawater	Flow line	WLC Galvanic Probes Dissolved 0_2 Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment 0_2 Scavenger Periodic Maintenance Pigging Operational Controls
	Well line	WLC Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment Periodic Maintenance Pigging Operational Controls
Export oil	Flow line	WLC ER Probes	CRM FIP CIP CUI	CI Carry Over Mixture Velocities Operational Controls Periodic Maintenance Pigging

*Applicable to all inspection programs noted
**No CI injection for FS-2 PW

GPB Table B.15 Corrosion Management System Implementation by Equip Type and Service

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Commitment to Corrosion Monitoring Year 2004

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Corrosion, Inspection and Chemicals (CIC) Group
BP Exploration (Alaska), Inc.

March 2005

Service	Equipment Type	Monitoring Technique	Inspection Program	Mitigation Program*
Oil	Flow line	ER Probes WLC Process Monitoring	CRM FIP CIP CUI	CI Injection Mixture Velocities Periodic Maintenance Pigging Operational Controls
	Well line	WLC Process Monitoring	CRM ERM FIP CIP CUI	CI Injection Mixture Velocities Mixture Velocities Operational Controls
Produced Water	Flow line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Periodic Maintenance Pigging Mixture Velocities Operational Controls
	Well line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Mixture Velocities Operational Controls
Seawater	Flow line	WLC Galvanic Probes Dissolved 0_2 Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment 0_2 Scavenger Periodic Maintenance Pigging Operational Controls
	Well line	WLC Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment Periodic Maintenance Pigging Operational Controls
Export oil	Flow line	WLC ER Probes	CRM FIP CIP CUI	CI Carry Over Mixture Velocities Operational Controls Periodic Maintenance Pigging

*Applicable to all inspection programs noted
**No CI injection for FS-2 PW

Table 15 Corrosion Management System Implementation by Equip Type and Service