BP'S PIPELINE SPILLS AT PRUDHOE BAY: WHAT WENT WRONG?

HEARING

BEFORE THE

SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS

OF THE

COMMITTEE ON ENERGY AND COMMERCE
HOUSE OF REPRESENTATIVES

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BP'S PIPELINE SPILLS AT PRUDHOE BAY: WHAT WENT WRONG?

THURSDAY, SEPTEMBER 7, 2006

HOUSE OF REPRESENTATIVES,
COMMITTEE ON ENERGY AND COMMERCE,
SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS,
Washington, DC.

The committee met, pursuant to call, at 10:15 a.m., in Room 2123 of the Rayburn House Office Building, Hon. Greg Walden (Chairman) presiding.

Members present: Representatives Stearns, Pickering, Walden, Burgess, Blackburn, Barton (ex officio), Stupak, DeGette, Schakowsky, Inslee, Baldwin, and Dingell (ex officio).

Members also present: Representatives Upton, Markey, and Green.

Staff present: Mark Paoletta, Chief Counsel for Oversight and Investigations; Alan Slobodin, Deputy Chief Counsel for Oversight and Investigations; Tom Feddo, Counsel; Andrew Snowdon, Counsel; Tom Hassenboehler, Counsel; Dave McCarthy, Chief Counsel for Energy and the Environment; Clayton Matheson, Analyst; Ryan Ambrose, Legislative Clerk; Matthew Johnson, Legislative Clerk; Chris Knauer, Minority Investigator; David Vogel, Minority Research Assistant; Bruce Harris, Professional Staff Member; and Chris Treanor, Minority Staff Assistant.

MR. WALDEN. Good morning and welcome.

The Chairman of the subcommittee, Mr. Whitfield, very much wanted to be here but had some important legislation he has worked on for a considerable length of time on the House floor this morning so I will be chairing this hearing in his absence.

Today the Oversight and Investigations Subcommittee will examine what went wrong on two crude oil pipelines operated by BP that service the Prudhoe Bay fields on Alaska's North Slope, the Nation's largest source of domestic oil. Oil spills on two separate lines within a five-month period are a cause of major concern. These spills threaten not only the environment but also the reliability of domestic oil production. BP's current marketing slogan is "Beyond petroleum." Unfortunately, it could also stand for "broken pipelines."

In March of this year, BP uncovered a leak in the western transmission line. This spill resulted in more than 200,000 gallons, or 5,000 barrels of crude oil, breaking into the Arctic tundra, the single largest spill in the history of the North Slope. In early August, BP identified areas of significant corrosion on its eastern transmission line necessitating an immediate shutdown of that line, a shutdown that remains in effect today, cutting the daily production of Prudhoe Bay nearly in half. How did two key pipelines, pipelines that transport 8 percent of this country's domestic oil, deteriorate so badly that the entire production of Prudhoe Bay fields could be in jeopardy? Hopefully today's hearings will yield some of those answers.

In public statements and in comments to committee staff during this investigation, BP has acknowledged that it made mistakes in its corrosion control program, and I commend them for admitting the obvious. Hindsight is always 20/20 but it appears BP ignored some red flags along the way.

First, there is evidence that BP received warnings from company employees about the condition of these lines. It is important for us to understand exactly what BP knew, when they knew it, what steps BP took to verify the allegations, and what actions BP took to respond to the concerns raised.

Second, BP seems to have ignored the results of its own inspections. In 1998, BP inserted the diagnostic probe, also known as a smart pig, into the western line to check for corrosion. These pig runs revealed moderate internal and external corrosion including six areas of internal corrosion at the very site where the March 2006 leak occurred. Despite this critical information, however, BP elected to wait until 2006, eight years, to conduct another pig run. Unfortunately, the leak occurred before that pig run took place and the eastern line was even worse. It had not been pigged since 1992.

Experts to a person have explained pig runs as an essential element of any sound corrosion control program. BP's own internal corrosion procedures tout the merits of small pigging. The question then is, why did BP not pig these lines on a more regular basis. Was cost a factor or were there other concerns about the condition of these lines such as sediment and sludge buildup that prevented the use of pigs.

I hope that the BP officials appearing here, Robert Malone, President of BP America, and Steve Marshall, President of BP Exploration Alaska, will be able to answer some of these questions. Unfortunately, Mr. Woollam, BP's former chief corrosion engineer on the North Slope, has elected to assert his Fifth Amendment right not to testify. We will also hear today from the Department of Transportation about the steps they took following these spills. I am encouraged by the Department of Transportation's confident assertions that BP's pipeline troubles are an isolated incident rather than an industry-wide problem and that the Department of Transportation's Integrity Management Program has resulted in a steady decline of serious incidents. I look forward to learning from Kevin Hostler, President and CEO of Alyeska, what his company is doing to ensure the integrity of the Trans Alaska Pipeline in the wake of these incidents and how Alyeska is working with BP to help get the eastern operating line back in service. I also want to welcome Dan Stears from Coffman Engineers and Kurt Fredriksson, Commissioner of the Alaska Department of Environmental Conservation. Many of the witnesses have traveled a long way to participate in today's hearings and the committee certainly appreciates their efforts.

Today's hearing is of tremendous importance to this committee and to the American people. Companies that operate oil pipelines have a responsibility to maintain the Nation's crucial energy infrastructure. Hopefully what we learn about BP's incidents on the North Slope will help prevent future spills so that both the environment and the reliable supply of a vital natural resource will not be compromised again.

With that, I now recognize the Ranking Member of the Subcommittee on Oversight and Investigations, Mr. Stupak, for 5 minutes.

[The prepared statement of Hon. Greg Walden follows:]

PREPARED STATEMENT OF THE HON. GREG WALDEN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OREGON

Good morning and welcome. The Chairman of the Subcommittee, Mr. Whitfield, very much wanted to be here, but has some important legislation on the House floor this morning, so I will be chairing this hearing in his absence.

Today, the Oversight and Investigations Subcommittee will examine what went wrong on two crude oil pipelines operated by BP that service the Prudhoe Bay fields on Alaska's North Slope, the nation's largest source of domestic oil. Oil spills on *two separate* lines within a 5-month period are a cause of major concern. These spills threaten not only the environment, but also the reliability of domestic oil production. BP's current marketing slogan is "Beyond Petroleum." Unfortunately, it could also stand for "Broken Pipelines."

In March of this year, BP uncovered a leak in the Western transmission line. This spill resulted in over 200,000 gallons (or 5,000 barrels) of crude oil leaking onto the Artic tundra -- the single largest spill in the history of the North Slope. In early August, BP identified areas of significant corrosion on its Eastern transmission line, necessitating an immediate shut-down of that line -- a shut-down that remains in effect today, cutting the daily production of Prudhoe Bay nearly in half. How did two key pipelines -- pipelines which transport nearly 8% of this country's domestic oil -- deteriorate so badly that the entire production of the Prudhoe Bay fields could be in jeopardy? Hopefully today's hearing will yield some answers.

In public statements and in comments to Committee staff during this investigation, BP has acknowledged that it made mistakes in its corrosion-control program. I commend them for at least admitting the obvious. Hindsight is always 20/20, but it appears that BP ignored some red flags along the way. First, there is evidence that BP received warnings from company employees about the condition of these lines. It is important for us to understand exactly what BP knew, when they knew it, what steps BP took to verify the allegations, and what actions BP took to respond to the concerns raised.

Second, BP seems to have ignored the results of its own inspections. In 1998, BP inserted a diagnostic probe -- also known as a "smart pig" -- into the Western Line to check for corrosion. This pig run revealed moderate internal and external corrosion, including 6 areas of internal corrosion at the very site where the March 2006 leak occurred. Despite this critical information, however, BP elected to wait until 2006 -- 8 years -- to conduct another pig run. Unfortunately, the leak occurred before that pig run took place. And the Eastern Line was even worse -- it had not been pigged since 1992!

Experts, to a person, have explained pigging is an essential element of any sound corrosion control program. BP's own internal corrosion procedures tout the merits of smart pigging. The question, then, is why did BP not pig these lines on a more regular basis? Was cost a factor, or were there other concerns about the condition of these lines -- such as sediment and sludge buildup -- that prevented the use of pigs? I hope that the BP officials appearing here -- Robert Malone, President of BP America, and Steve Marshall, President of BP Exploration Alaska -- will be able to answer some of these questions. Unfortunately, Mr. Wollam, BP's former chief corrosion engineer on the North Slope, has elected to assert his Fifth Amendment right not to testify.

We will also hear today from the Department of Transportation about the steps that they took following these spills. I am encouraged by DOT's confident assertions that BP's pipeline troubles are an isolated incident rather than an industry-wide problem and that DOT's Integrity Management Program has resulted in a steady decline of serious incidents.

I look forward to learning from Kevin Hostler, President and CEO of Alyeska, what his company is doing to ensure the integrity of the Trans Alaska Pipeline in the wake of these incidents and how Alyeska is working with BP to help get the Eastern Operating Line back in service.

I also want to welcome Dan Stears from Coffman Engineers and Kurt Frederickson, Commissioner of the Alaska Department of Environmental Conservation. Many of the witnesses have traveled a long way to participate in today's hearing, and the Committee certainly appreciates their efforts.

Today's hearing is of tremendous importance to this Committee and the American people. Companies that operate oil pipelines have a responsibility to maintain the nation's crucial energy infrastructure. Hopefully, what we learn about BP's incidents on the North Slope will help prevent future spills so that both the environment and the reliable supply of a vital natural resource won't be compromised again.

I now recognize the Ranking Member of the Subcommittee on Oversight and Investigations, Mr. Stupak, for 5 minutes.

MR. STUPAK. Thank you, Mr. Chairman, and thank you for holding this hearing.

On March 2 of this year, BP discovered that oil was leaking from a major transmission line largely responsible for connecting the west oil field with the Trans Alaskan Pipeline, TAPS. This spill included almost 2,700 gallons of crude and became the largest spill in North Slope history. Shortly thereafter, a letter was sent by Ranking Member Dingell seeking answers to the causes of the WOA, western operating area, line failure and BP's efforts to deal with corrosion. Over the next several months, what started as a single spill ended in the shutdown of the entire

Prudhoe Bay field, and for a time, reduction of 8 percent of the U.S. domestically produced oil supply.

Mr. Chairman, this hearing is about far more than oil spills or pipeline corrosion. It is about trying to understand how a company with the global standing of BP allowed its North Slope operations to deteriorate to where the company professes little understanding of the true condition of major operational assets. It is also about why, when the Nation is facing ongoing threats to its oil supply abroad, we don't have a better redundancy in an oil field as strategic as Prudhoe Bay. Given the record profits of this industry, this aspect of BP's recent North Slope failures was particular egregious.

Mr. Chairman, this committee's investigation into the failures of BP's Alaska operations began shortly after the Department of Transportation issuance of their March 15 corrective action order. Among the many requirements, that order mandated that BP smart pig a number of key lines including both the western operating area line and the eastern operating area line.

In April of this year, committee staff traveled to Alaska to seek answers to the causes of the western operating area line failure and determine the implications of the DOT order. In that process, it was learned that huge amounts of solids were believed to exist in key lines that BP was now ordered to pig. These solids, it was believed, could create a number of potential operational challenges. In particular, BP might not be able to run smart pigs through these lines because the solids were potentially so excessive as to risk pigs becoming stuck in the lines. If that occurred, this would essentially block the transit line's ability to deliver oil to the Trans Alaska Pipeline and perhaps shut down large parts of the oil field. It was also learned that the dislodging of such solids would later have profound consequences on TAPS itself including the introduction of corrosion-causing materials into that system and the potential for clogging Pump Station number 1 entry screeners. These new issues prompted Ranking Member Dingell to send a letter on April 25 to the Department of Transportation Secretary which posed a number of key questions about not only the ability of BP to meet DOT's March 15 order but also about the overall condition of BP's major transit lines.

The DOT's response to that letter raised several troubling issues, most notably that BP appeared to lack a fundamental understanding of the condition of both its western operating area or eastern operating area lines. Moreover, it became clear that despite what appeared to be knowledgeable buildup of scale and solids over the years, the company inexplicably failed to pig these lines frequently, if at all. In its response, DOT also noted that, based on current management information, the infrequency by BP to pig these lines, and I quote now, "did not represent sound management practice for internal corrosion control."

I would like to ask, Mr. Chairman, that this and all the letters from Mr. Dingell on this subject be placed in the record.

MR. WALDEN. Without objection.

MR. STUPAK. Mr. Chairman, I have a number of key questions for BP that I hope we will find answers to at this hearing. First, why was it that BP relied so heavily on ultrasonic thickness, UT testing, and the use of corrosion coupons when BP knew such techniques could not deliver data on the underground portions of the western operating area line where the caribou cross? The most recent run on the western operating area line was last done in 1998 and found that corrosion had increased, particularly in low-lying areas similar to the area where the March 2 spill occurred. Moreover, why did BP not install a more aggressive plan to seek data on these sections, given that the WOA line had a low flow rate and was thus subject to water and solid separation? It is not Monday morning quarterbacking to suggest that BP should have known it needed a plan to physically collect detailed data on these locations, even if it included moving soil to access the pipe for more aggressive pigging.

Second, why would the EOA, the eastern operating area line, a line that failed in August and prompted the entire field shutdown, why was that line not smart-pigged at all by BP until DOT ordered it do so? The EOA line is a primary transmission line. It is a key asset in BP's field yet this line was left for almost 15 years with not so much as a maintenance pig being run through its length. Indeed, the EOA line has both a pig launcher and a pig receiver and so was clearly designed for pigging. What explains this failure? So far we have not had a satisfactory explanation from BP.

Third, why is it that there were virtually no redundancies in either the eastern oil field or the western oil field which would have allowed BP to continue operating after the most recent corrosion problems were discovered? As we note today, BP is now seeking to construct a number of bypass solutions to reroute oil around the failed eastern operating area line.

Fourth, why are we suddenly now deciding to replace these lines with new pipe knowing that for years such pipes were aging and that their original diameter was not designed for the low flow rates both were experiencing before they were removed from service? These pipes were designed for 800-pounds-per-square-inch flow rate. Today they are only at 80- PSI flow rate. Indeed, some have accused BP of running these lines to failure or riding the throughput curve. Nonetheless, at a time of record profits, I find it remarkable that the first major plan to replace a mere 20 miles of pipe of such strategic importance as these two lines comes post failure.

Fifth, when did BP first learn that the solids in these pipes would make immediate pigging extremely difficult? In short, why did it become such an engineering ordeal to merely determine if pigs could be run? If BP knew its lines were increasingly collecting shale, sludge or solids, all of which are known to contribute to corrosion, why wouldn't it aggressively attempt to remove such materials regularly? Alyeska, the operator of the Trans Alaska Pipeline, sends a scraper pig down its entire 800-mile length every 14 days, yet the eastern operating area line was not pigged a single time in 14 years. Why not?

Sixth, more troubling, BP apparently claims it did not know how bad its lines were. If BP only became aware of the scale and sediment after the DOT order, then why did it know so little so late? Shouldn't it have known about the sediment buildup in the western operating area line given the kinds of crude they were pulling from the field? If BP truly had a world-class pipe integrity system, shouldn't it have known about the shale buildup in the EOA line, given its earlier history of huge problems when it was last pigged in 1992?

Seventh, we are now learning that there were a number of troubling personnel problems in BP's corrosion management program on the North Slope over the past several years. Though not fully understood, these problems apparently create a chilling atmosphere for workers' ability to report health and safety issues and had perhaps at least some impact on the effectiveness of BP's corrosion control efforts. For example, the committee is in receipt of an October 20, 2004, report by the Vinson and Elkins Law Firm that found that the very people that BP relied upon to detect corrosion in both the WOA and EOA line, the Corrosion Inspection and Chemical Group, were fraught with worker intimidation and harassment from senior management.

Eighth, rather than rely on smart pigs to find corrosion in its lines, BP relied on what are called corrosion coupons. Coupons are pieces of metal that are inserted into a pipe at various locations and are later removed and analyzed to determine how much corrosion is taking place inside the pipe. Unlike smart pigging, which gives you a view of the entire line, coupons only tell you how corrosion is affecting the general area where the coupon is located. Nonetheless, according to reports on worker intimidation and harassment that I just mentioned, the number of coupons used in BP's operation was reduced by 25 percent for reasons that remain unclear. At a time when BP pipes were aging and it was already relying on a limited program to detect corrosion, why would the company allow such a significant reduction?

Finally, and I appreciate you letting me go over a little bit, Mr. Chairman, what budget pressures were placed on the corrosion monitoring group at BP and did such pressures ultimately lead to a serious deficiency in BP's ability to truly assess corrosion risk? For example, there is a 2005 memo that I am sure we will get into. There is an audit, and all these I am sure we will get into during questions and answers.

Mr. Chairman, I have gone over my time. Thank you for allowing me extra time. I ask to have my entire statement be submitted for the record.

MR. WALDEN. Without objection.

MR. STUPAK. Thank you.

[The prepared statement of Hon. Bart Stupak follows:]

PREPARED STATEMENT OF THE HON. BART STUPAK, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Thank you Mr. Chairman, and thank you for having this hearing.

On March 2nd of this year, BP discovered that oil was leaking from a major transmission line largely responsible for connecting its west oilfield (WOA)with the Trans-Alaskan Pipeline (TAPS). That spill, included almost 270,000 gallons of crude and became the largest spill in North Slope history. Shortly thereafter, a letter was sent by ranking Member Dingell seeking answers to the causes of the WOA line's failure and BP's efforts to deal with corrosion. Over the next several months, what started as a single spill ended in the shutdown of the entire Prudhoe Bay field, and for a time, the reduction of 8% of the U.S. domestically-produced oil supply.

Mr. Chairman, this hearing is about far more than oil spills or pipeline corrosion. It is, about trying to understand how a company with the global standing of BP allowed its north slope operations to deteriorate to where the company professes little understanding of the true condition of major operational assets. It is also about why, when the nation is facing threats to its fuel supply abroad, we don't have better redundancy in a field as strategic as Prudhoe Bay. Given the record profits of this industry, this aspect of BP's recent north-slope failures is particularly egregious.

Mr. Chairman, this Committee's investigation into the failures of BP's Alaska operations began shortly after the Department of Transportation's (DOT) issuance of their March 15th Corrective Action Order. Among many requirements, that order mandated that BP "smart pig" a number of key lines, including both the Western Operating Area (WOA) line and the Eastern Operating Area (EOA) line.

In April of this year, Committee staff traveled to Alaska to seek answers to the causes of the WOA line's failure and determine the implications of the DOT order. In that process, it was learned that huge amounts of solids were believed to exist in key lines that BP was now ordered to pig. These solids -- it was believed -- could create a number of potential operational challenges. In particular, BP might not be able to run smart pigs through these lines because the solids were potentially so excessive, the cleaning pigs risked becoming stuck in the lines. If that occurred, this would essentially block the transit line's ability to deliver oil to the Trans Alaskan Pipeline and perhaps shut down large parts of the oilfield. It was also learned that the dislodging of such solids could later have profound consequences on TAPS itself, including the introduction of corrosion-causing materials into that system and the potential for clogging Pump-Station One's entry strainers.

These new issues prompted ranking Member Dingell to send an April 25th letter to the Department of Transportation's Secretary, which posed a number of key questions about not only the ability of BP to meet DOT's March 15th order, but also about the overall condition of BP's major transit lines.

The DOT's response to that letter raised several troubling issues. Most notably, that BP appeared to lack a fundamental understanding of the condition of both its WOA or EOA lines. Moreover, it became clear that despite what appeared to be knowledgeable buildup of scale and solids over the years, the company inexplicably failed to pig these lines frequently (if at all). In its response, DOT also noted that based on current management information, that the infrequency by BP to pig these lines "[did] not represent sound management practices for internal corrosion control." [I would ask that this and all of Mr. Dingell's letters on this subject be placed into the record.]

Mr. Chairman, I have a number of key questions for BP that I hope we will find answers to at this hearing and I will raise several of them here:

First, why is it that BP relied so heavily on ultrasonic thickness (UT) testing and the use of corrosion coupons when BP knew such techniques could not deliver data on the under ground portions of the WOA line (such as the caribou crossings)? The most recent run on the WOA line was last done in 1998 and found that corrosion had increased, particularly in low-lying areas similar to the area where the March 2nd spill occurred. Moreover, why did BP not install a more aggressive plan to seek data on these sections given that the WOA line had a low-flow rate and was thus subject to water and solids separation? It is not Monday-morning quarter backing to suggest that BP should have known it needed a plan to physically collect detailed data on these locations, even if it included removing soil to access the pipe or more aggressive pigging.

Second, why was the EAO line -- the line that failed in August and prompted the entire field's shutdown -- not smart-pigged at all by BP until DOT ordered it to do so? The EOA line is a primary transmission line. It is a key asset in BP's field. Yet this line was left for almost fifteen years with not so much as a maintenance pig being run through its length. Indeed, the EOA line has both a pig launcher and a pig receiver, and so was clearly designed for pigging. What explains this failure? So far we do not have a satisfactory explanation from BP.

Third, why is it that there were virtually no redundancies in either the eastern field or the western field which would have allowed BP to continue operating after the most recent corrosion problems were discovered? As we know today, BP is now seeking to construct a number of bypass solutions to re-route oil around the failed EOA line.

Fourth, why are we suddenly now deciding to replace these lines with new pipe knowing that for years such pipes were aging and that their original diameter was not designed for the low flow rates both were experiencing before they were removed from service? These pipes were designed for 800 psi flow rate. Today they are at only 80 psi flow rate. Indeed, some have accused BP of "running these lines to failure," or "riding the throughput curve." Nonetheless, at a time of record profits, I find it remarkable that the fist major plans to replace a mere 20 miles of pipe of such strategic importance as these two lines, comes post failure.

Fifth, when did BP first learn that the solids in these pipes would make immediate pigging extremely difficult? In short, why did it become such an engineering ordeal to merely determine if pigs could be run? If BP knew its lines were increasingly collecting scale, sludge, or solids -- all of which are known to contribute to corrosion -- why wouldn't it aggressively attempt to remove such material regularly? Alyeska -- the operator of the trans-Alaskan pipeline sends a scraper pig down its entire 800-mile length every 14 days. Yet, the EAO line was not pigged a single time in 14 years. Why?

Sixth, more troubling, BP apparently claims it did not know how bad its lines were? If BP only became aware of the scale and sediment after the DOT order, then why did it know so little, so late? Shouldn't it have known about the sediment build-up in the WOA line given the kinds of crude they were pulling from the field? If BP truly had a world-class pipeline integrity system, shouldn't it have known about the scale build up in the EOA line given its earlier history of huge cleaning problems when it was last pigged in 1992?

Seventh, we are now learning that there were a number of troubling personnel problems in BP's corrosion management program on the north slope over the past several years. Though not fully understood, these problems apparently created a "chilling" atmosphere in workers' ability to report health and safety issues, and perhaps had at least some impact on the effectiveness of BP's corrosion-control efforts. For example, the Committee is in receipt of an October 20, 2004 report by the Vincent and Elkins law firm that found that the very program that BP relied upon to detect corrosion in both the WOA and EOA lines -- the Corrosion Inspection and Chemicals Group (CIC) -- was fraught with workplace intimidation and harassment from senior management.

Eighth, rather than rely on smart pigs to find corrosion in its lines, BP relied upon what are called corrosion coupons. Coupons are pieces of metal that are inserted into the pipe at various locations and are later removed and analyzed to determine how much corrosion is taking place inside the pipe. Unlike smart pigging which gives you a view of the entire line, coupons only tell you how corrosion is affecting the general area where the coupon is located. Nonetheless, according to the report on worker intimidation and harassment I just mentioned, the number of coupons used in BP's operations was reduced by 25% for reasons that remain unclear. At a time when BP's pipes were aging and it was already relying on a limited program to detect corrosion, why would the company allow for such a significant reduction?

Finally, what budget pressures were placed on the corrosion monitoring group at BP and did such pressures ultimately lead to serious deficiencies in BP's ability to truly assess corrosion risks? For example, an April 2005 internal audit of BP's corrosion management system found the following:

"Currently [the program's] budget is set up-front in line with 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 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 longer term, and thereafter set the budget based on these activities."

Mr. Chairman, this audit suggests to me, that some in BP had grown concerned that cost cutting was having a troubling affect on the company's ability to design and maintain a sound corrosion control program.

Mr. Chairman, I could continue on here, but I will save other key findings for the question period. Nonetheless, I would like to wind down my statement by welcoming our witnesses.

In particular, I would like to welcome Mr. Bob Malone, who is now the newly-appointed President of BP America. I would like to point out -- Mr. Malone -- that you have an excellent reputation with this Committee. During the early 1990s when it was Alyeska -- the operator of the Trans-Alaskan Pipeline -- that was in so much trouble, it was in part your leadership as president that helped turn the company around. Over the years you have voluntarily worked closely with this Committee to keep us apprised of developments both while at Alyeska and later, while at BP. I thank you for your assistance in that regard and your interaction with this Committee was helpful and appreciated.

Nonetheless, in your current position, I truly believe that the situation on the North Slope demands your full attention, as it is frankly an embarrassment to your company. Like with the mess you found at Alyeska, this Committee is expecting that you will fully investigate and evaluate what broke down on the north slope and then pursue major fixes, whether financial or personnel. This nation cannot allow the kinds of fiascos we have witnessed over the past several months to continue with the nation's energy supply. This Committee is expecting answers and results and ultimately getting this field back up running in a professional and reliable manner. The public will expect nothing less, and neither should this Committee.

Mr. Chairman, thank you again for holding this hearing, and with that, I yield back.

MR. WALDEN. We will try to stick to the 5 minutes, but I know a lot of work has gone into this on both sides of the aisle, and as the Ranking Member, I thought it appropriate to accede you additional time.

MR. STUPAK. Thank you.

MR. WALDEN. I would now like to recognize the Chairman of the full committee, the very able and honorable Joe Barton. Mr. Barton.

CHAIRMAN BARTON. Thank you, Mr. Chairman, for chairing this hearing today. I hope that the testimony is going to provide us some answers about the recent crude spills on the North Slope of Alaska. I also hope that it is going to provide some answers about what is being done and what will continue to be done to prevent those very serious incidents from happening in the future.

The spills occurred on two transmission lines that move oil produced from Prudhoe Bay to the Trans Alaska Pipeline. BP Exploration of Alaska Incorporated, which is an operating unit of British Petroleum, is responsible for the operation and maintenance of those crude oil transmission lines. I think it is obvious, but we do need to emphasize that these lines move approximately 400,000 barrels of crude oil per day to markets. That is roughly 8 percent of the United States' domestic oil production. Given that fact, the safe, responsible and reliable operation of these pipelines is of paramount concern to this committee and to the country. It is critical that no further leaks occur on these lines. It is paramount to avoid the threat to human life and the environment. It is also important to our national security that the oil from Prudhoe Bay be reliably and safely transported on a daily basis.

On Sunday, August 6, BP announced the complete shutdown of the Prudhoe Bay oil field. The following Monday, the price that BP and others commanded on the world market for their crude oil jumped 3 percent to nearly $77 a barrel. This decision came on the heels of an accident last March when BP's western transmission lines at Prudhoe Bay leaked about 200,000 gallons of oil from a corroded pipe. Between that incident and the leak in August from the eastern transmission line, BP had repeatedly assured this committee, our staffs and me personally that the corrosion of that pipeline that failed in March was an anomaly. BP told us that their corrosion control program was effective, that they were monitoring on a constant basis and they were mitigating corrosion in the pipelines at Prudhoe Bay. If the March leak was an anomaly, why did BP suddenly shut down production from the entire Prudhoe Bay oil field in August due to excessive corrosion discovered in the eastern crude oil transmission lines? In fact, we now know that BP had failed to carefully inspect and maintain these pipelines. The decision to shut down the pipeline in August seems to be the direct result of a requirement to pig the eastern line because of last March's spill on the western line.

Pipeline experts and other pipeline operators have explained to us that internal inspection of pipelines, what is called smart pigging, is the most reliable, complete and informative way to assess the integrity of a pipeline's walls, interior walls. U.S. Department of Transportation officials explained to the committee staff that BP's failure to pig these lines regularly is unsound management. Other methods are available but pigging has a distinct advantage. I understand that pigging is relatively inexpensive on a pipeline that has been designed for it. We might point out at this point in tine that last year BP reported record earnings of over $25 billion, $25 billion, and that the Prudhoe Bay field is and was the lodestar of the BP production. Prior to this year's incidents, not either the western or the eastern gathering line that BP has been operating had been smart pigged for years. The western line was last maintenance pigged and smart pigged in 1998. That is eight years ago, or seven years ago. The eastern line was last maintenance pigged in 1990 and smart pigged in 1992, 14 years ago. By comparison, executives at Alyeska, the pipeline company operating the larger Trans Alaska Pipeline System, informed subcommittee staff that their line is maintenance pigged every two weeks, every two weeks, and smart pigged at least once every three years.

We now know that BP officials have admitted, and I am expecting that they will again say so today, that their corrosion control and inspection program for Prudhoe Bay was flawed and that in hindsight, BP should have been pigging these transmission lines in hindsight. Well, hindsight is better than blind sight, I guess, but it is not a substitute for ongoing sound management practices.

I suppose that this committee and Congress is expected to shrug our shoulders and say, well, now they get it, but the clever use of perfect hindsight to excuse consistent failure just doesn't cut it. Years of neglecting to inspect for the most vital gathering oil pipelines in this country is not acceptable. BP's neglect is having as we speak an adverse and disruptive effect on the American economy, American consumers and national security. That is not acceptable. If a company, one of the world's most successful oil companies, can't do simple, do basic maintenance needed to keep the Prudhoe Bay field operating safely without interruption, maybe it shouldn't operate the pipeline. Maybe we should find a way to get a different operator through the private market sale of this pipeline and let somebody else do it.

This hearing will largely focus on BP's failure to responsibly operate the Prudhoe Bay transmission lines but these two incidents of which the March spill also happens to be the continuing subject of a Federal grand jury are only part of this company's recent and unfortunately notorious track record. The Prudhoe Bay spill comes on the heels of the British Petroleum Texas City Refinery disaster that killed 15 people in 2005.

Now, I know that BP is investing significant amounts of time, energy and resources to bring Prudhoe Bay back at the full capacity and to address the very serious corrosion problems that have been discovered, but this is all after the fact. I understand that sludge and sediment issues existed in the lines for quite some time, that BP knew about the flaws in its corrosion control program. Impurities like sludge, sediment and water induce corrosion and provide a place for corrosion to hide.

Maybe I have the wrong impression, but it seems to me that BP was betting the company and their field that this field would be depleted before major parts of the pipeline failed and needed to be replaced. BP's policies are as rusty as its pipelines. I am very concerned about the specific incident but I am even more concerned about BP's corporate culture of seeming indifference to safety and environmental issues, and this comes from a company that prides itself in their ads on protecting the environment. Shame, shame, shame.

And I want to say something else before I conclude, Mr. Chairman. During the course of this investigation, the committee has been informed by certain individuals that we were trying to interview at the staff level that they are reluctant to come forward to provide information due to concerns over possible retribution throughout the oil industry in Alaska. I want to make it perfectly clear that if we find that any person is threatened, intimidated or attempted to be retaliated against as a result of cooperating with this committee, I will use every bit of power that I have as Chairman of the full committee to ensure that the retaliator is prosecuted to the fullest extent of the law, and to the extent that that retaliation against an individual is condoned by any corporate official, I will exercise the same authority against those officials. We are going to get to the bottom of this. We are going to make sure that the facts are in the public purview and we are going to, if necessary, change Federal law to do everything possible to minimize this happening again.

Mr. Chairman, I look forward to today's testimony. I hope we get the answers we need. If not, I am sure the subcommittee will continue to conduct aggressive oversight on a bipartisan basis on this issue.

With that, I yield back the balance of my time.

[The prepared statement of Hon. Joe Barton follows:]

PREPARED STATEMENT OF THE HON. JOE BARTON, CHAIRMAN, COMMITTEE ON ENERGY AND COMMERCE

Thank you, Mr. Chairman, for holding this hearing. I hope that the testimony today will provide us with some satisfactory answers about several recent crude oil spills on the North Slope of Alaska, and what is going to be done to prevent these very serious incidents in the future. The spills occurred on two transmission pipelines that move oil produced from Prudhoe Bay to the Trans-Alaska Pipeline System. BP Exploration (Alaska), Inc. – an operating unit of BP – is responsible for the operation and maintenance of those crude oil transmission lines.

I want to emphasize that these lines move nearly 400,000 barrels of crude oil a day to market. That's roughly 8 percent of the country's domestic oil production. Given that fact, the safe, responsible, and reliable operation of these pipelines is of paramount concern to this Committee.

It is critical that no further leaks occur on these lines. We certainly want to avoid the threat to human lives and the environment, but it is also imperative to our national security that this oil be reliably transported. On Sunday, August 6th, BP announced the complete shutdown of the Prudhoe Bay oil field, and the following Monday the price BP and others commanded on the world market jumped 3 percent, to nearly $77 per barrel.

Americans had already been facing record-high gasoline prices. Did BP think that shutting in 8 percent of U.S. production would relieve American consumer prices? We don't need prices suddenly kicked higher because the company responsible for bringing a vital part of this country's oil to market isn't taking care of the pipelines. BP owes Americans a higher standard of operation. These are energy resources which this country needs and they control.

In March of this year, BP's Western transmission line at Prudhoe Bay leaked about 200,000 gallons of oil from a corroded pipe. Between that incident and the leak in August from the Eastern transmission line, BP had repeatedly assured me, through staff, that the corrosion of the pipeline that failed in March was an anomaly. BP told us that their corrosion control program was effectively monitoring and mitigating corrosion in the pipelines at Prudhoe Bay.

If the March leak was an anomaly, why did BP suddenly shut down production from the entire Prudhoe Bay oil field in August due to excessive corrosion discovered in the Eastern crude oil transmission lines? In fact, what we now know is that BP has failed to carefully inspect and maintain these pipelines.

Pipeline experts and other pipeline operators have explained to us that internal inspection of pipelines – what is called smart-pigging – is the most reliable, complete, and informative way to assess the integrity of a pipeline's walls. U.S. Department of Transportation officials have explained to us that for BP's failure to pig these lines regularly is unsound management. Other methods are available, but pigging has distinct advantages. I understand that pigging is relatively inexpensive on a pipeline that has been designed for it.

Yet prior to this year's incidents, BP's pipelines had not been smart-pigged for many years. The Western line was last maintenance-pigged and smart-pigged in 1998. The Eastern line was last maintenance-pigged in 1990 and smart-pigged in 1992. By comparison, executives at Alyeska, the pipeline company operating the Trans-Alaska Pipeline System, informed the Subcommittee that TAPS is maintenance-pigged <u>every two weeks</u>, and smart-pigged every three years. I know that BP officials have admitted, as I expect they will also do here today, that their corrosion control and inspection program for Prudhoe Bay was flawed, and that in <u>hindsight</u> BP should have been pigging these transmission lines.

I suppose that we're expected to shrug and say, "Well, now they get it." But the clever use of perfect hindsight to excuse consistent failure just doesn't cut it. Years of neglecting to inspect two of the most vital oil pipelines in this country is simply unacceptable. Nor are the adverse and disruptive effects on the American economy, American consumers, and national security in any way acceptable. If a company -- a very successful company -- can't do the basic maintenance needed to keep Prudhoe Bay's oil field operating safely and without interruption, then maybe it shouldn't be operating the pipeline.

This hearing will largely focus on BP's failure to responsibly operate the Prudhoe Bay transmission lines, but these two incidents – of which the March spill also happens to be the subject of a federal grand jury – are only part of the company's recent and notorious track record. The Prudhoe Bay spills come on the heels of the BP Texas City refinery disaster that killed 15 people in 2005.

I know that BP is investing significant amounts of time, energy, and resources to bring Prudhoe Bay back up to full capacity and to address the very serious corrosion problems that have been discovered, but that is all after the fact. I understand that sludge and sediment issues existed in the lines for quite some time, and that BP knew about the flaws in its corrosion control program. Impurities like sludge, sediment, and water induce corrosion, and provide a place for corrosion to hide. Maybe I have the wrong impression, but it seems that BP might have been betting that the field would be depleted before major parts of the pipeline failed and needed replacement. BP's policies are as rusty as its pipelines.

Mr. Chairman, I look forward to today's testimony. I hope we can get all the answers we need; and if not, then I hope that the Subcommittee will continue to conduct its oversight work on these issues. I yield back the remainder of my time.

MR. WALDEN. Thank you, Mr. Chairman.

I would like to ask unanimous consent that members of the subcommittee who may not be present or are present and have written testimony or opening statements they would like to be submitted for the record may do so without objection, and I have the statement of the Honorable Ed Whitfield, Chairman of the Subcommittee on Oversight and Investigation, that we will enter into the record. We will have seven days for that.

At this point I would turn to the Ranking Member of the committee, the Honorable Mr. Dingell, for opening statement.

MR. DINGELL. Mr. Chairman, thank you. I commend you for holding this hearing.

I must confess myself disappointed at our reasons for being here today. We face many challenging energy issues ranging from high prices of oil and natural gas to the continued development of renewable fuels and the nagging problem of nuclear waste. That we find ourselves conducting oversight of an oil company that seems to be having trouble managing its core business in this day and age is indeed discouraging. Nevertheless, events relating to BP's performance over the last six months necessitate this hearing and I hope that we will learn what went wrong and what has to be done to assure that it does not happen again.

I welcome our witnesses here today, particularly Mr. Malone, President of BP North America. Mr. Malone is not a stranger to this committee during difficult times. I note that he has been straightforward and honest in his previous appearances and has kept his commitments made to the committee. His challenge today is quite difficult and I hope that his participation will assist this committee to get to the bottom of what went wrong here.

On March 2, 2006, a BP worker discovered a leak in an oil transmission line in the western operating area of Prudhoe Bay, Alaska. This previously unregulated pipeline had been leaking for approximately five days prior to the discovery and it spilled something like 270,000 gallons of crude oil into the Arctic tundra, making it the worst spill in the history of the North Slope.

On March 15, the Department of Transportation placed its line and other low-stress BP lines under its jurisdiction and required BP to thoroughly inspect the lines, to clean them and to analyze their condition using a smart pig. After extensive testing and the discovery of two additional leaks, BP reached the conclusion that the status of its transit lines was indeterminate and decided to proceed with an orderly shutdown of Prudhoe Bay. World oil markets reacted to the possibility of an 8 percent less domestic production shutdown by bidding up the price of crude to just over $76 per barrel which will be paid by American consumers.

For an oil company of BP's size and reputation to allow two of its most critical transit lines to the America's largest producing oil fields to reach such a sorry state of affairs is staggering. What went wrong? Did cost-cutting prove to be the undoing of standard maintenance? Did management turn a blind eye to problems on the line that at best it should have known about or at worst knew about and decided to ignore? We need those answers, because without those answers, we aren't going to know what should be done either by the regulatory agencies or by the Federal government or by the Congress.

The one bit of good news here is that the Department of Transportation has taken action since the initial spill in last March. The department has been reasonably aggressive in its enforcement of the initial corrective action order and subsequent amendments and responsive to the letters that I and others have sent asking questions about this matter. There are, however, two things that trouble me very much. First, the lines that failed were exempt from regulation by DOT itself despite longstanding concerns in the Congress that low-stress pipelines could pose significant risk. For a field that produces nearly 8 percent of American domestic production to have its main two lines left unregulated it simply unacceptable and needlessly risky. As we go forward, the Federal government must take a fresh look at critical energy infrastructure regardless of its present regulatory status.

Second, DOT should propose rules to regulate low-stress pipelines. At first glance, the rule appears inadequate and applies less rigorous standards to these lines than recent events would warrant. Furthermore, the rule leaves some 4,300 miles of low-stress lines without any regulation at all, not even the bare minimum requirement to manage for corrosion and to report spills. The proposed rule is eerily reminiscent of the Nation's view and experience with the industry which favored the industry preferred proposals and leads me to conclude that my increasing confidence in the performance of the Pipeline and Hazardous Materials Safety Administration on Pipeline Safety has been misplaced. I know our colleagues who are on the committee will be working together on the upcoming pipeline safety reauthorization to correct these deficiencies and this hearing will give us some reference as to what this committee must do and what we can expect from the Administration in terms of its administration of the statutes.

Mr. Chairman, thank you for holding this important hearing.

MR. WALDEN. Thank you. I appreciate your comments and your participation. Now we will go to other committee members, and I remind you, you have 5 minutes for your opening statements, and with that, Mrs. Blackburn.

MRS. BLACKBURN. Thank you, Mr. Chairman. I do want to thank you for holding the hearing and I want to thank the witnesses for presenting this committee with information on this issue. I will have to say I wish we were focused on a more positive topic. I wish it were something about achieving energy independence or new fuel usages, et cetera, and that it was not a hearing about failed policies, but we thank you for being here to visit with us.

I have several concerns on how BP maintained their oil pipelines and if their maintenance met the industry standards on corrosion prevention. Specifically, I would like to hear from our witnesses to discuss their known best practices and how those were implemented and how often extensive testing of oil pipelines should have taken place, as to how often it did take place, and I hope that you will present us with specifics.

My reading and research and preparing for the hearing today have led me to an understanding that most of the pipelines in Prudhoe Bay were not thoroughly inspected for over a decade and that warnings from engineers for more testing went unheeded, and I think you have heard that from some of the other members here who have already spoken today. That is of concern. It is not acceptable and I think it is quite appropriate for all of us to expect better from you and from your company and from a company that promotes itself as a safe and environmentally friendly energy company.

Another concern I have is how BP was prepared for an eventuality such as this. Currently, the eastern oil fields of the Bay are shut down for the next 6 months, which means that BP is not pumping 200,000 barrels of oil each and every day. It is unfortunate for you all. It is unfortunate for the American public. It is a loss from what I understand of about $14 million each day to your company. I want to hear from BP why they were not prepared for this and why it will take approximately 6 months before the fields are ready to operate again and what the ramp-up process will be as you look toward bringing that line back online.

Mr. Chairman, when events such as this occur in the U.S. and affect a critical market such as our oil supply, Congress needs to examine the safety and the inspection standards so that another accident like this does not happen again.

So I thank you for the information that you will bring to us, for the testimony that you have already supplied, and Mr. Chairman, I look forward to the time of questions.

MR. WALDEN. Thank you, and the gentlelady yields back her time. The Chair now recognizes the gentlewoman from Colorado, Ms. DeGette.

MS. DEGETTE. Thank you, Mr. Chairman. Mr. Chairman, the story unfolding at Prudhoe Bay in recent months has grown much more alarming as we learn new facts. Just as we heard this morning from the other members of this committee, it appears that this whole mess was preventable. Had BP exercised even basic periodic maintenance of its pipelines, they would not have had to order the shutdown of the country's number one domestic oil field at a time both strategically and economically that this country needed that oil field to be open.

We are all well aware of BP's aggressive advertising campaign, portraying it as the environmentally responsible and socially conscious oil company, so why then did it allow the condition of its low-stress pipeline to deteriorate to the point of the corrosion-induced spill of 270,000 of crude oil? Was it purely for cost-saving reasons as this April 2005 internal audit document intimates? These pipes are in such poor condition now we are told that they are going to need to be completely replaced. As I mentioned a minute ago, this was all preventable. Mr. Chairman, it is my understanding, and we discussed earlier, that smart pigging, though relatively inexpensive, is the single best way to detect corrosion. Now, I am no engineer but it seems to me that this high-tech procedure gives quite a bang for the buck and it perplexes me that the lines haven't been pigged in some cases since 1992. Now, I would think that the potential damage to BP's infrastructure, reputation and bottom line would have been enough to compel it to take care of its pipes but apparently this is not so.

I applaud BP's efforts in advertising campaigns to move beyond petroleum to help foster a more sustainable energy future and to become a truly compassionate corporate leader, but maybe it should start by sticking to the basics and begin to focus on rudimentary pipe maintenance as much as it has on PR. BP will undoubtedly assure us today that its corrosion prevention methodology in the run-up to this crisis was fully compliant with existing regulations. I look forward to hearing from the Department of Transportation as to whether that is true and whether or not we have adequate regulations.

Also, I am interested in hearing the contrasting testimony from the Trans Alaska Pipeline which pigs their lines every three years. BP may have believed that using coupons and ultrasonic testing were sufficient to protect the infrastructure but other industry leaders went well above and beyond regulatory requirements to properly maintain their pipes and they have avoided the problems that we have seen in recent months.

I am glad that the DOT is here with us today because the department has done an excellent job in responding to this crisis and deserves credit for its rapid response. While I am pleased at the DOT's new regulations issued in the aftermath of the Prudhoe Bay spill, I fear that they may not be adequate.

I am also dismayed as I am often these days with what has become an even more reactionary Federal government. It seems to me that we have the tendency to ignore major issues like this, exercising limited oversight and only after a crisis happens do we jump to fix a problem that should have been prevented in the first place. Perhaps we should have seen this coming. I hope to hear from the Federal officials today whether we should have predicted a major oil spill like this given the lax regulation of the low-pressure lines in unpopulated areas.

And frankly, Mr. Chairman, the United States Congress is not entirely without blame either. The Pipeline Safety Act reauthorization has languished in Congress for months. I hope some good will come out of this mess and that would be passage of this important legislation sooner rather than later.

Mr. Chairman, I am looking forward to probing these and other issues, and again, I want to thank you for holding this hearing, and I yield back.

[The prepared statement of Hon. Diana DeGette follows:]

PREPARED STATEMENT OF THE HON. DIANA DEGETTE, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF COLORADO

Thank you, Mr. Chairman and thank you for having this hearing.

Over the past few years we have experienced major corporate scandals in this country. At companies like Enron and WorldCom, Americans witnessed corporate executives break the law to enrich themselves at the expense of their customers and shareholders.

This Committee held multiple hearings on these corporate abuses. I was proud to be a Member during that time, as we helped shine a light on corporate excess and pave the way for reform. And, while the specific issues before us are different, I expect that we can play that same role again as we continue our series of hearings on "pretexting," this time in the corporate context.

The corporate context of pretexting we will be talking about today involves Hewlett-Packard, or H-P. It is indeed a very sad day for this very proud company. H-P is a company of iconic stature both here in the U.S., and frankly around the world. In fact, as I look around this room, there are many products – from the computers to PDA's to monitors to printers – all bearing the H-P name.

This company -- as we all know -- was started in a small garage in the Silicon Valley and grew to one of the nation's largest employers. We all know the story. We all know about how proud many should be about what H-P became over the years.

But Mr. Chairman, something has gone wrong -- terribly wrong -- at this once venerated institution.

I begin my statement by talking about the positive aspects of H-P because what we say here and what we do here will affect the lives of tens of thousands of the company's workers, and it is my opinion that they frankly do not deserve the wrath --- or taint -- that has been brought on them or this company's name by the actions of a few.

Unfortunately, though, what we will hear about today is one of the darker chapters of corporate chicanery this committee has seen in quite some time. And sadly, it is unavoidable, but the H-P name is at the center of it.

Let me be clear, Mr. Chairman, this is no Enron. I believe that at the heart of H-P's operations you will find a good product and a good workforce. You will also find some of the best traits of American business, namely entrepreneurship and competitive innovation. It is precisely because this company's now sullied reputation <u>is reversible</u>, that explains why we need to have this hearing. Indeed, it is because H-P is not Enron, that we need to find out what happened and who's accountable.

-- **Mr. Chairman, this hearing is about more than sorting through the mess that has sullied the HP name;**

-- **It is about more than how the "H-P Way" became synonymous with digging through people's trash, setting up bogus emails (approved at the highest levels of the company) and stinging unsuspecting reporters;**

-- **It is about more than how a computer company suddenly found itself in the business of trailing and photographing board Members across the globe or surveilling journalists using ex-FBI agents who sat in cars and watched as if their subjects were busy making truck bombs;**

-- **It is about more than how a company that purportedly respects electronic privacy found itself using deception and subterfuge to procure -- and then rummage through -- the private phone records of Americans (in some cases, their Social Security numbers given out to the world as well).**

Mr. Chairman, what this hearing is about is this Committee's attempt to sort through a dark chapter of corporate governance so that shareholders and the existing employees themselves can judge and determine who should be entrusted to continue making key decisions which may affect H-P's survival.

Understanding what happened here has not been easy. We have reviewed thousands of documents and countless reports. We have spent endless amounts of time working with the many lawyers who now represent

the key players in this scandal. But unfortunately, many who we would have liked to have spoken to about this matter before this hearing, have not made themselves available for interviews. Nonetheless, we have formulated a number of key questions that, again, I believe shareholders, current H-P employees -- and victims of certain tactics -- deserve answers to. These include the following:

-- **Why were such marginal methods used in this investigation and who approved them and who knew about them (and when)?**

-- **Have such tactics been used before (if so where) and will they ever be used again by H-P? What assurances will the company give us that they will not?**

-- **For those that did approve them, what was their justification and did such approval show good judgment?**

-- **Where was the legal and ethical guardians of HP's corporate interest when all of this was happening and whose job was it to steer the ship clear of the icebergs? For example, was it not a red flag when discussions were occurring about using fraud and deception to obtain third-party phone records from journalists? Was it not a red-flag when discussions were broached about even the possibility of placing janitors -- or fake employees -- in news organizations such as the Wall Street Journal or CNET to engage in spying? Was it not a red flag when covert teams began**

photographing board members or tracking their wives to bingo parlors or reporters to their children's schools?

I am very concerned about the judgment that went into these decisions and why with a company of H-P's sophistication, nobody -- neither the board, nor its CEO, nor its General Counsel, nor its outside counsel had the common sense to say "NO, this is not the 'H-P Way.'"

Finally, Mr. Chairman, as concerned as I am about who MAY have known about these things, and didn't say "NO," I am perhaps even more concerned about those who apparently now claim they DIDN'T know about these things. I frankly, can't understand how the entire board of directors -- all of them potential targets of a renegade HP spy ring – the CEO, or the General Counsel saw or knew little when it came to perhaps the most sensitive investigations ever conducted at the company. In sum, Mr. Chairman, who was on the bridge -- or at the helm -- when the HP hit the iceberg? Apparently nobody.

Mr. Chairman, I will conclude by saying that I look forward to obtaining answers at today's hearing and allowing the witnesses to hopefully set the record straight. But it is my prediction, that much of what we will hear today will be a "see no evil, hear no evil, speak no evil" set of answers. If that occurs, it really will be in the hands of shareholders and victimized employees to take the helm and put this once proud and distinctive ship back on course.

With that, I yield back.

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MR. WALDEN. I appreciate your participation and your comments. Just for the committee's edification and for the audience as well, we have been called to the floor for a vote on the rule. It is just one vote and then there will be a break at three to four hours before our next series of votes. We are going to continue to take opening statements during this period. The Chairman has gone over to vote and will come back and take the chair so I can go vote. Meanwhile, I will work through our list, and I have Dr. Burgess and then Ms. Baldwin next, and there are 11 minutes left in--oh, I am sorry. I actually have Mr. Inslee. It is Burgess, Inslee, Stearns, Baldwin. So Dr. Burgess for 5.

MR. BURGESS. Thank you, Mr. Chairman, and I want to thank you also for convening this hearing this morning. I want to thank our witnesses for being here with us. The remarks of the full committee Chairman, Chairman Barton, certainly echo my sentiments on this issue and I won't belabor those points that he has already brought up, but like most of my constituents, I was extremely concerned to learn of the oil spill in Alaska last March. It was the largest spill so far in Alaska but it is hoped that that remains the case. The spill posed a risk to both the environment and our domestic supply of oil. Experts believe that there will be no permanent environmental damage from the spill, and that is the good news, but we must ensure that the pipeline maintenance practices do not jeopardize the environment or expose us to further disruptions in our supply. While I believe that British Petroleum's initial decision in August to shut down the Prudhoe Bay field following the discovery of corrosion was prudent, I am also troubled by the fact that the situation could have been prevented. What is especially troubling is these transmission pipelines had not been pigged either with the scraping pig or smart pig since 1992 or 1998. Pigging is not a new technology but it is and should be a standard industry practice, and I would like to hear from our panel if in fact that there is recognition otherwise within the industry.

BP's failure to conduct this type of routine maintenance put in jeopardy our ability to access the crude oil produced by the entire field. The Prudhoe Bay field accounts for 5 percent of domestic production, 400,000 barrels per day as we have heard several times this morning, so the temporary loss of this supply has the potential to significantly impact oil prices.

We also had, the Chairman brought up the Texas City situation where 15 people were killed in my home State of Texas and while that may have been a preamble to the other problems that have now surfaced in Prudhoe Bay, I know it is difficult to separate out the complexities of the corporate structure but stipulating what the Chairman brought up that there was a significant profit earned by BP last year, I think this committee would be interested in knowing what commitment is going to be made in investing those profits in further maintenance and further assurances that these two types of accidents do not occur again in the future. Maintenance is just one of the primary responsibilities of the company that is managing the Prudhoe Bay fields, but I am looking forward to hearing from BP about what happened and having the opportunity to question the witnesses appearing before us today.

Thank you, Mr. Chairman. I will yield back.

MR. WALDEN. Thank you, Dr. Burgess. Now I will recognize the gentleman from Washington State, Mr. Inslee, for 5 minutes.

MR. INSLEE. In 1999, another pipeline company didn't do its job. A fireball erupted in Bellingham, Washington, and killed two young boys and a young man, and one of the parents of one of those children called me the other day when this happened and basically asked a question, when will they ever learn, and I think that is a pretty good question. When will they ever learn?

What is so profoundly disappointing in this circumstance is that this is not a matter of hindsight. This is a profound lack of foresight and responsibility by this particular company, and the reason we know that is, back in 2001, an engineering company from Seattle, Washington, did a preliminary draft of a report with the specific purpose of reviewing this protocol for maintaining these pipes included smart pigging as something that would be the most effective protocol to prevent this leak. We found a specific memo from this company, Coffman Engineering in Seattle, Washington, and it said, "Smart pigging is the only inspection technique capable of looking at the whole internal and external corrosion picture." British Petroleum, instead of deciding to smart pig, decided to quash that information from the public. That information never showed up in the public record until it was disclosed after this incident. That is a crying shame, and we are going to find out why that happened because this was a conscious, willful decision by the particular corporation involved here not to do smart pigging that they knew was an effective way of providing repair. This is not a matter of hindsight. This is a matter of lack of responsibility and foresight. And that is a good question, when will they ever learn?

Now, that is the profoundly obvious lesson of what happened here, but there is another profound one that is not so obvious. You know, I was amazed at what lessons people will take from a tragedy like this. One of my colleagues suggested that the lesson we should take from this is we need to drill more oil wells in the Arctic wildlife refuge. He said, you know, we need to expand our oil production capability. Well, I thought that was interesting. That would be sort of like after the Hindenburg saying the problem here is, we need more blimps; that is the whole problem, we don't have enough blimps. I don't think that is the lesson to be drawn from this. Eight percent of production has now been reduced because of one pipeline failure. The lesson is, we need a more diversified energy future for this country. We need a biofuels segment to our energy production capacity. We need development of cellulosic ethanol plants so we can displace some of our dependence on these vulnerable systems that have been reduced now 8 percent and yet a 3 percent spike that Mr. Barton suggested just from the loss of this one pipeline. We need a whole new energy policy. And I like the fact that British Petroleum has spent millions of dollars on things like this and that their plans for biofuels are growing, which is impressive PR, but unfortunately, their efforts are less than .2 percent of just their net profits this year of $26 billion. That is not a sincere effort. It is not enough. And I would agree with my colleague, Ms. DeGette, that Congress has a responsibility because it is an abysmal failure of Congress as well. You know, it is not just pipelines that lack integrity. It is our whole energy system in this country and Congressional inaction that lacks integrity of having a real energy policy that will be diversified and truly environmentally friendly, which this current policy is not.

So I am confident, relatively confident, that we will close this massive loophole, we will get regulation ultimately of this, but it is not enough. We need an energy policy in this country that will not leave us exposed to these terrible price spikes that we have when we have this vulnerable system go down. So I am hopeful that it is not just the obvious lessons that we learn but the more profound ones. I look forward in this hearing to find out why this Coffman Engineering report was not made available, why the public didn't know about this, why this was not done, and why the belts-and-suspenders approach to pipeline management was not followed.

It is obvious you need a belt-and-suspenders approach to pipeline management. This corporation is dependent on ultrasound, which is great technology, but it is like a CAT scan that only takes one slice through your body and doesn't look at the rest of your body. It is very, very good for that one slice. Ultrasound was very, very good for the one tiny slice of this pipeline they did but they ignored the rest of it at our peril, and we are going to get to the bottom of why this happened and make sure it doesn't happen again.

MR. WALDEN. I want to thank the gentleman for his comments. The full Chairman is going to take over the gavel so that we can go vote in the remaining 2 and a half minutes.

CHAIRMAN BARTON. We are going to continue the hearing but we have a number of members that wish to do opening statements, so the first one back gets to do an opening statement and we will alternate until we get regular order when everybody else gets back.

MR. STEARNS. Thank you, Mr. Chairman. Thank you for going ahead and having this hearing for this investigation.

As I understand, later on today one of the persons is going to take the Fifth, and having been through several oversight hearings, when you see an individual take the Fifth it means he does not want to testify under oath, and that should be a concern for all of us when we are trying to just explore the truth here.

In a larger sense, BP has to realize they have been given a public trust because of the impact of oil on our national security and our economy yet it would appear they failed to exercise this trust, so this is our concern today, especially in light of the fact that someone is going to take the Fifth and will not testify openly, clearly and honestly.

Now, the Department of Transportation monitors a lot of sensitive lines in this country in urban areas, environmental areas, but obviously not in areas that appear to be low-stress lines, low-pressure areas like in the tundra of Alaska. Yet these lines are vital, and even though the Department of Transportation does not monitor these lines, it would seem to me BP would want to be scrupulously careful to protect these lines because of their strategic value. Yet today we are here realizing that that did not occur. Fortunately, it appears it is not having a large impact on the price of oil. There has been a lot of trading, future trading, and as a result of trading and the surplus oil, it appears the price of gasoline is coming down. So despite BP's troubles, our oil infrastructure appears to be in reasonable shape but a concern we all should have is, as I understand, is 5,000 barrels of oil were dumped onto the environment. We are going to have somebody from the government that is going to explain to us about this cleanup and whether it was sufficient. Did BP act quickly and do it in such a way that there was no environmental damage? But think of that amount of oil in any kind of other area where there would be high urban or high environmental problems, what that would do and the enormous cost and effort it would create. So again, BP should realize that they have a fiduciary responsibility that goes beyond just the bottom line.

While many pipes are getting old, data from the Department of Transportation's Office of Pipeline Safety indicates a broad decline in the number of pipeline accidents from 245 in 1994 to 136 in 2005 with only 57 through July. So in light of the fact that we have these statistics and a broad decline, it is still a concern what happened.

The Department of Transportation has worked with BP to assess the extent of corrosion in its transmission lines and to prevent any repeal of these leaks. The department has also recently proposed a rule to cover the low-stress transmission lines we are discussing today, and that is a question for us as members of Congress should we implement legislation to do that. Right now we have no direct oversight authority up in the tundra there, and we should give it.

So Mr. Chairman, I appreciate this opportunity again to have the opportunity to question BP's executives, and I look forward to hearing their testimony and to make sure that this does not occur again and we as legislators can do that to make sure the Department of Transportation is involved where we have strategic value and we have public trust involved. Thank you.

CHAIRMAN BARTON. We thank the gentleman. The gentlelady from Wisconsin, Ms. Baldwin.

MS. BALDWIN. Thank you, Mr. Chairman. It is very important that we are holding this hearing today. Not only must we address what went wrong at Prudhoe Bay but we must examine how we can prevent it from ever occurring again. We have had some time to mull over the shutdown since it was first announced earlier last month, and time and time again, I simply find myself at a loss. I am frustrated that BP shut down 8 percent of domestic oil supply, I am angry that gas prices were pushed even higher during the peak summer season, and I am concerned that the Alaskan environment has been dealt a blow from which it will not quickly rebound.

But even more troubling is a trend that I see among companies that can only be described as a lack of corporate responsibility. Many of us can remember a time when our communities were proud to associate themselves with big companies that made their home in nearby towns. These companies realized that their long-term success depended upon investing in and improving the community, not just focusing on the bottom line. BP Alaska was such a company. It has been one of Alaska's largest employers, providing more than 1,300 jobs to State workers. It has supported Alaska's communities, offering millions of dollars for charitable giving and it has played a large role in the social fabric of the community. In return, the community trusted BP. They trusted that BP was listening to its workers, investing in its infrastructure and protecting the surrounding environment, but sadly, somewhere along that way, the trust has been broken. Consideration of the world in which neighbors and consumers live and work seems to have disappeared from BP executives' radar screens, and what has been left behind in Alaska is muck on the ground and distaste, not only among Alaskans but among all Americans.

The BP shutdown has brought to light what happens when a company turns its back on its responsibilities. It allowed years to pass, years to pass without inspecting the critical pipeline that carries 400,000 barrels of oil a day. Executives ignored workers who raised safety concerns and consumers have been left to foot the bill. The cost for BP is not simply calculated in lost production or replacing corroded pipes. Rather, it must also include the disappointment of loyal customers, the damage to Alaska's pristine environment and the violation of the community's trust.

Mr. Chairman, I recognize that we cannot force companies to elevate their commitment to corporate responsibility above profits, but we can find a way to ensure that companies are not abandoning their critical infrastructure by running their pipelines to failure or what is known as riding the throughput curve. The mess of a company's negligence must not be borne by the consumer, the environment or the community. Rather, companies must stand up and take responsibility and BP must be held accountable for its actions or inactions.

I am hopeful that the series of hearings that Congress is holding on this matter will force us to look at the way pipeline safety is regulated so that future disruptions will not occur, and more importantly, I hope this incident and these hearings will encourage other companies to look at their actions and keep corporate responsibility and public trust in mind as they decide what sort of commitment they make to public safety and maintenance.

Thank you, and I yield back the balance of my time, Mr. Chairman.

CHAIRMAN BARTON. The gentlelady yields back. Does the gentlelady from Chicago, Ms. Schakowsky, wish to make an opening statement?

MS. SCHAKOWSKY. Thank you, Mr. Chairman, and thank you, Ranking Member Stupak, for convening today's oversight hearing into BP's pipeline oil spills at Prudhoe Bay in Alaska.

Probably everything that needs to be said is said but I think it was Mo Udall that said, not everyone has said it, so I am going to say a few things about that as well.

I am really glad that we are taking the time to closely review what is going on at Prudhoe Bay over the last several years. However, what is obvious to me and to my constituents and to any reasonable person reviewing the facts of the case is that BP, a company that raked in over $7 billion in profits in the second quarter of this year alone neglected to conduct even remotely adequate or responsible maintenance on its operating lines in the greater Prudhoe Bay field.

Aside from environmental stewardship obligations, it seems like plain common sense to me and I think to just about everyone on this committee that a company extracting oil as a means of profit would want to routinely conduct thorough inspections of its pipelines to ensure safe transport of the product. Why BP refused to do it for years is something I want to know. Hopefully we will get some clue about that today.

BP has presented troubling indicators of diminishing quality in previous years and conducted no major investigation or corrective action, and despite discovering a leak on its western pipeline on March 2 of this year, which put over 200,000 gallons of oil in the Alaskan tundra and was the single largest leak in history on the North Slope, BP attempted to get out of conducting further review of its lines as had been ordered by the Department of Transportation on March 15.

Instead of doing the right thing and what would have been smart business and conduct an immediate internal investigation of all its lines, BP waited until June 6 and asked for relief and a pass on DOT's previous pigging order to conduct a thorough internal review of its lines, and it wasn't until late July, almost five months after the enormous leak was discovered and after it was further ordered by DOT that BP finally conducted internal testing. The results demonstrated numerous areas of concern and yet another leak. Finally, on August 6, more than five months after the initial March 2 leak was discovered, BP shut down production from its greater Prudhoe Bay field. It is astonishing and infuriating that any company entrusted by the public and the government to ensure level of safety for our environment and its use of natural resources to turn a profit, that it would be so irresponsible, but it is truly beyond comprehension that a company that is so grossly profitable would willfully avoid routine detailed inspection and maintenance on its pipelines. As has been mentioned now several times, BP as it turns out had not taken an in-depth internal look at its pipeline on its eastern line since 1992 and its western line since 1998. That is 14 and 8 years, respectively. If this company had spent as much on inspections, safety and maintenance as it does on advertising and lobbying for tax cuts, none of us would have to be here today in this hearing. BP executives could be counting their bonuses and the public would be assured of the company's pipeline integrity. Instead, BP chose to bury its head in the sand and tundra and operate a see-no-evil approach to its Prudhoe Bay operations.

This company has a lot of explaining to do, and as lawmakers on this committee, we all need to ask ourselves if our policies are adequate, if we can afford to trust companies like BP to do the right thing and if we can continue to rely so heavily on energy products that present such risks to our environment, our bank accounts and our economy.

I wanted to mention that my friend from Chicago, national leader Reverend Jesse Jackson, was here today. His organization has taken a great interest in this, is leading weekly pickets across the Nation at BP stations in several cities including Washington, D.C., and Chicago, Los Angeles, Atlanta, Detroit, Michigan, raising the questions that all consumers are asking right now, why are the profits so high at BP and yet we cannot be sure that they--we know that they are not doing the kind of maintenance and safety inspections that are needed.

All of us need to focus in on this, including the company, and I welcome our witnesses today. Thank you.

MR. WALDEN. I thank the gentlelady for her comments. The chair would now--we are waiting for Mr. Pickering, but in his absence, we will now go to Congressman Markey, who is not a member of the subcommittee but we welcome your participation today, and you are recognized for a 5-minute opening statement.

MR. MARKEY. Thank you, Mr. Chairman, very much, and I appreciate the courtesy of allowing me to speak on this issue in this subcommittee. I have been a member of the Energy Committee for 30 years, and this is one of the low points of those 30 years. This is without question an issue which has had a profound impact on the American public. At a minimum, they have had to have paid now tens or hundreds of millions of extra dollars at the pump because of the spike in the price of gasoline that occurred because of this accident. That is the beginning of the price that the public has to pay for this kind of a problem manifesting itself.

British Petroleum's marketing campaign claims that BP stands for Beyond Petroleum but today we are finding that BP stands for a company with bloated profits that failed to fix bad pipelines and the consumer at the pump is responsible for paying the price. It appears to me that management at BP's Alaska operation knew that they were essentially driving a car with over 100,000 miles on it without bothering to spend the money and time needed to properly maintain it. So it seems to me that BP senior management can't have been surprised that it broke down eventually. BP's corrosion management set up a testing system that was designed to save money but it failed miserably at ensuring the integrity of these critical pipelines. BP had a 2004 report from its attorneys at Vinson and Elkins that pointed out some of these problems. BP also had a 2005 audit report that reaffirmed the problems' continued existence but BP doesn't appear to have revamped the pipeline corrosion control systems after these warnings. It doesn't appear that the allegations of harassment or retaliation against whistleblowers were thoroughly investigated by and adequately responded to by senior management at BP. These whistleblowers are public interest Paul Reveres signaling a warning that something could go wrong so that the public interest could be protected. Those warnings were ignored. This is simply unacceptable.

BP is one of the largest oil companies in the world. It is an extraordinarily profitable company. It clearly has the money to be able to properly maintain their pipelines, and BP failed to do so. Instead, BP appears to have pursued a strategy of maximizing short-term profits at the expense of maintaining the integrity of those pipelines. BP appears to have ignored internal evidence that such a strategy would result in leaks and there are some indications that those within the company who raise concerns about this strategy would be harassed and retaliated against.

I would hope that before this committee takes up any pipeline safety reauthorization that we would get to the bottom of what happened here and make appropriate adjustments to the law to ensure that this type of problem does not happen again. We should not legislate in the area of pipeline safety until we understand completely what happened at BP, make an industry example and then change the laws of our country to ensure that it never happens again. I thank you again, Mr. Chairman, for your courtesy.

MR. WALDEN. You are welcome, and Mr. Stearns reminds me that I should have asked UC, unanimous consent, to allow members who are not on the subcommittee the opportunity to provide an opening statement, so I will do that, because Mr. Green is next. I ask unanimous consent to allow Mr. Green to offer an opening statement. Is there any objection? Hearing none, Mr. Green.

MR. GREEN. Thank you, Mr. Chairman, again. Thank you for allowing those of us who are not on the committee although serve on the Energy Subcommittee, and this hearing is very important, particularly in the area where I come from in Houston. I would like to keep my remarks brief because I really want to hear from our panelists but I am glad to be here today to express my frustration with the events in Alaska that caused this hearing today.

Last year we had two natural disasters, Hurricanes Katrina and Rita, that blocked domestic oil supplies at a very critical time, the summer driving season. We may dodge that bullet this year but the American drivers had to deal with a manmade disaster this year when BP's Alaska pipeline sprung a leak and had to be shut down due to corrosion. I have not reviewed all the documents that our subcommittee has obtained but what I have heard so far is not good. Corrosion on the pipeline does not seem to have taken BP by surprise, rather there were numerous warning signs that were underestimated or ignored. Even large corporations can have bureaucratic problems dealing with maintenance issues, but unfortunately, this is not the first time we have seen something like this with British Petroleum. Just last year, an explosion at a BP refinery in Texas City that is close to our district, in fact, it could be in it because I have all the other refineries in the Gulf Coast area it seems like, killed 15 contractors who were working in a temporary building placed too near to dangerous equipment, and again, the information that I understand from Federal investigators found several safety problems and the investigation is still ongoing and it makes two major public safety disasters in two years.

Mr. Malone, I know you are new to your job and we appreciate the fact that you are here to face this music but we need more than honesty and sincere apologies at this point. We need concrete action and some assurance that BP is going to spend the necessary resources on safety. When you own a pipeline or refinery, Congress and the American people expect you to invest the necessary amount in safety to protect our economy, the environment and human life. This committee should look at our pipeline safety legislation to make sure we are keeping our responsibility to improve safety at these low-stress oil pipelines. However, I don't want to have a pipeline safety accident hold up pipeline safety legislation that would make our pipelines actually safer. Mr. Chairman and Ranking Member, thank you for holding this hearing and allowing me to participate, and I look forward to authorizing the pipeline safety legislation in this Congress, I hope, in light of the accidents that have happened, and I yield back my time.

[Additional statement submitted for the record follows:]

PREPARED STATEMENT OF THE HON. ED WHITFIELD, CHAIRMAN, SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS

Today, the Subcommittee on Oversight and Investigations will examine the facts and circumstances surrounding two spills on crucial crude oil transmission pipelines operated by BP in Prudhoe Bay, Alaska. We will look at BP's decisions and actions concerning the maintenance and operation of these pipelines in order to better understand how the corrosion occurred and what can be done to prevent similar problems in the future.

In March this year, BP discovered the leak of roughly 5,000 barrels of crude on the Western Operating line, the largest spill in the history of the North Slope. Just a few months later, BP discovered serious corrosion problems in its Eastern Operating line, which forced it to shut down the line, effectively cutting production from the Prudhoe Bay field in half. BP cannot even say with any degree of certainly when it will be able to get this line back into operation.

There have been a series of maintenance and safety problems involving BP over the past several years that are troubling, including the Texas City refinery disaster and the recent leaks on the North Slope. Are these isolated incidents, or are they the result of fundamental problems within the company? I hope that the BP executives testifying before the Subcommittee today will be able to provide some assurances in this regard. As stewards of critical energy infrastructure, all pipeline operators, including BP, bear a tremendous responsibility.

I would like to thank all of the witnesses, and I hope that today's hearing will illuminate the facts of the situation surrounding BP's pipelines so that this Committee can help ensure a safe and reliable energy infrastructure.

MR. WALDEN. I appreciate the gentleman yielding back the time and his comments and participation in our hearing. With that, we are going to ask the following witnesses to come up to the table. Mr. Richard Woollam of BP, formerly corrosion engineer, formerly the manager of the CIC; Mr. Robert A. Malone, Chairman and President, BP America; Mr. Steve Marshall, president, BP Exploration Alaska; Mr. Kevin Hostler, President and CEO of Alyeska Pipeline Service Company; and

Mr. C. Dan Stears of Coffman Engineers. If you would come forward and be seated at the table.

As you know, when conducting an investigative hearing, this subcommittee follows the practice of taking testimony under oath. So now that you are comfortable, I am going to ask you to all rise and if you would raise your right hand.

[Witnesses sworn]

MR. WALDEN. Please be seated. Under the rules of the House and this committee, you have the right to be advised by counsel as to your constitutional rights. Do you have legal counsel here today, Mr. Woollam?

MR. WOOLLAM. Yes.

MR. WALDEN. And can you identify that counsel for us, please?

MR. WOOLLAM. Yes, Mr. Jim Torgesen with Heller Erman.

MR. WALDEN. Mr. Malone?

MR. MALONE. Yes, I do.

MR. WALDEN. Can you turn on your microphone there, sir? Thank you.

MR. MALONE. I have Ron Phillipe here.

MR. WALDEN. All right. Mr. Phillipe, welcome. Mr. Marshall?

MR. MARSHALL. Yes, I do, Mr. David Bukey.

MR. WALDEN. All right. Thank you. Mr. Hostler?

MR. HOSTLER. Yes, that is right, Hostler.

MR. WALDEN. Hostler. No counsel?

MR. HOSTLER. No.

MR. WALDEN. And Mr. Stears?

MR. STEARS. Yes, I do.

MR. WALDEN. Can you turn on that mic? That didn't help either. Sorry. Try again.

MR. STEARS. It indicates it is on.

MR. WALDEN. There we go. Now it is. All right. Thank you. The chair will now recognize you for purposes of making an opening statement if you so desire. Mr. Woollam?

TESTIMONY OF ROBERT A. MALONE, CHAIRMAN AND PRESIDENT, BP AMERICA, INC.; STEVE MARSHALL, PRESIDENT, BP EXPLORATION ALASKA, INC.; KEVIN HOSTLER, PRESIDENT AND CEO, ALYESKA PIPELINE SERVICE CO.; AND C. DAN STEARS, CATHODIC PROTECTION SPECIALIST, COFFMAN ENGINEERS, INC.

MR. WOOLLAM. Mr. Chairman, I have no prepared statement. Based upon the advice of counsel, I respectfully will not answer questions based upon my right under the Fifth Amendment of the United States Constitution. I ask that my counsel's written letter of this morning to the committee be entered into the record.

MR. WALDEN. Without objection. Mr. Malone, welcome.

[The information follows:]

HellerEhrman LLP

FILE

September 6, 2006

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The Honorable Joe Barton
Chairman
House Committee on Energy
and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515

Re: Subpoena to Richard C. Woollam

Dear Chairman Barton:

On behalf of our client, Richard C. Woollam, an employee of BP EPTG, we hereby inform the Committee, as we had informed your staff: Mr. Woollam, reluctantly and contrary to his desire to testify, will follow the advice of counsel and respectfully decline to testify, based upon his rights under the Fifth Amendment to the U.S. Constitution. In connection with Mr. Woollam's decision to invoke his Constitutional privilege, we respectfully make the following requests.

First, we ask the Committee to draw no adverse inference based on Mr. Woollam's invocation of his Fifth Amendment Constitutional rights and not to engage in a rush to judgment. As you know, the U.S. Supreme Court has repeatedly observed that one of the basic functions of the Fifth Amendment is to protect the innocent.

Second, if Mr. Woollam must assert his Constitutional rights in person before the Committee, we respectfully request you excuse him promptly after he makes it clear that he intends to assert such rights with respect to any questions that relate to your investigation of BP. In fact, as you may know, it is generally viewed as an abuse of a witness's Constitutional rights to require him to continue asserting the privilege repeatedly in response to questions in areas that he has indicated will not be answered. *See* John C. Grabow, Congressional Investigations, Law and Practice § 4.2[a], p. 126. In this connection, we note an opinion of the District of Columbia Bar, which stated that, in the context of a congressional hearing, it is unethical for a D.C.-licensed lawyer to continue to propound questions to an individual when, as a result of asserting the Fifth Amendment, it is clear that there will be no answer forthcoming. *See* District of Columbia Legal Ethics Committee, Opinion No. 31 (March 29, 1977).

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The Honorable Joe Barton
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Mr. Woollam and his counsel support your efforts to understand the facts related to oilspills on Alaska's North Slope. However, parallel inquiries that could subject individuals to potential criminal exposure require that we advise Mr. Woollam to invoke his Constitutional rights under the Fifth Amendment. We ask that (i) you respect his assertion of his Constitutional rights, and (ii) you take the other steps requested in this letter to ensure the fairness of the hearing and the avoidance of undue prejudice to Mr. Woollam.

Very truly yours,

James E. Torgerson
Counsel for Richard C. Woollam

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MR. MALONE. Thank you, Mr. Chairman.

Mr. Chairman, members of the subcommittee, good morning. My name is Bob Malone. I am the Chairman and President of BP America. I am joined today by Mr. Steve Marshall, who heads our Alaskan operations.

BP America's recent operating failures are unacceptable. They have fallen short of what you and the American people expect from BP and they have fallen short of what we expect of ourselves. We must and will work hard to fix the problems, and in doing so, regain your trust and that of the American people. We know we will be measured by what we do, not what we say.

I assumed this role on July 1 and immediately began to visit our facilities, meet with our employees and learn about our current operations. On August 6 I received word of severe corrosion in our of our transit lines in Alaska. The decision was made to shut down protection to avert any possibility of an oil spill and to prevent damage to the environment. We then conducted extensive testing of the transit lines on the western side of the field, assured ourselves they were fit for service and maintained production of about 200,000 barrels a day. Preventing environmental damage and protecting the safety of our employees and contractors are absolute priorities. We fully recognize this decision was not without consequences but it was the right thing to do. Many were concerned about the impact on crude oil and gasoline supplies. BP brought in cargos of crude oil from around the world and other suppliers did the same. A short-term supply shortage did not occur and we continue to acquire stocks to replace the production that is still shut down. BP is fully committed to restoring production from Prudhoe Bay as soon as we are confident that it can be done in a safe and environmentally responsible way.

Across BP, we have taken a number of actions to ensure that our businesses are run in a manner that meets our expectations and yours. I would like to highlight a few of those. These were announced--some of these were announced by John Browne on July 1 and they included my appointment.

First, I retained three of the foremost corrosion experts in the world to evaluate and make recommendations for improving the corrosion management program in Alaska. BP has added an additional $1 billion to the $6 billion already earmarked to upgrade all aspects of safety at our U.S. refineries and for the integrity management in Alaska. I have appointed former U.S. District Justice Stanley Sporkin as an independent ombudsman reporting directly to me. I have asked Judge Sporkin to conduct a review of all worker allegations that have been raised on the North Slope since 2000. I have established an operational advisory board that is composed of 15 of our most senior business leaders in the United States, who will advise me on safety operational integrity and compliance. I am in the process of recruiting an external advisory board to assist and advise me in the monitoring of BP's U.S. businesses with particular focus on safety, operational integrity, compliance and ethics. I am building an internal team of experts who will be employed to look at safety, process safety, operational integrity and compliance and ethics. I continue to meet with our employees to reinforce our expectations of them to ensure that BP operations are safe, to remind they have a responsibility and a right to shut down any process they feel is unsafe, and that I encourage them to raise concerns of anything that has to do with safety and environmental integrity.

I am personally committed to rebuilding the public's confidence in BP America. I have the full support of our Chief Executive, John Browne, our executive leadership and the entire BP group. I have been given all the authority necessary to accomplish this task. Bringing our operations to the level of excellence you expect and we demand is going to take time.

If the subcommittee would like, I would be happy to report back in 6 months and periodically thereafter to indicate to you the progress that we are making, and we will participate and cooperate with you in an open and honest fashion. Thank you, Mr. Chairman.

[The prepared statement of Robert A. Malone follows:]

PREPARED STATEMENT OF ROBERT A. MALONE, CHAIRMAN AND PRESIDENT, BP AMERICA, INC.

My name is Bob Malone and I am Chairman and President of BP America Inc. BP America is the U.S. holding company for all subsidiary companies operating in the United States. BP America, through its subsidiaries employs more than 36,000 people and produces 666,000 barrels of crude oil and 2.7 billion cubic feet of natural gas per day. We operate five refineries that process nearly 1.5 million barrels a day of crude oil, and a system of pipelines and terminals throughout the United States that supply over 70 million gallons per day of gasoline and distillate fuels to customers in 35 states.

BP Exploration Alaska (BPXA) is the operator of the largest oil field in North America – Prudhoe Bay on Alaska's North Slope. Our charge is to operate this field in a safe, efficient and environmentally responsible way for the benefit of the State of Alaska, our business partners, our customers, our employees and our shareholders. The public's faith in BP has been tested recently by corrosion discovered in the pipeline oil transit system that conveys processed crude oil from the North Slope gathering centers to Alaska's Trans Alaska Pipeline System (TAPS).

While we would never wish to lose the confidence of the American public, we have fallen short of the high standards we hold for ourselves, and the expectations that others have for us. I commit that BP America will work closely with the State of Alaska, our employees, our regulators and Congress to take the necessary steps to ensure that you can have confidence in BP.

Steve Marshall, President of BP Exploration, Alaska has submitted comments regarding the operational incident at Prudhoe Bay. In the pages that follow, I will discuss several other operational challenges BP has experienced over the last 18 months and address many of the questions members of the Committee, regulators and others have raised. Most importantly, I will outline the steps that BP has taken or is committed to undertaking to address these challenges and enhance the public's confidence in our company.

Employee Concerns

As soon as I was named head of BP America in July 2006, I took a tour – to find out what our people were saying in the field. I visited facilities and offices across America from Alaska to Texas with many stops in between. I can tell you that the solution to many issues that BP America faces rests right at home – with those who are our BP employees.

I made it clear that they had three obligations –

- Workers must feel that operations are safe and the integrity of our infrastructure is sound at our facilities
- If they don't feel safe or if process integrity is in question – they have the authority to shut operations down
- Workers must feel comfortable raising concerns

I know that BP has processes in place to address employee concerns. People can raise concerns through line management, they can raise concerns through our safety committees, and they can call in to a world wide anonymous hot line. Alaska has had its own hotline for worker concerns. We believe, in fact, that most of the concerns have been raised through one or more of these systems. The problem has not been in workers raising concerns – sometimes it's been our responsiveness.

In recognizing that the current situation may not provide complete assurance – I have created a new position of Ombudsman, reporting directly to me.

This new person will provide an independent team to assess and to bring to resolution any safety-related operational concerns raised to his office. I expect this individual will call them as he sees them. This is critical, as workers are going to speak out. We encourage it.

The new ombudsman will initiate a full review of all the worker allegations that have been raised on the North Slope since the acquisition of ARCO in 2000. I have asked that these concerns be reviewed to determine if the problems have been addressed and rectified to BP's standard, with appropriate feedback to the worker.

BP America is committed to finding out about and acting on operational and other issues. This is why we have created the new Ombudsman role to help facilitate this information gathering and exchange.

Supply/Price and Consumer Impacts

Upon the August 6, 2006 announcement that BPXA intended to shut down the Prudhoe Bay field, concerns were expressed about the impact this decision would have on crude supplies and prices to the West Coast. Early estimates that the entire production from Prudhoe Bay of approximately 400,000 barrels/day would be shut-in proved wrong. Extensive ultrasonic testing of the western oil transit lines provided BPXA with sufficient data to determine that production in the Western Operating Area could continue in a safe and environmentally responsible manner. The loss of crude shipments to the Trans Alaska Pipeline was thus limited to roughly 200,000 barrels per day.

In light of this supply gap, many policymakers voiced concerns that West Coast refiners would be unable to find alternative sources of crude to keep their refineries operating and the gasoline market supplied. At the time of the incident, West Coast inventory levels for both crude and products were seasonally high, near record levels in some cases.

On news of the curtailment in production, BP and others in the Industry made moves to source incremental barrels from alternative sources including West Africa (WAF), the Middle East and South America (see Exhibit 1). BP's activity was focused largely on meeting the crude oil and refined product demands of our refineries and customers. To this end, BP has secured an incremental 3.5 Million barrels of crude oil for delivery to the West Coast in September and October.

The company has also agreed to take steps that will ensure the continued flow of oil to both Flint Hills Resources and Petro Star refineries in Alaska which depend on North Slope oil for their operations.

How have these incremental supplies impacted the price structure of the West Coast markets? As shown in Exhibits 2 and 3 the market reaction was relatively benign over the period due to the availability of alternative crude and product supplies. The few impacts that have been seen in the product markets were largely the result of local refinery issues rather than disruption in Alaska crude deliveries (Exhibit 4). Nevertheless, in the two weeks after the incident both crude and product prices were lower than the levels of August 6.

A few people have alleged that BP engineered the shutdown of Prudhoe Bay as a way to manipulate prices. I am here to assure you that nothing could be further from the truth. BPXA took the extraordinary step to shut down production because we saw unexpectedly severe corrosion that couldn't be explained and which caused us to question the condition of other transit lines serving the oil field. We were simply not willing to risk worker safety or a major oil spill. Further, BP has gone to great lengths to not only guarantee supplies to Alaska refiners but also secure incremental crude for delivery to the West Coast.

BP's commitment to ensuring product supply to the market and its customers is not a new phenomenon. Immediately following Hurricanes Katrina and Rita, BP also took extraordinary steps to ensure product supplies to the United States. Some of these activities are listed below:

- Importing more than 29.5 Million barrels of gasoline, diesel and jet fuel for delivery into markets in the Northeast, Florida and Gulf Coast through October of 2005.
- Transporting additional supplies to Florida, where this fuel can then be used in supply-short areas typically served by the Colonial Pipeline.
- Reversing the pipeline on the Texas City marine dock to accept vessel shipments and deliver product into Colonial pipeline.
- Extending supplies by utilizing the adjustments in environmental regulations (RVP and sulfur) that will help increase the overall supply of gasoline and aid distribution flexibility. This brought millions of extra barrels into the Midwest, Northeast and Southeast markets.
- Reaching an agreement with DoE to draw, on an exchange basis, up to 2 million barrels of sweet crude from the Strategic Petroleum Reserve for use in its Midwestern refineries. BP has drawn down 200,000 barrels of this loan amount. Additionally in an SPR auction held the week of September 12, we bid for and won 2.7 million barrels of sweet crude.

- Obtaining a Jones Act Waiver to enable a foreign flag vessel to shuttle crude oil from a platform to onshore facilities. This action enables an additional 50k BOPD and 200 MSCF of gas per day to be delivered to our US system.

BP America will continue to play an active role in securing the crude and product supplies necessary to meet our refinery and customer demands. The market has shown great resiliency in its ability to quickly respond to supply disruptions and thus minimize impacts to the consumer. BP America is confident that market dynamics will successfully meet West Coast needs until full production is restored in Prudhoe Bay.

Other Matters

Over the last 18 months, BP America has also experienced several other incidents about which I would like to briefly comment.

In Texas City, a March 2005 explosion at one of our facilities was the greatest tragedy ever experienced by the BP family. The harm it caused and the lessons learned from it will never be forgotten. In the aftermath of this tragedy we made and continue to make making significant changes in our approach to process safety and in the way we operate and monitor operations at Texas City and our other US refining facilities. We are committed to attaining the highest levels of safety, reliability and environmental performance.

BP has publicly accepted responsibility for the March 23rd explosion and for the management system failures and employee mistakes which contributed to or caused it.

Immediately following the incident, BP Products North America (BPPNA), the subsidiary that owns the US refining assets, promised to fully investigate the explosion, make public the findings of its investigation and take action to prevent a recurrence. The company also promised its full cooperation to government agencies investigating the incident and said it would assist workers and families harmed by the company's mistakes.

BP has fully cooperated with the U.S. Chemical Safety and Hazard Investigation Board (CSB), the U.S. Environmental Protection Agency and the Texas Commission on Environmental Quality regarding their investigations of the Texas City explosion.

On the recommendation of the CSB, BP has voluntarily appointed an independent panel to assess and make recommendations for improvement of process safety management and safety culture at the company's five U.S. refineries. Former U.S. Secretary of State James A. Baker, III is chairman of the panel. The panel has visited each of BPPNA's five US refineries in Texas City, TX; Carson, CA and Whiting, IN, Oregon (Toledo), OH and Cherry Point, WA. BPPNA looks forward to receiving the Panel's final report and improvement recommendations later this year.

BP has put a new management team in place at Texas City, simplified the organization, improved communication, clarified roles and responsibilities and taken steps to update and verify compliance with procedures.

BP expects to invest an estimated additional $1 billion to improve and maintain the Texas City site over the next five years.

BP operations and maintenance personnel have reviewed and updated operating and maintenance procedures and received training on process safety management, hazard recognition, process control, process trouble shooting and control of work. Site employees have completed over 300,000 man hours of operational and process safety related training since March 23, 2005.

The company has set aside $1.2 billion to compensate victims of the explosion and has worked to resolve claims arising from the incident without the need for lengthy litigation. Settlements have been achieved with nearly all family members of every worker who died. The company has also agreed to compensation with more than 500 injured workers.

The Thunder Horse platform is the largest semi-submersible oil production platform in the world, at 130,000 tons displacement, and is designed to process 250,000 barrels of oil and 200 million cubic feet of natural gas per day. The Thunder Horse field is located in 6000 ft. of water and involves extremely challenging high pressure and high temperature hydrocarbon reservoirs. Much of the technology being utilized on the project is industry-first involving new metallurgy, new engineering designs and 'serial number one' equipment. Thunder Horse is operated by BP, with a 75 percent working interest. ExxonMobil owns the remaining 25 percent interest.

In April 2005, the platform was towed to its location in Mississippi Canyon Block 778 in the deepwater Gulf of Mexico, 150 miles southeast of New Orleans.

Upon the approach of Hurricane Dennis in July 2005, all personnel evacuated the Thunder Horse platform in conformance with standard BP safety procedures. Following passage of the storm, the Coast Guard Marine Safety Unit Morgan City was notified that the Thunder Horse platform was listing.

A BP investigation was begun to determine the cause of the stability imbalance that saw the Thunder Horse platform list to port at an estimated 20 degrees. The U.S. Coast Guard and the Department of the Interior's Minerals Management Service also opened a joint investigation to determine the cause of the listing and their investigation is continuing. BP is cooperating fully with this investigation.

On August 1, 2006, the Thunder Horse platform completed major repairs and was declared ready for the introduction of hydrocarbons. This massive undertaking was completed on schedule and safely, with zero days away from work cases.

Some of BP's U.S. Trading operations have come under scrutiny by federal regulators. BP is cooperating with the Commodity Futures Trading Commission and the Department of Justice in their investigations by providing responsive documents, data and witness testimony.

BP has initiated a review by independent external auditors of the compliance systems in its US trading business. The auditors will examine the design of the trading organization, delegations of authority, standards and guidelines, resources and the effectiveness of control and compliance. The results of the review will be shared with relevant US regulatory authorities and the auditors' recommendations will be acted upon by BP.

Some policymakers and regulators have begun to question whether these operational problems at BP are symptoms of a systemic problem. Clearly, BP has had its share of issues from which we've taken important learnings. I believe BP is, overall, a well-managed company with a solid long-term record. We recognize that there has been a series of troubling problems that are unacceptable to us and contrary to our values. We want to understand why they have occurred and do whatever it takes to set them right.

I don't believe in bad luck. We need to understand these issues and then translate the lessons we learn across all of our operations.

Conclusion

For many, the shine has come off of BP over the last year as we have stumbled operationally. Some have questioned our environmental credentials while others have accused BP of profiteering at the expense of employee safety. BP holds itself to a higher standard and consequently expects the scrutiny that comes when we fall. Part of my job as Chairman and President of BP America is to ensure that the standards we have set are met. My commitment is to make it happen.

In response to the specific challenges that we have faced in the US, BP has announced several specific actions that it will be taking. These include:

- US refining – a major increase in expenditure on refining maintenance, turnarounds, inspections and staff training and the upgrade of our process safety management system.
- Alaska – major additional investment in pipeline integrity.
- Trading – a detailed review by independent external auditors of the compliance system in the US trading business.
- Organization – the creation of a new outside advisory board to assist and advise BP America Inc.

As this critical work unfolds, BP won't lose sight of the opportunities to create a different kind of company. We will continue to invest in emerging technologies like hydrogen, wind, solar and biofuels. Because it is only in doing so that BP can aspire to be an energy company for the 21st century. We will also continue our work on important policy issues of the day such as climate change and offer our expertise and ideas as options are formulated.

I was sent to the US by our Group CEO, John Browne, with some advice and a set of principles that will guide me and our work in the US. He says the real measure of a great company is not the absence of challenges but how they are dealt with.

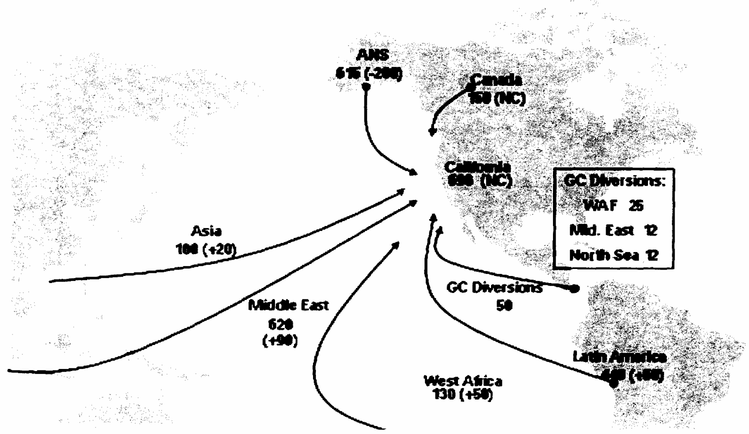
I commit to members of Congress that I have been given the authority, the resources and the people to assure you that BP America will overcome and ultimately be strengthened by this challenge.

EXHIBIT 1

Estimated West Coast Crude Oil Balance (Sep-Oct 2006) in MBPD

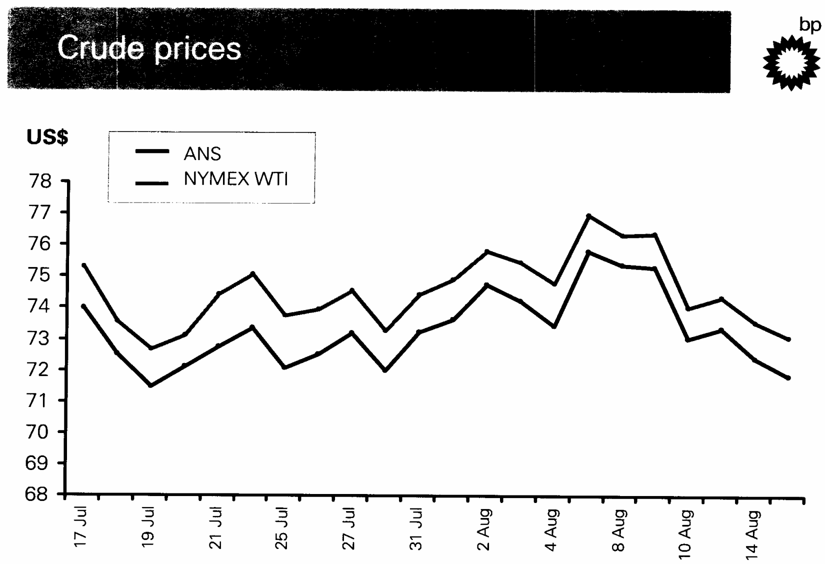
bp

Total & Preexisting Flows in Blue, Changes & New Flows in Red



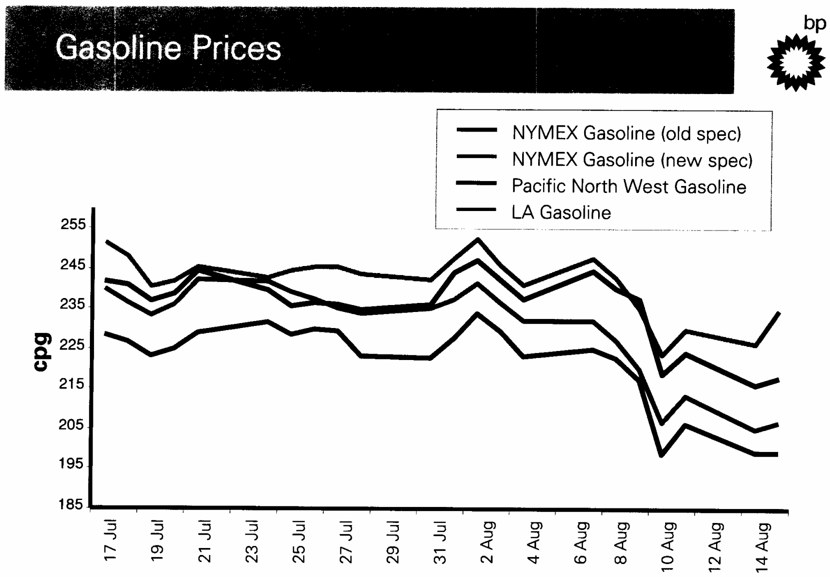
Source: BP Internal Analysis

EXHIBIT 2



Source: OPIS

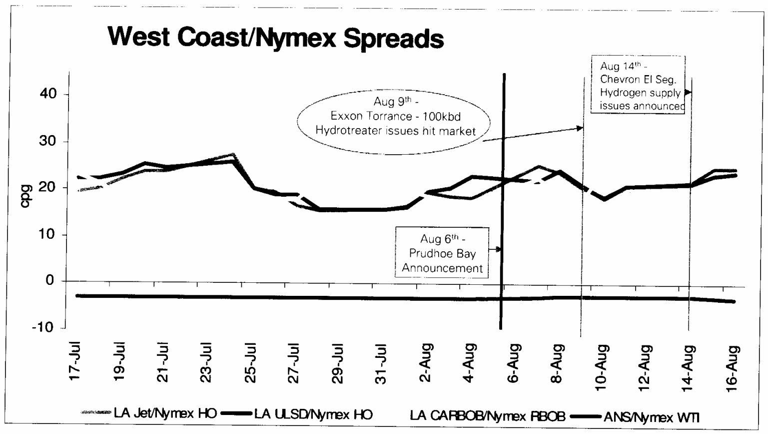
EXHIBIT 3



Source: OPIS

Exhibit 4

West Coast Basis



Source: OPIS and Platt's data

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MR. WALDEN. Mr. Malone, thank you for your testimony today. We look forward to discussing this issue more with you as we open up into questions in a few moments.

Mr. Marshall, welcome. We are delighted to have you with us today and we look forward to your comments on this issue.

MR. MARSHALL. Mr. Chairman, members of the subcommittee, thank you for the opportunity to be here today. I am Steve Marshall, President of BP Exploration Alaska.

In the past 6 months, we have had two leaks from the oil transit lines at Prudhoe Bay. These spills occurred on my watch, and as President, I am in charge of the overall business in Alaska and the buck stops with me, and I commit that I and my team will do everything we can to rectify this situation, going forward and doing everything to get production back as quickly and as safely as we can and apply the lessons that we continue to learn from these two events in our forward programs.

We take very seriously the public trust, the trust of government, our serious role of protecting the environment. Both spills have been fully cleaned up. We have received a number, several comments from external sources about the quality of that cleanup and we believe at this point there will be no lasting damage to the environment. We won't know the exact cause of the spills until we complete the failure analysis of the pipe, and that work still remains to be done. We did believe we had a very comprehensive corrosion management system covering over 1,500 miles of oil pipelines, flow lines, gathering lines and transit lines. Inspections that we did told us time and again that these transit lines were in good shape. Clearly, in retrospect, since these leaks, it has clearly identified gaps in our program and we are going to take the learnings and apply them going forward.

On August 6, the pigging data that we received was very unexpected. We encountered a 23-barrel leak from a pipeline. Something was happening to our flow lines which we didn't understand and we took the only action we believed we could to prevent the potential of a major spill in shutting down Prudhoe Bay until we could confirm the integrity of the remaining lines. Over the next five days we brought in hundreds of people to complete inspections on the western transit line, sufficient inspections to give us confidence the line there was in good enough shape to keep production on, so we never actually shut down the western side of the line, and today we have in excess of 200,000 barrels a day producing from the west side and we have heightened surveillance and contingency plans in place in the remote event of a further incident.

On the east side of the field, we are pursuing two operations. We are vigorously inspecting the lines. To date we have completed over 4,500 inspections and we are aggressively pursuing bypasses for each of the facilities to get them into existing lines which are known to be of good condition. We expect those bypasses to be complete by the end of October.

Where next? What we believe so far is that the inspections that we have completed on the west and the east indicate that 10 of 16 miles of transit lines are in good condition and we are working with the DOT to understand whether we can bring back the eastern side of the field in order to smart pig that operation as soon as possible. A very good discussion is going on with the DOT in that respect.

So looking ahead, step one, we will pig and smart pig the 10 miles of remaining transit lines and we will implement routine pigging and smart pigging going forwards on all of our transit lines. Two, we will determine the corrosion cause and modify our corrosion management system going forward. Three, we will include all of BP's operated transit lines, all 122 miles of those lines, in the DOT's PIM program, pipeline integrity management program. And fourth, we will replace 60 miles of transit lines at Prudhoe Bay. Fifth, we have already made organizational changes, added a technical director to define and establish operating standards and to verify that those standards are indeed being met by the business.

We have a lot to do but we will get it done, and since 2000, we have completed many internal and external reviews of our corrosion management program. We have covered everything from the work environment to the technical integrity of the program to the integrity of our data that we use. I rely daily on teams of experts in Alaska to manage corrosion management, indeed as I rely on many teams to manage the entirety of our business in the State.

But it doesn't stop there. I welcome challenge, scrutiny, whether it comes from government, whether it comes from partners, whether it comes from external consultants, indeed whether it comes from the workforce. Having worked on the slope for five years, I know the importance of getting worker input. It just good business and I take very seriously any way we can to shine a spotlight on our systems and am determined to make improvements. We have had State reviews, multiple internal audits including two reviews by our chief engineer. As we have gone back on any of those reviews, no one pointed to the east transit lines as a particular problem. If they had, we would have acted on it.

I deeply regret this situation occurring on my watch after five years. Everyone has talked about the importance of this. I regret it very deeply. I am determined to do what we can to get production back safely, quickly and efficiently. Thank you.

[The prepared statement of Steve Marshall follows:]

PREPARED STATEMENT OF STEVE MARSHALL, PRESIDENT, BP EXPLORATION ALASKA, INC.

My name is Steve Marshall and I am President of BP Exploration (Alaska) Inc. (BPXA). BPXA is the operator of the largest oil field in North America – Prudhoe Bay on Alaska's North Slope.

I will discuss BPXA's Prudhoe Bay oil field operations and the actions taken on August 6th to begin the orderly shutdown of Prudhoe Bay - a decision I believe was our only option in order to avoid the risk of an oil spill. I will also present some background material on the corrosion prevention programs in the field.

Prudhoe Bay

The Prudhoe Bay field is located 650 miles north of Anchorage and 400 miles north of Fairbanks. It is 1200 miles from the North Pole and 250 miles north of the Arctic Circle. Pump Station 1, the beginning of the Trans Alaska Pipeline System (TAPS), is located within the perimeter of the Prudhoe Bay field. For additional detail on Prudhoe Bay operations please refer to Exhibit 1 in the appendix.

Prior to 2000 the Prudhoe Bay field comprised the East Operating Area, operated by Atlantic Richfield Company (ARCO), and the West Operating Area, operated by BPXA. Upon acquisition of ARCO by BP, BPXA became the sole operator of Greater Prudhoe Bay. Although BPXA operates the field, a total of nine companies have a so-called "working interest" in the field leases. The costs and production are shared amongst the working interest owners, according to their ownership.

In March of 2006, BPXA discovered a leak along the GC-21 line in the Western Operating Area (Exhibit 2). This is a 34" line that carries sales quality crude oil to a central gathering center for ultimate delivery into TAPS at pump station 1. The leak was approximately 5,000 barrels, the largest spill ever on the Alaskan North Slope. Shortly thereafter, the U.S. Department of Transportation (DOT) issued a Corrective Action Order (CAO) to BPXA ordering it to perform "smart pig" tests along with other inspection methods along both the Western and Eastern Oil Transit Lines (OTLs). There were a number of complex technical issues to resolve before the tests could be conducted, including developing a solution for managing the solids generated during the pigging operation.

BPXA began pigging operations along the Lisburne OTL in June. In-Line Inspection (ILI) of the Lisburne OTL showed good results and affirmed our confidence that the lines where fit for service. BPXA began pigging operations along the Eastern OTL in early July. Analyses of these "smart pig" inspections were received on Friday, August 4 and indicated 16 significant anomalies at 12 different locations along a segment of the Eastern OTL. BPXA began immediate physical and ultrasonic testing of these anomalies and verified the presence of additional corrosion. BPXA's inspections also revealed insulation staining along a segment of the Eastern OTL. With the knowledge of these results, BPXA immediately shut down production at Flow Station 2 as a precautionary measure and BPXA technicians subsequently discovered a small leak after close visual inspection along the FS-2 to FS-1 pipeline segment.

The smart pig results along the Eastern OTL were unexpected. Because the exact cause of the corrosion mechanism was unknown, BPXA was concerned over the condition of the Western OTL. Thus, BPXA took the prudent step on the morning of August 6 of announcing our intent to systematically shut-down both sides of the Prudhoe Bay field until existing inspection data could be further assessed and verified with follow up inspections.

Some have questioned whether BPXA made a rash decision to shut down the field over a small leak. To me, as President of BPXA, the decision to shut-down was a reaffirmation of BP's values and was the responsible thing to do. We took this step to prevent a potential release from occurring.

In light of these incidents, many have alleged that BPXA's inspection and maintenance program was inadequate. Given our almost 30 year performance history and our existing programs, we believed we had an effective corrosion management program in place. Clearly, recent events have shown that our program did not detect the type of pitting corrosion identified here. We are examining and analyzing this data closely to ensure that we apply this learning to improve our program.

BP Corrosion Prevention Program for the North Slope

Corrosion is the natural degradation of a material like steel pipe that results from a reaction with its environment. While corrosion cannot be eliminated, it can be effectively managed through a combination of monitoring and mitigation treatments. The goal of corrosion mitigation programs is to control corrosion rates to acceptable levels.

Corrosion rates are not static, however, and they can increase or decrease depending on fluid properties or changes in conditions that affect the efficacy of corrosion inhibitors. For that reason, locations that are prone to corrosion damage, or where damage has been identified, are inspected as often as every three to six months.

BPXA uses pigging, ultrasonic testing (UT), visual inspections, corrosion inhibitors and other techniques as appropriate for each individual oil field's characteristics. We employ a risk-based management program whereby resources/activities are concentrated in areas where corrosion is expected to occur. Exhibits 3 and 4 describe the operations of a gathering center in producing, separating and pumping oil and show a graphical representation of a producing field.

BPXA's program was designed to control corrosion, extending the useful life of valuable North Slope infrastructure. The 2006 annual budget for BPXA's corrosion monitoring and mitigation program is $74 million, an increase of 15 percent from 2005, and 80% from 2001. As Exhibit 5 demonstrates, corrosion management "spend" has increased significantly over the last 5 years despite the reduction in Prudhoe Bay production volumes.

Inhibition

A key element of the program is widespread continuous inhibitor injection. In short, the best way to address corrosion is to prevent it from happening in the first place. Our commitment to effectively managing corrosion on the North Slope is reflected in our corrosion inhibitor injection rates. Exhibit 6 is a diagram of the inhibitor concentrations and the corresponding corrosion rates achieved as measured by corrosion coupons.

We continuously monitor the effectiveness of the inhibition programs with corrosion coupons and electrical resistance (ER) probes. The ER probes take readings every 4 hours of the corrosion potential of the fluids and allow us to make adjustments to corrosion inhibitor injection rates on a weekly basis. Exhibit 7 is a typical configuration of a corrosion coupon and ER probe.

We have not been satisfied with simply maintaining the *status quo*. We conduct an on-going and very active inhibitor research program outlined in Exhibit 8.

Monitoring and Inspections

BP's North Slope pipeline monitoring and inspection program incorporates combinations of ultrasonic, radiographic, magnetic flux, guided wave and electromagnetic inspection techniques. Ultrasonic and radiographic testing are used as an indicator to trigger further action and is sound for pipelines that are accessible above-ground.

BPXA's overall annual inspection program consists of conducting inspections at about 100,000 locations on pipelines in Prudhoe Bay. Of these inspections, approximately 60,000 are for internal corrosion inspection and approximately 40,000 are for external corrosion inspection.

BPXA runs approximately 370 maintenance pigs per year on the North Slope. In addition, we utilize coupon monitoring, smart pigging, leak detection systems and surveillance by personnel to provide integrity assurance and maintain safe operations (See Exhibit 9 for detail regarding pigging operations).

Lines are pigged in Prudhoe Bay either because of mechanical issues or because corrosion monitoring suggests it. The frequency of pigging is specific to each pipeline and varies significantly across the North Slope and the industry. For example, the Northstar oil pipeline is pigged every two weeks to prevent paraffin buildup.

Another technology is ultrasonic testing (UT) which involves the use of a high frequency sound wave to produce a precise measurement of the thickness of a material. Our UT inspections are not simply one reading at one location on the pipe. Rather, they are an inspection of the full circumference of the pipe over a one foot length. So when we count one UT inspection, it is really hundreds of individual readings at one location. The technology is a proven diagnostic tool routinely used for corrosion monitoring.

We also use corrosion coupons (see Exhibit 7) throughout our operations in order to obtain additional information about any corrosive conditions that might exist in our systems that escaped other inhibition and monitoring programs. The majority of our coupons are read on a three to four month basis.

Important components of pipeline inspections also include regular visual inspections and the use of Forward Looking Infrared (FLIR) devices. FLIR technology is used to spot heat signatures of crude oil and is especially useful during winter months.

Mitigation of Corrosion

In the design of pipelines, many corrosion mitigation methods are considered. The selection of material from which to manufacture pipe, such as corrosion resistant alloys like stainless or low carbon steel, is one consideration. Another option is the use of various coatings and linings that provide pipelines protection against corrosive agents.

Technology used to protect metal structures from corrosion includes cathodic protection, a technique that is usually used in buried pipelines and takes advantage of electrochemical properties that reduces a metal structure's corrosion potential.

Mitigation also involves the application of corrosion inhibitors and biocides in conjunction with preventative maintenance such as pigging and physical repair of external damage.

External corrosion is mitigated by removal of the source for the water, drying, cleaning and buffing of the damage area and application of new insulation and/or coatings. If external corrosion limits the integrity of the pipeline, then repair techniques are used such as sleeves, clock springs, clamps and or composite wraps.

If the programs are so good, what happened?

The recent leaks were on the oil transit lines, which are the last step in the process before TAPS. By this point, the major corrosion battles have already been fought. General corrosion and pitting in the OTLs were monitored by corrosion coupons on a quarterly basis, and have consistently shown very low corrosive conditions in these lines, always below the BP targeted wall thickness loss of less than .002 inches per year. Exhibit 10 shows coupon results in the OTLs. In spite of their low corrosivity, the OTLs were included in our on-going UT monitoring program. Monitoring results were confirmed annually, and have consistently revealed corrosion to be under control on these lines.

It has been frequently reported that BPXA didn't perform in-line inspections (ILI) on these lines, and that if we had, this problem would have been prevented. In fact, the March 2006 pipeline failure occurred on the WOA line, which had been pigged in both 1990 and 1998. These inspections did not identify a corrosion mechanism at work.

The first indication of a change in conditions came from our corrosion monitoring program in the facilities upstream of the WOA OTLs. An increase in facility corrosion upstream of the WOA OTLs, while not alarming, caused us to perform additional UT inspections of the OTLs. The results of these inspections led us to schedule another ILI of the WOA OTL for mid- 2006. Unfortunately, the March release occurred before that pig run was conducted.

It has been misreported that the OTLs have wide-spread corrosion. In fact, no evidence of general corrosion (i.e. wall loss throughout the pipe) along the OTLs has been found. If there was, it would have been quickly detected by our monitoring programs. Instead, the OTLs have widely spaced, mostly isolated dime-sized pits about 5 to 10 feet apart. The corrosion is more serious on the upstream segments of these lines, which have the lowest flow velocities.

Why wasn't the pitting corrosion detected by BP's monitoring program? BP had an active inspection program for these lines, but the isolated pits were too widely spaced to be detected by that program. For example, there was an inspection site adjacent to the site where a leak occurred. The inspection did not detect any corrosion – just a few feet away from a pit.

We initially believed that the corrosion along the WOA had developed due to certain operational changes in the WOA, and that the EOA was not similarly affected. Our initial inspections of the EOA line appeared to confirm this. However, these conclusions were premature and made before the latest inspections were completed. The in-line inspection of the EOA OTL revealed that the pattern of corrosion damage is similar in both the EOA and WOA, although the precise corrosion mechanism remains under study.

Coffman Report

In the last few days, mention has been made of the annual reports that have been submitted by an engineering firm, Coffman, which reviewed BPXA's inspection and maintenance program on behalf of the State of Alaska and found several deficiencies in BPXA's program. The implication is that if these deficiencies had been addressed, then the recent pipeline incidents would have been prevented.

Previous Coffman reports have noted there were isolated pockets of accelerated corrosion in BPXA's North Slope infrastructure. Notably, Coffman also stated those problem areas were discovered during the regular course of inspection. Excerpts from recent Coffman reports are shown below:

- The 2003 report states: "From a global perspective of oil and gas production, Greater Prudhoe Bay (GPB) and related facilities have an aggressively managed corrosion control program. This suggests an adequate long-term commitment to preserving facilities for future production and sensitivity to environmental consequences."

- The 2004 report credits BP with transparency and candor, and for maintaining a corrosion program in which there is no "acceptable" risk. It said BP's program "is effective and exceeds common industry practice," and that "Corrosion in most of the pipeline system has been reduced to a negligible level."

When discussing internal corrosion on oil lines, the Coffman reports focus attention on the "production system" of well lines and flow lines, the "three-phase" lines that carry a mix of oil, water and gas. These are the lines where corrosion is more of a known threat than in the transit lines that carry "processed oil". Coffman does not specifically discuss the oil transit lines in any of its reports.

Thus, while there were areas in Coffman's reports recommending additional inspection and maintenance activities, on balance they offered support for the efficacy of BPXA's corrosion management program.

Path Forward

BPXA's incident analysis is underway, but we have already taken steps to characterize the problem and assess the integrity of all the OTL lines. This information has been submitted to the Office of Pipeline Safety (OPS), whose staff is currently reviewing it. We also have outside experts who are reviewing the data and who will provide independent opinions about its adequacy.

We have been working in cooperation with OPS to ensure the safety and integrity of these systems. We pledge to continue working in cooperation with DOT and other interested stakeholders to ensure that these lines, and all our pipeline operations on the North Slope, are operated to a high standard of operational excellence.

Now we must focus our attention on the future – and what we will do to mitigate the risk of future leaks occurring in these oil transit lines. We have committed to undertake seven key actions:

First - Run an in- line inspection tool in each of the Prudhoe Bay Oil Transit Lines that are returned to service.

Second - Confirm through testing the exact corrosion mechanism that caused this problem and modify our mitigation programs accordingly.

Third - Implement maintenance pigging in all Oil Transit Lines.

Fourth - Include all BP operated Oil Transit Lines on the North Slope into DOT's Pipeline Integrity Management Program. This will cover all 122 miles of BP Oil Transit Lines in Alaska.

Fifth - Replace 16 miles of WOA / EOA oil transit lines; regardless of in line inspections outcome, in order to ensure velocity rates are acceptable. The estimated cost of this is in excess of $150 million.

Sixth - The organizational structure has been changed with the addition of a Technical Director to provide independent assurance of our integrity management efforts.

Seventh - Spending on Prudhoe Bay major maintenance will increase to $195 million in 2007, a nearly four fold increase from 2004 spending levels.

In addition to these physical changes we remain committed to work collaboratively and proactively with the DOT and State regulators.

Business Resumption Plan

Western Operating Area

BPXA has conducted more than 4,876 UT tests of the Western Operating Area OTLs subsequent to the August 6th announcement. These subsequent inspection results have not indicated any wall thickness loss greater than 36%. In addition, BPXA has begun a surveillance effort that includes daily over-flights using infrared cameras, as well as the use of hand-held infrared cameras on the ground. The cameras can detect small leaks by sensing changes in pipeline surface temperatures. Two vehicles with spill response equipment and carrying observers with infra-red leak detection equipment are patrolling the line 24 hours a day. They will be teamed with pipeline walkers who will visually inspect the line 10 times a day.

Ongoing UT inspections have slowed in recent days due to the detection of asbestos fibers in the mastic used to secure the pipeline insulation. Additional tests are being conducted to determine what (if any) additional protective measures need to be put in place to enable employees to continue to perform insulation removal.

Production had been reduced by 90,000 barrels/day due to a compressor malfunction in GC-2. Replacement of the compressor was completed on Sunday, August 27 and production in the WOA has been restored to approximately 220,000 barrels/day.

Eastern Operating Area

Work continues on removal of insulation from pipe; line inspections and testing are underway. We are averaging 200 to 300 inspections per day. About 160 workers are dedicated to this inspection effort.

We are currently inspecting the 34" segment that runs from FS-1 to Skid 50 (see Exhibit 2). If the inspection results show that the line has integrity, we will request permission to re-start that line from the DOT. We are currently working through a process with DOT to make that request once we can provide assurance that the line can be safely re-started and pigged.

This will allow resumption of partial production from Flow stations 1 and 3. After re-start, these line segments will need to be inspected with a smart pig to meet requirements imposed by the DOT. If inspection results indicate that the remaining EOA OTLs are not fit for service, then by-pass options will be completed as soon as practicable.

Regarding the leak along the FS-2 transit line, the estimated 23 barrels of oil spilled has been cleaned up. The line currently holds about 13,000 barrels of crude. Metal sleeves have been installed on those sections of the transit line with severe corrosion. BPXA has submitted a plan to the U.S. Department of Transportation for de-oiling this segment of line.

Concurrent with our inspection activities, by-pass options are being pursued to restore as much production as possible in an environmentally safe manner. The focus is largely on the EOA and includes new options to divert production from each of the existing Flow Stations to Skid 50 (see Exhibit 2).

- The production from FS-2 is being engineered to route to the Endicott production line through new piping.
- The production from FS-1 is being engineered to route to the Endicott production line through new piping.
- The production from FS-3 is being engineered to route through Drill Site 15 and then to a jumper into the Lisburne OTL.

Work on these options will be completed by the end of October.

All of this work is taking place as BPXA prepares for ultimate replacement of the 16 miles of WOA/EOA oil transit lines. Sixteen miles of pipe has been ordered and is expected on the slope during the fourth quarter. We are hopeful that work can be completed during the winter construction season.

At this point, we do not have a schedule for restoring all or a portion of EOA production and can't speculate on how long it's going to take.

While many of the circumstances surrounding the incidents at Prudhoe Bay are known there is much more that needs to be done to fully understand the corrosion mechanism we experienced. These results will be known in due course and will be shared in a fully transparent way. In the meantime, BPXA is committed to restoring full production to the EOA as soon as we are confident it can be done in a safe and environmentally responsible way.

New Pipeline Safety Regulations

Historically, certain pipelines that operate at low stress were exempt from U.S. DOT oversight. This exemption applied to onshore pipelines such as oil transit lines on the Alaskan North Slope.

However, since the March 2, 2006 spill from BP's Western OTL (a low-stress system), DOT has proposed a rule to revise the low-stress exemption. Upon completion of its rulemaking process, it is likely that any low-stress pipeline that is in an environmental high consequence area will become a regulated pipeline under DOT jurisdiction. These proposed regulatory changes are strongly supported by BP.

Employee Concerns

I'd like to now turn to a final point about a related subject, that of employee concerns. A number of people have raised questions and concerns about our corrosion inspection, monitoring and prevention program. Sometimes these concerns have been voiced inside the company. Sometimes, they have been taken to regulators or to the media.

I view every employee concern as an opportunity to address a problem. I don't care how or with whom they are raised. I just want to know about them. We need the input of our workers to continuously improve and be the best business we can be.

BP feels the same way. Harassment, intimidation, retaliation and discrimination against workers who raise concerns are not tolerated within BP.

We have a number of channels through which workers can raise concerns. In addition to just the normal line management channels, we have employee-run safety committees, we have a worldwide anonymous program called Open Talk, and in Alaska we have other, confidential methods for employees to communicate workplace concerns. As you have just heard, BP America has made the decision to add an ombudsman reporting to Bob Malone with specific emphasis on Alaska issues. We also track employee satisfaction and concerns via a People Assurance Survey conducted annually. The results from the 2006 survey indicate a 13% improvement year over year for our Slope-based workforce.

BP has a track record of acting on employee concerns. Over the last several years employee safety committees have raised, and we have jointly addressed over 600 safety concerns. They range from the quality of vehicle headlights to challenging whether the injection of fluids into disposal wells was appropriate.

More importantly, BP has investigated and addressed concerns raised about our corrosion inspection, monitoring and inspection program.

During the summer of 2002 a BP employee received two anonymous calls alleging falsification of corrosion inspection reports by a handful of contract workers. BP brought in an outside firm, audited the work performed on the program year-to-date, and determined that a small percentage of inspections had indeed been falsified. The investigation also called into question our inspection contractor's quality assurance program.

Our inspection contractor dismissed the workers responsible for falsifying inspection reports and three months later, when the inspection contract was up for renewal, we brought in a new company to do this work.

As another example, in 2004, after receiving allegations of harassment, intimidation and retaliation by a BP corrosion program manager we brought in an outside law firm, Vinson and Elkins (V&E) to conduct an investigation. Vinson and Elkins found evidence of intimidating behavior that had made some corrosion workers reluctant to raise health and safety concerns.

We acted on the recommendation of V&E and transferred the manager in question outside Alaska into a technical consulting role.

When the company received non-specific allegations that cost cutting and deficiencies in the corrosion program were going to lead to a major incident on the North Slope, the BP Group sent John Baxter, BP Group chief engineer and several technical experts from outside Alaska to assess the overall quality of the program. Their review assessed the process, procedures and controls in sufficient detail to validate the results of the program with specific focus on areas thought to be encompassed by the allegations.

The top line finding of the "Baxter" audit was "BPXA has an adequate corrosion management system which to some extent may be overly detailed, but the extent, complexity and ageing state of the pipe work will always create the potential for leaks."

Again, this audit is an example of BP receiving concerns and investigating them. It resulted in recommendations for improving the program that have been or which are still being implemented.

When concerns were raised about whether BPXA had inappropriately influenced edits made in an Alaska state review of the company's corrosion management program, BP again brought in an outside law firm to investigate. The investigation found no evidence of improper behavior on the part of the company or its employees.

Bob Malone has announced today that he plans to review how the company has handled every employee concern raised in Alaska since the ARCO acquisition was completed in 2000.

I welcome the inquiry. I see it as a way to improve an important aspect of how we operate our business.

Conclusion

In closing Mr. Chairman, since March, we identified an unexpected gap in our corrosion control program, and we will correct it. In the future, we will have a better system to protect our pipelines and we have already gained important new operating knowledge.

I deeply regret the problems caused by the situation we discovered. But we will emerge stronger and more knowledgeable as a result of this challenge.

EXHIBIT 1

Fact Sheet Prudhoe Bay

Background
The Prudhoe Bay field is the largest field in North America and the 18th largest field ever discovered worldwide. Of the 25 billion barrels of original oil in place, more than 13 billion barrels can be recovered with current technology.

Prudhoe Bay field was discovered on March 12, 1968, by ARCO and Exxon with the drilling of the Prudhoe Bay State #1 well. A confirmation well was drilled by BP Exploration in 1969. The next 8 years saw frenetic activity as ARCO, BP, Exxon, and other companies with lease holdings in the vicinity worked to delineate the reservoir, resolve equity participation, and put together an initial infrastructure. Prudhoe Bay came on stream in June 20, 1977, rapidly increasing production until the field's maximum rate was reached in 1979 at 1.5 million barrels per day. This rate was maintained until early 1989, and is currently declining by 10% per year. Production totaled approximately 475,000 barrels per day on January 1, 2004. More than 10 billion barrels have already been produced.

Prior to 2000 the Prudhoe Bay field was comprised of the East Operating Area, operated by ARCO, and the West Operating Area, operated by BP Exploration. Upon acquisition of ARCO by BP and sale of ARCO Alaska assets to Phillips Petroleum, the two operating areas were consolidated and BP became the sole operator of Greater Prudhoe Bay. Although BP operates the field, a total of nine companies have an interest in the field leases. The profits and costs are shared amongst the owners, according to their ownership.

Ownership
BP Exploration (Operator), 26%
ConocoPhillips Alaska Inc., 36%
ExxonMobil, 36%
Others, 2%

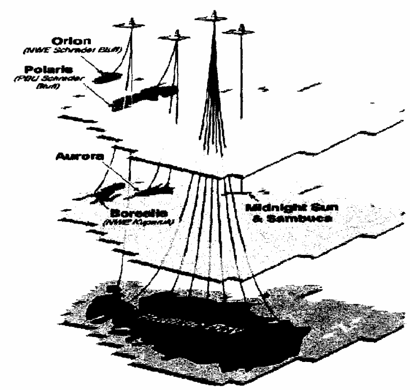
Greater Prudhoe Bay Fast Facts	Discovered	[illegible]
	Production started	[illegible]
	Oil production wells	[illegible]
	Participating field area (including satellites)	[illegible]
	Daily production (thousands)	[illegible]
	[illegible]	[illegible]
Midnight Sun Fast Facts	Production started	[illegible]
	Oil production wells	[illegible]
	Participating field area (including satellites)	[illegible]
	Daily production (thousands)	[illegible]
Aurora Fast Facts	Production started	[illegible]
	Oil production wells	[illegible]
	Participating field area (including satellites)	[illegible]
	Daily production (thousands)	[illegible]
Orion Fast Facts	Production started	[illegible]
	Oil production wells	[illegible]
	Participating field area (including satellites)	[illegible]
	Daily production (thousands)	[illegible]
Polaris Fast Facts	Production started	[illegible]
	Oil production wells	[illegible]
	Participating field area (including satellites)	[illegible]
	Daily production (thousands)	[illegible]
Borealis Fast Facts	Production started	[illegible]
	Oil production wells	[illegible]
	Participating field area (including satellites)	[illegible]
	Daily production (thousands)	[illegible]

Location
The Prudhoe Bay field is located 650 miles north of Anchorage and 400 miles north of Fairbanks. It is 1200 miles from the North Pole and 250 miles north of the Arctic Circle. Pump Station 1, the beginning of the Trans Alaska Pipeline, is located with in the perimeter of the Prudhoe Bay field.

Source:
Page: 1

Revised: August 06

EXHIBIT 1 (page 2)



Geologic Features
The Prudhoe Bay field, like many oil fields, consists of layers of porous rock that contain gas, oil, and water. The water, being the heaviest, lies in the lower rock layers of the field. The oil lies above the water, and the gas rests atop the oil. The oil, gas, and water are held in the Prudhoe Bay field by changes in the rock type (stratigraphy) and by the tilt and faulting of the rock layers. Sandstones are porous and allow the fields' fluids to flow through them. Shales, however, act as barriers to fluid flow. Thus, whenever a sandstone layer meets a shale layer, either through faulting or as a factor of how the rock was originally deposited, the shale stops the fluid flow and the fluids are trapped.

The oil at Prudhoe Bay is trapped in the Sadlerochit formation, a sandstone and gravel structure nearly 9,000 feet underground. In some locations the oil-bearing sandstone was 600 feet thick during the field's early life. Today, average thickness of the oil bearing zone is about 60 feet.

Natural gas
The field contains an estimated 46 trillion cubic feet of natural gas (in place) in an overlying gas cap and in solution with the oil. Of that, about 26 trillion cubic feet are classified as recoverable.

Investment
The major owners have invested more than $25 billion to develop the Prudhoe Bay field and the transportation system necessary to move Prudhoe Bay crude oil to market.

Satellite Fields
Since 1998 five satellite fields have been discovered and developed within the unit boundaries of the Prudhoe Bay oil field. These fields are Midnight Sun, Aurora, Orion, Polaris, and Borealis. One of the key objectives of the field's development has been to maximize sharing of existing infrastructure, including production and support facilities. The production wells for these satellite fields are located on one of the Prudhoe production pads. The liquids are processed through Prudhoe Bay facilities.

Source:
Page: 2

Revised: August 06

EXHIBIT 1 (page 3)

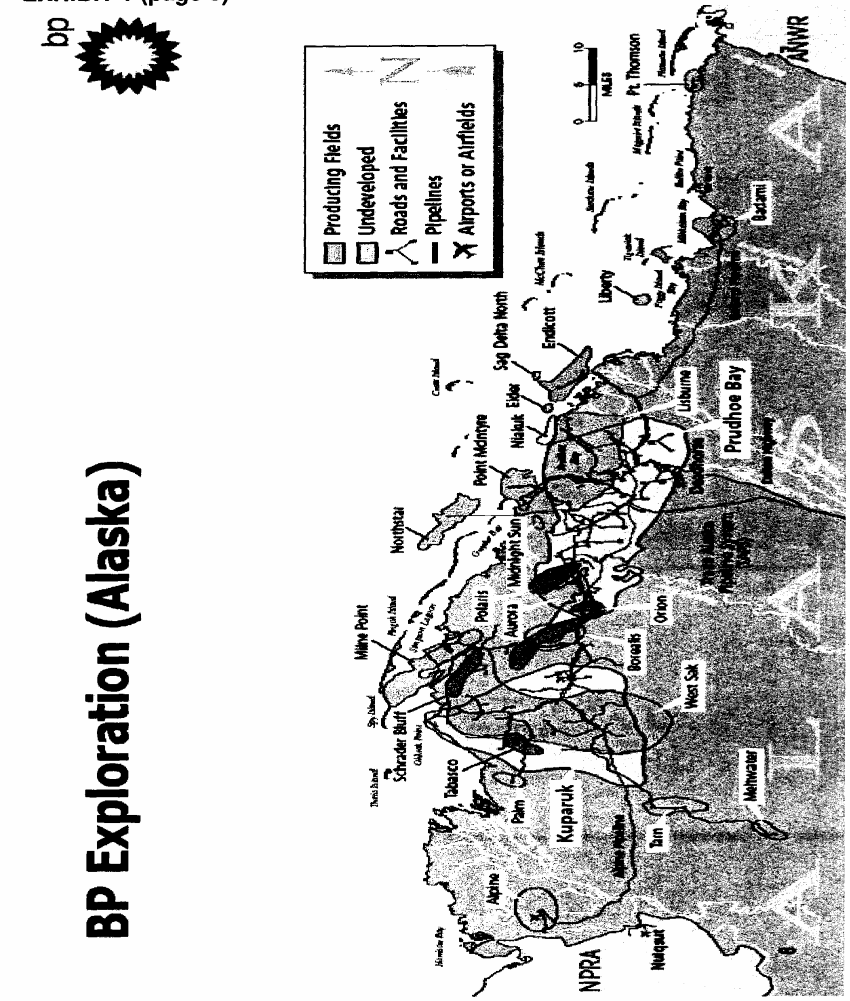


EXHIBIT 2

Oil Transit Line Diagram

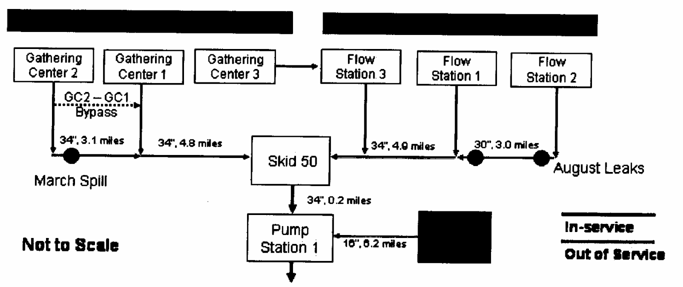


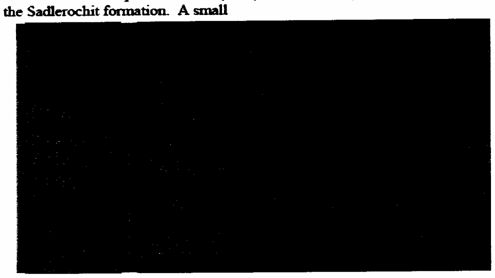
EXHIBIT 3

Fact Sheet Gathering Centers, Flow Stations

Introduction
The purpose of separation facilities (known as "**gathering centers**" on the western side of the field **GC-1, GC-2, GC-3**,and "**flow stations**" on the eastern side **Flow-1, Flow-2, Flow-3**) is to separate raw crude oil, water and gas produced from the wells into the three main components. The crude must meet certain pipeline specifications before being shipped to Pump Station 1 at the start of the Trans Alaska Pipeline System (TAPS). Each separation facility is designed to process about 350,000 barrels of raw crude oil per day. The separation facilities can also handle various amounts of gas and water. The largest gas handling facilities are Flow Station 1 and Gathering Center 1, each capable of processing 2.7 billion cubic feet of gas per day. The largest water handling facility is Flow Station 2 which can process up to 600,000 barrels of water per day.

Oil System
Raw crude produced from individual production wells located at well pads is diverted to flowlines (pipelines). The flowlines transport the raw crude to the separation facilities, where the water and natural gas mixed with the raw crude are removed. The stabilized crude is then sent to Pump Station 1, the beginning of TAPS.

Gas System
The separated natural gas is compressed, dehydrated, and transported to the Central Gas Facility (CGF) where natural gas liquids are recovered and sent to TAPS and a portion are used to make miscible injectant which is used in enhanced oil recovery. The remaining dry gas goes to the Central Compression Plant (CCP), where the majority is injected into the Sadlerochit formation. A small



portion of the compressed and dehydrated produced gas is used within the Prudhoe Bay Unit as fuel gas. At GC-1 and FS-3, another portion is diverted to the "gas lift" compression plant. Gas lift is a process where recovered natural gas is re-injected into the wells to add buoyancy to the oil to help "lift" it to the surface.

Water System
The "produced" water separated from the raw crude is processed to remove oil and solids. This treatment process yields an oil stream (which is returned to oil processing equipment), a dirty water stream (which is injected into the Cretaceous formation nearly 1 mile below the Earth's surface), and a treated produced water stream (which goes to injection wells at the well pads). The treated produced water injected into the formation supports a field-wide waterflood program designed to maintain reservoir pressure and "sweep" crude oil from injection wells toward oil production wells.

EXHIBIT 4

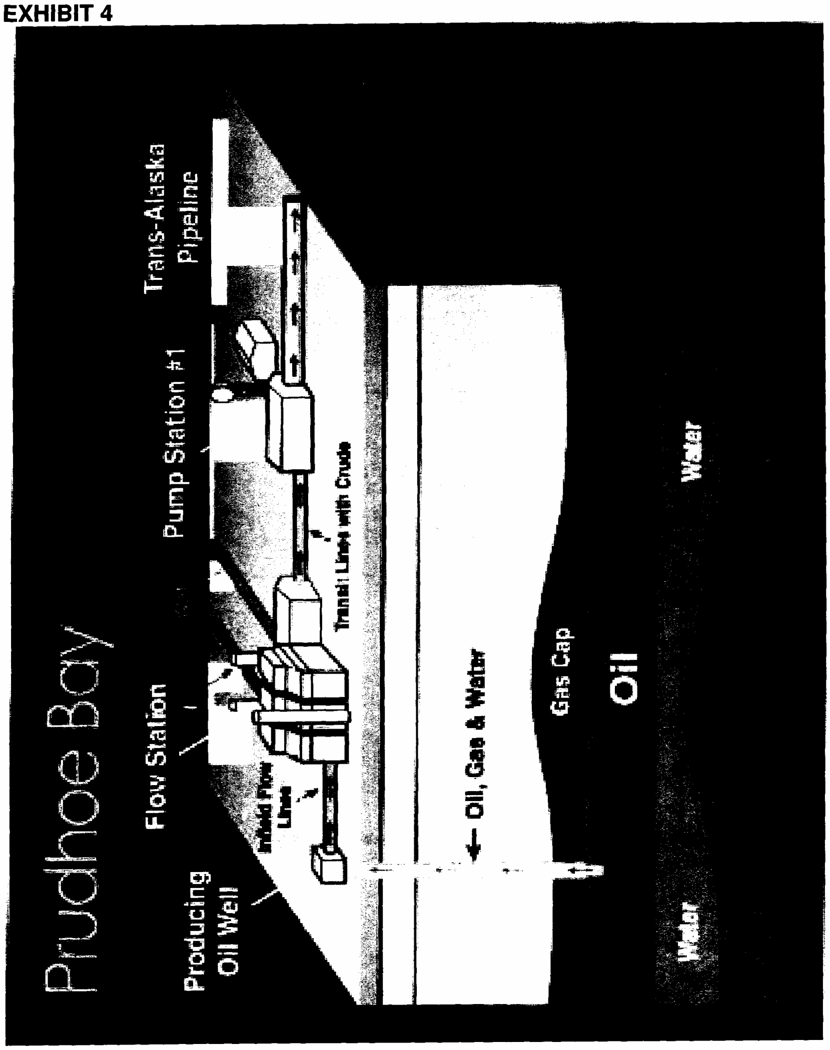

Prudhoe Bay
Producing Oil Well
Flow Station
Pump Station #1
Trans-Alaska Pipeline
Transit Lines with Crude
Oil, Gas & Water
Gas Cap
Oil
Water
Water

EXHIBIT 5

Prudhoe Bay Corrosion Spend Versus Production

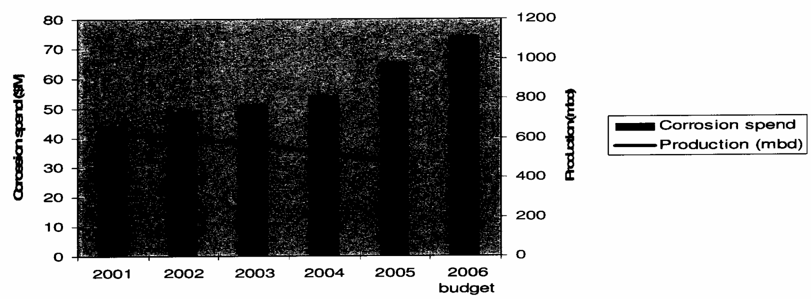


Exhibit 6

Diagram of Inhibitor Injection Rates

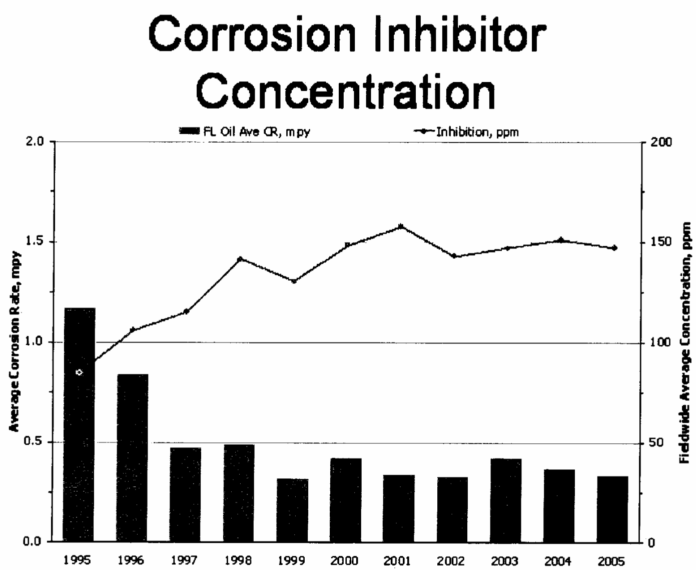
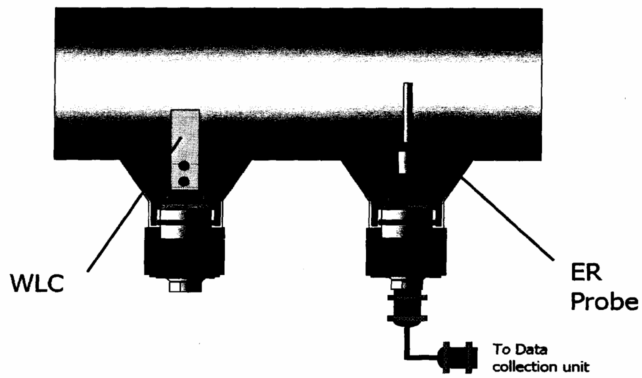


EXHIBIT 7

Corrosion Monitoring Schematic



WLC – Weight loss coupon ER – Electrical resistance

Coupon monitoring is a method that involves exposing a sample of the pipeline material (the coupon) to conditions within the pipe for a given duration, then removing the specimen for analysis. Material loss observed over the exposure period is expressed as corrosion rate.

Exhibit 8

Inhibitor Research Program

Inhibitor field Trials

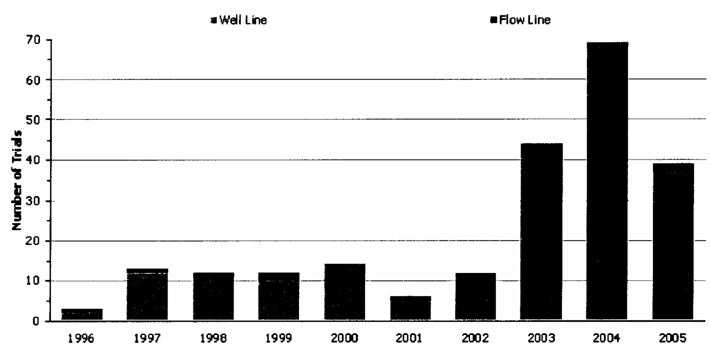
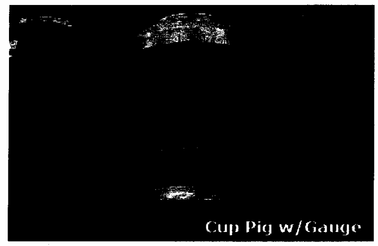
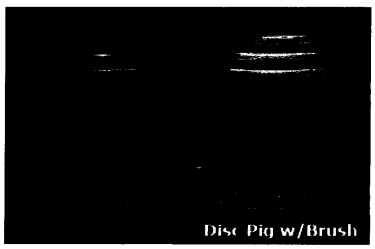


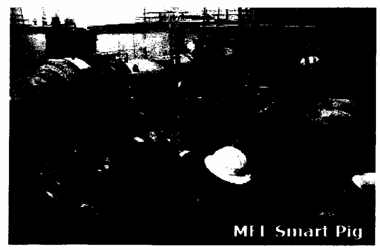
EXHIBIT 9

Pigging Operations


Foam Pig


Cup Pig w/Gauge


Disc Pig w/Brush

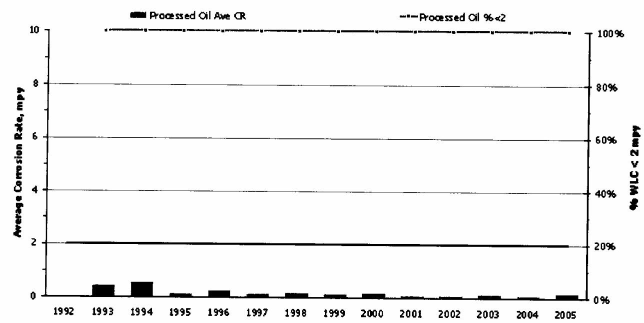

MFL Smart Pig

Maintenance pigging is the term for using a mechanical tool to clean the inside of a pipeline. The tool comes in various configurations depending on the application (e.g. foam, disc, cup or brush). Typically the tool is used with fluids remaining in the line. The pressure of the fluids (oil, gas and/or water) acts as the drive mechanism for moving the pig from point to point. Maintenance pigging removes undesirable material, debris (liquid or solid) e.g., wax, paraffin, scale, sediment and water.

For mechanical integrity, specialty tools like "Smart Pigs" rigged with Magnetic Flux Leakage (MFL) and Ultrasonic Thickness testing (UTT) modules are used for accurate inspections of the wall of pipelines. Smart pigs can also perform mapping with inertial guidance technology and detect cracks from stress corrosion. Smart pigs and other automated techniques are helpful in identifying locations that should be more closely monitored using one of the point inspection methods (e.g. visual; ultrasonic; radiographic).

Exhibit 10: Corrosion Coupon Results in OTLs

GPB Oil Transit Line Coupons



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MR. WALDEN. Thank you, Mr. Marshall. If you welcome scrutiny, you are going to feel real welcome here today.

Mr. Hostler, thank you for being here, sir, and we look forward to your comments.

MR. HOSTLER. Mr. Chairman, distinguished members, thank you for inviting me to appear before your subcommittee.

I am Kevin Hostler and I am President and CEO of Alyeska Pipeline Service Company. I am here representing 1,600 employees and contractors who operate and maintain the Trans Alaska Pipeline System, or TAPS. We understand the critical importance of our operation of this system to the State of Alaska and to the Nation.

I am here today to answer two fundamental questions I believe you have about our operation. First, to address the question of the potential for accelerated corrosion on our operations at TAPS, and second, to address the impact of reduced throughout as a result of the recent spills. My written testimony covers the fundamentals of both of these questions. It also provides a clear description of our integrity management program. We have a thorough integrity management program that has been vetted by regulators. My team and I are confident that the steps we have taken to mitigate the potential for accelerated corrosion are the right ones. In my written testimony, you will find a description of our routine monitoring and maintenance program to prevent both internal and external corrosion in the main line as well as in our pump stations and terminal. I would be happy to answer any questions regarding our integrity management program, about the potential for corrosion in the TAPS system, the impact of low throughput on our system, or any other question you may have.

I would like to repeat that I represent a team of high-quality people who operate and maintain this system, a system that has delivered 15 billion barrels of oil to the American public. I am confident our employees are capable of dealing with the challenges ahead and would bring any issue that they had to our attention, any issue that impacts the integrity of our pipeline.

I thank the subcommittee for this opportunity.

[The prepared statement of Mr. Kevin Hostler follows:]

PREPARED STATEMENT OF KEVIN HOSTLER, PRESIDENT AND CEO, ALYESKA PIPELINE SERVICE CO.

Alyeska pipeline SERVICE COMPANY P.O Box 196660 ANCHORAGE, ALASKA 99519-6660 TELEPHONE (907) 787-8700

Summary of Kevin Hostler Testimony
Subcommittee on Oversight and Investigations
House Energy and Commerce
September 7th, 2006

Kevin Hostler, President and CEO of Alyeska Pipeline Service Company, will discuss two important issues with the Subcommittee: to provide the committee with assurance about corrosion prevention on the Trans Alaska Pipeline System (TAPS) through its integrity management program; and to provide insight into the challenges Alyeska may face due to reduced throughput in the TAPS mainline and how the company will manage these challenges.

Hostler also explains how Alyeska has been involved with managing any potential solids generated by Prudhoe Bay oil field pigging operations.

CORROSION CONTROL AND INTEGRITY MANAGEMENT ON TAPS

Alyeska has not found evidence of accelerated corrosion in the TAPS mainline. After the Prudhoe Bay spill in March, Alyeska operations and engineering personnel reviewed the company's corrosion control program and have been implementing enhancements identified during this review. Alyeska has an integrity management program that includes corrosion control. This program is audited annually by the U.S. Department of Transportation Office of Pipeline Safety. The company runs instrumentation pigs through the line every 3 years and has run 60 since the start up of operations in 1977.

OPERATING TAPS AT REDUCED THROUGHPUT

Based upon technical reviews conducted to date, it is likely, although not certain, that Alyeska will be able to safely manage lower throughputs associated the partial suspension of Prudhoe Bay production. To do this, Alyeska will need to resolve several technical challenges including: managing issues associated with cooler temperatures of the oil, particularly in the winter, and the potential for water and paraffin drop out from the oil; managing the efficiency of the biological treatment process of our ballast water plant because of lower ballast water flows due to reduced tanker traffic to the Valdez Marine Terminal; and managing the potential for increased vibration due to slack line conditions at the three mountain passes the pipeline must cross.

PRUDHOE BAY TRANSIT LINE PIGGING SOLIDS

Alyeska has constructed pipe and processing facilities at Pump Station One that will allow the company to receive pigging solids from BPXA transit line pigging operations without exposing TAPS to unacceptable risks. This is expected to be fully operational by the middle of September.

Thank you for the opportunity to address the subcommittee about the trans-Alaska pipeline and Alyeska Pipeline Service Company. My name is Kevin Hostler and I am the President & CEO of Alyeska Pipeline Service Company. I am here today representing the 1600 people who operate and maintain the Trans Alaska Pipeline System – or TAPS. Our company was founded in 1970 to design, construct, and operate TAPS to safely and efficiently move oil from the North Slope of Alaska through the Valdez Marine Terminal 800 miles to the south. Alyeska Pipeline Service Company is owned by a consortium of five companies: BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska, Inc., ExxonMobil Pipeline Company, Unocal Pipeline Company, and Koch Alaska Pipeline Company.

I am here today to discuss two important issues: to provide the committee with assurance about corrosion prevention on TAPS through our integrity management program; and to provide insight into the challenges we may face due to reduced throughput in the TAPS mainline and how we will manage these challenges.

I will also explain how Alyeska has been involved with managing any potential solids generated by Prudhoe Bay oil field pigging operations.

The issues outlined in this testimony are important to me, our employees, and our stakeholders. I take seriously the responsibility I have to run a safe operation that is properly maintained to transport the oil we receive. Safety is our first priority in resolving the issues we currently face.

Since the March 2006 Prudhoe Bay spill by – and continuing through the August spill and production shutdown, we have offered our assistance to and worked with BP Exploration Alaska Inc. (BPXA) on a wide range of operational issues. We have offered response personnel and equipment; we received a technical briefing on the root causes of the March spill; conducted and then shared our impact assessment analysis of the impact of potential pigging solids being introduced into the TAPS mainline; discussed various options to address these solids; and completed construction of a bypass line to offer a method to receive and process any solids generated by Prudhoe Bay pigging activities.

CORROSION CONTROL AND INTEGRITY MANAGEMENT ON TAPS

Alyeska has not found evidence of accelerated corrosion in the TAPS mainline. After the Prudhoe Bay spill in March, our operations and engineering personnel reviewed our corrosion control program and have been implementing enhancements identified during this review.

When I learned that the apparent cause of the spill was corrosion, I asked my integrity engineering staff and my pipeline operations staff to provide me with assurance that accelerated corrosion was not a threat to TAPS integrity and what additional precautions, beyond our existing program, should we undertake. This technical group held a brainstorming session to think through all of the potential impacts to TAPS based upon what we knew about the March spill. From this we created a Top Ten list of issues we should pursue from an integrity perspective. The review verified we have a solid corrosion control program and did not identify any immediate corrosion related threats to TAPS. Alyeska staff are making satisfactory progress on the issues in the list. I have shared this list and a status matrix with committee staff. I will answer any questions from the subcommittee about this list.

Specific to potential accelerated corrosion on TAPS similar to what BPXA reported, the first place we believe we would see this type of corrosion would be in the piping at Pump Station One. As part of our Top Ten list, we added several new corrosion monitoring locations at Pump Station One, including the deadlegs at the station. Deadlegs are sections of pipe inside the Pump Stations that have no active flow. As an additional precaution we have increased our corrosion inhibitor injection volumes by about 25% throughout the system.

It is important to note that TAPS generally benefits from the co-mingling of the oil from all of the North Slope fields before they enter the mainline. In addition, TAPS benefits from a velocity in the mainline that is greater than the lines feeding into the system at Pump Station One. This multi-field mixing action and velocity reduces the risk of sediment and water from dropping out of the oil stream. This is worth noting because standing water is where we would most likely encounter significant internal corrosion in TAPS.

Also of note from our Top Ten list, we moved forward our 2007 smart pig run to 2006. The first part of the TAPS mainline was pigged the first week in August and the remainder of the line will be pigged by the end of the year. I requested that the data from this pig run be analyzed expeditiously so that we can compare it with the 2004 data to determine if additional integrity actions are necessary. Since the startup of TAPS we have run 60 inline inspections. This 2006 pig run will be the 61st smart pig run on TAPS. These smart pigs have identified minimal pipe wall loss due to internal corrosion. Alyeska has not identified any wall loss due to corrosion that exceeds Alyeska's internal criteria for wall loss, which is stricter or more conservative than the federal DOT regulatory criteria.

While we have a lot of faith in our pigging program based upon nearly 30 years of experience, we do continue to challenge ourselves to make sure we are evaluating the right things on TAPS. It is a process of continuous improvement.

Alyeska analyzes the pig run data for anomalies. From this our engineers make recommendations about what sections of the pipeline should be physically looked at for additional validation and possible repair. This is what we call our integrity investigations. We investigate sections of the pipeline – above and below ground – to determine the significance of anomalies, including corrosion in those areas. Based upon this assessment the appropriate corrective actions are taken, including repairing the section of pipe with a sleeve. Since initial startup of TAPS operations in 1977, we have made 656 below ground investigations and 293 above ground investigations.

We run a cleaning pig through the entire pipeline every seven to fourteen days. A cleaning pig pushes wax, water, and sediment that may accumulate within the pipeline down the line for removal. Further, as throughput declines this will be an even more important tool because it will remove water that may drop out of the crude oil at slower velocities.

In addition to pigging and integrity investigations, our corrosion control program also includes the following:

- Corrosion inhibitor is injected in the deadlegs at the pump stations and Valdez Marine Terminal every two weeks. Deadleg corrosion management is not new to us. We have had a deadleg corrosion program since the early 1990's. This program includes a manual ultra sonic inspection of the dead legs on a regular basis. The frequency of the investigations is based on engineering analysis and calculated corrosion rates.
- Buried pipeline sections were coated and wrapped with tape to protect the steel from the environment. (Aboveground pipe has minimal external corrosion risk.)
- A cathodic protection (CP) system passively and actively protects the below ground pipe from external corrosion. The passive CP system uses sacrificial zinc and magnesium anodes which preferentially corrode, thus protecting the pipeline from corrosion (similar to the zinc anodes in home water tanks). The active system applies electrical current to the pipeline to prevent corrosion. 680 CP coupons and 1018 CP test stations are placed along the pipeline to provide a way to measure CP effectiveness. Cathodic protection monitoring including CP coupons and close interval survey verifies the system data. This survey is performed on one-third of the pipeline each year. Areas failing to meet CP criteria are either mitigated or if of a minor nature, the system is electrically adjusted and resurveyed the following year. We are working with the DOT to assess low CP readings on the last 20 miles of the mainline to determine appropriate remedial actions.
- Our facilities corrosion monitoring program includes the use of coupons to assess and monitor internal corrosion rates.

Alyeska's corrosion control program is annually monitored by the Joint Pipeline Office and is audited routinely by the DOT.

Our corrosion control program is a part of our Integrity Management Program. Alyeska operates its Integrity Management Program through a controlled document (IM-

244) titled, "TAPS Integrity Management Program for High Consequence Areas". This is one of the first documents I read upon arriving at Alyeska and was impressed by the breadth and depth of our program. If you are interested in reviewing a copy of the program, I would be happy to provide it for you.

This document is subject to periodic inspections by the U.S. Department of Transportation Office of Pipeline Safety as a part of our DOT regulatory program. The DOT has inspected this program in 2002, 2003, 2004 and will do so again this October.

The Grant and Lease Right of Way agreements require Alyeska to have a comprehensive corrosion control program. Corrosion management is extensive and monitored by the Joint Pipeline Office to ensure we are meeting its requirements in addition to those of the DOT. JPO required Alyeska to develop a comprehensive approach to corrosion monitoring activities on TAPS and this became the Corrosion Control Management Plan (CCMP) adopted in 2000. The CCMP has been incorporated into IM-244.

Alyeska's Integrity Management Program has the following objectives:

- Prevent leaks to protect public safety and the environment
- Comply with State and Federal regulations
- Manage risks – assess, prevent, or mitigate
- Preserve our assets thus providing reliable oil transportation
- Provide stakeholder assurance

We have a number of major elements within the Integrity Management Program for the mainline pipe. We also focus on internal corrosion on the piping in our pump stations and the Valdez Marine Terminal. The major elements of our Integrity Management Program are:

- <u>Mainline pipeline inspection:</u> Corrosion In Line Inspection; Curvature and Deformation In Line Inspection
- <u>Cathodic Protection (CP):</u> CP Monitoring; CP System Improvements
- <u>Aboveground Pipeline Support System:</u> AG Monitoring and Maintenance; Vertical Support Member Monitoring and Maintenance; Pipeline Bridges
- <u>Valve Maintenance Program</u>
- <u>Right of Way Monitoring and Maintenance:</u> ROW Monitoring and Surveillance; Rivers and Floodplain Monitoring
- <u>Earthquake Preparedness:</u> Earthquake Monitoring; Fault Monitoring; Seismic Design Control; Seismic Housekeeping
- <u>Leak Detection System</u>
- <u>Overpressure Protection System</u>
- <u>Pump Station Facilities:</u> Piping Systems; Tanks
- <u>Valdez Marine Terminal Facilities:</u> Piping Systems; Tanks
- <u>Oil Spill Response and Contingency Planning</u>
- <u>Fuel Gas Line</u>.

As you can see we have a commitment to a comprehensive, systematic, and documented approach to integrity management, including corrosion monitoring and mitigation.

Additionally, I want to stress that our program is primarily focused on preventing a leak. Should we encounter a pipeline discharge, we have also worked diligently to be prepared to respond to an incident. We have an approved oil discharge prevention and contingency plan (C-Plan) that guides our response efforts. The plan is reviewed and approved by four regulatory agencies: the Alaska Department of Environmental Conservation; the Environmental Protection Agency; the U.S. Department of Transportation; and the Bureau of Land Management. We also have a large inventory of contingency repair equipment and materials that includes a wide range of replacement piping, stopples, and leak clamps. We exercise our personnel and equipment on a regular basis. It remains our goal through our Integrity Management program to avoid an oil discharge. However, I want the committee to know that we are prepared for an incident and can respond in a timely manner.

PRUDHOE BAY TRANSIT LINE PIGGING SOLIDS

Alyeska has constructed pipe and processing facilities at Pump Station One that will allow us to receive pigging solids from BPXA transit line pigging operations without exposing TAPS to unacceptable risks.

Upon learning about the potential for substantial solids in the Prudhoe Bay transit lines, I established a technical team to undertake a thorough risk assessment of the potential impacts from the solids to TAPS equipment, systems, and operations, and regulatory requirements. I asked them to determine if we could manage the solids in the mainline or into our tanks at Pump Station One. My priority was that any solution not adversely impact TAPS safety or integrity, nor the safe and efficient transportation of oil, which is our responsibility as a common carrier pipeline. The impacts assessment clearly raised concerns about allowing solids into the mainline and therefore I made the decision that we would not allow this to happen. We shared this position with BPXA and interested stakeholders in May.

Some of the concerns we had with the potential for a high concentration of solids that may be liberated in a short time period include: clogging and damage to strainers potentially resulting in a blockage; impacts and damage to meters; impacts or blocking transmitter and safety instrument devices that could result in an immediate shutdown of a pump station; solids potentially settling in station piping, valves and deadleg piping making it difficult to remove; impacts to pressure transmitters and leak detection systems; and potentially impacting valves and valve seats, drain lines, strainer baskets as the solids passed through each facility.

Since that time, we have been working with BPXA to determine the best path forward and at their request in August we constructed a temporary line to allow the solids to bypass Pump Station 1 piping directly from Skid 50 into a storage tank (Tank 110) for temporary storage and then removal and disposal. We will decant the oil received from the pigging operations through a line from the tank to our pump station. The solids will be processed via centrifuges and clean, marketable oil will be injected into TAPS for transportation to market. Remaining water and solids will be managed in compliance with federal, state and local laws. Tank 110 was scheduled for routine maintenance next summer and any remaining solids will be disposed of when we clean out the tank.

This bypass line and processing capacity should be operational no later than the middle of September.

As we were provided with updated information regarding the volume and constituency of the pigging solids in the various lines, we have been able to make appropriate decisions. We have approved of the pigging of those lines where we reasonably believe we can support the pigging without adverse impact to TAPS. An example of this is the pigging that proceeded with the Lisburne transit line. As BPXA ran more aggressive cleaning pigs through the Lisburne line we monitored our instruments closely to ensure the pigging envelope did not push solids into our system. Prior to approving acceptance of Lisburne pigging solids we agreed that the estimates of the amount of potential solids would not adversely impact TAPS. BPXA Lisburne pigging commenced on June 10th and was concluded on June 16th with the running of a smart pig through the line. The data from pigging this line demonstrated that this was an accurate estimate and the data from this was incorporated into the estimates and analysis for the remaining transit lines.

Throughout this process there have been many meetings and discussions about the implications and impacts associated with solutions to address the potential for solids in amount that could cause adverse impacts on TAPS from the transit lines. Alyeska was researching two options that TAPS could perform and BPXA was exploring two options they could perform. The bypass line we constructed has been our preferred option since we determined the volume of potential solids in the remaining transit lines would have an adverse impact if received directly into the TAPS mainline.

OPERATING TAPS AT REDUCED THROUGHPUT

Based upon technical reviews conducted to date, it is likely, although not certain, that Alyeska will be able to safely manage lower throughputs associated the partial suspension of Prudhoe Bay production. To do this, Alyeska will need to resolve several technical challenges outlined below.

Upon learning of the decision to shutdown the Prudhoe Bay field, I called up our Crisis Management Team and asked them to look at the short and long term issues this would have upon the operation of TAPS. For the short term, I wanted to know what issues we would face for significantly lower throughputs. My Oil Movements, Operations, and Engineering team put together a plan that would allow for continuous operations down to 400,000 barrels per day. The first night following the news, we ran the system at 500,000 bpd and the second night tested it at 400,000 bpd. While this is not an ideal operating situation our initial report is that it is workable.

We then began looking at the long term challenges this presents for TAPS and this analysis continues today. While we are confident we can operate normally down to 500,000 barrels per day, we will face challenges as throughput drops below this rate. Among the more significant challenges we are currently evaluating are:

- Managing issues associated with cooler temperatures of the oil, particularly in the winter, and the potential for water and paraffin drop out from the oil;
- Managing the efficiency of the biological treatment process of our ballast water plant because of lower ballast water flows due to reduced tanker traffic to the Valdez Marine Terminal; and
- Managing the potential for increased vibration due to slack line conditions at the three mountain passes the pipeline must cross;

Alyeska technical experts are evaluating all of these issues to determine the full extent of the potential impacts upon TAPS. They are establishing appropriate mitigating plans for my management team to consider. From our perspective, we definitely have challenges in front of us due to the Prudhoe Bay shutdown. I also know that I have some of the best technical resources available for this situation. I want each of you to know that our decisions will be based upon the safe operation of TAPS and with no adverse impacts to the integrity of TAPS.

In conclusion, I wish to restate that we have not seen accelerated corrosion on TAPS. We have a healthy concern for the potential for increased rates of corrosion and what that could mean to TAPS. I believe we have the right programs and people to address corrosion and integrity management on TAPS.

We will continue to work with BPXA on the best path forward regarding the pigging solids – one that does not compromise the integrity of our system. We have the right people assigned to this task and I trust their ability to accomplish this task safely.

And last, we share your concerns about operating TAPS at lower throughputs. We're looking at all of the potential impacts this will have on our system and will develop responsible plans to mitigate these impacts. I have qualified people working on these challenges and they understand my expectations that we proceed with the safety and integrity of our operations as our first priority. It is worth noting that our $500 million dollar pipeline upgrade project will introduce significantly more flexibility into our ability to manage through a situation like the one we are facing today.

I thank you for this opportunity to discuss Alyeska and TAPS operations and welcome any questions you may have about our operations.

MR. WALDEN. Mr. Hostler, thank you for being here today.

Mr. Stears, do you have an opening statement this morning?

MR. STEARS. I have no opening statement. I am just here to cooperate and to help answer questions.

MR. WALDEN. Thank you very much. We appreciate the opening statements of all of you and your participation in this oversight hearing.

Mr. Woollam, I am going to start with you. I know you indicated in your brief opening comments you were going to assert the Fifth Amendment, which is certainly your right under the Constitution. The committee believes that in order to assert that amendment, it needs to be in response to a question and so with that, Mr. Woollam, you were formerly in charge of the Corrosion Inspection and Chemicals Group at BP Exploration Alaska, Incorporated. You were the decision-making manager and engineer responsible for all operations related to corrosion control and monitoring of the pipelines operated by BP at Prudhoe Bay. The subcommittee has learned from several sources that numerous red flags were raised about the integrity of the Prudhoe Bay pipelines while you were in charge of the CIC group including the 2000 final draft Coffman report. Yet in 2002 you initiated and implemented a plan to reduce the manpower of a key pipeline corrosion monitoring team by 25 percent. So my question, Mr. Woollam, when did you become aware of the pipeline integrity problems faced by the Prudhoe Bay transmission lines including concerns about accelerated localized corrosion, microbial corrosion and that the failure to send maintenance pigs or smart pigs down the transmission lines was placing those pipelines at high risk of failure.

MR. WOOLLAM. Mr. Chairman, based upon the advice of counsel, I respectfully will not answer questions based upon my right under the Fifth Amendment of the United States Constitution.

MR. WALDEN. Mr. Woollam, are you refusing to answer all of our questions based on the right against self-incrimination afforded to you under the Fifth Amendment of the U.S. Constitution?

MR. WOOLLAM. Yes, Mr. Chairman.

MR. WALDEN. And is it your intention to assert such right in response to all further questions from the subcommittee today?

MR. WOOLLAM. Yes, Mr. Chairman.

MR. WALDEN. Given that, if there are no further questions from the members, I will dismiss you at this time subject to the right of the subcommittee to recall you if necessary, and at this time you are excused, sir.

MR. WOOLLAM. Thank you.

MR. WALDEN. Thank you.

Mr. Marshall, according to information provided by British Petroleum, the western operating line had not been pigged since 1998 and the eastern operating line had not been pigged since 1992. Why was there not more regular pigging of these transit lines?

MR. MARSHALL. Mr. Chairman, you are indeed correct. The western line was pigged and smart pigged in 1998. We recovered a very insignificant amount of solids, less than two cubic yards, from that pig run. The line indicated it was in good condition. What we have in each intervening year is a series of ultrasonic testing at various points along the line to basically confirm and corroborate the information from the smart pig run. We also have electrical resistance probes, coupons, and all of this is on the back of a very comprehensive program of corrosion inhibition across the entirety of the operations going all the way back to the well head, through the gathering lines, through the flow lines, through our facilities, so we are watching all of the corrosion at those points.

MR. WALDEN. Could you turn to Exhibit 4 in the book, which you should have at the witness table. Do we have a book at the witness table? Our staff will be bringing that to you. I will go ahead. On page 2, it says--this Exhibit 4, page 2, it says, "For example, smart pigs can inspect the service of an entire pipeline. Smart pigs and other automated techniques are helpful in identifying locations that should be more closely monitored using one of the point inspection methods, e.g., visual, ultrasonic, radiographic. Smart pigs can also provide assurance that the spot inspections are truly representative of the pipeline condition." Given that BP's own internal corrosion procedures highlight the merits of smart pigging, and that is what I was reading from, can you explain the lack of the smart pigs on these lines? I mean, I think that is what we are getting at here in the committee. We understand you do these other checks. Why when Alyeska is running smart pigs down the TAP every two weeks, why would it be years in between when you would run smart pigs down these feeder lines?

MR. MARSHALL. Again, Mr. Chairman, we looked at the data from 1998, confirmed the line was in good condition, did the ultrasonic testing. We did see some increases in corrosion starting in 2004 and 2005, and at that point we did take the action to increase the frequency of testing and--

MR. WALDEN. But not with smart pigs.

MR. MARSHALL. And commissioned a smart pig in 4Q of 2005 to be run this year. Unfortunately, that smart pig was not run before the spill but it was planned and budgeted for in Prudhoe Bay's budget this year.

MR. WALDEN. How much does it cost? What do you have to budget for a smart pig to run down those lines?

MR. MARSHALL. To the best of my knowledge, it is not a huge amount.

MR. WALDEN. So budget is really not the issue?

MR. MARSHALL. Budget is not the issue, no.

MR. WALDEN. Okay. Please turn to Exhibit 7 again in this. This document is an instant investigation report on the March 2006 spill on the western operating line. According to the report, the leak occurred at a buried caribou crossing. Aren't bends and low points in the line such as buried crossings at higher risk of corrosion because of sludge, sediment, scale and/or water that tend to build up at these locations, particularly in low-flow lines? Aren't these dips in the line really more subject to this type of failure and corrosion?

MR. MARSHALL. Mr. Chairman, I am not a corrosion expert but certainly the lines on the west side of Prudhoe Bay have a number of road crossings and caribou crossings where there are elevation changes. What appears to have occurred is the--we believe the accumulation of solids which had occurred perhaps more recently than we might have expected in these low areas.

MR. WALDEN. On page 11 of the report, it points out that the 1998 smart pigging of the western operating line showed "moderate internal and external corrosion" with many areas having 30 percent to 50 percent wall loss. The pig run specifically identified six locations within the caribou crossing that was the site of the March leak where internal corrosion pitting was occurring. Given these results, why didn't BP accelerate the schedule for the next pigging? Again, this was back in 1998 and it identified some areas with 30 to 50 percent wall loss.

MR. MARSHALL. Mr. Chairman, my understanding here is that the 30 to 50 percent wall thickness loss is not actually generalized wall loss. It is pitting corrosion, discrete pitting corrosion, generally at the 6:00 position in the bottom of the line, and the inspections that we did, the ultrasonic testing, was done and the coupons were looked at four times per year, twice the industry average on those lines, to confirm the deterioration in the system was not occurring at a greater rate.

MR. WALDEN. Well, on page 6 it says that, and I quote again, "With the exception of smart pig runs, there isn't a way to directly monitor internal corrosion inside of the cased pipe road and caribou crossings without having to excavate the crossing and remove the outer casing from the pipe." So despite being aware of pitting and corrosion at this crossing and knowing that these points were not accessible for ultrasonic testing, BP nonetheless decided to wait 8 years between smart pig runs, right?

MR. MARSHALL. We did encounter some increased corrosion in--

MR. WALDEN. In the dips?

MR. MARSHALL. In the--

MR. WALDEN. In the crossings?

MR. MARSHALL. I can't say they were actually at the crossings. The inspection points we were doing through ultrasonic testing, we did start to see some increases in 2004 and critically in 2005 which led to the establishment of the smart pig run scheduled for 2006.

MR. WALDEN. So where the problem really was, was in the place where the leak occurred in the caribou crossing, right?

MR. MARSHALL. Sorry. Could you repeat the question again?

MR. WALDEN. Well, let me go to the exhibit here, and it says, "The accuracy of the smart pig data was"--I assume it should be were--"confirmed the follow-up UT inspections. The '98 smart pig run also identified six specific areas inside this caribou crossing where internal corrosion pitting was occurring. Percent wall loss at these six locations in this particular caribou crossing showed relatively low line wall loss of between 5 and 25 percent." The leak was one of these six locations and had a wall thickness loss of 9 percent in the 1998 pig run. So you are seeing leaks where there wasn't even earlier identified much wall loss, right, if it was 9 percent, and yet the leak then occurred in one of those areas. It would seem to me that you are really missing the boat by not putting those smart pigs in there.

MR. MARSHALL. Mr. Chairman, we believe that the changing conditions on the western side of the field had some bearing on that. We will not be able to confirm that absolutely until we do the laboratory analysis of the failed pipe.

MR. WALDEN. Let me ask you this. In other operations you may be familiar with, with similar feed lines outside of Prudhoe Bay, do companies run smart pigs on a regular basis, regular being more than every eight years?

MR. MARSHALL. Mr. Chairman, I am not a pipeline expert. I have to state that. I am aware of some lines that are pigged. I am also aware that some lines are not pigged. But I can't give you exact details of that.

MR. WALDEN. Your written testimony notes that BP runs nearly 370 maintenance pig runs per year on the North Slope. Why have none of these been run on these key transmission lines for the last eight years? And that is the heart of what we are after here.

MR. MARSHALL. Mr. Chairman, we have a very--notwithstanding these leaks, we have a very comprehensive corrosion management system. It is one that is recognized by many as being very comprehensive in that it covers 1,500 miles of pipelines all the way through the facilities. Notwithstanding the leaks though, we tend to focus--we do focus all of our efforts where we believe the risk of corrosion to be the highest. That typically is where we have gas and water, where it is three-phase flow. We have high carbon dioxide content in the gas. Left unchecked, that can corrode about a quarter of an inch of steel per year. That is where we put the vast majority of our efforts upstream.

MR. WALDEN. Given all that though, clearly in this case the procedures and protocols failed your company and the American people, right? I mean, because you ended up with these leaks and now you have discovered basically you are going to have to replace how many miles of the pipe?

MR. MARSHALL. We are going to replace 16 miles of pipe. Even though we believe 10 miles are actually in good condition, we have committed to replace all 16 with lower diameter pipe which will provide a firm foundation for future business for a field that has the potential now to run for many, many years with the prospect of gas pipeline coming down the line.

MR. WALDEN. My time has expired. I turn to the gentleman from Michigan, Mr. Stupak, for 10.

MR. STUPAK. Thank you, Mr. Chairman. Mr. Marshall, if I may continue. The Chairman asked you a lot about the western operating area line. I want to ask you about the eastern operating line. And if you can, just answer yes or no, I would appreciate that. It is the eastern operating line that had the August spill. Is that correct?

MR. MARSHALL. The eastern line from Flow Station 2 to Flow Station 1, yes.

MR. STUPAK. And the eastern operating line was last pigged somewhere around 1992?

MR. MARSHALL. I believe the eastern line was pigged in the early 1990s, maintenance pigged, and smart pigged just after that.

MR. STUPAK. Isn't it true that when the line was last pigged, it had significant scale buildup and possibly other materials that made pigging so difficult that it caused problems downstream for the operators at the Trans Alaskan Pipeline?

MR. MARSHALL. Mr. Congressman, since the March spill, I have become aware of discussions about solids occurring in those lines and yes, indeed--

MR. STUPAK. Caused problems for the operators down the line? The strainers were--

MR. MARSHALL. The strainers were plugging with scale, as I understood.

MR. STUPAK. And that was 1992?

MR. MARSHALL. I believe it was in the early 1990s. I can't give you the exact date.

MR. STUPAK. Okay. Isn't it true that it is generally the solids including scale and sediment can be a contributing factor for corrosive activity because they can trap water or other corrosion-causing organisms against the pipe wall? Is that true?

MR. MARSHALL. I am not a corrosion expert but I do believe that is to be true, yes.

MR. STUPAK. Okay. And isn't it true that sludge, sediment and scale can also make it harder for corrosive inhibitors to effectively reach the pipe wall and therefore make them less effective in reducing corrosion?

MR. MARSHALL. Again, I am not a corrosion expert but I do believe that to be a possibility, yes.

MR. STUPAK. But you are the head of the corrosion program up here on the North Slope, right?

MR. MARSHALL. No, I am President of the--

MR. STUPAK. President of the--I am sorry.

MR. MARSHALL. I do rely on a lot of people to give me advice on all aspects of business including corrosion.

MR. STUPAK. Well, on the eastern operating area line, it has a pig receiver and a pig launcher, and so it was designed to accept a pig to go through line, right?

MR. MARSHALL. That is my understanding, yes.

MR. STUPAK. Can we go to photo number 8 right here? This was taken by the committee staff. That is the pigs in your warehouse up there, and you can see all of them, different sizes and for all parts of it. Then why in your best estimation was the eastern line never pigged since 1992? You have all this equipment in here, different sizes, to get it through the line. Why wasn't it done since 1992 if you had the best comprehensive corrosion program in the world?

MR. MARSHALL. Mr. Congressman, I cannot comment on the period from the early 1990s through to 2000. When BP took over operation of the eastern transit lines in 2000 as a result of the ARCO merger, we instituted ultrasonic testing. It was something we instituted of the eastern transit lines. Only two--

MR. STUPAK. Photo 7, please. Photo 7. See, my problem with the ultrasound, if you had started this in 2000 when you took over the line, it is so tedious. I mean, all you do is take a little swab and put it on part of the pipe and then you do a detection much like an ultrasound, correct?

MR. MARSHALL. That is correct.

MR. STUPAK. And that is only where the swab is, and you can do very little pipe, and those underground, like the caribou crossing, where we had the spill earlier, you can't do that because it is underground, so that doesn't seem very effective. So that is why I am thinking, well, why would you go to ultrasound, not pig it then in 2000 if you didn't know the quality of it? You are trying to prevent spills and improve the flow of oil? If you took it over in 2000, if you were unsure of the quality and the corrosion problem, why didn't you pig it then if it is already designed for pigging?

MR. MARSHALL. I can't comment specifically on decisions that were made in 2000 or not. What I can say is that only two years previously, the western area transit--

MR. STUPAK. I am talking eastern now, eastern line. I want to stay with the eastern line. The Chairman got you on the western. I am on eastern.

MR. MARSHALL. If you just allow me--

MR. STUPAK. Sure.

MR. MARSHALL. --a few minutes to explain how the west has relevance, potential relevance to the east. Only two years previously, BP in operating the western lines had pigged and smart pigged those western transit lines. The indications were given that the lines were in good condition. We were taking over the eastern transit lines as a result of the ARCO merger. Those transit lines are broadly similar in geometry, eight miles on either side handling essentially the same fluids. We instituted a spot check of the ultrasonic testing and essentially confirmed a very similar condition of the eastern transit lines as the west.

MR. STUPAK. I don't mean to be argumentative, but all of our reports show that even the western line in 1998 had corrosion problems, and if it had been 1992 until 2000 when you took over, 8 years, and now we are 6 years later, 14 years, it was never pigged. If you knew in 1998 when they did the pigging on the western line there were corrosion problems, I think it would lead you to at least look at the eastern line a little bit closer. I don't mean to be argumentative with you but common sense will tell you that.

Mr. Hostler, if I may, you scrape your entire 800-mile line every 14 days. Is there a reason for that other than reducing drag on the pipe? Why is it generally a good idea for pipeline maintenance, in other words?

MR. HOSTLER. Congressman, it is rather simple. We do that every 14 days just to keep the pipe in good, clean condition.

MR. STUPAK. Can corrosion start in 14 days?

MR. HOSTLER. No, no, but we worry about the buildup of solids or liquids, water, in the pipeline and so we run a cleaning pig, a mechanical pig, every 14 days.

MR. STUPAK. Okay. Mr. Marshall, let me ask you this then. When did BP first know that major solids to the amount that the line could not easily be pigged were in the eastern operating area line--eastern line?

MR. MARSHALL. Mr. Congressman, to the best of my knowledge, the discussions started after the March spill. That was when it was first brought to my attention when conversations turned to the existence of solids, recollections of the problems that had occurred in the early 1990s with the plugged strainers and it caused us to consider what might be the worst case, solids accumulation in these lines. We wanted to--

MR. STUPAK. Okay, so that was March and that was after the Department of Transportation issued its corrective action order, and from what I understand, you spent a considerable amount of time engineering efforts to determine how significant the sludge and scale buildup was in both the eastern and western line. Isn't that correct?

MR. MARSHALL. Sorry. Could you repeat your--

MR. STUPAK. Sure. After you got your corrective action order, you spent a lot of time engineering that, that is what you are telling me, to determine how much buildup did you have in the eastern and western line. Isn't that correct?

MR. MARSHALL. That is correct. Yes.

MR. STUPAK. Did you have any information prior to the Department of Transportation March 15 corrective order about the buildup in the eastern line?

MR. MARSHALL. I can't speak for every level of the organization but I became aware of that after the March 2 spill.

MR. STUPAK. Well, if you had no idea how much scale, sludge or other deposits were in your lines, then what does that say about BP's understanding of the quality of its pipelines? How can BP say it had a good integrity management plan of its pipelines if it doesn't know the true condition of its pipes and the volume of solids they contain?

MR. MARSHALL. Certainly we have relied extensively on the pigging data from 1998 on the western where we had recovered--

MR. STUPAK. I am still on the eastern one, because last time you pigged that was 1992. It is the major line. I mean, we had to shut that down. So how can you sit here today and say you have a good integrity management plan of its pipes when you do not know the true condition of the pipes or the volumes of the solids they contain and the last time it was pigged was 1992? So I see a contradiction here. It sounds like you didn't really explore it until you got the corrective order from the Department of Transportation in March of 2006.

MR. MARSHALL. It was certainly the spill that caused us to consider what might be the implications of pigging those lines.

MR. STUPAK. Right. How would you not know that something is causing corrosion? How would you not know that? I guess that is the best way to put it. You saw it in the western line in 1998, the one that hadn't been pigged since 1992. You know your PSI is going down, don't you, the pounds, the pressure to move the oil through? You know that is going down every year, right? What was it in 1992? Do you know?

MR. MARSHALL. I don't have that information.

MR. STUPAK. They tell us it was about 800, and at the time of the spill it is down to 80. You have lost 10 times the pressure. That in itself tells you right there that we have a problem with the corrosion, doesn't it?

MR. MARSHALL. Certainly velocity of fluid through the line appears to be one of the indicators. The two sections of line that have failed, the two three-mile sections--

MR. STUPAK. And isn't another thing you look at is how much oil you are getting out? Isn't most of the stuff you are getting out right now, isn't that mostly water and sand and less and less oil each year from 1992 to 2006?

MR. MARSHALL. You are absolutely correct about the water, Congressman.

MR. STUPAK. And therefore if you got more water, isn't that going to cause corrosion and buildup in these lines?

MR. MARSHALL. Mr. Congressman, the facilities upstream, the flow stations and gathering centers, are designed to take out the water. We operate to the same--

MR. STUPAK. But it doesn't take it all out. We know that, and we know where there are dips in there. That is where it settles and that is when we have problems. You have slow flow, less oil coming up, more sand and water. How could you not know that there was buildup and solids and how could you not pig since 1992? I guess I am just baffled on that.

MR. MARSHALL. Mr. Congressman, if I could try and offer my perspective on that. Certainly the conditions of the reservoir are changing. You are absolutely correct. As the oil production has dropped, the water production increases. We certainly see some solids from the west, not necessarily from the east, but the facilities, the producing facilities, the flow stations and gathering centers, are designed to take the incoming flows from the wells down to the same specification, the .35 bottom sediment and water specification that has been in existence for 29 years at Prudhoe Bay. Our records show that the performance of those facilities is indeed broadly similar over the years so those facilities are actually operating and there isn't increasing amounts of water through those transit lines than there has been over time.

MR. STUPAK. Thank you, Mr. Chairman.

MR. WALDEN. Thank you. The chair now recognizes the gentleman from Texas, Dr. Burgess, for 10 minutes.

MR. BURGESS. Thank you, Mr. Chairman. Maybe we could just stay on this subject for a moment, Mr. Marshall, the allegations that BP did not pig the lines more frequently because of concerns that there was so much sediment, sludge or scale in the lines that the pigs might get stuck or unacceptable levels of junk would get flushed into the Trans Alaska Pipeline. Are those reflections accurate?

MR. MARSHALL. Mr. Congressman, certainly those are some of the conversations we have had in BP and talking with Alyeska. We are concerned about any downstream impacts that the pigging operations might have had. We wanted to fully understand what the implications of any pigging operation would need to be. We made some very early estimates of what a worst case solids buildup might have been. We did some subsequent testing using gamma ray analysis, thermal imaging and velocity calculations and determined those initial estimates were very conservative. We determined that the actual solids level was about 10 percent of those initial estimates. It did take us some time to get to that point. In retrospect, I wish we could have done that quicker. I would say that. But once we determined that those solids levels were indeed lower, we have been aggressively pursuing two options to enable pigging without impacting the strainers or the downstream operations. There has been a crossover back into our existing facilities that we can pig into that through Flow Station 3 and we have been working with Alyeska to institute a crossover into one of the Pump Station 1 tanks. Both of those crossovers are essentially complete and now we are working with the Department of Transportation to determine whether the inspections we have completed on the east side are sufficient enough to allow us to go ahead and start pigging and start pigging the eastern transit line to determine the condition it is in.

MR. BURGESS. On the--in the evidence binder that you have, Exhibit 20, there are some handwritten notes that appear to indicate that as a result of pigging by ARCO in the eastern operating line in 1990, so much debris was generated that it caused severe damage to Alyeska's strainers at Pump Station 1. There were also apparently some debris problems during a September 1991 pig run. Was BP ever made aware of these problems either before or after it acquired the eastern operating line from ARCO?

MR. MARSHALL. Mr. Congressman, I haven't seen this particular copy of this document. What I am aware of personally is that it was only after the spill that the conversations around solids really started to take hold. It was in the last few weeks that we actually spoke to the--a member of my team actually spoke to the engineer with ARCO who actually was involved in these pigging runs, and what I understand to be the result of that was that the lines were indeed cleaned, they were pigged with maintenance pigs and that the smart pig was run but we didn't get good data or ARCO did not get good data from that smart pig run. We understand there was scale buildup in the strainers at Pump Station 1 and that is why we are actually pursuing the bypasses now to allow pigging to alternative locations so we don't jeopardize those strainers and meters at Pump Station 1.

MR. BURGESS. That is a 15-year time jump though from when ARCO did that investigation to when the leak occurred, so I mean, that was a significant amount of time involved between the pigging that showed some scale buildup and the demonstration of a problem with the leak. Is that--am I correct in that?

MR. MARSHALL. It is 15 or 16 years, yes.

MR. BURGESS. Well, let me ask you this. If the company didn't have concerns about the possibility of buildup in the lines, why didn't it pig the lines immediately after the corrective action order was issued by the Department of Transportation in March of 2006?

MR. MARSHALL. It was only when we started--after the March spill, it was only when we started thinking about the implications of pigging either the east line or the west line that we started to have conversations with Alyeska and the concerns were raised about the potential of solids, and that is when we did some estimates and then we did the further testing as I said. One of the other things that precluded us from doing a rapid pigging of the line, we originally indicated that we would intend to pig the western line within 3 months of the spill and as it turned out, the Department of Justice required a section of the failed line to be preserved, and not to be able--and to not pig the line in the west to disturb the solids and the sediment that may exist on that failed section of line. So that has proved to be a difficulty and we have not been able to use the pig launcher on the western section of the line to pig to Pump Station 1. In order to pig the remainder of the west, we are installing a 34-inch launcher at GC-1, at Gathering Center 1, to enable the 5-mile section of line to be pigged. We expect that work to be completed in October and we will be able to pig that line shortly after that.

MR. BURGESS. Let me just ask an opinion or ask your opinion that, would the company BP have an obligation to know the condition of its lines at all times?

MR. MARSHALL. I am not sure of my opinion. I need to think about that. We strive to understand the condition of all of our equipment and lines.

MR. BURGESS. But as someone on the other side pointed out, it is your core business. I think Mr. Dingell said your core business is the recovery and delivery of oil to the Nation's energy supply.

MR. MARSHALL. And we spend--

MR. BURGESS. And the pipelines are a critical part of that.

MR. MARSHALL. Indeed, we spend considerable amounts of money. We have increased the corrosion spent 80 percent since I have been in Alaska. We spread that effort over the areas where we judge the corrosion risk likely to have corrosion to be the highest, so we--clearly in retrospect, this is something we missed.

MR. BURGESS. Now, Admiral Barrett has publicly expressed significant concern, disappointment about BP's failure to plan for, invest in bypass solutions for the Prudhoe Bay transmission lines. Why did BP not have any contingencies in place for crucial transmissions so that a complete shutdown could have been avoided?

MR. MARSHALL. Mr. Congressman, there are a number of lines on the North Slope, a considerable number of flow lines carrying different products various places. The western side of Prudhoe Bay, which is the side of Prudhoe Bay that BP has operated since 1977, indeed has a number of bypass options there. We were able to use one of those, a 24-inch line, on the back of the GC-2 transit line failure, to bring the majority of GC-2's production over to Pump Station 1. We were able to take advantage of that. Unfortunately, there are not the same level of bypasses and options designed in to the eastern side of the field. I can't go back and comment on the design basis from the 1970s but we are working very diligently now to implement the bypasses to the Endicott and Lisburne flow lines. We expect to have those done and the potential to have the field fully back up to over 400,000 barrels a day by the end of October subject to DOT approval.

MR. BURGESS. Mr. Hostler, does Alyeska have redundancies or contingency plans in place?

MR. HOSTLER. Yes, Congressman, we do. You know, our first focus is on preventing any type of oil spill or leakage from the pipeline but we do have contingency repair equipment in place. We have additional pipe in place so that if we do have a spill, we can replace the damaged area. In addition to that, as a result of the bullet hole that we experienced in the early part of this decade, we have bullet hole repair equipment and items like that that are available to us. In addition, we have built redundancy in our pumping system that allows us to continue to operate in the event of a shutdown.

MR. BURGESS. Great. I will take that as a yes.

Mr. Marshall, my time is just about up and there is a series of questions that relate to the Vinson and Elkins redacted report which I in fact just received this morning about the whistleblower concerns and I am concerned about some of the health and safety issues that were raised in this, and Mr. Chairman, I am going to ask permission to submit these questions in writing for the record, but I would just ask in the two seconds I have left, Mr. Marshall, that it appears that there have been--some of these concerns have been going on for several years, that when we had an individual just take the Fifth Amendment here on your panel, were there concerns over the behavior of someone on your team who was supposed to be overseeing some of these issues and listening to the concerns of the employees who actually operated and administered the pipeline?

MR. MARSHALL. Yes, there was. I first became aware of some employee concerns in this particular area to the best of my knowledge in early 2003. Those concerns were raised through our safety committee, and at the same time to one of our external contacts that we have. We have a number of avenues there.

MR. BURGESS. And again, I am going to submit these questions in writing and I would appreciate an answer, but can you reassure the committee with all of the problems that we have seen, not just in Alaska but in my home State of Texas where 15 people died, that the people who bring up health and safety concerns, whether they be whistleblowers or just regular people who are voicing concerns, that those concerns are being addressed and that there is not retaliation brought against employees who bring up these problems?

MR. MARSHALL. You have my absolute assurance on that, that that is totally against BP's policy. We--I don't care where employee concerns are raised, through one of our internal channels, externally, I don't care where they are raised, as long as they are raised. If we get specificity so we can go out and external what the issue is, we will investigate it, take the appropriate action and move on. That is just simply good business. As I said earlier, I worked on the slope for five years. It is the people on the slope that know what is working well, what isn't, and if any of us ignore those concerns, that is just simply not good business.

MR. BURGESS. I have been there. There is not much margin for error in that environment.

Mr. Chairman, you have been very indulgent and I will yield back. I do want to submit these questions--

MR. WALDEN. Without objection, the questions will be submitted. We look forward to your answers.

Before I go to Mr. Dingell, I just want to clarify one thing I think I heard you say. Did you say the Department of Justice has subpoenaed a piece of the pipe?

MR. MARSHALL. That is correct.

MR. WALDEN. Do you know why they would have done that? That seems like a rather extraordinary piece of evidence to--

MR. MARSHALL. I believe it is to understand and do the testing on the corrosion mechanism and confirm what the basis for that leak in the GC-2 line was.

MR. WALDEN. Why would the Department of Justice do that though as opposed to the Department of Transportation?

MR. MARSHALL. This is part of the criminal investigation going into the potential violation of the Clean Water Act.

MR. WALDEN. I see. Thank you. Mr. Dingell.

MR. DINGELL. Mr. Chairman, I thank you.

Mr. Marshall, as the President of BP Exploration Alaska, you are primarily responsible for the operation of the Prudhoe Bay field. Is that correct? Yes or no?

MR. MARSHALL. I am responsible for all of BP's activities in Alaska.

MR. DINGELL. Great. And you have held that position for how long?

MR. MARSHALL. I arrived in September 2001.

MR. DINGELL. Thank you. With regard to the oil transit line that failed in the western operating area of Prudhoe Bay in March, isn't it true that the last time that line was inspected and smart pigged was 1998?

MR. MARSHALL. The last time it was smart pigged indeed was 1998, yes.

MR. DINGELL. Are you familiar with the term "viscous oil"?

MR. MARSHALL. Yes, I am.

MR. DINGELL. If so, would you agree that the characterization of that production of this type of oil is known to increase the amount of water in the crude stream and the amount of sediment also known as sand fines or flower? Is that true?

MR. MARSHALL. Mr. Congressman, I am aware that the production of viscous oil does indeed produce more sands through the well bore into the flow lines and into the facilities, yes.

MR. DINGELL. Okay. Isn't it true that a buildup of these flower sands in a line could cause corrosion either by trapping water beneath them or by providing an environment in which bacteria could flourish?

MR. MARSHALL. Mr. Congressman, I am not a corrosion expert. I believe that to be a possibility. In this particular case, it is only when we do the failure analysis of the pipe will we truly understand what mechanism actually caused the failure of both the east and west transit lines.

MR. DINGELL. All right. Now, isn't it true that BP did not schedule a maintenance pig run through the western transit line in 2000 when it began to increase the amount of viscous oil in the line?

MR. MARSHALL. Mr. Congressman, the viscous oil production actually started in 2004 when we started drilling the western flank of Prudhoe Bay from the Orion field. So that was a 2004 startup, I believe.

MR. DINGELL. Let me do the question again, if you please, sir, and the question is this, and all it really requires is a yes or no. Isn't it true that BP did not schedule a maintenance pig run through the western transit line in 2000 when it began to increase the amount of viscous oil in that line? Is it true or false?

MR. MARSHALL. I am not sure I can answer your question, Mr. Congressman.

MR. DINGELL. Well, let me read this. This language says this: "Electronic data collected during the investigation in graph below documents an increase in viscous oil production at GC-2 from approximately 1,500 BPD in January 2000 through a production high of 16,098 BPD in October 30. G-2 produces more viscous oil than any other facility on the North Slope and today represents approximately 15 percent of total GC-2 production." Is that a true statement?

MR. MARSHALL. I can't comment on the statement. I haven't seen that. My understanding, Mr. Congressman, is that we did not start viscous oil production until 2004--2000.

MR. DINGELL. Now, the document is regarding the GC transit line spill at Prudhoe Bay western areas or rather western operating area March 2, 2006, incident investigation report. That is a BP document.

MR. MARSHALL. I am not familiar with the specific reference but I would be happy to look into that and provide back to the subcommittee a specific answer.

MR. DINGELL. I find myself somewhat hard-placed to ask questions when you are not prepared to answer. Let me ask another question. Isn't it true that since 2000 BP's production of viscous oil moving through the western transit line increased from 1,500 barrels a day to a high of 16,000 as reported in the document from BP which I just read to you?

MR. MARSHALL. Mr. Congressman, I don't have the information available to me to be able to confirm or corroborate that. I would be happy to look into it. The increases in viscous oil production occurred primarily when we started drilling the Orion field in 2004 but I would be happy to look into the specifics--

MR. DINGELL. Mr. Marshall, I want to be courteous to you but I have a limited amount of time and I am trying to get answers to questions that I think we should agree are important. Now, I assume you are aware, Mr. Marshall, of internal BP data that suggests that the amount of sediment moving through the western transit lines was increasing and that the increase was commensurate with the amount of viscous oil that you are moving through the line. Now, this is from the Chapman Report, page 14. Just yes or no.

MR. MARSHALL. I am not in a position to say yes or no. I am sorry, Mr. Congressman.

MR. DINGELL. All right. Now, are you aware of a report issued by John Baxter, an employee of BP, entitled Alaska Transit Pipeline Technology Review released in April of 2006, yes or no?

MR. MARSHALL. Yes, I am.

MR. DINGELL. That report indicates that since the introduction of viscous oil in the western transit lines, one of your gathering centers had experienced a number of upsets which resulted in increased amounts of water and sediment being released into the transit line. Are you aware of this?

MR. MARSHALL. Yes, I am.

MR. DINGELL. Now, the Baxter Report cites an upset of nearly 10,000 barrels of water being unintentionally released from Gathering Center 2 into the western oil transit line. Isn't it true that you did not run a maintenance pig after this event in the western transit line to ensure that the water didn't get trapped in low-lying spots in the line?

MR. MARSHALL. It is correct that we did not run a pig after that incident, yes.

MR. DINGELL. You did not. Given all this, isn't it true that you had potentially corrosive agents in your lines as a result of increased production of viscous oil and that you should have scheduled a maintenance pig run sooner than the 8-year interval that you had this line on?

MR. MARSHALL. I am not sure I am in a position to say that there was definitive evidence of that.

MR. DINGELL. Well, that is--

MR. MARSHALL. Clearly in retrospect, you know, pigging would have been a positive step we could have taken--

MR. DINGELL. Well, let us--

MR. MARSHALL. --to clean those lines.

MR. DINGELL. --look at this. Alyeska, which runs a pipeline with which I am sure you are familiar, said this in their testimony today: "We run a cleaning pig through the entire pipeline system every seven to 14 days. A cleaning pig pushes wax, water and sediment that may accumulate within the pipeline down the line for removal. Further, as throughput declines, this will be an even more important tool because it will remove water that may drop out of the crude oil at slower velocities." Now, how many times did you run maintenance pigs through the western line and how many times did you run them through the eastern line?

MR. MARSHALL. We ran--

MR. DINGELL. Just the maintenance pig.

MR. MARSHALL. We ran maintenance pigs in 1990 and 1998 and we ran smart pigs in 1990 and 1998.

MR. DINGELL. Why didn't you run them more often? You knew that the amount of viscous oil that was being put through the line was increasing on a continuing basis and you knew that that changed the characteristics of the oil, or at least you should have, and you knew that that oil because of its changing characteristics had a potential for increasing the risk of increased corrosion because of acid formation or other things such as water which might have created problems but you didn't do anything at all about increasing the number of times that you ran a pig through the line or checked to see whether the change in the quality of the oil going through the line was going to impair the capability of the line to resist corrosion.

MR. MARSHALL. Mr. Congressman, certainly as the viscous oil increased more significantly in 2004 and 2005, we were aware of, as you pointed out, a number of the incidents there but the general quality of the crude oil there is sales-quality crude oil which is--

MR. DINGELL. It is still quality crude oil but it has got more viscous oil in it, a significant increase as we have already shown in the questions.

MR. MARSHALL. But the viscous oil in and of itself does not--is not a corrosive agent.

MR. DINGELL. Well, let us look at the numbers again. The Baxter Report cites an upset of nearly 10,000 barrels of water being unintentionally released from Gathering Center 2 and the western oil transit line. Also, as we discussed earlier in my questions, you had a significant increase in the amount of viscous oil that you are moving through the line and other things which had a potential risk in terms of increasing corrosion. BP's production of viscous oil increased from 1,500 barrels a day to 16,000 barrels in 2005. Is that a significant increase or not?

MR. MARSHALL. Certainly that is the increase as mentioned earlier that when the Orion field came in, we saw the increase start in 2004 into 2005.

MR. DINGELL. Doesn't that warn you that you ought to do something about it to check to see what is happening? I trust in God but I know he expects me to lift my end of the log and find out whether I am doing what I should be doing or whether it is going to have the proper effect. Obviously you are a very trusting man and it is very clear to me you have great trust in God but don't you have some responsibility to do a little better job of running pigs through to find out what is going on?

MR. MARSHALL. Mr. Congressman, indeed in 2005, we did plan and schedule a smart pig run.

MR. DINGELL. You told me about three times that you ran pigs through there and Alyeska does it every seven to 14 days. They are running the same oil you are. Are they smarter than you or less trusting than you, or what is the situation there?

MR. MARSHALL. Mr. Congressman, pigs and smart pigs are run for many different reasons. We run 370--about 370 pigs every year on our lines.

MR. DINGELL. Now here again is from attorney-client privilege ATP Technological Review. It says here: "With such a release, it is most likely that some water and also basic sediment will be held back in the lower elevation sections of the O-21 line." Now, that is where this occurred. It occurred in the lower elevation sections. And what did you do to prevent this holdback or to find out if this holdback was going to create you any problems?

MR. WALDEN. Mr. Marshall, I am going to go ahead and let you answer that and then I--

MR. DINGELL. Mr. Chairman, you have been most kind.

MR. WALDEN. We need to move on.

MR. DINGELL. I am not sure I am getting answers anyhow so I am happy to yield back.

MR. WALDEN. Mr. Marshall, go ahead and respond.

MR. MARSHALL. Mr. Congressman, we did schedule a maintenance pig and cleaning pig run in 2005. It is my regret that that was too late.

MR. DINGELL. Thank you. Mr. Chairman, thank you for your courtesy.

MR. WALDEN. Absolutely, Mr. Dingell.

The Chair now recognizes the full committee chairman, Mr. Barton.

CHAIRMAN BARTON. Thank you, Mr. Chairman.

Mr. Stears, you work for Coffman Engineering or Engineers. What is your company's relationship with the State of Alaska and with British Petroleum?

MR. STEARS. We are providing corrosion expertise or corrosion expert opinions for the State of Alaska on BP's program.

CHAIRMAN BARTON. So would you say your client is the State of Alaska or is your client British Petroleum?

MR. STEARS. Our client is the State of Alaska.

CHAIRMAN BARTON. State of Alaska. So you are a private contractor helping the State of Alaska do oversight on some of these issues with the various, I assume all the pipelines or is it just these particular pipelines?

MR. STEARS. It is the non-common-carrier pipelines.

CHAIRMAN BARTON. Okay. Do you--we have repeatedly been told that there is no Federal regulation of these particular lines because they are low-pressure lines and they are also an intrastate commerce. What is the definition of low pressure versus high pressure in an oil pipeline?

MR. STEARS. I don't have that information.

CHAIRMAN BARTON. Does anybody know the difference? No one? I can't believe I have asked a question--

MR. HOSTLER. Congressman, I believe the answer is, any time a line operates below 20 percent of its design pressure, it is considered a low-pressure line, but I would confirm that with the DOT.

CHAIRMAN BARTON. So there is not a specific pressure, it is depending on the capacity?

MR. HOSTLER. The capacity of the pipeline that is installed, but I would confirm that with the DOT this afternoon.

CHAIRMAN BARTON. All right. Now, these lines that are in question are called gathering lines. Now, in Texas, a gathering line is a much smaller line. I am told these are 34-inch-diameter lines. Is that correct?

MR. MARSHALL. Thirty-inch and 34-inch, Mr. Congressman. That is correct.

CHAIRMAN BARTON. So I am told that each of these lines was transporting about 200,000 barrels of oil a day. What is the capacity of these lines? What could they transport?

MR. MARSHALL. Mr. Congressman, I don't know the ultimate capacity. I do know that at the peak, Prudhoe Bay was producing in excess of a million barrels a day, and--

CHAIRMAN BARTON. So each of these lines at peak would have been transporting 500,000 barrels a day?

MR. MARSHALL. I can confirm that. I would say probably at least and maybe even more but I will get back to you with a more specific number on that.

CHAIRMAN BARTON. All right. Now, I am an engineer but I am not a petroleum engineer or hydrostatic engineer, and in fluid mechanics, I made a D, so I am--I did pass but just by the skin of my teeth.

MR. WALDEN. I figured you made an R.

CHAIRMAN BARTON. An R? A pipeline that could carry 500,000 barrels a day, that it is only carrying 200,000 barrels a day, if a layman, if we did a cross section and looked inside that pipeline, would it be full, would the total volume be oil or would it be half full and you would have air above the oil?

MR. MARSHALL. I am a mechanical engineer so but even with that, I would say that the pipeline remains full and it is a function of the velocity--

CHAIRMAN BARTON. That is what I would think, so it would have to be full in order to push the oil through the pipeline.

MR. MARSHALL. That is correct. It is pumped through from each of the flow stations or gathering centers and the line is full. It is simply the 500,000 barrels a day versus 200 results in low velocities through that line.

CHAIRMAN BARTON. Now, we have--these pipelines that are under question today, I assume that they have been in service for over 30 years. Is that correct?

MR. MARSHALL. Mr. Congressman, the lines have been in service for--since June 1977.

CHAIRMAN BARTON. Okay. So almost 30 years. And they were designed to carry much more oil than they are carrying today so they are operating under much lower pressure than they were designed to operate under, and the probability based on the inspection reports that we have is that there is sludge and water and other sediment in there. So was it a decision of BP that they didn't have to do the smart pigs or the maintenance pigs because the pressure differential was down and there wasn't as much pressure on the wall?

MR. MARSHALL. Mr. Congressman, I am not aware of any--personally aware of any discussions that led to that conclusion.

CHAIRMAN BARTON. Okay. Well, I want to ask the gentleman from Alyeska, Mr. Hostler, your company, which operates the Trans Alaska pipeline which is the much bigger pipeline. It is, what, 5 feet in diameter?

MR. HOSTLER. Four feet, sir.

CHAIRMAN BARTON. Four feet in diameter. So it is not much bigger than these lines. You inspect your line every two weeks. BP--with the pig, clean it every two weeks--BP doesn't do it at all except by exception. Why is your operating procedure so much different than BP's was? It is the same oil and the--I actually thought the line was much bigger but apparently it is not that much bigger so why are you doing something every two weeks that BP basically wasn't doing at all?

MR. HOSTLER. Well, Congressman, I can't speak for BP but the reason as we spoke earlier today that we clean the line every two weeks is one, for hydraulics, as mentioned, and two, to take out any accumulation of solids or water in the system and then we smart pig every three weeks as has been mentioned as well.

CHAIRMAN BARTON. But what is--this is kind of key to the whole issue here. Why would BP on their 34-inch-diameter lines of which they had two not do what you are doing on one 48-inch line? What is the difference in management approach there? It is the same oil.

MR. MARSHALL. Mr. Congressman, we didn't believe we had a corrosion problem in those lines. Clearly in retrospect, in two sections of those lines, the eastern sections of those lines, the two three-mile sections that have failed, we did. The inner 10 miles of those 16 miles appear to be in far better shape based on the inspections so far but clearly in retrospect, the corrosion did occur.

CHAIRMAN BARTON. Well, now, we have in our reference book for this hearing tabs 9, 10 and 11 which deal with an inspection report that Coffman Engineering prepared back in 2001 and the State of Alaska environmental officer, a lady named Susan Harvey, has told our committee staff that the draft report which was critical of BP's corrosion control program was extensively changed after she was removed from the project and she feels like that she was removed because of pressure by BP to remove her, and the subsequent final report that came out was much different and less critical of BP's corrosion control program. So how could it be, Mr. Marshall, that BP wasn't aware of some of these problems because at least they are implicitly alluded to in this 2001 draft report which BP objected to?

MR. MARSHALL. Mr. Congressman, I am not aware of Susan Harvey's involvement. I don't have any information--

CHAIRMAN BARTON. Are you aware of the debate over the report that the Coffman associates helped prepare in 2001?

MR. MARSHALL. I became aware of that after the March spill and we launched an investigation into the reports from the 2000 program, I believe the one in question. We interviewed as many people as we could, both with Coffman and with BP and with the Department of Environmental Conservation. While we haven't been able to interview everybody, we found no evidence of pressure to change those reports. What I understand to have been the case was this was the first report that was produced as part of the charter agreement with the State that BP and indeed the other operator, ConocoPhillips, was preparing and that as we developed this report, there were some conclusions drawn that appeared to BP to be perhaps not quite accurate, that the Coffman and the State did not have all the information that we could have provided.

CHAIRMAN BARTON. But when this report happened back in 2001--you have been in your current position since 2001. Is that not correct?

MR. MARSHALL. That is correct, yes.

CHAIRMAN BARTON. And you are testifying under oath here, you did not have any knowledge of this draft report in 2001?

MR. MARSHALL. I did not. I wasn't even aware of a Coffman report at that time, no. That is correct.

CHAIRMAN BARTON. And you became aware of this situation when?

MR. MARSHALL. After the March spill.

CHAIRMAN BARTON. Okay. This year?

Okay. I have got one final question. We have got all kinds of anecdotal--evidence is too strong a term but we have been told by a number of individuals that the reason BP decided to discontinue pigging was because the last time they attempted it, there was so much sludge in the line that it fouled the screens at the endpoint of the pipeline and that because of that, BP just decided the field was depleting and it wasn't worth messing with and they would rely on other means to do inspections for corrosion. So my question is to you, Mr. Marshall, isn't it normal in a pipeline that you are going to have sediment and sludge buildup? I mean, that should be, I would think--and again, I am not a pipeline engineer, but I would think that would be a problem that you know is going to occur and that you would take steps to manage as it occurred. Am I wrong in that assumption?

MR. MARSHALL. Mr. Congressman, I can't comment definitively that all pipelines necessarily have solids. Our experience has been that some do, some don't. It depends on--

CHAIRMAN BARTON. Well, this is one that you know did. I mean, you knew the last time you tried to put a pig through one of these lines that there was sediment and sludge and material in it that wasn't oil. I mean, that is a fact.

MR. MARSHALL. What I understand to be the case--again, if I separate the east and west for one second. On the west, which is what BP pigged in 1998, we received virtually no solids, less than two cubic yards out of 10 miles of pipe which is a very relatively low amount of solids. I understand when ARCO tried to pig the eastern lines in the early 1990s, there was considerable scale. I am not aware if there were other solids other than calcium scale that had build up on the inside of the pipeline which did indeed cause some fouling of the screens and strainers at Pump Station 1.

CHAIRMAN BARTON. But that would tell me, the last statement, that you needed to do more maintenance pigging, you needed to have some program to get that out of the pipeline and again, not being a pipeline engineer, I can't state this definitively but it would seem to me that that would be an engineeringly manageable problem, that you would take steps to prevent that and clean it out and keep it clean, and apparently the BP action was to do nothing, to just say okay, we can't run a pig through here, there is too much garbage in the line and so we are not going to mess with it, and to me, that seems to be 180 degrees from what you should do. Apparently you are doing today what you should have done a long time ago. You are building a bypass line. You are doing some cutout valves. You are doing all this stuff to rectify the problem today. The only thing that is different between today and the early 1990s is that you have got the United States Congress watching you and you have got the State of Alaska watching you and it has become an environmental disaster.

MR. MARSHALL. Mr. Congressman, to my knowledge, I found no evidence so far of any deliberate decisions to not pig those lines because of solids. We are still looking at that but I have found no evidence so far to say that is indeed the case.

CHAIRMAN BARTON. Well, you have got a different operator operating the main line that goes from the gathering station down to Valdez that does maintenance inspection pigging every two weeks. It is the same oil coming from the same oil field coming from your two transit pipelines. They are doing something every two weeks routinely that your company has only attempted intermittently on either line over the last 15 years. I mean, it just--there has to be a conscious decision somewhere in your chain of command to ignore the reports that are coming out. I mean, the corrosion manager for BP took the Fifth Amendment, which he has got the right to do, but I cannot believe that he is the only one in the company that knew about this problem. It just doesn't make sense.

So my time has expired, Mr. Chairman, I would yield back. I hope we continue to--

MR. WALDEN. Before you do that, Mr. Chairman, I would like to ask unanimous consent to enter into the record the committee's hearing book dated Thursday, September 7, 2006, BP's Pipeline Spills at Prudhoe Bay: What Went Wrong? It is the document binder from the Subcommittee on Oversight and Investigations. And so without objection, I will enter that into the record. Mr. Chairman.

[The information follows:]

Ex. #	Description	Date
1	BXPA Corrective Action Order (CPF No. 5-2006-5015H)	3/15/06
2	Amendment No. 1 to Corrective Action Order	7/20/06
3	Amendment No. 2 to Corrective Action Order	8/10/06
4	Summary of BPXA Corrosion Monitoring and Prevention Program	
5	BP Internal Audit: BPXA Corrosion Management System - Technical Review, Final Report ("Baxter Report 1")	Apr-05
6	Alaska Transit Pipeline Technology Review, Final Report ("Baxter Report 2")	Apr-06
7	BP Incident Investigation Report: GC-2 Transit Line Spill, Prudhoe Bay Western Operating Area, March 2, 2006	4/14/06
8	Report for BPXA Concerning Allegations of Workplace Harassment from Raising HSE Issues and Corrosion Data Falsification (redacted), prepared by Vinson & Elkins ("V&E Report")	10/20/04
9	BP Concerns/Comments on the Final Draft Coffman Engineers Report	Nov-01
10	Draft Report prepared by Coffman Engineers on BPXA's Prudhoe Bay corrosion control program for 2000 ("Coffman Draft Report")	11/2/01
11	Final Report prepared by Coffman Engineers on BPXA's Prudhoe Bay corrosion control program for 2000 ("Coffman Final Report")	Jan-02
12	2001 Coffman Report	
13	2002 Coffman Report	
14	2003 Coffman Report	
15	2004 Coffman Report	
16	BP Report of Investigation of Revisions to Coffman Report (redacted), prepared by Jeffrey M. Feldman ("Feldman Report")	4/24/06
17	Alyeska *Top Ten List* re: internal corrosion	8/23/06
18	Alyeska Letter to Steve Marshall, President of BPXA, re: Receipt of Material from Non-routine Pigging of Producer Lines	5/12/06
19	Alyeska Memo from Mike Joynor to Kevin Hostler re: Re-evaluation of the TAPS Impact Assessment of Receiving Pigging Solids from BPXA Produced Oil Transit Lines - Interim Report	8/8/06
20	Alyeska notes re: ARCO Pigging of Eastern Operating Line	1990-1991

21	PHMSA Recommendations re: Issue Order Directing Amendment for BPXA	4/11/06
22	Email from Nancy Foust to Neil McCleary re: "FW: Charter Agreement - Corrosion Monitoring"	11/7/01
23	Email from Dominic Paisley re: "Coffman Report Comments"	11/8/01
24	Email from Nancy Foust to Neil McCleary re: "Response from Bill Colbert in Regards to Charter Agreement"	11/8/01
25	Email from Richard Woollam to Michelle Martin re: "BP/Coffman Engineers Contract"	11/11/01
26	Email from Chris Phillips to Richard Woollam re: "RE: Coffman Report for BPXA"	11/12/01
27	Email from Elsa Tutaan to Richard Woollam re: "RE: BP/ADEC Meetings Nov 19th and Nov 21st"	11/14/01
28	Email from Richard Woollam to Cherry & Snyder re: "ADEC Meeting Feedback"	11/20/01
29	Email from Richard Woollam to Neil McCleary and Nancy Foust re: "RE: ADEC/Coffman Review Meeting Feedback"	11/25/01
30	Email from Richard Woollam re: "FW: Coffman revisions to BPXA review"	12/21/01
31	ADEC Request for Proposals: Corrosion Monitoring of Non-Common Carrier North Slope Pipelines - Section 5: "Scope of Work"	6/11/01
32	Letter from Hon. John D. Dingell to Steve Marshall, President of BPXA and Marshall response	3/24/06 4/3/06
33	Letter from Hon. John D. Dingell to Hon. Norman Y. Mineta, Secretary, U.S. Dept. of Transportation and DOT response	4/25/06 6/5/06

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DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
BP Exploration (Alaska), Inc.,	)	CPF No. 5-2006-5015H
Respondent	)	

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order is being issued, under authority of 49 U.S.C. § 60112, to require BP Exploration (Alaska), Inc. (Respondent), to take necessary corrective action to protect the public, property, and the environment from potential hazards associated with a failure involving Respondent's Prudhoe Bay West Operating Area (PBWOA) hazardous liquid pipeline.

On March 2, 2006, Respondent discovered a leak on the PBWOA hazardous liquid pipeline in North Slope Borough, Alaska. The probable cause of the failure is internal corrosion. Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA) initiated an investigation of the accident.

Preliminary Findings

- On March 2, 2006, at approximately 5:30 AM AKST, Respondent's surveillance crew discovered a crude oil spill in the proximity of Respondent's PBWOA hazardous liquid transmission pipeline in North Slope Borough, Alaska. Respondent determined the failure site to be at or near Mile 1.0 between Gathering Center 2 (GC-2) and Gathering Center 1 (GC-1) on the PBWOA pipeline, several miles upstream of the Trans Alaska Pipeline's first pump station (PS-1). No fires, injuries, or fatalities were reported in connection with the accident.

- The pipeline failure resulted in a release currently estimated at 5,000 barrels of processed crude oil, impacting the arctic tundra and covering approximately 2 acres of permafrost. Potential damage to the ecology and environment is presently unknown.

- Respondent's leak detection system was not effective in recognizing and identifing the failure. Following discovery of the spill, Respondent isolated the segment between GC-2 and GC-1, initiated shutdown at 6:49 AM AKST and depressurized the segment. Respondent located the leak site and installed a containment welded sleeve. Respondent also initiated oil spill response.

- The failure point is a 0.25-inch by 0.5-inch hole in the pipe. The probable cause of the failure is internal corrosion. There is evidence of bacterial corrosion (increased hydrogen sulfide and nitric acid in the crude oil) and increased water content.

- Respondent's PBWOA hazardous liquid pipeline system is approximately 10 miles in length and transports processed crude oil from GC-2 to PS-1 on the Trans Alaska Pipeline in North Slope, Alaska. The PBWOA system is constructed of 34-inch nominal diameter, X52 Grade, 0.375-inch wall thickness, submerged arc welded pipe manufactured in 1975 through 1977. The pipe is not coated and it is not cathodically protected. The pipeline sits on a vertical support member above-ground and is surrounded by an air culvert. The pipe is insulated and has a steel jacket. Although the pipeline is above-ground, at the time of the failure, the pipeline was lying in water that had pooled from melting snow.

- The established maximum operating pressure (MOP) for the PBWOA is 826 pounds per square inch gauge (psig) established by design pressure. Estimated maximum normal operating pressure is 100 psig. Actual operating pressure was approximately 80 psig when the failure was discovered.

- The PBWOA operates at less than 20% of the specified minimum yield strength (SMYS) and is therefore a low-stress pipeline under 49 C.F.R. § 195.2. Federal hazardous liquid pipeline safety regulations (49 C.F.R. Part 195) do not apply to the PBWOA under the exception in 49 C.F.R. § 195.1 for onshore low-stress pipelines located in a rural area, outside a waterway currently used for commercial navigation, which do not transport highly volatile liquids.

- The PBWOA is one of three similar low-stress pipelines operated by Respondent that feed into PS-1. The other two pipelines are the Prudhoe Bay East Operating Area (PBEOA) pipeline and the Lisburne pipeline. All three pipelines were constructed around the same time, operate in similar environmental conditions, transport the same quality crude oil that contributed to the cause of the internal corrosion in PBWOA, and are operated and maintained in a similar manner by Respondent.

- Respondent's failure investigation has identified at least six additional anomalies on the PBWOA segment between GC-2 and GC-1. Internal corrosion has been observed at several of those anomalies. The worst noted anomaly had a remaining wall thickness of 0.04-inches.

- An internal inspection of the PBWOA was last performed in 1998 using a high-resolution magnetic flux leakage (MFL) tool. Respondent has not established a regular internal inspection or maintenance pigging (cleaning pig) program.

- Respondent plans to bypass the segment between GC-2 and GC-1 using a 24-inch flow-line. Once the bypass is in place, Respondent plans to restart the PBWOA. Respondent anticipates the bypass process will take up to 10 days before the PBWOA pipeline can be restarted.

Determination of Necessity for Corrective Action Order and Right to Hearing

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, when PHMSA decides that a pipeline facility is hazardous. A pipeline facility is a pipeline, right-of-way, facility, building, or equipment used or intended to be used in the movement of hazardous liquid by pipeline, or the storage of hazardous liquid incidental to the movement of hazardous liquid by pipeline, in or affecting interstate or foreign commerce. A pipeline facility does not include movement of hazardous liquid through gathering lines in a rural area; onshore production, refining, or manufacturing facilities; or storage or in-plant piping systems associated with onshore production, refining, or manufacturing facilities. The basis for deciding that a pipeline facility is hazardous, requiring corrective action, is set forth both in the above-referenced statute and 49 C.F.R. § 190.233, a copy of which is enclosed.

Section 60112 of Title 49, United States Code, and the regulations promulgated thereunder, provide for the issuance of a Corrective Action Order without prior opportunity for notice and hearing upon a finding that a failure to issue the Order expeditiously will likely result in serious harm to life, property, or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the Order.

After evaluating the foregoing preliminary findings of fact, I find that the PBWOA, PBEOA, and Lisburne pipelines operated by Respondent are pipeline facilities within the meaning of that term as used in 49 U.S.C. §§ 60101 and 60112, notwithstanding the inapplicability of the pipeline safety regulations at 49 C.F.R. Part 195. Those pipelines are used in the movement of hazardous liquid by pipeline in interstate commerce and are not gathering lines in a rural area, onshore production, refining, or manufacturing facilities, or in-plant piping systems. Additionally, after considering the age of the pipe, the hazardousness of the product the pipelines transport, the large spill volume, the ineffectiveness of the leak detection system to identify the leak, the number, type, and severity of anomalies discovered on the segment that was inspected, the similarity of the PBEOA and Lisburne pipelines to the pipeline that failed, and the proximity of the pipelines to wildlife areas or other possible sensitive areas, I find that the continued operation of Respondent's PBWOA, PBEOA, and Lisburne hazardous liquid pipelines without corrective measures will be hazardous to life, property, and the environment. Moreover, failure to expeditiously issue this Order requiring immediate corrective action would likely result in serious harm to life, property, or the environment.

Accordingly, this Corrective Action Order mandating immediate corrective action is issued without prior notice and opportunity for hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by facsimile at (202) 366-4566. The hearing will be held in Lakewood, Colorado or Washington, D.C. on a date that is mutually convenient to PHMSA and the Respondent.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective action measures that need to be taken. In that event, Respondent will be notified of any additional measures required and amendment of this Order will be considered. To the extent it is consistent with safety considerations, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of additional corrective measures.

Required Corrective Action

Pursuant to 49 U.S.C. § 60112, I hereby order BP Exploration (Alaska), Inc. to immediately take the following corrective actions with respect to the PBWOA, PBEOA, and Lisburne hazardous liquid pipeline systems:

1. Repair all anomalies on the PBWOA segment between GC-2 and GC-1, including those anomalies identified after the March 2, 2006 pipeline failure before resuming service. Extract and record dimensional data of all anomalies found, including data on distance from upstream and downstream girth weld, o'clock position, minimum and maximum remaining wall thickness, and remedial actions taken on each anomaly.

2. Obtain prior written approval from the Director, Western Region, PHMSA before resuming operations on the PBWOA pipeline. Operating pressure on the PBWOA is not to exceed 80 psig. This pressure restriction shall remain in effect until written approval to increase the pressure is obtained from the Director, Western Region, PHMSA.

3. Perform an internal inspection using a calibrated smart pig on the PBWOA pipeline within 3 months of placing the pipeline back in service. Take appropriate action to address all anomalies discovered by this inline inspection device, in accordance with the standards for anomaly repair in 49 C.F.R. Part 195. Record differences between inline inspection data and actual "as found" data for all anomalies and integrate that data in future analyses, mapping corrosion growth, and confirming data gathered by inline inspection tool. Develop and submit for approval a plan to perform internal inspections at regular intervals, not to exceed 5 years, and schedule for the repair of anomalies identified through those inspections. Implement that plan upon approval.

4. Develop and submit for approval a plan for running maintenance pigs (cleaning pigs) on the PBWOA, PBEOA, and Lisburne pipelines at regular intervals. Implement that plan upon approval. Until that plan has been approved and implemented, run maintenance pigs on those pipelines on a weekly basis. Conduct laboratory analyses on sludge to determine its corrosive properties and integrate those findings into the internal corrosion management plan in Item 5 below.

5. Conduct a review of the leak detection system for the PBWOA, PBEOA, and Lisburne pipelines and make necessary modifications to ensure that the leak detection systems comply with API 1130, within 3 months of receipt of this order.

6. Develop and submit for approval an internal corrosion management plan to reduce internal corrosion on the PBWOA, PBEOA, and Lisburne pipelines within 3 months of receipt of this order. The plan must address the use of corrosion inhibitors, emulsion breakers, and mechanisms to reduce water and solid particles. This plan should also allow for monitoring sludge extracted from pipelines to ensure that internal corrosion is being controlled. Implement that plan upon approval.

7. Perform an internal inspection using a calibrated smart pig on the PBEOA and Lisburne pipelines within 3 months of receipt of this Order. Take appropriate action to address all anomalies discovered, in accordance with the standards for anomaly repair in 49 C.F.R. Part 195. Record differences between inline inspection data and actual "as found" data for all anomalies and integrate that data in future analyses, mapping corrosion growth, and confirming data gathered by inline inspection tool. Develop and submit for approval a plan to perform internal inspections at regular intervals, not to exceed 5 years, and schedule for the repair of anomalies identified through those inspections. Implement that plan upon approval.

8. Perform infrared aerial surveys at already-established intervals for the entirety of the PBWOA, PBEOA, and Lisburne pipelines.

9. At the earliest practicable moment following discovery of any pipeline failure on the PBWOA, PBEOA, and Lisburne pipelines that involves the release of any amount of the hazardous liquid transported, give telephonic notice of the failure to the National Response Center in accordance with 49 C.F.R. § 195.52(b).

10. Submit for review each oil spill response plan developed pursuant to the requirements of Federal law or regulation for the PBWOA, PBEOA, and Lisburne pipelines.

The Director, Western Region, PHMSA may grant an extension of time for compliance with any of the terms of this Order for good cause. A request for an extension must be in writing.

Respondent may appeal any decision of the Director, Western Region, PHMSA to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator are final.

In accordance with 49 U.S.C. § 60122 and 49 C.F.R. § 190.223, failure to comply with this Order may result in the assessment of civil penalties of not more than $100,000 per day and in referral to the Attorney General for appropriate relief in a United States District Court.

Stacey Gerard
Associate Administrator
for Pipeline Safety

MAR 15 2006

Date Issued

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DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
	)	
BP Exploration (Alaska) Inc.,	)	**CPF No. 5-2006-5015H**
	)	
BP	)	
	)	

AMENDMENT No.1 TO CORRECTIVE ACTION ORDER

Background & Purpose

On March 15, 2006, under authority of 49 U.S.C. §60112, the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order (CAO) to BP Exploration (Alaska) Inc. (BP), finding that the continued operation of BP's Prudhoe Bay Western Operating Area (WOA), Eastern Operating Area (EOA) and Lisburne crude oil pipelines, would be hazardous to life, property, or the environment without the implementation of corrective measures. The CAO was issued in response to a failure on BP's WOA pipeline that caused the discharge of an estimated 201,000 gallons of crude oil on the North Slope tundra.

Additional Preliminary Findings

Prudhoe Bay Transmission Pipelines (EOA, WOA, and Lisburne)

1. BP has been on notice since at least May 2006 that cleaning of the WOA, EOA, and Lisburne pipelines could dislodge sediments and solids that had accumulated in the pipelines over a period of years.

2. In 1992, BP's predecessor suspended cleaning of the EOA oil transmission pipeline when residues, waxes, and calcium carbonate deposits clogged the strainers maintained by Alyeska Pipeline Service Company (Alyeska) at Pump Station-1 on the Trans Alaska Pipeline System (TAPS). The calcium carbonate was primarily encountered between Flow Station-3 and Skid 50.

3. In May 2006, BP performed gamma ray scans to determine the volume of sludge inside the EOA and WOA oil transmission pipelines. BP advised PHMSA that sediment levels in some areas in the EOA oil transmission pipeline were in the range of 9 to 12 inches.

4. On May 22, 2006, PHMSA received a copy of a report by Alyeska entitled *TAPS Impact Assessment of BPXA Pigging -Interim Report*. Alyeska performed this study to understand the potential risk to TAPS if the sludge volumes estimated by BP were pushed into the TAPS pipeline in the process of performing cleaning operations on the pipelines. The report concluded that the solids from the WOA and EOA pipelines could adversely impact the operations of TAPS.

5. Alyeska's analysis was based on anecdotal evidence and results from the last time the EOA and WOA pipelines were pigged, and reports of the gamma ray surveys performed by BP in May 2006.

6. In June 2006, BP informed PHMSA that it had overestimated the volume of solids detected by the May 2006 gamma ray scans and that, upon reinterpretation of the scans, it estimated average sediment levels as follows:

   a. Lisburne pipeline: 0.4-inch from LS 1 to TAPS Pump Station-1;
   b. EOA pipeline: 1-inch from FS2 to FS1 and 0.6-inch from FS 1 to Skid 50;
   c. WOA pipeline: 2.8-inches from GC 2 to GC 1; 0.8-inch from GC1 to GC3, and 1.9-inches from GC3 to Skid 50;
   d. Skid 50 to TAPS Pump Station-1: 1-inch.

7. BP began cleaning and maintenance pigging of the Lisburne pipeline on or about June 9, 2006, and ending on or about June 22, 2006. Approximately one cubic yard of sediment was removed from the Lisburne oil transmission pipeline. That amount is consistent with the predicted volume from the gamma ray scan conducted in May 2006.

8. BP inspected the Lisburne oil transmission pipeline with an instrumented in-line inspection device on or about June 30, 2006. The inspection results are still pending.

9. BP launched the first cleaning pig in the outer segment of EOA from FS-2 to FS-1 during the week of July 3, 2006. BP has advised PHMSA that these cleaning operations are ongoing.

10. Based on reported cleaning results to date, it appears that additional scale, debris or sediment may have been pushed from the 30-inch EOA segment into the 34-inch segment during these cleaning operations.

11. Strainers on TAPS Pump Station -1 meter runs have an approximately 1 barrel capacity, and a ¾ inch mesh size.

12. BP does not currently have large volume facilities to sequester solids displaced by cleaning pigs.

13. TAPS has two 210,000 BBL storage tanks located at Pump Station-1. Beginning in August, these breakout tanks are expected to have excess capacity for the remainder of 2006.

14. BP has not reached an agreement or arrangement with Alyeska concerning handling of the solids in the WOA and EAO pipelines and has not made arrangements for capturing and removing sediments from the pipelines without the use of Alyeska facilities.

Idled OT-21 Section of WOA pipeline

15. After the failure on BP's WOA pipeline, the segment that failed extending from Gathering Center two (GC2) to Gathering Center one (GC1) and is known as the OT-21 Segment (OT-21) was idled. The approximately three-mile long OT-21 segment was not drained after it was idled and still contains crude oil. BP has not run cleaning and maintenance pigs on the OT-21 segment or on the connecting segments of WOA, as required by Items 3 and 4 of the March 15, 2006 CAO.

16. According to information provided by BP, OT-21 currently contains approximately 17,000 barrels (BBL)[1]

17. At this time, BP theorizes that OT-21 leaked because of "enhanced corrosion." BP's theory of this corrosion is based on the aggregate effect of several likely factors: [2]
    a. Although corrosion inhibitor was injected at the production stage, none was being injected at GC2 for an extended period prior to the pipeline failure.
    b. The OT-21 crude oil stream contained a reduced level of corrosion inhibitor.
    c. This resulted in a corresponding decrease in the toxicity of the water in the pipeline and a corresponding increase in the bacterial activity in the pipeline.

18. PHMSA has preliminarily determined that these conditions created an environment in which extensive corrosion occurred. Although the ultimate cause of failure cannot be determined until a metallurgical analysis to determine the root cause of failure and the contents of OT-21 from the failure is analyzed, the postulated corrosive environment that existed inside OT-21 and led to the failure most likely remains in existence today and the pipeline may still be corroding OT-21, even at the current lower temperatures (40 to 50 degrees Fahrenheit) of the idled oil.

19. The stagnant environment inside OT-21, in combination with other risk factors, including the presence of water in the pipeline, poses an ongoing leak threat. In the aggregate, the

[1] 1 BBL = 42 US gallons. 17,000 BBL = 714,000 gallons.
[2] BP's June 6, 2006 Request for Extension, Appendix G, OT-21 Leak Failure Theory and Application, 1-2.

risk factors warrant corrective action to remove the contents of OT-21 before the onset of winter weather conditions on the North Slope.

20. The oil in OT-21 will become more viscous and difficult to extract as temperatures drop. All other factors being equal, conducting the de-oiling operation before the onset of winter weather will minimize engineering complications and associated risks.

DETERMINATION OF NECESSITY FOR AMENDMENT OF CORRECTIVE ACTION ORDER AND RIGHT TO A HEARING

Section 60112 of Title 49, United States Code, provides for the issuance of a corrective action order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other appropriate action. The basis for making the determination that a pipeline facility is hazardous, requiring corrective action, is set forth in the above-referenced statute and in 49 C.F.R. §190.233.

Section 60112(e) and the regulations promulgated there under (49 C.F.R. §190.233(b), provide for the issuance of a corrective action order without prior opportunity for notice and hearing upon a finding that failure to issue the order expeditiously will result in likely serious harm to life, property or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the order.

Based upon the preliminary and additional findings, I continue to find that the presence of hazardous conditions on the specified pipelines, including the OT-21 segment, without the implementation of corrective measures, would result in likely serious harm to life, property or the environment. BP has failed to meet its continuing responsibility to pursue all available options for meeting the requirements of Items 3, 4, and 7 of the March 15, 2006 CAO, and to address the risks associated with idling of OT-21, including simultaneous preparation of contingency plans, risk analyses, and engineering plans for alternative options and timely acquisition of necessary information and materials. The lack of sufficient progress towards completing items 3, 4, and 7 of the CAO necessitates a permanent solution that is not dependent on, and does not pose a risk to, TAPS.

Additionally, after considering the circumstances surrounding the failure discovered on March 2, 2006, the hazardous nature of the liquids remaining in OT-21, the immediate proximity of the pipeline to environmentally sensitive areas, the extensive corrosion and wall thinning found in OT-21, the potential for additional corrosion and wall thinning due to current idle conditions, the presence of water, and the safety and environmental threats posed by those conditions, I find that failure to expeditiously issue this Amendment would result in likely serious harm to property and the environment.

Accordingly, this Amendment ordering immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Amendment are effective upon receipt.

Within 10 days of receipt of this Amendment, BP may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by facsimile at (202) 366-3666. A hearing, if requested, will be held in Lakewood, CO or Washington, DC on a date that is mutually convenient to PHMSA and BP. A hearing requested on this Amendment may be consolidated with the hearing BP has already requested on this CAO.

In the course of this investigation, PHMSA has identified and may identify additional measures that need to be taken to ensure the safety of BP's pipelines covered by the CAO. Such measures will be embodied in subsequent amendment(s) to the March 15, 2006, CAO and will impose additional requirements pending BP's completion of cleaning and smart pigging operations required by the March 15, 2006 CAO. The terms of the March 15, 2006 CAO and the additional terms added by this Amendment and subsequent amendment(s) will remain in place for as long as the Associate Administrator deems necessary to ensure that the specified pipelines are operated in a safe and environmentally sound manner.

AMENDMENTS TO REQUIRED CORRECTIVE ACTION

Pursuant to 49 U.S.C. §60112, I hereby order BP to immediately take the following additional corrective actions with respect to BP's Prudhoe Bay oil transmission pipeline system:

The following items are added to the Corrective Action Order:

Item 11. Within fourteen (14) days from receipt of this Amendment No. 1, BP shall conduct and provide to PHMSA additional gamma ray scans of the EOA 34-inch (FS-1 to Skid 50) segment, at the same locations scanned with gamma ray technology in May 2006. BP shall conduct the gamma ray scans in a manner sufficient to ensure that the results are accurate and representative of the sediment loads throughout the EOA 34-inch segment of the oil transmission pipeline. Following each successive run, BP shall provide PHMSA an estimate of the volume of sediment removed and supporting field data for that estimate.

Item 12. At least 30 days prior to beginning cleaning operations on any segment of the WOA oil transmission pipeline, BP shall conduct and provide to PHMSA gamma ray scans at all elevation change locations on those segments. BP shall conduct the gamma ray scans in a manner and at locations sufficient to ensure that the results are accurate and representative of the sediment loads throughout the inspected segments. Following each successive run, BP shall provide PHMSA an estimate of the volume of sediment removed and supporting field data for that estimate. BP shall complete all requirements of the March 15 CAO with respect to all segments of the WOA, EOA, and Lisburne pipelines that BP is operating or intends to restore to operations.

Item 13. Within seven (7) days of receipt of this Amendment, BP shall submit a plan for approval by the Western Region Director to extract and analyze representative samples from the pipe wall of the EOA 34-inch pipeline. The plan shall be designed to ensure that the sampling and analysis is sufficient to enable BP to determine the amount of calcium carbonate deposits present in this section of the EOA oil transmission pipeline. These representative pipe samples will be taken from locations in the pipe wall to avoid disrupting the cleaning pig operations. BP shall implement the plan within seven (7) days of approval.

Item 14. Within 48 hours of receiving the contractor report, BP shall report to Alyeska the information collected in accordance with Items 11, 12, and 13, so that Alyeska can revise its *Impact Assessment of BPXA Pigging–Interim Report* and evaluate the downstream risks to TAPS of permitting BP to move sediments, deposits, or other materials dislodged in cleaning operations into the TAPS pipeline.

Item 15. No later than August 8, 2006, BP shall develop, and submit for approval by the Western Region Director, preliminary engineering design and implementation plans to install permanent facilities for handling solids that may result from cleaning pig operations on the specified pipelines. BP shall ensure the facilities do not impair or pose a risk to the operations of TAPS and do not allow large amounts of solids to be moved into the TAPS metering and station piping facilities. Furthermore, these plans shall demonstrate to PHMSA and Alyeska that the oil will meet transit quality specifications. In addition to any facilities that BP proposes, BP shall also concurrently develop a contingency plan, including preliminary engineering design and implementation plans, to create a by-pass around TAPS PS-1 facilities, so solids can be delivered directly into TAPS storage tanks. Upon approval by the Western Region Director, BP shall commence construction in accordance with the plans, unless it has earlier demonstrated to the satisfaction of the Western Region Director that it is implementing or immediately prepared to implement an alternative method for handling solids dislodged in cleaning operations or that such construction is otherwise unnecessary.

Item 16. No later than August 1, 2006, BP shall develop, and submit for approval to the Western Region Director, a plan to safely remove the crude oil in the OT-21 line segment by August 22, 2006. The plan shall provide for removal of the crude oil in the OT-21 pipeline segment in a safe and environmentally sound manner, and in compliance with all applicable federal, state and local laws and regulations.

Item 17. Within 30 days from receipt of this Amendment, BP shall submit a report to the Western Region Director, detailing its actions and plans for replacing, abandoning, and/or restoring operation of OT-21. The report shall include preliminary or final engineering and implementation plans and timetables.

Item 18. BP shall carry out the requirements of the CAO, as amended, in accordance with all applicable federal, state and local laws and regulations, including any applicable federal, state and/or local regulations regarding oil transfer procedures, spill prevention and response, the State of Alaska's Oil and Hazardous Substances Control Statutes and Regulations in the Alaska Administrative Code, Title 18, Chapter 75, and the US Environmental Protection Agency's Spill Prevention Countermeasures and Control Regulations found in Title 40 Code of Federal Regulations, Part 112. These regulations as well as others may contain certain requirements for transfer procedures, spill containment, clean-up and reporting requirements that pertain to operations associated with removal of the crude oil from the pipeline.

Item 19. With respect to each submission that under this Order requires the approval of the Western Region Director, the Director may: (a) approve, in whole or part, the submission, (b) approve the submission on specified conditions, (c) modify the submission to cure the deficiencies, (d) disapprove, in whole or in part, the submission, directing that BP modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Western Region Director, BP shall proceed to take all action required by the submission as approved or modified by the Western Region Director. In the event that the Western Region Director disapproves all or any portion of the submission, BP shall correct all deficiencies within the time specified by the Western Region Director, and resubmit it for approval. In the event that a resubmitted item is disapproved in whole or in part, the Director may again require BP to correct the deficiencies in accordance with the foregoing procedure, and/or the Director may otherwise proceed to enforce the terms of this Order.

Item 20. BP shall maintain documentation of the safety improvement costs associated with fulfilling the March 15, 2006 CAO and submit to the Western Region Director, Pipeline and Hazardous Materials Safety Administration. Costs shall be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.

Item 21. The requirements of this Amendment may be modified only by written notice of the Associate Administrator for Pipeline Safety. A request for modification of any requirements imposed by this order shall be in writing and include an engineering justification and certification by an authorized officer of the company as to the accuracy of any facts offered in support of the request.

This Amendment does not modify, waive or supplant any requirements imposed under the March 15, 2006 CAO or any requirements that apply to BP's pipeline systems under any other provision of federal, state, or local law, or permit.

With respect to all actions undertaken pursuant to this Amendment, BP is responsible for achieving and maintaining compliance with all applicable federal, state, and local laws, regulations, and permits. This Amendment is not and shall not be construed to be a permit, or a modification of any permit, under any federal, state, or local law or regulation.

In accordance with 49 U.S.C. §60122 and 49 C.F.R. § 190.233, failure to comply with the CAO, as amended, may result in the assessment of administrative civil penalties of up to $100,000 per violation per day pursuant to 29 U.S.C. §60122, or in the imposition of civil judicial penalties and other appropriate relief pursuant to 49 U.S.C. §60120. The terms and conditions of this Amendment are effective upon receipt.

Stacey Gerard
Associate Administrator
for Pipeline Safety

JUL 20 2006

Date Issued

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DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
	)	
BP Exploration (Alaska) Inc.,	)	**CPF No. 5-2006-5015H**
	)	
Respondent	)	

AMENDMENT No. 2 TO CORRECTIVE ACTION ORDER

Background & Purpose

On March 15, 2006, under authority of 49 U.S.C. § 60112, the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration (PHMSA), issued a Corrective Action Order (CAO) to BP Exploration (Alaska), Inc., (BP), finding that the continued operation of three crude oil transmission pipelines in BP's Prudhoe Bay Operating Area – the Western Operating Area (WOA), Eastern Operating Area (EOA) and Lisburne crude oil pipelines – would be hazardous to life, property, or the environment without the implementation of corrective measures. The CAO was issued in response to a failure on BP's WOA pipeline that caused the discharge of an estimated 201,000 gallons of crude oil.

In addition to addressing the immediate consequences of the pipeline failure, the March 15, 2006 CAO required BP to take various measures to evaluate the condition of the subject lines, and to make any necessary repairs. Items 3, 4, and 7 of the CAO required BP to perform cleaning operations on the three pipelines, assess the condition of the pipeline walls, and measure any corrosion or other defects using an instrumented in-line inspection tool (known as a "smart-pig").

On July 20, 2006, under authority of 49 U.S.C. §60112, the Associate Administrator issued Amendment No. 1 to the March 15, 2006 CAO. Amendment No. 1 set forth additional preliminary findings based on PHMSA's oversight of BP's activities and PHMSA's continuing investigation of pipeline conditions on BP's Prudhoe Bay Operating Area. Amendment No. 1 required BP to perform additional integrity assessments and to develop and implement plans for addressing new and ongoing safety risks associated with its failure to complete diagnostic measures required by Items 3, 4, and 7 of the March 15, 2006 CAO.

Additional Preliminary Findings

Prudhoe Bay EOA Transmission Pipeline

1. The EOA pipeline is constructed of X60 Grade, 0.344-inch wall thickness pipe manufactured between 1976 and 1979. The first segment of the EOA pipeline, extending approximately three (3) miles from Flow Station 2 (FS2) to Flow Station 1 (FS1), is constructed of 30-inch nominal diameter pipe. The second segment, constructed of 34-inch nominal diameter pipe, extends approximately five (5) miles from FS1 to Skid 50; just upstream of the Trans Alaska Pipeline System (TAPS).

2. On or about July 22, 2006, 37 days after the deadline established under the March 15, 2006 CAO (as extended), BP performed smart pigging of the FS2-FS1 segment of the EOA pipeline. BP reportedly received initial reports of the smart pig data on August 4, 2006.

3. These reports identified sixteen (16) anomalies (representing wall loss in excess of 70 percent, including two (2) over 80 percent) at twelve (12) separate areas on the FS2-FS1 segment of EOA pipeline. According to BP, the data indicated each of the sixteen anomalies is approximately 1.5 by 1.5 inches in size and is located in the lower quadrant of the pipe (between the 5:45 to 6:45 positions).

4. On or about August 5, 2006, BP began performing direct visual and ultrasonic inspection of the locations identified by the smart-pig data as having significant wall loss. In the course of that work, according to BP reports, BP discovered a location where crude oil apparently had leaked through the pipe wall and onto the insulation material. On the basis of that discovery, BP reportedly initiated shut down of the FS2-FS1 segment of the EOA pipeline at approximately 6:00 a.m. on August 6, 2006.

5. Later in the morning of August 6, 2006, according to BP, BP personnel discovered crude oil leaking from a different location on the FS2-FS1 segment of the EOA pipeline. According to BP, field inspection of the leak site revealed multiple holes in the pipe wall at a single location, contributing to an estimated spill of approximately five (5) barrels of processed crude oil.

6. Since August 6, 2006, BP reportedly has discovered pinhole leaks on at least four additional locations on the FS2-FS1 segment of the EOA pipeline.

7. On the afternoon of August 6, 2006, BP notified the Director of PHMSA's Western Region Pipeline Safety Office of the EOA pipeline spill and advised PHMSA that BP had decided to shut down all of its Prudhoe Bay production fields on the North Slope. BP further stated that the Lisburne pipeline and associated production facilities would remain in service. On August 8, 2006, BP indicated its desire to maintain operations of the WOA pipeline if pipeline integrity could be demonstrated through further field assessments.

8. To date, BP has not performed cleaning or smart pigging operations on the FS1-Skid 50 (34-inch diameter) segment of the EOA pipeline.

9. On or about August 7, 2006, a team of PHMSA personnel and officials were deployed to BP facilities in Alaska to investigate the August 6, 2006 spill, examine the basis for BP's decision to cease operations, oversee BP's shutting down of pipeline operations, and evaluate what procedures would be necessary to safely restart operations.

10. On August 9, 2006, BP announced that it had decided to replace the FS2-FS1 segment and that BP had no plans to return the segment to operation.

Prudhoe Bay Lisburne Transmission Pipeline

11. On or about June 30, 2006, fifteen (15) days after the deadline established under the March 15, 2006 CAO (as extended), BP performed smart pigging of the Lisburne pipeline. BP reportedly received initial reports of the smart pig data on or about July 13, 2006.

12. BP reports that smart-pigging data indicate ten (10) areas in which external wall loss exceeded 40 percent.

Prudhoe Bay WOA Transmission Pipeline

13. The WOA pipeline consists of two segments of 34-inch nominal diameter pipe. The first segment (OT-21) extends approximately three (3) miles from Gathering Center 2 (GC2) to Gathering Center 1 (GC1). The OT-21 segment is currently bypassed by a jumper pipeline (GHX21). The second, downstream segment extends approximately five (5) miles from GC1 to Skid 50, and then to Pump Station 1 (PS1), just upstream of TAPS.

14. To date, BP has not performed cleaning or smart-pigging operations on either segment of the WOA pipeline.

15. BP took the OT-21 segment out of service following the spill discovered March 2, 2006 and has not returned the line to service since that date. Pursuant to Item 16 of Amendment No. 1 to the March 15, 2006 CAO, BP has submitted a plan for de-oiling the OT-21 segment beginning on or before August 22, 2006. The Director of the Western Region Pipeline Safety Office has reviewed and concurs with the plan.

16. BP has advised PHMSA by letter dated July 28, 2006, that the OT-21 segment will not be returned to service and will be permanently replaced with a new pipeline. To the extent that OT-21 will not be returned to service and is deoiled, BP is not required to complete smart-pigging of that segment as otherwise required by the March 15, 2006 CAO.

17. On June 6, 2006, BP submitted a plan for conducting assessment of pipeline wall integrity using ultrasonic testing (UT) to measure the thickness of the pipe wall at particular points on the line. BP proposed to use this inspection method until it conducts

smart pigging as required by the March 15, 2006 CAO, and interprets the results. BP contended that by extrapolation from the UT data, BP could obtain information, of equivalent reliability to smart pig results, for understanding the pattern and extent of internal corrosion in its pipelines. BP submitted the results of ultrasonic testing, performed from March through July, 2006, on the GC1-Skid 50 segment of the WOA pipeline.

18. Following the recent discovery of leaks and internal corrosion on the EOA line, BP announced a plan to conduct more thorough continuous automatic UT testing (AUT) of the in-service segment of its WOA pipeline. As of August 9, 2006, BP reportedly had initiated AUT testing on the GC1-Skid 50 segment.

19. As of August 8, 2006, BP has advised PHMSA investigators that all available resources are being deployed for completing inspection of the in-service segment of the WOA pipeline as soon as possible. BP representatives have advised PHMSA investigators and officials that they have deployed all available equipment and resources in support of completing continuous AUT testing as soon as possible. At the same time, BP reports that it is moving ahead with plans to smart pig all or part of the WOA pipeline by acquiring equipment and planning preliminary operations.

20. PHMSA has not ordered BP to cease operating the GC1-Skid 50 segment or the OT21 bypass (GHX21) of the WOA pipeline, and PHMSA is not aware of any data concerning the current condition of pipe on the GC1-Skid 50 segment, or the GHX21 bypass, that would necessitate an immediate cessation of operations on the WOA pipeline in order to protect life, property, or the environment.

DETERMINATION OF NECESSITY FOR AMENDMENT OF CORRECTIVE ACTION ORDER AND RIGHT TO A HEARING

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, when PHMSA decides that a pipeline facility is hazardous. Corrective action may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement or other appropriate action. The basis for deciding that a pipeline facility is hazardous, requiring corrective action, is set forth both in the above-referenced statute and 49 C.F.R. § 190.233.

Section 60112(e) of Title 49, United States Code, and the regulations promulgated thereunder (49 C.F.R. §190.233(b)), provide for the issuance of a Corrective Action Order without prior opportunity for notice and hearing upon a finding that a failure to issue the Order expeditiously will likely result in serious harm to life, property, or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the Order.

Based on the additional preliminary findings set forth above and the preliminary findings in the March 15, 2006 CAO and Amendment No. 1, I continue to find that the presence of hazardous conditions on the EOA, Lisburne, and WOA pipelines, without the implementation of corrective measures, would result in likely serious harm to property or the environment.

Additionally, after considering the circumstances surrounding the failures discovered on August 6 and March 2, 2006, the number and severity of anomalies discovered on the EOA line, the immediate proximity of the pipeline to environmentally sensitive areas, and the safety and environmental threats posed by serious internal corrosion of the EOA line, I find that failure to expeditiously issue this Amendment would result in likely serious harm to life, property and the environment.

Within ten (10) days of receipt of this Order, BP may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by facsimile at (202) 366-3666. A hearing, if requested, will be held in Lakewood, Colorado or Washington, DC on a date that is mutually convenient to PHMSA and BP. A hearing requested on this Amendment may be consolidated with the hearing BP has already requested on this CAO.

In the course of this investigation, PHMSA may identify additional measures that need to be taken to ensure the safety of BP's pipelines covered by the CAO. The terms of the March 15, 2006 CAO and the additional terms added by Amendment No. 1, this amendment, and subsequent amendment(s) will remain in place for as long as the Associate Administrator deems necessary to ensure the subject pipelines are operated in a safe and environmentally sound manner. The actions required by this CAO are in addition to and do not waive or modify any requirements that apply to BP's pipeline systems under any provision of Federal or state law, or under any other order issued to BP under authority of 49 U.S.C. §§60101 et seq.

Amendments to Required Corrective Action

Pursuant to 49 U.S.C. § 60112, I hereby order BP to immediately take the following additional corrective actions with respect to BP's Prudhoe Bay oil transmission pipeline system:

The following items are added to the Corrective Action Order:

Item 22. Additional Measures for Monitoring and Response. Within one (1) day of receipt of this Amendment No. 2, and until further order of the Western Region Director, BP shall begin four times daily visual and handheld infrared surveys via ground patrol of the entire length of the EOA, Lisburne, and WOA pipelines. Surveys shall seek out signs of leaks and any other threats to pipeline integrity. BP shall report the results of the surveys to the Western Region Director on a weekly basis, provided that any leaks or threats to pipeline integrity must be reported immediately.

Prudhoe Bay EOA Transmission Pipeline

Item 23. EOA Plan. Within 30 days of receipt of this Amendment No. 2, BP shall submit a report to the Western Region Director, detailing its proposed actions and plans for replacing, abandoning, and/or restoring operation of the FS2-FS1 and FS1-Skid 50 segments of EOA. The report shall include preliminary or final engineering plans and timetables, and identify all necessary equipment, parts, and supplies, specifying, inventories, availability and delivery schedules.

Item 24. Interim Ultrasonic Testing of EOA FS1-Skid 50 Segment. Until BP has completed cleaning and smart pigging of the EOA pipeline in accordance with Items 4 and 7 of the March 15, 2006 CAO, BP shall perform interim alternative testing in accordance with the requirements of this paragraph, on a basis not to interfere with AUT inspections on operational oil transmission lines. BP shall conduct AUT inspection of the 34-inch diameter segment of the EOA line from FS1 to Skid 50. The AUT inspection shall cover 100% of the length of the FS1-Skid50 segment and the bottom 120 degrees of pipe circumference (between the 4:00 and 8:00 positions). BP shall ensure that the AUT scans are performed, verified, calibrated, and recorded in accordance with established industry practices and shall submit data to the Western Region Director, in raw and graphical formats, within seven (7) days of receipt of AUT results by BP.

Item 25. Ultrasonic Testing of Anomalies Identified by Smart-Pigging. Within three weeks of receipt of this Amendment No. 2, BP shall perform external UT assessment at the location of each anomaly where wall loss exceeds 50%, as revealed by smart-pig data collected on the FS2-FS1 segment. BP shall provide PHMSA data reports and a graphical comparison of smart-pig and UT data for anomalies specified above within six (6) weeks of receipt of this order.

Item 26. Plan For De-Oiling EOA Pipeline. Within 30 days of receipt of this Amendment No. 2, BP shall develop, and submit for approval to the Western Region Director, a plan to safely remove the crude oil in the segments of the EOA pipeline that will not be restored to operation. The plan shall provide for removal of the crude oil in a safe and environmentally sound manner, and in compliance with all applicable federal, state and local laws and regulations. BP shall implement such plan upon approval.

Item 27. Safe Resumption of Operations. BP may return the EOA pipeline to operation only with the prior approval of the Director of PHMSA's Western Region Pipeline Safety Office, upon a record of satisfactory testing, repair, inspection, and planning in accordance with the March 15, 2006 CAO, the July 20, 1006 Amendment No. 1, and this Amendment No. 2. Any request for resumption of operations, temporary or otherwise, shall be submitted no fewer than fourteen (14) days in advance of the proposed restart date.

<u>Prudhoe Bay Lisburne Transmission Pipeline</u>

Item 28. Ultrasonic Testing of Anomalies Identified by Smart-Pigging. Within three weeks of receipt of this Amendment No. 2, BP shall perform external UT assessment at the location of each anomaly where wall loss exceeds 50 %, as revealed by smart-pig data collected on the Lisburne line. BP shall provide PHMSA data reports and a graphical comparison of smart-pig and UT data for anomalies specified above within six (6) weeks of receipt of this order.

Item 29. Repair of Pipeline Defects. BP shall document and repair all defects and other conditions defined under 49 C.F.R. §195.452(h)(4)(i) through (iv) on a schedule that at a minimum, comports with the deadlines set out in 49 C.F.R. §195.452(h)(4) and in a manner consistent with ASME B-31.4. Within 30 days of receipt of this order, BP shall extract, record and provide to the Western Region Director dimensional data of all anomalies found, including data on distance from upstream and downstream girth weld, position, minimum and maximum remaining wall thickness, and remedial actions taken with respect to each anomaly. As repairs are made, BP shall submit monthly reports to the Western Region Director documenting each repair made (including photographs) with respect to each such anomaly.

Prudhoe Bay WOA Transmission Pipeline

Item 30. Information Request. Within 48 hours of receipt of this Amendment No. 2, BP shall provide the Western Region Director with all data and risk analyses not previously provided by BP, concerning the current condition of the WOA pipeline, including all data and analyses on the basis of which BP announced its original decision to cease operation of the WOA pipeline.

Item 31. Ultrasonic Testing Pending Smart-Pigging. Until BP has completed cleaning and smart pigging of the GC1-Skid 50 segment of the WOA pipeline in accordance with Items 3 and 4 of the March 15, 2006 CAO, BP shall perform testing in accordance with the requirements of this paragraph. BP shall conduct AUT inspection of the GC1-Skid 50 segment of WOA. The AUT inspection shall cover 100% of the length of the GC1-Skid 50 segment and the lowest 120 degrees of pipe circumference (between the 4:00 and 8:00 positions). The entire circumference of the pipe shall be visually inspected and any areas of general external corrosion shall be assessed and documented. BP shall ensure that the AUT scans are performed, verified, calibrated, and recorded in accordance with established industry practices and shall submit data to the Western Region Director, in raw and graphical formats, within seven (7) days of receipt of AUT results by BP. Any external corrosion shall also be reported at that time.

Item 32. Documentation and Repair of Pipeline Defects. BP shall document and repair all defects and other conditions defined under 49 C.F.R. §195.452(h)(4)(i) through (iv) on a schedule that at a minimum, comports with the deadlines set out in 49 C.F.R. §195.452(h)(4) and in a manner consistent with ASME B-31.4. Within 30 days of receipt of this order, BP shall extract, record and provide to the Western Region Director dimensional data of all anomalies found, including data on distance from upstream and downstream girth weld, position, minimum and maximum remaining wall thickness, and remedial actions taken with respect to each anomaly. As repairs are made, BP shall submit monthly reports to the Western Region Director documenting each repair made (including photographs) with respect to each such anomaly.

Item 33. Condition of GHX21 Bypass. Within 30 days of receipt of this Amendment No. 2, BP shall provide a report to the Western Region Director detailing all maintenance, cleaning and inspection, and repair activities with respect to GHX21. BP shall also develop, submit to the Western Region Director for review and approval, a plan for performance of smart pigging at regular intervals not to exceed five (5) years, and a schedule for the repair of anomalies identified through those inspections.

Item 34. Inspection Plan for OT501. Within 30 days of receipt of this Amendment No. 2, BP shall provide a report to the Western Region Director detailing the results of inspections and testing of the OT501 section, and plans for future inspection and testing.

* * *

Except as expressly provided in Additional Preliminary Finding No. 16, this Amendment does not modify, waive or supplant any requirements imposed under the March 15, 2006 CAO, the July 20, 2006 CAO Amendment No.1. This Amendment No.2 does not modify, waive, or supplant any requirements that apply to BP's pipeline systems under any other provision of federal, state, or local law, or permit.

With respect to all actions undertaken pursuant to this Amendment, BP is responsible for achieving and maintaining compliance with all applicable federal, state and, local laws, regulations and permits. This Amendment is not and shall not be construed to be a permit, or a modification of any permit, under any federal, state, or local law or regulation.

In accordance with 49 U.S.C. § 60122 and 49 C.F.R. § 190.223, failure to comply with the CAO, as amended, may result in the assessment of administrative civil penalties of not more than $100,000 per violation per day pursuant to 49 U.S.C. §60122, or in the imposition of civil judicial penalties and other appropriate relief pursuant to 49 U.S.C. §60120. The terms and conditions of this Amendment are effective upon receipt.

Theodore L. Willke
Acting Associate Administrator
for Pipeline Safety

8/10/06
Date Issued

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8/29/06

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

Overview - Oil Field Corrosion

The oil formations at Prudhoe Bay and other North Slope fields produce a mixture of oil, natural gas and water – these three components need to be separated before the oil can be delivered to the Trans Alaska Pipeline System. The presence of water and natural gas, together with physical properties of the hydrocarbon reservoir can result in substances that are corrosive to internal components of carbon steel equipment common in oil fields, such as pipelines. This corrosion generally occurs due to the presence of carbon dioxide and/or bacteria.

1. Carbonic acid corrosion can occur when associated natural gas contains carbon dioxide dissolves in the water to form carbonic acid. This is the most common type of corrosion in the Prudhoe Bay facilities.

2. Bacterial corrosion can occur when bacteria are present and conditions are conducive to the growth of bacteria. The bacteria and bacterial byproducts can also result in internal corrosion Bacterial corrosion.

Both types of internal corrosion are mitigated through the use of chemical corrosion inhibitors, biocides and maintenance pigging.

The produced liquids may also entrain sand and rock particles which, at high velocity in the pipelines, can erode the wall of the pipe. In addition, moisture on the outside of pipe from snow, rain, and condensation can cause external corrosion if they contact the pipe.

Program Objectives and the "Fit for Service" Strategy

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

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

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

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

Specific Processes and Procedures

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

Corrosion Monitoring: A variety of techniques are used to monitor corrosion rates, including the use of metal weight loss coupons at approximately 1,500 locations. These coupons are inserted into the fluid stream. After the coupons have been exposed to the stream for a set period, they are removed and analyzed to determine the coupon corrosion rate. In addition, BPXA has installed 90 electrical resistance corrosion probes that continuously monitor the corrosivity of the fluids. The data obtained from the corrosion coupons and probes are used to adjust corrosion inhibitor injection rates and to initiate other corrosion mitigation actions.

8/29/06

Corrosion Mitigation: A variety of methods are used to mitigate corrosion. The type of method used is dependent upon the type of corrosion most likely to occur at a given location. CO_2 or carbonic acid corrosion is typically controlled by injection of corrosion inhibitor chemicals into the production streams. BPXA currently injects over 2.5 million gallons of corrosion inhibitor annually.

Bacterial corrosion is controlled by injection of a biocide chemical. In addition, many corrosion inhibitors contain quaternary amines, which can help control bacterial corrosion. Mechanical pigging of pipelines is also used to remove solids and water that may build up in low points in the pipelines over time. BPXA has a team dedicated to pipeline pigging activities. Maintenance pigs are run approximately 370 times per year in a variety of three phase production, produced water, and seawater pipelines.

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

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

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

- Corrosion Rate Monitoring (CRM) programs repeat inspections at the same location, typically every 6 months, to look for loss of metal.
- Corrosion Under Insulation (CUI) programs are designed to detect external corrosion that can be hidden by the thermal insulation that is on the outside of the pipelines.
- Erosion Rate Monitoring (ERM) is conducted at locations that could be susceptible to erosion inside the pipe due to high velocities and fluid characteristics. ERM is typically performed at bends every 3 months.
- Comprehensive Inspection Program (CIP) is an annual program aimed at detecting new internal corrosion mechanisms and new locations of corrosion. It also monitors damage at known locations and thus assesses the extent of degradation and fitness-for-service.
- In-Line Inspection Program is designed to detect internal and external damage but still requires verification of actual damage by Ultrasonic and/or Radiographic Inspections.

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

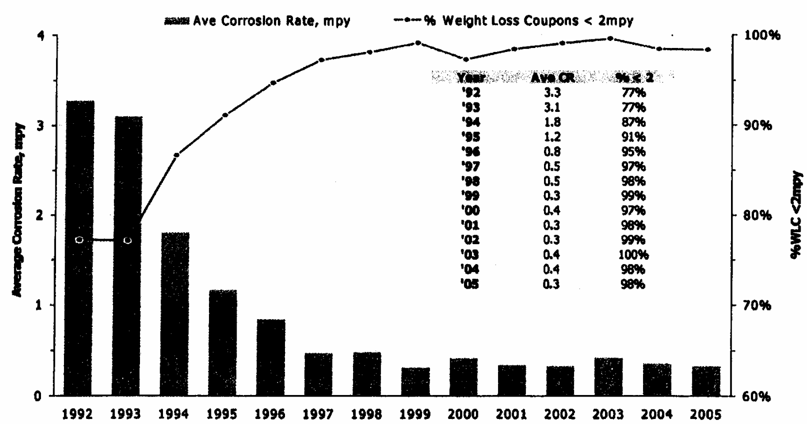
The risk based inspection program includes a number of factors contribute to the selection of locations, extent and frequency of inspection programs. Some of these include but are not limited to equipment condition, rate of wastage, transported fluids, personnel safety and environmental concerns.

Corrosion Program Resources and Results

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

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

Internal Flow Line Corrosion Control



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

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Version 2.0 15/04/05 Final Report

"PRIVILEGED & CONFIDENTIAL:
Prepared at the request of and for the
assistance of counsel"

bp

internal audit

BPXA Corrosion Management System
Technical Review
Final Report

Report Number: 5001-104
Issued: April 2005

Team: John Baxter (Lead), Martin Hinchliffe, Don Harrop,
Ian Bradley, John Boyle

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Appendices

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Review Period: November & December 2004
Draft Issued: February 2005
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1. Introduction

The Director of Engineering, John Baxter, was asked to lead a review to assess the integrity of the BPXA Corrosion Management System (CMS) in place at Greater Prudhoe Bay (GPB). The review assessed the processes, procedures and controls in sufficient detail to validate the results of the program with specific focus on areas addressed by a number of recent allegations. Additionally, the audit provided a comparison to E&P Segment norms. The detailed terms of reference are attached in Appendix 1.

A small team of specialists external to BPXA, but internal to BP, carried out the review. The team members spent two separate periods of four days in Alaska with a total of ten man days in GPB. A visit was also made to the EnviroScience Laboratory in Dallas, which carries out the corrosion coupon inspections. Interviews were held with key personnel across GPB BU and a wide range of documentation was reviewed. Visit agendas and topics covered for each visit are attached in Appendix 2.

An outline schematic detailing the BPXA Corrosion Management System as seen by the review team is attached in Appendix 3.

2. Executive Summary

Based on the review carried out under the terms of reference, the review team is of the opinion that BP does not have an immediate technical problem with the CMS at GPB. BPXA has an adequate CMS which to some extent may be overly detailed – BUT the extent, complexity and ageing state of the pipework will always create the potential for leaks.

However the review team identified the following key issues and associated recommendations that require the prompt attention of BPXA, in order to improve the overall effectiveness of the CMS at GPB:

- The current corrosion strategy was last formally updated in 1999 and covered only the former BP heritage West side of the field. The strategy should be updated to:
  - Reflect the long term business strategy around Alaska Gas and Heavy Oil.
  - Better align the corrosion and inspection practices across both sides of the field.
  - Clarify the various roles associated with Integrity Management.

- The drive to maintain flat lifting costs has put pressure on the Corrosion, Inspection and Chemicals Group (CIC) budget. Plans and budgets for the CMS should be updated:
  - To reflect the delivery of any revised business strategy over the longer term.
  - With more focus on an activity based budget approach.

- Two key players from the CIC organisation (CIC Manager and his deputy, the Senior Corrosion Engineer) left BPXA in December 2004 and January 2005. There is an urgent need to:
  - o Recruit and rapidly induct successors for these two key positions.
  - o Develop and implement a succession programme for key positions in the CIC organisation.

- Corrosion Management activities are not well communicated across the BU, with more effort going into external communication. The current internal communication strategy, which has yet to be issued, requires further development to ensure a robust communications package can be rolled out effectively across BPXA to both BP employees and contractors.

- An extensive inspection and corrosion monitoring programme is in place and is rigorously implemented. However a technical review and update of the current corrosion mitigation and inspection techniques should be carried out by the newly appointed CIC managers to consider:
  - o A broader use of Risk Based Inspection (RBI).
  - o Alternatives to the use of weight loss coupons due to the potentially hazardous pulling operation.
  - o The application of new inspection technologies.
  - o Learnings from across the E&P Segment.

- The BPXA strategy to maintain flat lifting costs is driving behaviours counterproductive to ensuring integrity and the delivery of effective corrosion management systems. Leadership should therefore consider the full lifecycle implications of the single minded focus on flat lifting costs. This is compounded by the difficult HR and internal/external communications environment, where proposals to change any inspection monitoring programme can be interpreted purely as a means to cut costs.

During the review a broader Segment wide issue was identified:

- There is a limited supply of corrosion and inspection engineers within the Segment. The drive to ensure the integrity of our assets together with compliance to the upcoming Group Integrity Management Standard is creating a demand which is becoming increasingly more difficult to meet. A Segment organizational capability plan should be developed to ensure both the current and future needs in this area are able to be met.

These issues and associated recommendations are further detailed in Section 3 of the report, together with a number of other items where the audit team believes further improvements can be made to the corrosion management system.

3. Review Findings & Recommendations.

3.1 Corrosion Strategy

Strategy Update:
The corrosion strategy was developed circa1999 for the BP heritage West side of the field, with no evidence of an update since then. The Alaska Gas/Heavy Oil strategy will create new risks, namely, extended field life, external corrosion and increased water production. The emphasis for internal corrosion mitigation has been the production flowlines and appears to be under control, CIC now needs to obtain that same level of mitigation for the water injection system.
Although much effort is being put into applying a common CMS approach across both the east and west sides of the field, significant cultural and operational differences are creating a challenge to implementing a more aligned strategy.
There is a need therefore to update the corrosion strategy to help ensure adequate mitigation plans are put in place to eliminate the potential for spills, and build a common understanding and greater alignment of the strategy across GPB.
On completion of the update to the Corrosion Strategy, a review, independent of the BPXA team, should be carried out.

Budgeting Process:
Currently, the budget is set up-front in line 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 longer term, and thereafter set the budget based on these activities.
Plans and budgets for the CMS should also be updated to reflect any revised corrosion strategy taking into account the longer term business strategy (Alaska Gas/Heavy Oil).
The current inspection programme is heavily weighted towards internal corrosion versus external corrosion (70000 v 30000 inspection activities per year). Trend analysis now shows internal corrosion is under control, with the exception of the water injection facilities, with greater deterioration rates for external corrosion. The methodology around budget allocation should therefore be revised, to take into account the need for the inspection focus to shift to internal corrosion of the water injection system and external corrosion of all systems. .
Thought should also be put into the development of a multi-year plan with funding, for high cost external corrosion activities such as road crossings, corrosion under insulation and weldpacks.

Accountabilities:
The strategic position and role of CIC within BPXA needs clarifying. There are many roles (Engineering Authority, Integrity & Assurance Manager, CIC Manager, Compliance Manager) associated with integrity and corrosion management within BPXA which creates some confusion in the organization. Hence there is a need to clarify both organizational and personal accountabilities to help ensure staff fully understand their individual roles and responsibilities.

Key Recommendations:
3.1.1 The CMS strategy should be updated to:
- Reflect the long term business strategy around Alaska Gas and Heavy Oil.
- Align the corrosion and inspection practices across both sides of the field.
- Clarify the various roles associated with Integrity Management

On completion of the update to the Corrosion Strategy, a review, independent of the BPXA team, should be carried out.

Risk Category: Medium
Management Response:
Owner/Close out date:

3.1.2. BPXA Leadership should review the full lifecycle implications on the integrity risk to their assets of the single minded focus on flat lifting costs.
Risk Category: Medium
Management Response:
Owner/Close out date

3.1.3 Plans and budgets for the CMS should be updated:

- To reflect the delivery of any revised business strategy over the longer term.
- With more focus on an activity based budget approach.

Risk Category: Medium
Management Response:
Owner/Close out date

3.2 Organisation

Recruitment:
The CIC organisation has two key players (CIC Manager and his deputy, the Senior Corrosion Engineer) leaving during December 2004 and January 2005. There is little evidence of a management of change process or transition plan, and replacements need to be quickly identified from BP's limited pool of corrosion management expertise or externally if necessary. This creates a significant risk to delivery of the CIC performance contract. Poor handover plans will lead to a breakdown in the management system and may also impact contractor relationships. The review team recommends the urgent appointment of the two CIC Managers and implementation of the management of change process and associated handover activities.

CIC Team Development:
Technical competence of the CIC team is high, but has been dominated by strong leadership and an apparent lack of empowerment. This may have stifled the broader development of other members of the CIC team. The review team recommends that the new managers focus on building the team capability of CIC, with an emphasis on team development, empowerment and succession planning.

Performance Review and Learning:
Performance review of the CMS is a regular feature of the BPXA business, with weekly CIC programme review meetings, quarterly performance reviews, annual planning meetings (part of which the Review Team attended), and the issue of the annual Alaska Department of Environmental Conservation (ADEC) report.
Internal technical learning appears good within the CIC team but it is not clear how much is shared outside (especially with operational personnel) and how structured this process is. There is no strong evidence of learning from, and interaction with, other operating centres as a regular feature and hence there is scope for improvement here.
Seeking broader peer recognition and endorsement of the CIC CMS and its implementation could well significantly deflate and/or deter technical accusations.

Key recommendations:
3.2.1 There is an urgent need to:

- Recruit and rapidly induct successors for the two key leadership positions in CIC.
- Develop and implement a succession programme for key positions in the CIC organisation.

Risk Category: Medium
Management Response:
Owner/Close out date:

3.3 Communications

Internal v External:
Corrosion Management activities are not well communicated across the BU with more focus being put on communication to external parties. There is a need for a greater internal focus especially as the BU operates in a unique environment which is heavily regulated, constantly under scrutiny, with external pressures and whistleblowers.
The review team recognises there is an opportunity to better utilise the GPB workforce to communicate the facts around the GPB corrosion strategy and activities both on the slope and to the local community. More emphasis should be put on explaining why certain decisions are made, especially when any associated change can be interpreted as cost cutting with a potential to adversely impact corrosion performance.

Communication Strategy:
The current internal communication strategy, which has yet to be issued, requires urgent further development to ensure a robust communications package can be rolled out effectively across GPB. The communication strategy and associated plan should include key messages to be delivered, who they need to be delivered to, and by whom, and should cover both internal and external communication. A need for a detailed training programme should be assessed to ensure BPXA staff are able to deliver the communications strategy effectively.

Corrosion Awareness:
Corrosion management and inspection programmes are fundamental to the success of BPXA. There are many specialists working in these areas, but the review team felt those who work outside of corrosion mitigation would benefit from a corrosion awareness training programme. This would enable a broader community to communicate the efforts being made by GPB to prevent any spills, and provide a better understanding of any decisions and changes made to the corrosion strategy.

Key Recommendations:

3.3.1. The current internal communication strategy requires further development to ensure a robust communications package can be rolled out effectively across GPB to both BP employees and contractors.
Risk Category: Medium
Management Response:
Owner/Close out date:

3.4 Technical

Risk Assessment:
Corrosion risk assessment and mitigation is focused on (1) an extensive inspection programme with a heavy reliance on weight loss coupons, (2) corrosion rates identified over time by detailed research and (3) fit for service criteria based on this research and the current identified field life. These tactics are based on the 1999 corrosion strategy and need to be reviewed to reflect the risks associated with the Alaska Gas and Heavy Oil strategies.
The review should include a more accurate definition of field life and its criticality and risk associated with achieving the current operating criterion of < 2 mpy internal corrosion rate, noting that ~100% of production flowlines, for example, are now exhibiting corrosion rates of ~0.4 mpy. More attention should now be given to the criticality of the life extension of the water injection system as the corrosion rates in the production flowlines are now under control.
In meeting the < 2 mpy criterion a heavy reliance is put on weight loss coupons that are labour intensive and represent a potentially high safety risk operation to pull them. It is felt that more could be done with Electrical Resistance corrosion probe technology to reduce the number, and extend the frequency, of coupon pulls; and therefore a review of the approach to corrosion monitoring is recommended, including drawing on experience from other assets.
Given the number of internal and external inspections currently conducted annually there would seem to be scope to adopt a more rigorous RBI methodology, as typically applied by other BP assets, to optimise the number, locations and balance between internal and external inspection.

Weight Loss Coupons:
The extraction of weight loss coupons can present a potential safety hazard due to the extraction tool itself becoming part of the pressure system during coupon extraction. Some areas of E&P are now reducing, if not eliminating this practice due to this hazard. CIC should explore alternative corrosion monitoring techniques eg Electrical Resistance probes.

The weight loss coupons are weighed and examined by Enviroscience, an independent laboratory in Dallas. A review of their facilities to assess the management systems in place, competency of personnel and the weighing process was carried out by BP staff - the results and recommendations are attached in Appendix 4.

Inspection Technology:
The inspection techniques currently used by BPXA are based on well established inspection and monitoring technologies such as weight loss coupons, ultrasonics and radiography. Consideration should be given to the application of newer inspection technologies and the development of monitoring techniques. CIC are planning to put more focus into this area with their new inspection contractor (Rockwood) which is a significant organisation with their own technology programmes.

Data Management:
Mechanical Integrity Management Information Repository (MIMIR) is the key data management tool used by CIC but its original specification and ability to interface with other key management packages (e.g. EAMES, Maximo) needs clarifying. It is perceived to have grown "too big" with a significant backlog of data validation outstanding. There are off-the–shelf packages that can handle the types and amounts of information and data involved in the CMS process applied by BPXA (e.g. all North Sea assets use a commercial package called ACET which is also in use in the Caspian and Colombia and shortly by Angola). MIMIR is still being developed but it is recommended that a "time out" is taken to revisit and review its specification and need for any additional functionality versus the case for not adopting an off-the–shelf package.
MIMIR currently has a significant backlog (circa 700) of inspection items and an assessment of the impact of this size of backlog should be carried out.

Leveraging Contractor Relationships:
The corrosion inhibitor development/deployment programme is seen as being best in class, even world class, in pushing the envelope of this technology through an integrated working relationship with the chemical vendor (Nalco). CIC are now looking to develop a similar technology development relationship with their inspection contractor (Rockwood/Canspec). Pushing the technology envelope in these areas is seen as a key enabler for CIC to deliver within their budget against the flat lifting cost KPI.

Key Recommendations:
3.4.1. A technical review and update of the current corrosion mitigation and inspection techniques should be carried out by the newly appointed CIC managers to consider:

- A broader use of Risk Based Inspection (RBI).
- Alternatives to the use of weight loss coupons due to the potentially hazardous pulling operation.
- The application of new inspection technology supported by Rockwoods expertise.
- Learnings from across the E&P Segment.

Risk Category: Medium
Management Response:
Owner/Close out date

3.5 Segment wide issue:

During the review the team identified the following issue for Segment wide consideration.

Engineering resources:
As a general observation across the Segment, it is becoming increasingly more difficult to identify and place corrosion managers and engineers partly due to a lack of earlier development and recruitment into this area of increasing demand. Additionally the drive to ensure the integrity of our assets together with compliance to the upcoming Group Integrity Management Standard is going to sustain this demand, both in E&P and in the other Segments.

Key Recommendation:
3.5.1. A Segment organizational capability plan should be developed to ensure both the current and future requirements for corrosion and inspection engineers are met.
Risk Category: Medium
Management Response:
Owner/Close out date

3.6 Comparison with other E&P Segment Corrosion and Inspection activities.

The review team were asked to provide a comparison of the BPXA CMS with other BP E&P assets. The complexity, external influences and working environment make GPB a unique asset within BP, and hence the team have found it difficult to make any meaningful comparisons with other assets.

However the review team see the BPXA CMS as consistent with the E&P "Corrosion Control System" Model with the following key differences:

- Data management tool (MIMIR) has been developed in preference to an off the shelf tool.
- A vast number of inspections, with a greater proportion of weight loss coupon pulls than in other E&P assets.

- o A low level use of external lessons and little apparent exchange of practices with other E&P assets.

These differences have been reflected throughout this report.

Appendix 1: Terms of Reference

Terms of
:ference.doc (39 KB)

Appendix 2: Visit Agendas - Interviews and Activities covered by review

Corro Audit
,genda.doc (42 KB)..

CMP review
agenda.doc

Appendix 3: Corrosion Management System Overview Schematic

CMS Overview
Diagram.ppt (1 MB..

Appendix 4: Enviroscience Report – Coupon Loss Measurement

Enviro Sciences
Lab.doc (36 KB...

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ATP Technology Review

ALASKA TRANSIT PIPELINE TECHNLOGY REVIEW
10th – 12th April 2006
Final Report

Team Members:
John Baxter – Group Technology
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Issued: 7th June 2006

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ATP Technology Review

1. Introduction

The BP Exploration (Alaska) Inc. (BPXA) Greater Prudhoe Bay (GPB) operations on the North Slope of Alaska are probably one of the most highly regulated and scrutinised hydrocarbon operations in the world. Scrutiny includes both media and public interest in the ongoing operations. This presents a significant challenge to BP, but equally an opportunity to demonstrate a world class standard of operation and environmental care.

The leak from the OT-21 segment of the GPB Western Operating Area (WOA) Oil Transit Line between GPB Gathering Centre 2 (GC2) and Gathering Centre 1 (GC1), first detected on 2nd March 2006, is unacceptable to BP and is most regrettable. However the company has shown a corporate intent to learn from this incident and put in place appropriate measures to help ensure such a leak is not repeated anywhere worldwide in the BP Group. The spill impacted two acres of Arctic tundra which will be fully remediated by the BPXA team.

As part of this intent a diverse team of specialists from within BP (but outside BPXA) led by the Group Engineering Director, was asked by BP Legal to review technology issues related to the incident and recommend appropriate actions. This report should be read in conjunction with the 14 April, 2006 GC-2 Transit Line Spill Incident Investigation Report conducted by BP Exploration and Production (E&P) staff from BPXA and North American onshore operations, along with a representative from the Alaska Department of Environmental Conservation (ADEC) (referred to as the E&P Report).

This report does not repeat the explanatory sections of the E&P Report but makes additional comments where identified on process, people and technology issues.

In conducting the review the team visited Alaska and met with selected members of the BPXA staff. Four of the team members travelled to the North Slope to visit with GPB staff and view the leak site on the OT-21 line.

2. Overview

BPXA has been managing a comprehensive corrosion management and pipeline inspection programme since inception of the GPB oil production facilities. BPXA has operated the GPB WOA since the start-up of field operations. BPXA has only operated the GPB Eastern Operating Area (EOA) since 2000, when it took over as operator of the EOA from ARCO Alaska Inc. (now ConocoPhillips Alaska Inc.). Regular reports on these programmes are submitted to regulatory and other bodies, including an annual report to ADEC which is independently reviewed on behalf of ADEC by a third-party independent consultant. The programme is based on an assessment of loss

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of metal (pipe wall thickness) primarily through the use of metal coupons in the product stream and, more recently, through the increased use of electrical resistance probes, supported by selective ultrasonic pipe wall thickness measurements and intelligent pigging to validate the data from the corrosion coupons and probes.

In recent years the view was that internal corrosion of produced and processed crude oil product lines was under control, and therefore greater focus needed to be directed on external corrosion under insulation on the three oil transit lines and internal corrosion on the three phase and produced water lines. This approach is based on a strategy developed in 1999. The leak on OT-21 line now questions this strategy.

Because of the nature of the fluids being carried, likelihood of corrosion in oil transit lines is generally agreed to be low to begin with. On top of that, any corrosion that may occur is kept under control by the carryover of corrosion inhibitor from treatment of produced fluids at the wellhead and by maintaining the specification for Basic Sediment and Water (BS&W) in sales quality crude oil exiting from the product Gathering Centres. The corrosion inhibitor also acts as a biocide to control bacteria below levels which could initiate Microbial Influenced Corrosion (MIC).

In the case of the OT-21 line, GC2 collects product from the WOA of GPB, including approximately 15% of the production as viscous crude oil production which commenced in 2002. The viscous crude stream has a greater proportion of BS&W, and at times it also has sand fines (termed "flour") from the less well consolidated parts of the reservoir. This results in 'upsets' to the GC2 processing plant with consequential out of specification processed crude oil being delivered to the OT-21 line and potentially on to the Alyeska operated Trans Alaska Pipeline System (TAPS). In most cases, the mixing with the processed crude at Skid 50 keeps the final product going to TAPS within their specification; however, from time to time significant upsets have caused problems for TAPS. For example, we were told that at least on one occasion perhaps as much as 10,000 barrels of water may have been unintentionally released from GC2. With such a release, it is most likely that some water and also basic sediment were held back in the lower elevation sections of the OT-21 line. The topography of this section of the line combined with the low flow rate of the fluids creates the opportunity for water and solids to separate out and settle in the bottom of the pipeline. It is conceivable that several inches – or more – of water and solids with microbial activity were present in the OT-21 line from one or a number of upsets. Also the low flowrate (reported to be approximately 1 foot/sec) might result in water and solids separation along the 17,000 foot pipeline length.

Pigging facilities are present in the GPB oil transit lines; although a regular maintenance pigging program was not in place to provide routine displacement of any sediment and water that may have accumulated in low spots. In addition, there are few facilities to remove or handle the pigging debris and concerns have been raised by Alyeska regarding the pigging debris that may be generated during GPB oil transit line pigging operations and the potential for this debris to enter TAPS.

With the advent of viscous crude oil production and the consequential 'upsets' in GC2 considerable attention has been paid to the processing plant separator design and the chemicals, particularly the emulsion breaker but also corrosion inhibitor. Changes to the chemical mix have resulted in much smoother and more predictable operation of GC2 in the past year.

However there has not been commensurate focus on the OT-21 line and the possible effects of static water and sediment present at the bottom of the pipe.

3. Findings and Recommendations

3.1 Process

Key Findings

- In the past two years the strategic intent has moved from maintaining flat lifting costs on a declining production volume to increased production running to 2050. Additionally the existing CIC strategy document dated 1999 requires updating to cover all areas of GPB. This raises the need for a change in the pipeline infrastructure management strategy and related corrosion management system.
- BPXA is managing an ageing pipeline infrastructure. Overall corrosion management has been good with line replacements being avoided but now there is a requirement to commence a risk based pipeline infrastructure replacement programme.
- The regulatory demand on the BPXA team (particularly CIC) imposes a cyclical load that absorbs considerable resource.
- The advent of viscous oil production has created the potential for process upsets in GC2 resulting in excessive BS&W content in the oil export line, possibly promoting corrosion forming conditions. The use of an MOC process to examine and mitigate the corrosion consequences from process upsets is essential.
- Historically BPXA was acknowledged within BP as a leader in corrosion management and inspection systems, but this had the potential for creating a silo effect with little time spent on looking into other best practices and strategies within BP and externally.
- The current inspection and leak detection regime will not necessarily minimise the likelihood of another significant hydrocarbon spill.

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Key Recommendations

3.1.1 Carry out a strategic full lifecycle review of the corrosion management system (CMS), processes and resourcing in the light of the 2nd March '06 incident, the revised GPB 50 year business plan, and the new Group Integrity Management Standard. This should include a review of the current fitness for service criteria and CIC manning levels against the predicted future workload.

3.1.2 Develop a risk based replacement programme for the GPB pipeline infrastructure to reflect the revised GPB 50 year business plan.

3.1.3 In the light of experience over a number of years, consideration should be given in concert with the regulators whether the current detail and style of reporting CIC work is appropriate.

3.1.4 BPXA needs to assure the Management of Change (MOC) process is used in a holistic manner to consider the broader ramifications to pipeline and facility piping corrosion of changes in process conditions.

3.1.5. A plan needs to be developed for Knowledge Management within BPXA with a greater emphasis on learning from others across BP, and from professional institutions and technology suppliers.

3.2 People

Key Findings;

- In the present GPB operational model the CIC and the GPB operations teams are deeply absorbed in delivering day to day operations and other demands, with seemingly little or no scope to consider longer term issues. The effect of the U.S. Department of Transportation (DOT) Corrective Action Order and the potential for further governmental investigations will further increase demand on BPXA staff.
- The Mechanical Integrity Management Information Repository (MIMIR) is the key data management tool currently used by CIC. Considerable resources are being drawn towards managing the data within the MIMIR tool. No evidence was provided as to the increased effectiveness of this data management tool or to when its development would be deemed completed.
- The CIC Team Leader and Senior Corrosion Engineer both left BPXA at the end of 2004. A replacement Team Leader was recruited in Q1 of 2005 but was not able to take up the post until Q3. The Senior Corrosion Engineer post remains vacant.
- There have been a number of changes in the GPB Field Manager's organisation covering maintenance, reliability, integrity and operations over the last year. The Operations Integrity role is currently vacant and the Maintenance & Reliability Team Leader is fairly new into the position. Such factors reduce the capacity of the teams to take a broader strategic view of the corrosion management programme.
- The Operations Team Leader for GPB has a broad span of control following the reduction from two to one Team Leader.

- Corrosion and inspection knowledge and understanding seems to vary across the GPB workforce. There are many specialists working in these areas, but the review team felt those who work outside of corrosion mitigation would benefit from corrosion and inspection awareness programmes. For example, there was apparent confusion amongst site operations personnel as to the capabilities and limitations of guided wave inspection techniques.

Key Recommendations

3.2.1 A "time out" should be taken to revisit and review the MIMIR data management tool and need for any additional functionality versus the case for not adopting an off-the-shelf package. This will enhance the availability of resources within the BPXA CIC department

3.2.2 The CIC team should undertake a review of its resource make-up to match the forward needs as determined by the previously recommended strategic review and subsequent revised CMS. The review should consider the size and professional qualification of the resource together with a development and training programme.

3.2.3 There is an urgent need to:

- Recruit and rapidly induct a successor for the vacant Senior Corrosion Engineer position in CIC, and the Operations Integrity Team Leader in the Field Manager's organisation.
- Develop and implement a succession programme for key positions in the CIC organisation.
- Review the span of control for key positions.

3.2.4. An MOC review should be carried out to identify and mitigate any risks associated with the vacant positions.

3.2.5 Field-wide corrosion and inspection awareness sessions should be held to address any future misunderstanding of corrosion mechanisms and inspection techniques capabilities. This would enable a broader community to support the efforts being made by GPB to prevent any spills, and provide a better understanding of any decisions and changes made to the corrosion management strategy.

3.3 Technology

Key Findings:

- The cause of the accelerated localised corrosion within the OT-21 pipeline cannot be unequivocally determined without detailed internal evaluation of the pipe; and even then evidence may have been lost or destroyed due to the incident or if the pipeline needs to be pigged to de-inventory before any failure investigation could be undertaken. The pitting associated with the failure was found to be highly localized with a low aspect ratio. The potential therefore for routine in-service detection at road and caribou crossings of a similar damage mechanism using current external NDE inspection methods is very low.

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- Where sand deposits and entrained water are able to drop out from the fluid stream onto the bottom of the pipeline as a result of low velocity flow (typically reported to be 1ft/sec), this creates ideal conditions for the proliferation of Sulphate Reducing Bacteria (SRB) on the pipe surface. The most likely cause of the accelerated corrosion is therefore believed to be Microbial Influenced Corrosion (MIC) under sediment deposited onto the bottom of the pipe.
- Since the introduction of viscous oil into the GC2 process, operational upsets in the GC2 facility have caused multiple excursions in the BS&W content of the export oil entering the OT-21 line.
- Microbial agents may have survived the inhibition treatment (which also acts as a biocide) possibly due to:
    - adsorption of that chemical onto the "flour" fines exiting the GC2 facility
    - inability of that chemical to gain contact with bacteria due to shielding beneath static accumulations of solids and established biofilm.
    - microbes becoming immune to the incumbent chemical.
- Change of emulsion breaker in 2005 may have negatively affected the carry over of inhibitor into the OT-21 line.
- The upset conditions occurring at the GC2 facility – reported to be 2 or more a week on occasions - have not been examined and analysed for trends and possible negative consequences on the pipelines downstream of the facility.
- Apart from smart pigging of pipelines the current corrosion inspection regime does not provide the capability to detect dispersed pitting corrosion in buried cased pipe locations. Furthermore, the low velocities in certain lines, the absence of pig launcher/receiver facilities for certain well and flow lines, and little capacity for handling pigging debris mitigate against a regular pigging programme.
- The CIC NDE team is utilizing a number of emerging technologies such as Magneto-strictive guided wave sensors, computed radiography and real-time radiography to complement the more standard NDE techniques used. Magneto-strictive guided wave sensors cannot be relied upon to find isolated pitting but the consideration of other techniques is beyond the scope of this report.
- Current trials by the CIC team of wireless technology to monitor pipeline corrosion via electrical resistance probes, if successful, represents a major step forward that would ease pressures on CIC resources directed at data collection and provide a more responsive approach to optimizing inhibitor treatment to meet changing operating conditions.
- The leak detection system on the GPB oil transit lines is a mass balance type system. Although the system has been tested to verify it meets the ADEC requirements for detecting leaks of 1% of flow, the flow

characteristics of OT-21line during GC2 upsets negatively impacts the system performance. Therefore, while the current pipeline leak detection system can detect leakage above 1% within a 24 hour period in steady/normal operating conditions, doing so during GC2 facility upsets would be challenging. Further, process upset conditions create the need for frequent recalibration of the leak detection instruments.

- The leak at OT21 was less than 1% and therefore would not have been revealed by the leak detection system.
- BPXA is using external welded and bolted sleeves to repair the OT-21 line. Use of external pipeline repair sleeves is allowed within ASME code. Elsewhere in BP and the wider hydrocarbon industry sleeve repair of hydrocarbon pipelines is not normally instituted as a permanent repair where internal pitting corrosion exists in buried or subsea pipelines.

Key Recommendations

3.3.1, Prior to any maintenance or intelligent pigging, develop a proposal to carry out a forensic evaluation of the OT-21 pipeline pitting corrosion mechanism to assess whether such a mechanism could exist in other GPB pipelines.

3.3.2 Smart pig the oil transit lines and other low velocity pipelines on a risk prioritised basis to ascertain where dispersed pitting corrosion exists.

3.3.3. Pursue options for handling maintenance pigging debris.

3.3.4 Institute a review of the microbial burden across the GPB pipeline system and assess potential corrosion consequences.

3.3.5 Evaluate the use of other guided wave technology such as GUL G3 and Teletest II to identify whether they are more reliable in detecting isolated pitting flaws/defects. Additionally, conduct a review to identify any other possible inspection techniques capable of detecting isolated pitting, particularly at cased road and caribou crossings.

3.3.6 Where pipeline insulation is removed for inspection/repair and the pipe is inaccessible consider installing a local leak detection capability (eg. fibre optic sensors in the insulation) prior to reinstatement.

3.3.7 The current Leak detection System (LDS) vendor and an independent leak detection consultant should review the system re-calibration procedure to assure optimum detectability.

3.3.8 A wider technology review of current leak detection methodologies should be conducted, including a review of the recent testing and evaluation of leak detection systems performed by BP Pipelines North America (BPNA) and several BP major pipeline projects world-wide.

3.3.9 BPXA should review the regulatory requirements for sleeve repairs and ensure alignment with proposals outlined by the DOT and be consistent with, or exceed best practice at other BP locations.

Report End.

7

8/29/06

GC-2 TRANSIT LINE SPILL
Prudhoe Bay Western Operating Area
March 2, 2006

INCIDENT INVESTIGATION REPORT

April 14, 2006

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ADEC's Role in this Investigation

Gary Evans, an environmental specialist in ADEC's Industry Preparedness Program, was a participant in BP's initial investigation into the causes of the GC-2 Transit Line spill. ADEC will be conducting an independent review and assessment of the findings of this report. Mr. Evans participation in the BP investigation has been helpful to ADEC's understanding of the issues and ADEC appreciates BP's willingness to include him on the investigation team.

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A. EXECUTIVE SUMMARY

In the early morning of March 2, 2006, a BP Exploration (Alaska) Inc. (BPXA) Gathering Center 2 (GC-2) well pad operator detected a hydrocarbon smell while driving the pipeline road between GC-2 and GC-1 on the Western side of the Prudhoe Bay Field. Being cognizant of his personal safety, the operator decided not to investigate alone, and continued on to the Base Operations Camp (BOC), whereupon he verbally notified a Security guard and the GC-2 Area Manager. Upon notification, the GC-2 Area Manager and another GC-2 well pad operator departed to drive the same area and after about two miles, they too detected the smell. The GC-2 Area Manager exited the vehicle, carefully climbed up on the piperack and observed oil on the frozen and snow-covered tundra.

The GC-2 Area Manager immediately made a "Code Black" (emergency spill response) notification to the BPXA Communications Center. He and others then worked to confirm the identity of the leak, as there are three pipelines adjacent to the road. Over the next hour, the GC-2 Area Manager initiated the process of shutting down Y and P Pads, the produced water line between GC-2 and GC-1, and all of the GC-2 process facilities and wells pads.

The Mobile Command Center (MCC) was dispatched to the scene. The Incident Command System was activated and a Unified Command structure put in place to develop a spill response, clean-up and disposal plan.

There are 3 separate teams responding to this incident:

- Incident Response Team
- Business Resumption Team
- Incident Investigation Team

The Incident Investigation team, as per the Terms of Reference (Appendix D), was assigned the following objectives:

- Determine the facts and circumstances surrounding the incident
- Establish the sequence of events
- Review applications of management systems, practices, and their impacts
- Compile the report to include incident and response description

Based on an educated assumption that the line failure was a result of corrosion, the investigation team has inquired into the following subject areas:

- Chronology of events leading to the line failure
- History of the GC-2 to GC-1 34 inch pipeline
- Production and operations history that is pertinent to the failure
- Performance of the leak detection system
- History and performance of the corrosion and inspection program

The major factual findings, which are further substantiated and elaborated on in this report, are as follows:

1. Response to the Leak

- The notification and identification of the leak was immediately acted upon in a timely manner
- The shutdown occurred in a logical, expeditious and safe manner
- On March 10, 2006 the Unified Command agreed upon a preliminary spill estimate of 201,169 gallons (4800 barrels) plus/minus 33 percent for a range of 134,783 gallons to 267,555 gallons

2. History of Line

- The GC-2 to GC-1 line has a design pressure of 740 psi
- The current maximum allowable operating pressure (MAOP) is 500 psi. Although the line itself was not explicitly derated from its 740 psi rating, the skid 50 bypass connected to it was derated in 1997, and as a result lowered the entire GC-2 to GC-1 segment to 500 psi. Current operating pressure is 63-91 psi
- Smart pig runs were conducted in 1990 and 1998
- The line has been covered by a comprehensive risk-based corrosion monitoring and management program since the early 1990's
- Production rates from GC-2 through the pipeline were ¼ of peak rate
- There have been no previous leaks or repairs made to this line

3. Production Operations

- There were no operational upsets, i.e., high pressures or rates, that seemed to initiate the leak
- The introduction of viscous oil over the past few years has resulted in higher BS&W content in the GC-2 to GC-1 oil export line and more plant upsets
- GC-2 was experiencing high Basic Sediment and Water (BS&W) the week prior to the leak

4. Leak Detection System

- The leak detection system alarms went off several times during the week preceding March 2, but were ruled out as a spill because of the high BS&W in GC-2 and negative alarm readings on the adjoining segment of line. The leak detection did not sound on March 1st or March 2nd
- Based on the hole size in the pipe, the maximum flow rate is calculated to have been 1000 to 1300 barrels of oil per day (bopd)
- Based on an estimated mean spill volume of 4800 barrels of oil, the leak would have been going on for at least five days and probably much longer
- The leak detection system was working at the time during the incident. We can not identify the event even after the fact.
- Due to process upsets and the non-steady state nature of the process, leak rates of less than 1% may not be detected by this system. It is designed to identify a 1% leak over 24 hours

- The Prudhoe Bay leak detection system, including the GC-2 to GC-1 line segment, was tested and witnessed by ADEC in December 2002 and passed the 1% over 24 hours criteria
- Procedures exist for dealing with positive spill alarms. The established procedure was followed
- The GC-2 to GC-1 oil export line segment has a documented history as being the least accurate in the Prudhoe Bay system due to more BS&W fluctuations

5. Corrosion and Inspection

- Buried caribou and road crossings are not capable, without excavation and sleeve removal, of being inspected via Ultrasonic Thickness (UT) technology
- UT surveillance points on aboveground sections of the line were used to confirm and calibrate the 1998 smart pig run
- The leak location showed only 9% wall loss in the 1998 smart pig run
- Based on numerous surveillance points and corrosion coupons, this line was seen as low corrosion likelihood
- Guided wave UT inspections done both prior to and post leak at the leak location do not show evidence of internal corrosion, nor would it be expected to.
- With the exception of smart pig runs, there isn't a way to directly monitor internal corrosion inside of cased pipe (road and caribou crossings) without having to excavate the crossing and remove the outer casing from the pipe
- Since the leak, UT inspections are suggesting a significantly higher corrosion rate over the past six months since the last set of UT inspections on the aboveground sections of the line in September 2005
- There was some evidence of a slight increase in corrosion rates beginning in 2004 and, although they were not alarmingly high, increased inspections were scheduled for 2005
- The increased inspections that were scheduled in 2004 were inspected in the fall of 2005 and the UT inspections again showed a slight increase. As a result of these inspections the line was placed on a biennial monitoring program and a smart pig run was scheduled for 2006 and funding was secured
- A change in the fall of 2005 in emulsion breaking chemicals inside GC-2 coincide with the time of the recent increased corrosion rate
- Evidence exists of bacterial growth in GC-2
- Evidence exists that carry over corrosion inhibitor is less in GC-2 than in similar facilities
- Facts suggest that the increase in corrosivity in this line may be due to increased bacteria activity from growth in GC-2 and lack of sufficient inhibitor carryover

B. CHRONOLOGY

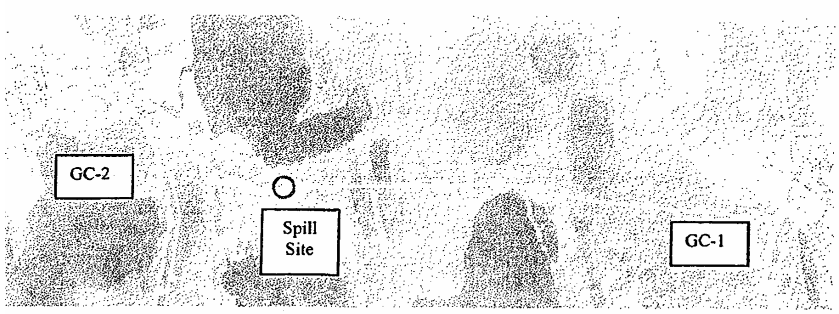
(See Appendix A for the detailed Sequence of Events)

On Thursday, March 2, 2006 at 5:30 a.m., a GC-2 well pad operator notified the GC-2 lead operator, a Security guard, and the GC-2 Area Manager that he had just driven the GC-2 to GC-1 line segment and had noticed the smell of hydrocarbons. Being cognizant of his personal safety, the operator had decided not to investigate alone, and had continued on to the BOC to make the notifications.

Following this notification, the GC-2 Area Manager and another GC-2 well pad operator immediately departed the BOC to drive the pipeline road to investigate. After traveling two miles driving slowly, they too detected the hydrocarbon smell. They swept the area slowly with a truck spotlight, looking for indications of a leak or heat plume. While passing near the first caribou crossing from the GC-2 end of the pipeline road, heading east, the well pad operator thought he noticed a small heat plume. The GC-2 Area Manager exited the vehicle and approached the pipelines but still could not detect the leak. He informed the well pad operator that he was going to walk out on the snow covering the pipelines and proceeded to carefully do so, taking care to distribute his weight evenly to protect from snow caves. After ascending onto the pipeline, he saw an open snow cave with liquids running off what appeared to be the third pipeline in from the road. He removed himself to a safe location and called GC-2 and the Central Control Room and activated a "Code Black" (emergency spill response). The BP Communication Center logged the Code Black at 5:58 a.m.

BPXA began to immediately notify relevant agencies, including the Alaska Department of Environmental Conservation ("ADEC") through a call to the Alaska State Troopers at 6:15 a.m., the Alaska Department of Natural Resources at 6:20 a.m., the North Slope Borough at 6:22 a.m. and the Environmental Protection Agency ("EPA") through a call to the National Response Center at 6:25 a.m.

Both of them stayed on location and were joined by other operators and they all worked to determine which of the three pipelines adjacent to the road had the leak. At 6:15 a.m. it was initially believed that the leak was on the Y/P LDF (large diameter flowline).

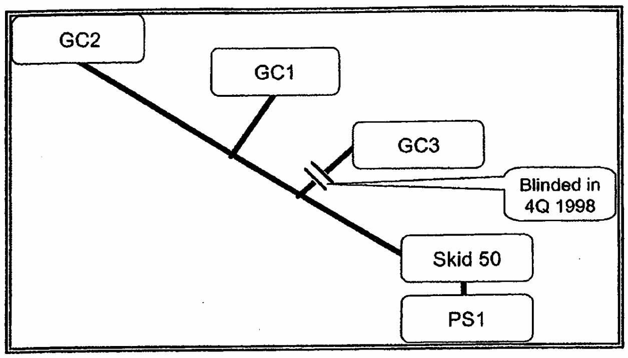


The GC-2 Area Manager called to have the pads shut in immediately. They then proceeded to shut down the Produced Water line from GC-1 at 6:27 a.m., which took less than 30 seconds for the pressure to bleed off. Finally, at 6:47 a.m., the GC-2 Area Manager called for GC-2 to be shut down which took approximately 10 minutes, and at 6:49 a.m., the block valve that isolates GC-2 from the Oil Transit line was shut in. The flow immediately ebbed and by 9:00 a.m. the leak had stopped.

C. HISTORY OF THE GC-2 OIL TRANSMISSION LINE

1. Background

The GC-2 Oil Transit Line runs from GC-2 to Skid 50 as shown in the following schematic:



The pipeline is continuous but is divided into three segments as follows:

GC-2 to GC-1	~16,573 feet (OT-21)
GC-1 to GC-3	~11,420 feet (OT-13)
GC-3 to Skid 50	~13,881 feet (OT-31)
Total:	**~41,874 feet (7.9 miles)**

Design and relevant operating data are shown in the following table:

Outside Diameter (OD – inches)	34"
Nominal Wall Thickness (inches)	0.375" (3/8 ths of an inch) ± 12% Tolerance
Material Specification:	API 5L X52 (standard material)
Design Code	ASME B31.4
Year of Commission	1977
Design Pressure	740 psig
Current MAOP	500 psig (line was de-rated in the late 1990's as a result of corrosion in the Skid 50 by-pass line)
Typical Operating Pressure	< 100 psig
Typical Operating Temperature	110-130 F (exit dehydrators at GC2)
Fluids	Sales Specification Crude Oil: • BS&W 0.35% • Final Separator P: 14-16 psig

2. Line Integrity Overview

The BPXA corrosion inspection program is summarized below and is described in more detail in Section F of this report and in Appendix C.

Internal corrosion: The threat of internal corrosion in sales quality crude oil lines is commonly thought of as low because most of the water and gas has been removed from the fluids at the gathering centers. The risk is increased with (1) decreased flow rate and (2) increased BS&W, which allow water pockets to build up with time. Line condition pre leak is discussed in more detail in the corrosion and inspection section.

External corrosion: The threat of external corrosion is similar for all of the piping in the Prudhoe Bay field. Moisture from rain, melting snow or dew has the potential to migrate into the insulation which provides the right conditions for oxygen attack. The hotter the piping, the higher the risk. On this line the risk is generally considered to be lower than other areas of the field because:

1. The 3-piece design of the insulation does not trap water like some other designs do

2. The pipeline has a corrosion resistant coating in the cased sections

Corrosion Coupon & Probe Monitoring: Corrosion monitoring coupons are located in GC-2, GC-1 and at Skid 50 which see representative fluids entering the pipeline. All are below the target of less than 0.002 inches (2 mils) per year target.

Inspection Programs: The following inspection programs are in place for the GC-2 to GC-1 segment of the pipeline.

Inspection Program	Primarily Looks For:	Frequency	Number of Locations
Corrosion Rate Monitoring (CRM)	Internal Corrosion	Biannual	9 - Formally Established in September 2005
Comprehensive Program	Internal Corrosion	Annual	~50
Cased Piping	External	Depends on findings	14 out of 16. Casings. Plan is to permanently install on all.
Walking speed - Visual	External Problems	5 years	Whole Line
Intelligent Pigging	Internal & External Corrosion	Every 8 years (1990, 1998, was scheduled for April/May 2006)	Entire Line

A recurring risk based inspection program has been determined to be the best measure to identify equipment at risk. Prioritization of inspection surveys is determined by average temperature of the equipment, age of equipment or the last time a complete screening process was completed. Cased piping examinations are achieved through in-line inspection or relatively new non-destructive examination (NDE) technologies such as guided wave and electromagnetic inspection.

3. OT-21 Pressure Derating and 1998 Smart Pig

Management of Change (MOC) 97354382, dated July 24, 1997 formally derated the GC-2 Oil Transit Line to 500 PSIG per PMP # 97-088, dated July 2, 1997. The recommendation to derate the entirety of the line was based on both internal and external corrosion at the Skid 50 by-pass and a calculated MAOP of 572 PSIG on the by-pass section of the line. The lowest calculated MAOP for the OT-21 segment was 653 PSIG. However, the entire line carried the derating of the lowest calculated MAOP – that of the Skid 50 by-pass loop. The MOC was implemented around April 1, 1998 and recommended that the line be smart pigged that summer. That recommendation was acted upon and the line was pigged in the summer of 1998.

The 1990 smart pig run noted nothing of significance for the oil transit line. The 1998 smart pig run on the other hand showed moderate internal and external corrosion. The smart pig identified many areas of both internal and external corrosion on the OT-21 segment of the oil transit line of between 30% and 50% wall loss. The accuracy of the smart pig data was confirmed with follow-up UT inspections. The 1998 smart pig run also identified six specific areas inside this caribou crossing where internal corrosion pitting was occurring. Percent wall loss at these six locations in this particular caribou crossing showed a relatively low line wall loss of between 5% and 25% (B and C rankings). The leak location was one of these six locations and had a wall thickness loss of 9% in the 1998 pig run.

In September 2003, the decision was made to abandon the skid 50 bypass line. However, as a result of the1998 smart pig run and the yearly data that had been gathered on the OT-21 segment, the decision was made to keep the line rated at 500 PSIG instead of rate it back upwards. Condition of the OT-21 line pre-leak is discussed in more detail in later sections of this report.

D. PRODUCTION OPERATIONS

1. Production Operations

Sales quality crude oil from GC-2 is transported to TAPS Pump Station 1 (PS-1) via the GC-2 to GC-1 (OT-21) oil transit line. Operational factors affecting this line have been identified as pressure or flow rate upsets, changes in production fluid quality relative to viscous oil production, and a reduction in fluid velocities due to overall reduced oil production since field startup in 1977. These factors combine to create the production operational parameters presented in this report.

2. Production Upsets

Electronic data retrieved from the Production Control computer system and graphed below indicates that normal operating parameters were present prior to the leak discovery. The only item of note recorded from February 16th thru March 2nd occurred during the shut-in process when pipeline pressure increased from normal operating pressure (approx. 80 PSI) to 209 PS.

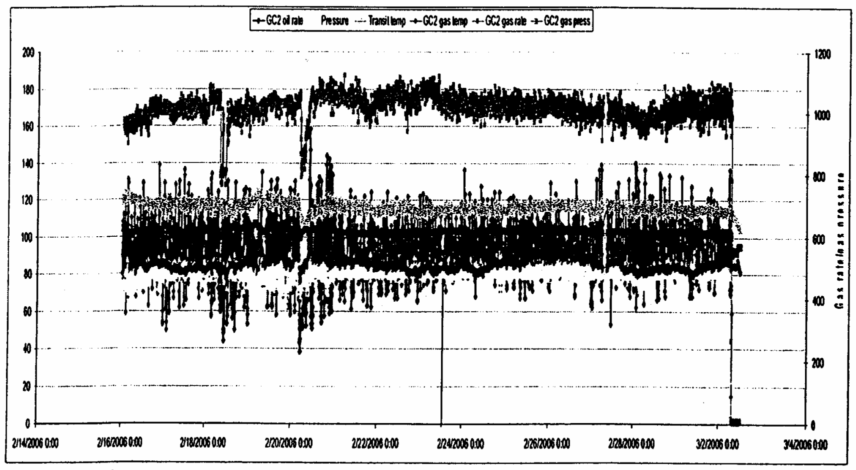


Chart data ranges

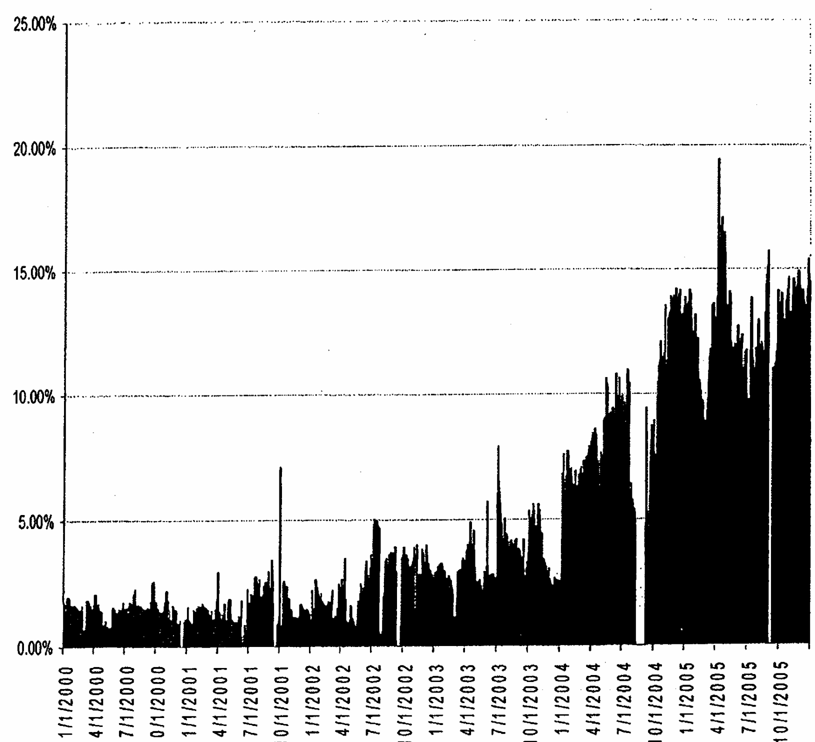
Pipeline Pressure	Fluid Temperature	Flow Rate
63-91 PSI	104-126F	38-158 MBPD

3. Viscous Oil Production

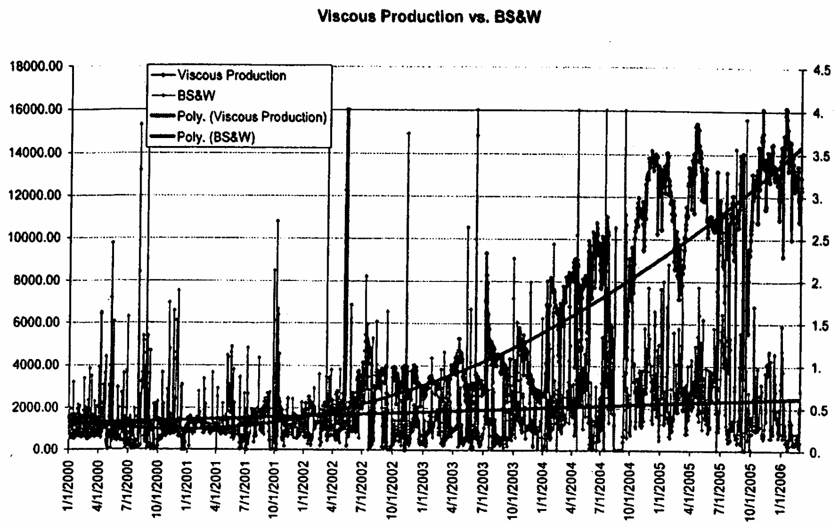
Electronic data collected during the investigation and graphed below documents an increase of viscous oil production at GC-2 from approximately 1,500 BPD in January, 2000 to a production high of 16,098 BPD on October 30, 2005. GC-2 produces more viscous oil than any other facility on the North Slope and today represents approximately 15% of total GC-2 production.

The increase in viscous oil production at GC-2 has, however, resulted in an increase in Basic Sediment and Water (BS&W) entrained in the production fluids as they leave the GC-2 facility and are carried through the OT-21 line.

Percent of Viscous Oil of Total Production



The electronic BS&W statistical data collected between 1/1/2000 through 2/28/2006 is graphed below and indicates a steady increase in mean BS&W as viscous oil production rates increased through GC-2.



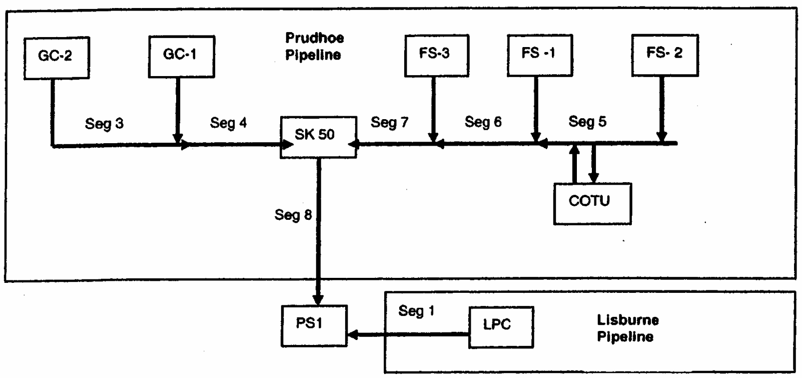
4. Production Rates

Prudhoe Bay oil production output has fallen by nearly 75 percent from its peak in 1987. As discussed and diagrammed below in Section F of this report, the resultant decrease in production of oil through GC-2 has reduced the overall flow rate of oil in this segment of the Oil Transit Line by nearly a factor of four.

E. PRUDHOE BAY LEAK DETECTION SYSTEM

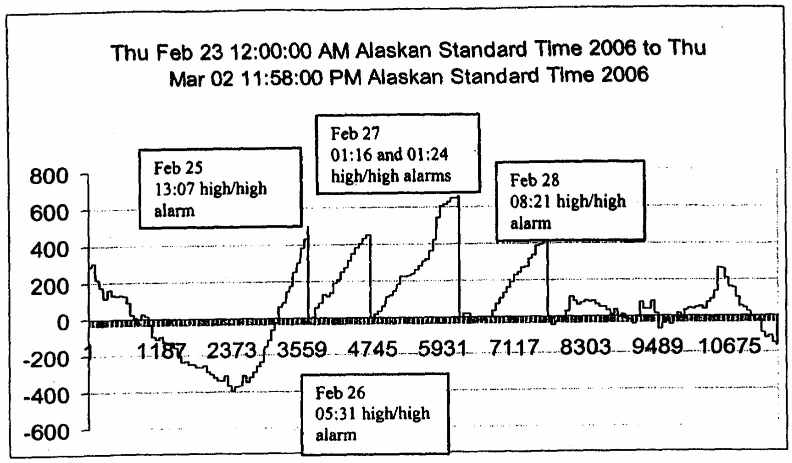
1. Summary

The Prudhoe Bay leak detection system covers oil transit lines from all of the production facilities at Prudhoe Bay and Lisburne to PS-1. As described below, the system is divided into individual segments for purpose of leak detection. The OT-21 line from GC-2 to GC-1 is termed segment 3 and the line from GC-1 to Skid 50 is termed segment 4.

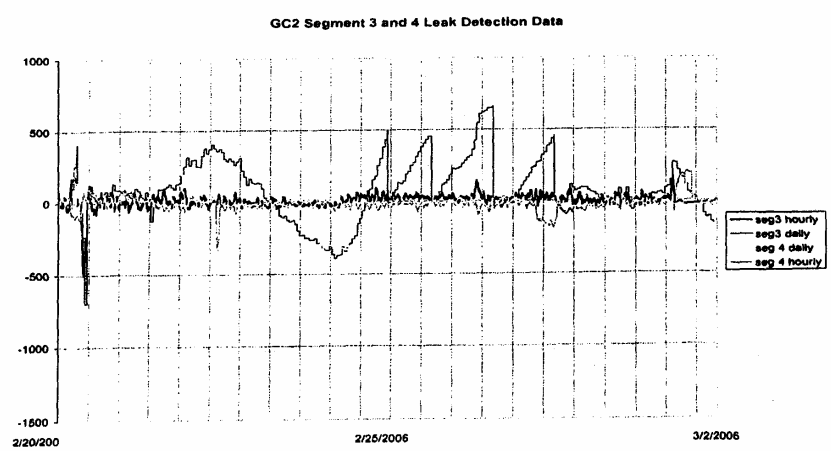


Prudhoe Bay Leak Detection System Segments

The leak detection system works by using a daily mathematical accumulator to measure positive and negative volumes between the meters at the beginning and end of each segment. For segment 3, the daily accumulator looks at the daily volume measured at the GC-2 sonic meter minus the daily volume as measured at the GC-1 sonic meter. For each segment, four alarm points are set: high/high, high, low and low/low. The high/high alarm set point for the system is set at approximately 0.5% of the average flow rate over a 24 hours period. For segment 3, the high/high alarm point is 440 bopd. Following is a graph of the daily accumulator rates for segment 3 for the week preceding March 2, 2006.

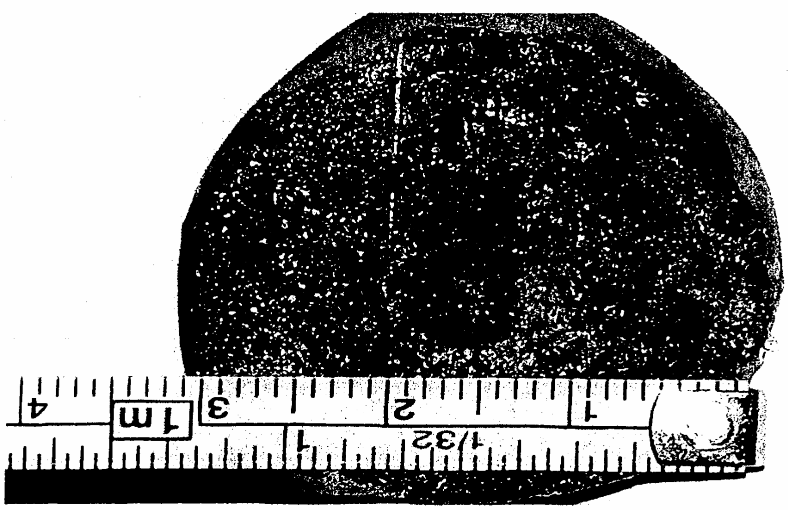


High/high alarms were noted by the automation engineer in their Leak Monitoring Tuning Log on February 25 through February 28. The Eastern Operating Center (EOC) Specialists, who monitor the alarms, also keep an event message log which confirms the high/high alarm readings on the times noted above. As shown in the preceding graph, the magnitude of the high/high alarms ranged from 440 bopd to 600 bopd. Starting on February 25, the notes in the Leak Monitoring Tuning Log note that GC-2 had been producing water on a regular basis and that segment 4 was mirroring negative readings as shown in the following graph.



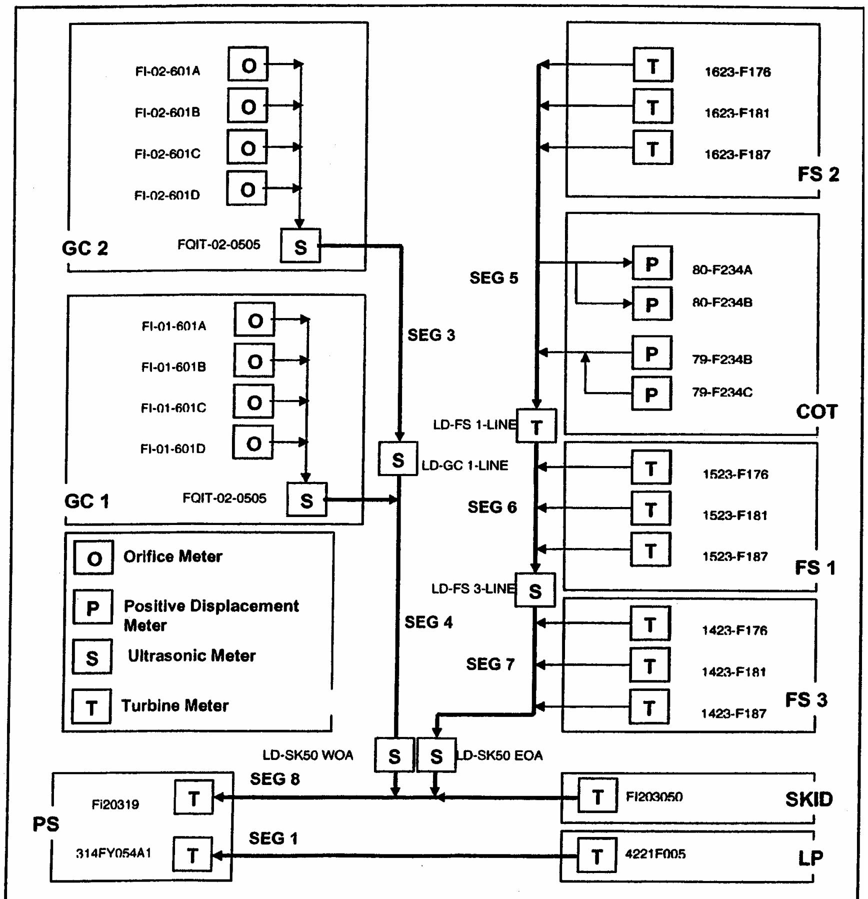
Based on the known GC-2 BS&W upsets that were occurring and the fact that line 4 was mirroring segment 3, the Leak Monitoring Tuning Log system states that the readings were interpreted as an error in the meters and both segment 3 and 4 were reset on each of these days (13:07 on the 25th; 06:49 on the 26th; 07:45 on the 27th; and 08:24 on the 28th). Our conversations with the automation engineers and the EOC Specialists who monitor the leak detection system confirm this statement. During this timeframe a tuning adjustment was also made to the leak detection system at 08:12 on February 28th. There was no high/high alarm detected on March 1 or March 2.

To try and determine how long the leak may have been occurring and at what rate, the rate of pressure bleed down after GC-2 and OT-21 were shutdown was used to estimate an equivalent hole diameter of 0.4 inches. An impression of the actual hole in the pipe measures roughly 0.25 inches by 0.5 inches. The equivalent diameter of this hole approximates the 0.4 inches calculated from pressure bleed down data. Based on this equivalent diameter, it is estimated that the maximum leak rate could have been in the range of 1000 to 1300 bopd at an operating line pressure of circa 80 psig. On March 9, 2006, the Unified Command released a joint estimate with an agreed upon estimated size for the spill of 4,800 barrels plus/minus 33 percent or between 134,783 gallons and 267,555 gallons. Based on the mean estimated spill volume of 4,800 barrels, the leak is estimated to have been going for at least five days. As a result of shutting down the GC-2 flow to GC-1, there was a pressure spike in the line that went to 239 psi for a short duration. This could have also impacted the final hole size. In consideration of this pressure spike, the fact that the hole most likely grew from the inception of the leak, the fact that insulation around the pipe would have caused a flow restriction and the uncertainty of how much of the final hole size may have been created as a function of removing the insulation, it is very likely, although impossible to prove, that the majority of the leak was most probably occurring at rates less than 1000 bopd.



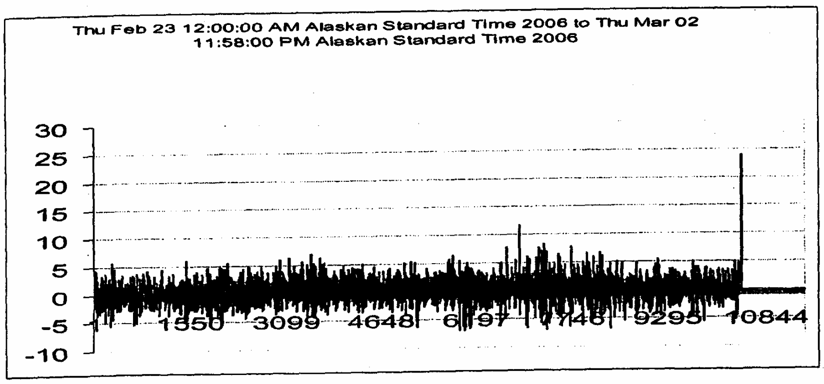
2. Detailed Description of the Prudhoe Bay Leak Detection System

The Prudhoe Bay leak detection system is designed around a 1% detection threshold over a 24 hour period and utilizes either sonic flow or turbine flow meters that compare the flow rate into a given segment of pipe versus the flow rate out of that segment of pipe. The 16,573' of 34" line between GC-2 and GC-1 is referenced as Segment 3.



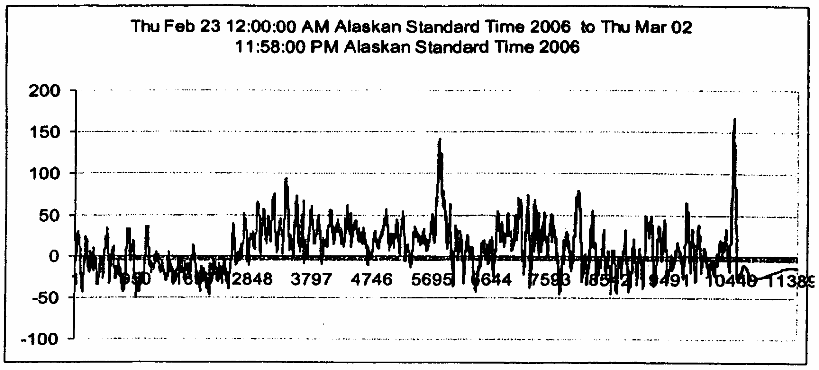
Prudhoe Bay Leak Detection System Meters

Theoretically, with no process fluctuations at GC-2 and no leaks in the pipeline, the measured flow rate at the sonic meter at GC-1 should be identical to that of the rate at the sonic meter measured at GC-2. Practically this is not the case. Due to process upsets (BS&W) and the non-steady state nature of the process, leak rates of less than 1% may not be detected by the system. As a result, it is designed to identify a 1% leak over 24 hours by use of a mathematical accumulator that adds up the delta of measured flow rates (GC-2 minus GC-1). It is also worth noting that the high-high alarm is set at a leak rate of approximately 0.5% to add a level of insurance to try and act on an event more quickly than if set at 1%. How the system works is that a positive accumulator number would indicate less oil coming out of GC-1 than what is going in at GC-2 and conversely, a negative accumulator number would suggest more oil exiting GC-1 than what is entering at GC-2. The graph below shows a week long history of minute by minute readings of GC-2 minus GC-1 for the week prior to the spill.



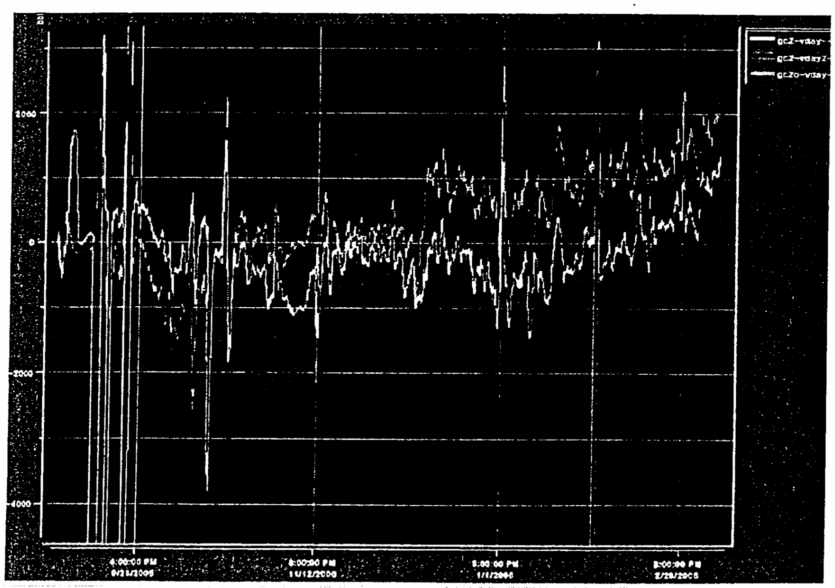
The graph illustrates a continual swing of positive and negative readings, with the absolute swings being in the 4 barrel per minute range. At 4 barrels per minute, this is the equivalent of 5760 bopd or just under 6% of a 100,000 bopd nominal flow rate.

To compensate for these dynamics, the ups and downs are smoothed using the accumulator and are looked at on an hourly basis as shown below over the same timeframe.



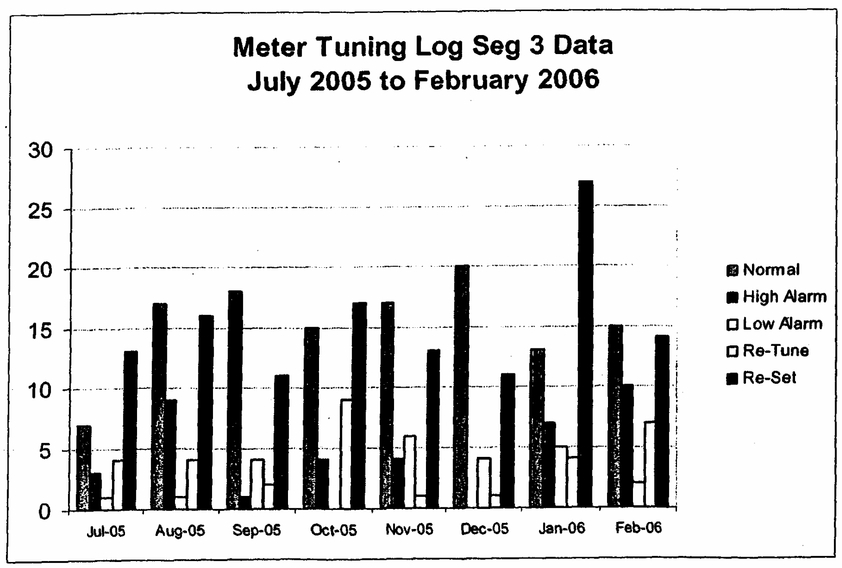
This graph still shows quite a variation in both negative and positive swings in the system on an hourly basis. As a result, it takes one further smoothing over a 12-24 hour period of the accumulated data to detect a small leak.

The graph below illustrates the uncorrected delta in daily meter readings from September 2005 to March 2, 2006.



This graph shows that there are three meters at GC-2: orifice plate meters and two sonic meters. All measure the meter readings at GC-2 minus the readings at GC-1. The blue curve is the delta between the summation of the orifice plate meters and the sonic meter at GC-1; the white curve is the delta between the first sonic meter at GC-2 and the sonic meter at GC-1; and the red curve is the delta between the second (newer) sonic meter at GC-2 and the sonic meter at GC-1. Note the magnitude of the differences between the three sets of meters is in the 1000 to 2000 bopd range. The spikes are usually associated with some sort of process upset. When this happens the EOC Specialists follow the Leak Detection Monitoring and Response Procedure and the systems and procedures outlines in the GPB Leak Detection System Overview, both of which are attached in Appendix C, to evaluate what is happening in the plant and the line. As described in those documents and discussed below, they must continually reset the accumulator and work to re-tune the meter factors for improved accuracy.

In 2005, BPXA evaluated the Prudhoe leak detection system to see if it could meet a 0.5 % leak detection threshold being considered by ADEC in a proposed rulemaking. The analysis concluded that meeting a 0.5 % leak detection threshold is not feasible. Nonetheless, as stated above, prior to the leak the system was set to alarm at approximately 0.5%. The 2005 analysis also determined that segment 3 has a high number of false alarms and a lot of unsteady state conditions – more than any other segment. Most of the false alarms are ruled out as process upsets due to high water content in the exported crude and the mirroring of a neighboring segment of pipe with negative readings. In the absence of these two facts, a request is made for the pipe to be either driven or flown over. According to the Leak Detection Monitoring and Response Procedure, it is the responsibility of the EOC Specialist to make this call, in consultation with the automation engineer, the Leak Detection Technical Authority, and other available resources. Below is a summary of the high and low alarms and number of resets and retuning that occurred from July 2005 through February 2006.



In summary, based on the minute by minute flow rate fluctuations, known process upsets and fluid composition changes, it is a challenge, if not next to impossible to detect instantaneous leaks of less than 1%. As a result, in order to detect a 1% leak, it will require 12 to 24 hours at a minimum to confirm the trend. Even then, because of the false alarms associated with the system in general and long term process upsets in particular, leak detection at the 1% threshold would be challenged.

F. CORROSION INSPECTION PROGRAM

1. Overview

The best source of information on the BPXA corrosion inspection and monitoring program is the publicly available Annual Report for the Year 2004 that BPXA submitted to ADEC in March 2005 on its Commitment to Corrosion Monitoring. This was the 5th such Annual Report and provides a detailed look on a yearly basis of BPXA's corrosion management and monitoring program for non-common carrier pipelines on the North Slope. Its contents reflect the Corrosion Work Plan jointly agreed to between BPXA, ADEC, and ConocoPhillips in 2000 as well as feedback from ADEC on previous Annual Reports and the twice-per-year meetings with ADEC on BPXA's corrosion inspection and monitoring program. Both the Work Plan and Appendix 3 to the March 2005 Annual Update, Corrosion Management System, are included in Appendix C.

Following is a high level summary of the program with an emphasis of those components of the program to better understand the internal corrosion activity in OT-21 and factors that have affected the recent and sudden increase in the rate of corrosion activity. Specifically, we look at:

- Internal condition of OT-21 pre leak
- Factors that affect internal corrosion of OT-21
- Known factors and actions taken

2. Pre-leak Condition of OT-21

Historical and current inspection programs provide insight into the pre leak condition of OT21.

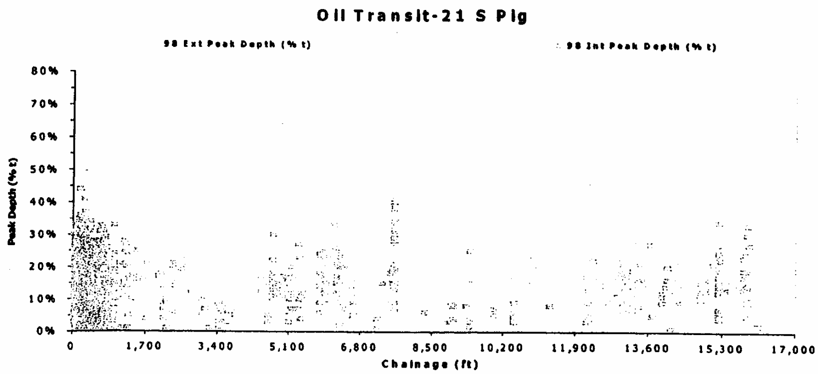
• 1990 Smart Pig Inspection: OT-21 was inspected via a Pipetronix first generation (P1) smart pig in 1990. The following Table summarizes the results of that inspection.

1990 Smart Pig Data

Wall Loss	Indications
0-20%	22
20%-40%	30
40%-60%	6
>60%	0

CIC followed up the 1990 smart pig with manual UT (Ultrasonic Thickness) measurements to verify the smart pig data. The UT data showed a maximum loss of 32% with a minimum remaining wall of 0.265 inches. According to the UT results, the smart pig had significantly overestimated the amount of damage to OT-21.

- 1998 Smart Pig Inspection: OT-21 was again inspected using a Pipetronics smart pig (Generation 2) in 1998. As can be seen from the following figure, the 1998 smart pig run found quite a few more corrosion indications than were found in the 1990 smart pig run.



According to the 1998 smart pig run, the maximum internal corrosion loss was approximately 50% of the wall (corresponding to 0.187 inches wall remaining). As in 1990, the 1998 smart pig run was followed up with manual UT measurements. Unlike 1990, however, these follow-up manual UT measurements largely confirmed the results of the smart pig. The results of both the smart pig and UT inspection indicated that there had been continuing internal corrosion damage between 1990 and 1998. However, while experiencing some corrosion, OT-21 was well within the BPXA "fit for service" criterion. The basic fitness-for-service criterion used by BPXA is ANSI/ASME B31G – 0.100 inch wall thickness or a thickness required for 105% MAOP (the specifics of the fit-for-service definition are discussed in greater detail in the above referenced Appendix 3 at section 3.3.5 to the 2004 Annual Update included in Appendix C).

The amount of wall loss at this particular caribou crossing at the site of the leak was reported to be 9% in the 1998 survey.

- Post 1998 UT Inspection program: No smart pigs were run between 1998 and the present. However, information on the condition of the line can be obtained from the UT inspection program results from 1999 to 2005. Those results from the UT internal corrosion inspections over this timeframe are shown below.

UT Inspection Data Summary OT-21 from 1999 to 2005

Year	Number of Locations Inspected	Number of locations showing corrosion activity	Maximum rate of corrosion activity MPY	Wall thickness at location with highest activity	Location # of point with highest activity	Min wall thickness of all locations reported	Location with min wall
1999	15	1	13	0.230	229	0.180	262
2001	21	0	0			0.180	262
2002	20	2	21	0.240	136	0.180	262
2003	21	0	0			0.180	262
2004	15	1	3	0.260	7532	0.180	262
2005	47	7	32	0.300	263	0.140	14168

MPY = mils per year. One mil = 0.001 inches of wall loss per year.

Note: There were no UT evaluations in 2000

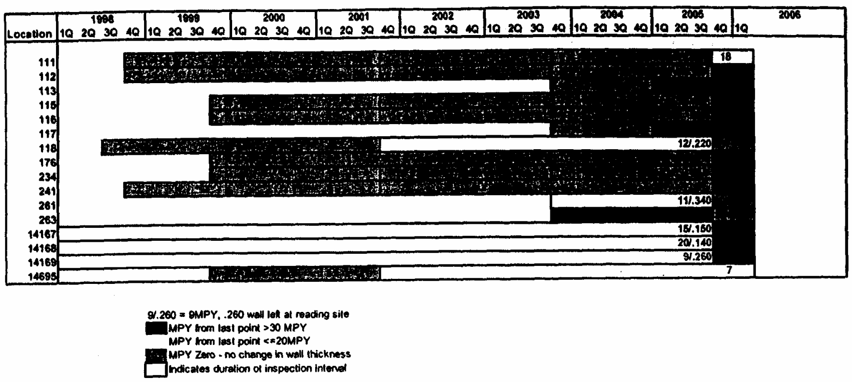
Only a few points (4 out of 92) showed an increase in corrosion activity from 1999 to 2004. This indicates that corrosion was not highly active during this period. In addition, the fact that the location showing the highest increase in activity kept changing from year to year is further evidence of minimal and random corrosion activity. The sporadic rate increases during the 1999-2004 period did not give rise for concern since the locations at which they were measured could withstand many years of similar corrosion activity (rate) before becoming unfit for service.

Further evidence of low corrosion activity comes from the observation that during this time period there was no further wall loss at the location historically reported with the minimum wall thickness (most historic corrosion activity) on OT-21, Location 262 which remained at a constant wall thickness of 0.180 in.

Clearly though something began to change in 2005 when the data from seven locations inspected in September/October 2005 showed an increase and the corrosion activity was the highest it had been over the past six years at 32 MPY. As a result, the OT-21 section of line was put on a biennial rate monitoring program and a smart pig run was scheduled for 2006.

This sudden increase in corrosion rate is shown in the following table and shows a representative sample of the data from 2005 inspection locations including all of the locations that showed an increase in corrosion activity in 2005. More importantly, the results of the UT inspections that were just conducted after the incident have been compared to the last set of data for that same location.

OT21 Inspection Data with Increases in 2005



What the above table shows is the status of a particular inspection point from one point in time to the next point in time that the location was inspected. As can be seen from the extensive and long term green and yellow bars, corrosion activity was very low for the majority of these locations through at least September/October 2005 -- the date of the last inspections that BPXA had for the line prior to the March 2, 2006 leak. In other words, the sudden increase did not begin to occur until sometime after the last date that measurements were taken in the fall of 2005. As already mentioned above, there was only one location shown in red above that was known prior to the spill – location 263. However, while not a concern on an individual location specific basis because is had 0.300 wall remaining, the collective picture did cause some concern and actions were taken to increase the frequency and nature of the review of the line as discussed above and in more detail below.

The remainder of the red bars are based on inspections done at that particular location after the leak. The post leak inspection data, i.e. all of the data collected in the past few weeks clearly shows that something has drastically changed as nearly all locations that have been UT inspected show a large increase in corrosion activity with measured rates in the 40-80 MPY range.

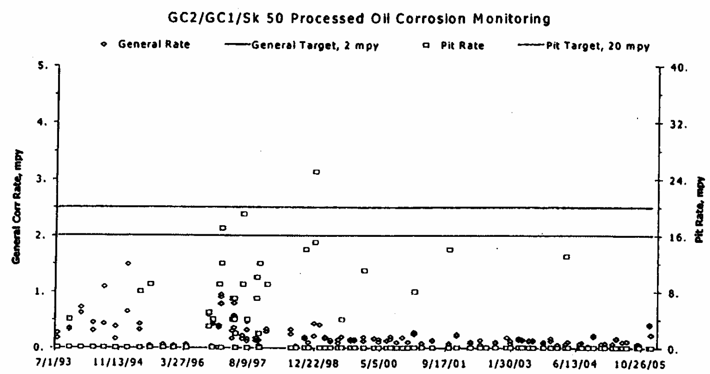
- Guided Wave UT: Road and Caribou Crossing Inspections

The May 2005 Annual Report discusses in detail the BPXA inspection program at buried road and caribou crossings on the North Slope. In particular, it describes the Guided Wave UT inspection program for these areas. A guided wave UT was recently conducted at this particular caribou crossing and another was just conducted after the incident. Neither of these inspections, however, shows evidence of internal corrosion on the pipeline. This is largely because the guided wave UT method mainly detects large volumetric metal loss. As a result, by design it is not as sensitive to internal pitting as it would be to large amounts of external corrosion which, prior to now have been viewed as the main corrosion threat on the North

Slope at cased crossings. BPXA is in the process of implementing a guided wave UT inspection program that will provide repeated scans over the same area that should be better able to detect changes in external corrosion activity. Without excavation and removal of the outer casing from the pipeline, smart pigging is the only accurate way to determine the condition of cased or buried pipelines with respect to internal corrosion. As stated above, a smart pig was scheduled for this line in 2006.

- Corrosion Coupon Data

The graph below shows data from corrosion coupons installed in the oil transit line between GC-2 and Skid50.



As can be seen from the graph, the coupon data are all well below the target corrosion rate of 2 MPY. Some slight pitting has been observed over the years, but nothing excessive. The coupon data does not show any evidence of increasing corrosion trend. This may be explained by the fact that the coupons are in the flow stream and the corrosion damage appears to be primarily located on the bottom of the line on certain uphill runs.

In summary, the above discussion indicates that there was existing pre-leak corrosion damage to OT-21 that was known to exist. However, the data also shows that the line easily met the "fit for service" criteria. The UT data also indicates that internal corrosion was largely under control until sometime between late 2005 and now. Neither guided wave UT at the caribou crossing nor corrosion coupons showed any indication of an increase in corrosion activity.

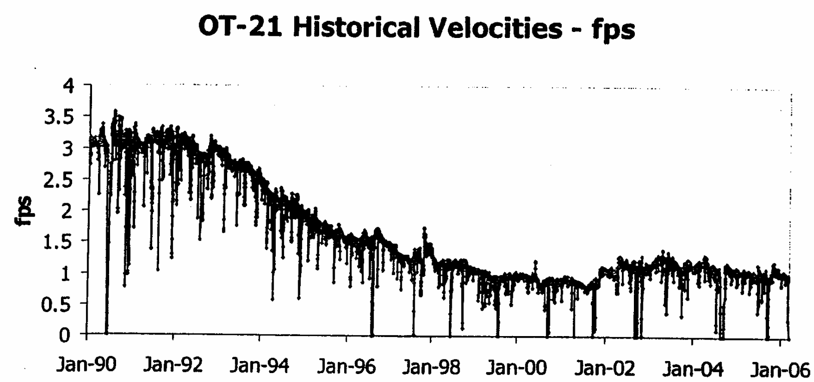
3. Potential Factors for Increased Internal Corrosion Rate

In an attempt to analyze what could have caused the rapid increased corrosion activity over the past six months, we looked at numerous factors that might have led to the sudden increase in internal corrosion activity observed after the leak.

- Water in the OT-21 Line

Water must be present in the line for internal corrosion to occur. The smart pig data from 1990 and 1998 shows that corrosion had occurred slowly over time, therefore water must have been present at sometime in the past. Likewise, the recent increased corrosion rates also would have required water.

To help with the analysis, we calculated the flow velocity of fluids through the OT-21 based on production rates from 1990 forward. Those historical rates are shown below in feet per second.



Next, we modeled the OT-21 pipeline and determined that a velocity of about 8 ft/sec would be required to sweep residual water from the line. This would be true even at various inclinations like that at the caribou crossing. Based on these two data points, we can conclude that with a velocity of 4 ft/sec or less, water has likely been present in the OT-21 line since at least 1990 and probably long before that given the fact that corrosion was found in the1990 smart pig. Therefore, although Section D of this report shows the relationship between the increase in Viscous Oil production at GC-2 and the resultant increase in BS&W carryover into OT-21, water was present long before Viscous Oil although likely in lesser amounts.

- CO2

CO2 is widely present in Prudhoe Bay fluids and if uncorrected for can cause corrosion. However, the crude oil leaving the GC- 2 production process is depressured to 15 psig in the last separation vessels. As a result, the fluids should be in equilibrium with CO2 in the gas at that pressure. Corrosion predictions show that this amount of CO2 would produce a corrosion rate of 8 MPY, far below that observed in the last six months on the OT-21 line.

- H2S

H2S is known to be present in the GC-2 inlet separators at 20 ppm and builds somewhat throughout the facility. However, by itself it does not reach levels that could cause the corrosion rates observed.

- Erosion

Erosion of the inside of the wall of a pipeline can and does occur in certain instances, especially where sediment is present. However, the velocities shown in the above graph for this line are much too low for erosion, even if increased BS&W and Viscous Oil "flour sand" is carried over into the OT-21 line.

- Water Chemistry

No significant changes were found in water chemistry or pH since 1995.

- Well Activities

No evidence was found of recent significant changes in well fracturizations or acidizing work upstream of GC-2.

- Under Deposit Corrosion

The pipeline was not directly opened up to view what is inside it at this location. As a result, there is no direct evidence for or against under deposit corrosion at this time. However, the mechanism associated with under deposit corrosion is usually a longer term corrosion issue and by itself would not be expected to suddenly increase and produce the rates observed.

- Corrosion Inhibition

In 2006, the annual budget for the BPXA Corrosion, Inspection, and Chemical (CIC) program was $62 million, an increase of 80% from 2001. A large portion of that is spent on corrosion inhibitors to add to the produced fluids system. These corrosion inhibitors are water soluble and carry over in small amounts into the production facility and the downstream piping leading from it. The same would be true for GC-2 and the OT-21 line. BPXA enhanced its corrosion inhibition program in the mid-1990's and corrosion inhibitor usage has increased from 1.62 million gallons in 1995 to 2.71 million gallons in 2004. This increase is likely responsible for the reduction in corrosion activity observed in OT-21 after 1998. Changes in inhibitor or inhibitor carryover could affect downstream corrosion rates.

Records show that two corrosion inhibitors have recently been used -- Nalco 01VD121 (2002 to September 2004) and DVE4D002 (September 2004 to October 2005). The facility returned back to using Nalco 01VD121 in October 2005. While this fact alone might lead one to look into its potential impacts on the recent increases in corrosion rates, that fact is unlikely since it was used successfully from 2002 through September 2004 with no resultant increase in corrosion rate over that timeframe.

Inhibitor carryover was tested by Nalco on samples of produced water from GC 1, 2 and 3 and FS 1, 2 and 3 in February 2005. As shown below, this data shows GC-2 had the least carryover of corrosion inhibitor of the six facilities. At 17 ppm the amount was 30% of the average of the other GC's or FS's. Upstream inhibitor injection appeared normal at this time. This low level of corrosion inhibitor carried over into the OT-21 pipeline system could contribute to an increase in corrosivity of the GC-2 water in the line. The reason for this low level of corrosion inhibitor carryover is not totally known. However, facts suggest it could be the result of the additional solids brought in by Viscous Oil production into GC-2. Increased solids provide sites for adsorption of the corrosion inhibitor, which would then reduce the level of residual corrosion inhibitor in the water. Because of the increase in Viscous Oil production and the resultant increase in BS&W, GC-2 has had to experiment with various emulsion breakers to try and address the BS&W upsets. Because of the various chemical interfaces this too could have contributed to the reduction of corrosion inhibitor carryover.

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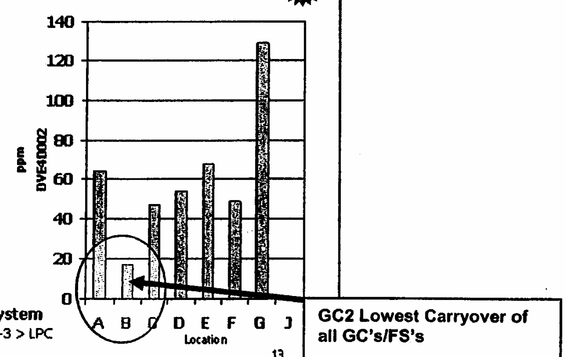
Filming Inhibitor Test Results

	Sample Site	Residual ppm
▸ A	GC-1	64
▸ B	GC-2	17
▸ C	GC-3	47
▸ D	FS-1	54
▸ E	FS-2	68
▸ F	FS-3	49
▸ G	LPC	129
▸ J	Uninhib PW	0



- Potential for corrosion in PW system
  - GC-2 > GC-1, GC-2, FS-1, FS-2, FS-3 > LPC

2005

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- Bacteria

Bacteria, particularly Sulfate Reducing Bacteria (SRB), are well documented to cause corrosion in oilfield equipment although their presence in sales quality crude oil lines is unexpected. However, bacteria can thrive in low velocity vessels and tanks, especially under deposits, sand, or sludge. Corrosion rates from SRB activity can reach 50-100MPY.

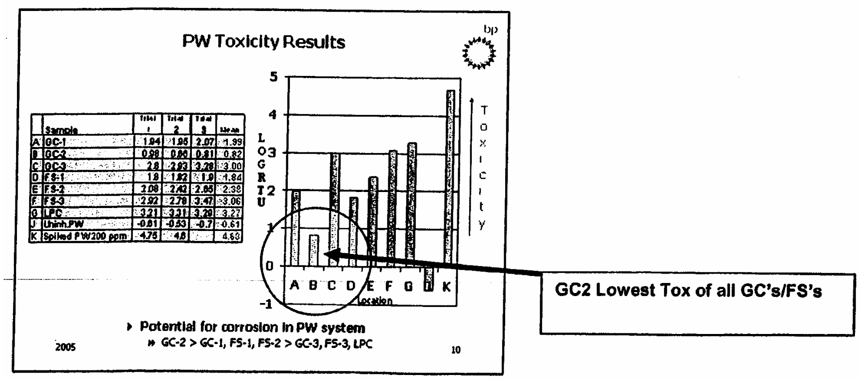
Some historical data exists on bacterial activity at GC-2 that shows some activity from 1990 to 1998 in inlet vessels. However, several recent events indicate that bacterial activity has increased at GC-2 and in the OT021 line.

Concerns about H2S levels in 2005 prompted a sampling program around GC-2. Results shown below indicate that the inlet gas H2S levels are fairly low, 20-30 ppm. However, gas samples taken at more downstream parts of the plant indicate a rise in H2S. This indicates a rise in SRB levels through the plant vessels. A new set of samples has been taken to verify SRB activity and results will be available in early to mid-April.

GC-2 H2S Sample Log Sheet

Location	PPM Result	PPM Result	PPM Result	Date	Sample Method
Gas Off B Slug Catcher	30	30	30	7/1/05	direct gas
Gas Off C Slug Catcher	20	20	20	7/1/05	direct gas
Water Off D Slug Catcher	140	140	140	7/1/05	gas off the water / shake & drake
Water Out of A Dehy	180	150	130	7/1/05	gas off the water / shake & drake
Water Out of B Dehy	50	30	30	7/1/05	gas off the water / shake & drake
Water Out of C Dehy	25	30	30	7/1/05	gas off the water / shake & drake
Water Out of D Dehy	275	350	325	7/1/05	gas off the water / shake & drake
Water Out of T-8512	600	400	400	7/1/05	gas off the water / shake & drake
Water Out of T-7703	600	625	600	7/1/05	gas off the water / shake & drake
Vent Gas Blower gas	175	200	200	7/1/05	direct gas
Discharge off Booster Pump in 407	400	800	800	7/1/05	gas off the water / shake & drake
Discharge off Booster Pump in 402	275	350	300	7/1/05	gas off the water / shake & drake
Dirty Water Tank Gas Phase	175	225	200	7/1/05	direct gas

In addition to the inhibitor residuals mentioned above, Nalco conducted tests on GC-2 produced water on samples taken in February 2005 that showed GC-2 inhibitor carryover had the least affect on SRB growth of any of the production facilities tested. This is graphed below. The importance of this fact is that corrosion inhibitor, although not a biocide, is toxic to SRB's. As a result, a reduction in corrosion inhibitor carryover into the OT-21 line could have led to an increase in SRB activity in the line.

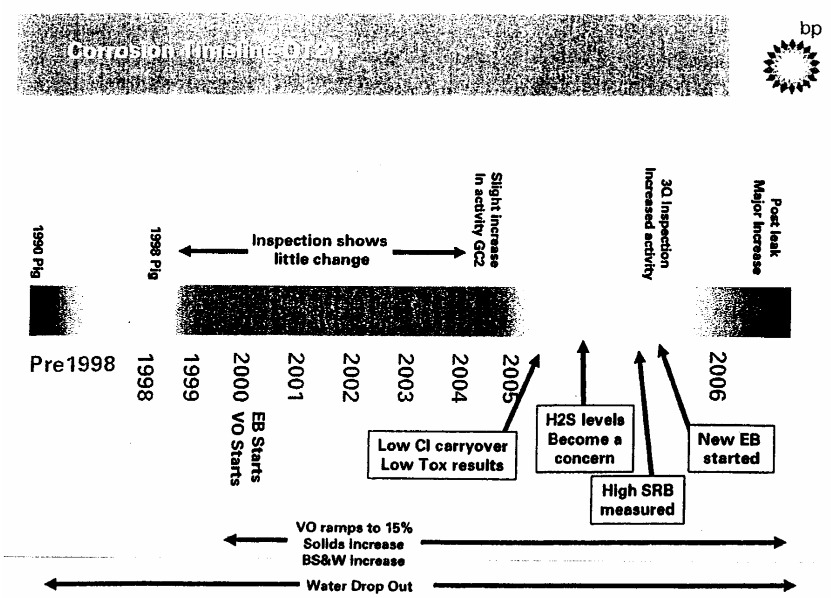


Another Nalco study in July 2005 showed that SRB activity was 10^4 col/ml at the oil-water skim tanks at GC-2. This is a relatively high level of SRB growth and was the highest of any of the GC's/FS's.

Other Chemical Changes: We also evaluated whether or not any other recent changes in production chemicals could have had an affect on corrosion activity or inhibitor carryover. Our inquiry identified two such potential chemical changes in GC-2. First, GC-2 uses a Champion product called X-1421, which is commonly referred to as "Pad Buster." It is used on occasion to break up bad emulsions in GC-2 vessels. This chemical has been in use since 2002 in GC-2 and other processing locations. Second, Viscous Oil production has made oil/water separation more difficult at GC-2 and Nalco brought on an emulsion breaker, EC2011A, in January 2000 to address the issue. This chemical was recently changed to VX8055 (also labeled as DVE4Z026) in 3Q and 4Q 2005 with good results – better oil/water separation – reported.

No changes in scale inhibitors were reported since 1Q04.

Some of the more pertinent facts from above are shown in the following timeline.

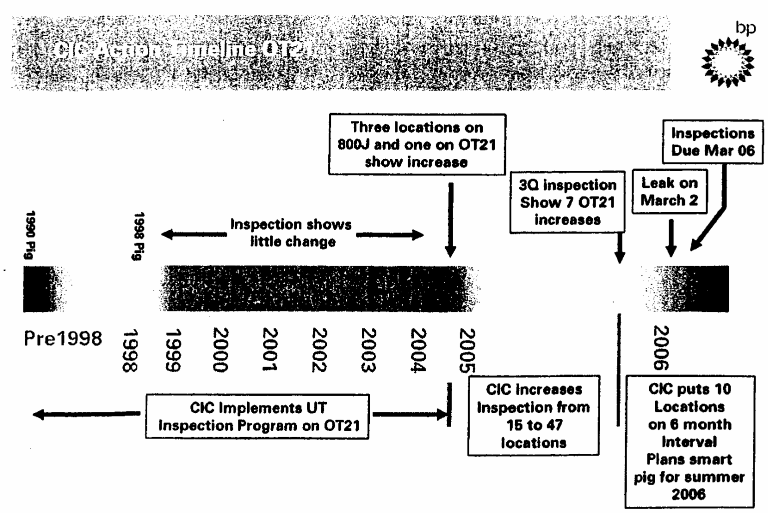


4. Conclusion

Much of the data collected in hindsight after the leak points towards an increase in SRB activity in GC-2 and the pipeline as a likely factor in the recent and sudden increase in corrosion activity. Data shows that SRB are present in GC2 as shown by the elevated H2S levels and the bacterial test results. The presence of bacteria combined with the demonstrated low carryover of corrosion inhibitor in GC-2 and the low toxicity test results increases the likelihood of this occurrence.

The lack of corrosion inhibitor carryover may be due to two factors. First, through adsorption on solids present in the GC-2 process trains as a result of Viscous Oil production and the resultant increase in BS&W and the fine "flour sand" that is produced. This would provide a large surface area for adsorption of the corrosion inhibitor. Second, by using emulsion breakers to promote oil/water separation, these chemicals could aid in removal of the active components in the corrosion inhibitor from the water. However, with respect to this latter point the low levels of inhibitor carryover at GC-2 were measured in 1Q05 well before the recent change in emulsion breaker.

The following Action Timeline attempts to document actions taken with facts known about the corrosion on the OT-21 line.



As discussed in detail above, there was very little change in the corrosion rates on the OT-21 line segment until the 2004 program data was reported in 3Q04. At that time, three locations in the 800j 24" line, the line that feeds into the OT-21 line at GC2 increased along with one location on OT21. None of these increases gave rise to concern about the fitness for service of 800J or OT-21. Based on these results, however, BPXA increased the number of inspections on the OT-21 segment from 15 to 47 for the year 2005 program. The results of that program in 3Q05 showed seven locations on the OT-21 line had increased corrosion rates. As a result, ten OT-21 locations were placed on a six-month inspection interval, as opposed to the previous 12 month interval, and the smart pig was confirmed for 2006. None of the data in either 2004 or 2005 indicated a concern for the "fitness for service" of OT-21.

The leak occurred March 2, 2006. The next round of bi-annual UT inspections for the ten locations was scheduled for March 2006. The smart pig was scheduled for 2006 as well. Since the leak, BPXA has conducted in excess of 2,500 UT inspections including over 1,800 on this line. This post leak inspection data clearly shows sudden and unexpected increases in corrosion activity since the last set of data was gathered in fall of 2005. Had the leak not occurred, either the next round of bi-annual UT inspections or the smart pig run would likely have detected this increase and actions would have been taken.

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Note: redactions indicated in italic text in brackets

REPORT FOR BPXA CONCERNING ALLEGATIONS OF WORKPLACE HARASSMENT FROM RAISING HSE ISSUES AND CORROSION DATA FALSIFICATION

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October 20, 2004

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EXECUTIVE SUMMARY

- EPA's Region 10 Office of Suspension and Debarment and the U.S. District Court's Anchorage Office of Probation and Pretrial Services asked BPXA, which in turn asked us, to look into two areas: allegations of retaliation/intimidation and a resulting chilling effect on reporting HSE issues, and certain specific allegations about to the CIC program, raised by *[the concerned BPXA employee]* and others.

- We believe some employees on the coupon crew experience an unintended chilling effect on reporting HSE concerns. This is a consequence of events that occurred before and after HSE-1838. Secondarily, the reluctance to raise HSE concerns is present but less pronounced in other parts of CIC, such as CANSPEC, as a consequence of the competing pressures of reporting HSE incidents while contractor performance is being judged in part on the number of recordable incidents. The perception of those that we interviewed is that this pressure is also found among contractors outside of the CIC group. An example involved contractor use of the Deadhorse Clinic to avoid OSHA recordables, which was one of the allegations we investigated. These contractors directed their employees to use the Deadhorse Clinic rather than the BP clinics, when injured, to control their recordable incidents. At least one contractor has rescinded this directive. BP is aware of the natural tension that exists between reporting and contractor performance. Its culture is one of safety first and BP actively manages to avoid the unintended consequences of implementing laudable policies targeted at reducing workplace injuries.

- Problems have shown up in CIC, which we believe can be attributed to *[the CIC manager]*'s management style. While his hard-charging, "extreme performance management" approach has probably made the CIC program more effective, his demands for performance to metrics of his choosing, even in cases where those metrics may not be soundly based (e.g. the reduction of coupon crew from 8 to 6), and treatment of HSE incident numbers as just another performance metric that contractors must hit (or else) creates discontent within the organization. This discontent manifests itself in a variety of ways, such as HSE 1838. We found evidence of managers forcing the adoption of decisions made by *[the CIC manager]* regardless of their reservations over them and line worker complaints about them, largely because of *[the CIC manager]*'s overbearing management style, which does not countenance debate and open discussion. We did not find any evidence that *[the CIC manager]* tells people not to report HSE incidents – it was universally acknowledged that he said to report – but his pressure on contractor management to hit performance metrics (e.g. fewer OSHA recordables) creates an environment where the fear of retaliation and intimidation could and did occur. The questionable quality of contractor management in CIC contributes to this problem.

- We did not find any evidence that the allegations regarding data fraud in the CIC program had merit, although our review did not rise to the level of a comprehensive audit

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Note: redactions indicated in italic text in brackets

of the CIC program's data system. Our investigation, however, revealed that there were facts relating to these allegations, which, when viewed in the negative light used by critics of the Company, allow negative inferences to be drawn.

- Recommendations:

To address the chill associated with HSE-1838 and the anxiety of some contractor employees and contractors over reporting HSE concerns, we recommend the following:

1. Transfer *[the CIC manager]* from a management to a technical position. This will remove him from management of the corrosion program, while allowing BPXA to continue to utilize his impressive technical skills.

2. Direct ASRC to take *[the AES manager]* out of the management chain for CIC. This will move out of the CIC program a manager who is not considered particularly effective and send a message that a threat to fire an employee for raising an HSE concern will not be tolerated even if the threat was not carried out.

3. Evaluate and implement appropriate measures to improve morale in the coupon crew. Such measures could include the following: request that ASRC increase the size of the crew back to 8; evaluate whether additional administrative support for the coupon-pullers is needed; reassess the overtime limitations to determine if a total ban on overtime is necessary or appropriate; review pay for the crew to ensure it is in line with the risks and physical demands of the job, and; investigate ways to improve work load and scheduling issues for the coupon crew.

4. Review contracts with CIC contractors that are less than 3 years in length and consider extending them to at least 3 years to reduce the perception that a BPXA manager has de facto control over the contractor as a consequence of the contract constantly being up for renewal.

5. Better educate BPXA managers, contract managers, and contractor employees that the HSE metrics dealing with reportable incidents are only tools to reach the laudable goal of a safer and an environmentally better workplace, not an end unto themselves.

6. Strengthen the process used to address issues related to intimidation and retaliation and make the procedures used to investigate allegations more formal. Currently, allegations of retaliation and intimidation are handled ad hoc. The HSE Committee does not address these issues, and while *[name redacted]* does investigate some allegations, there is no formal process to track an allegation from beginning to closure, nor is there a centralized record system to find records of current or past complaints of incidents or the actions taken to address them.

To improve confidence in the corrosion program and address allegations of falsification and manipulation of corrosion data, we recommend:

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1. Undertake a focused review to assess the corrosion program data systems, which should examine the data system (MIMIR) itself, procedures for gathering, documenting and inputting data, and how corrosion engineers and others access the data and use it. The purpose of this review would be to address allegations of corrosion data falsification.

2. Better educate the employees within CIC (and possibly across the entire North Slope) as to the overall corrosion program to reduce confusion over its goals and actions. If a major incident occurs, it is imperative to thoroughly explain its causes and BPXA's responses to limit the rumors and potentially inaccurate information that otherwise will be circulated on the North Slope.

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INTRODUCTION

In May 2004, a number of allegations regarding the management of the Corrosion, Inspection, and Chemicals program ("CIC") at Prudhoe Bay came to the attention of senior BPXA management through Jeanne Pascal, the EPA Region 10 Suspension and Debarment Officer, and Mary Frances Barnes, BPXA's assigned Probation Officer from the U.S. District Court's Office of Probation and Pretrial Services, who passed along allegations raised by *[the concerned BPXA employee]*, a BPXA field mechanic. *[The concerned BPXA employee]* had submitted an HSE concern, assigned the number HSE-1838, to the HSE Committee that he claimed was on behalf of a number of contractor employees in the CIC group, who had concerns regarding a proposed reduction in staffing levels and related safety issues. This concern was submitted on March 3, 2003, and *[the concerned BPXA employee]* alleged that as of mid-2004 the concerns had still not been addressed and the employees feared retaliation for raising them. *[The concerned BPXA employee]* also alleged that there were significant problems with falsification of data in the CIC program, which posed risks to the environment and worker safety due to inaccurate and inadequate monitoring of corrosion on the North Slope. Having waited a month for documentation of these allegations, Carol Dinkins of Vinson & Elkins again requested the documentation from Ms. Pascal. Ms. Pascal then prompted *[the concerned BPXA employee]* to transmit a collection of documents purporting to support his allegations to Ms. Dinkins via email on June 18, 2004.

In light of these and other serious allegations, BPXA management decided to undertake a comprehensive internal investigation regarding these issues. The investigation was conducted by attorneys from Vinson & Elkins (Kevin Gaynor and Ben Lippard) and Graham & Dunn (David Dabroski). Preliminary work began in June of 2004 with review of documents and background interviews. The bulk of the investigation was conducted during two trips to the North Slope and to the BPXA offices in Anchorage in July and August of 2004. During the investigation, the team conducted over 45 interviews, including of many present and former workers on the corrosion monitoring or coupon crew[1] (the source of many of the allegations that prompted the investigation), BPXA hourly employees, and BPXA and contractor management. The individuals we interviewed were advised that the interviews were voluntary, that the team represented only the Company, not any individuals, and that the interviews were subject to the attorney-client privilege, but that the privilege belongs to BPXA and could be waived by BPXA if it chose. Exhibit 1 is a table of the interviews we conducted for this investigation.

This report more completely documents the preliminary results of our investigation, which we presented orally to senior BPXA management in Anchorage on August 24, 2004. The inquiry focused on two primary areas: allegations of a climate of harassment, intimidation, and retaliation for raising HSE concerns, and a variety of allegations regarding various types of fraud or falsification of data in the corrosion program. There were also a number of related allegations, such as contractor employees being sent to the clinic in Deadhorse, off the BPXA lease, in order to avoid reporting workplace injuries. The major allegations are addressed in the body of this report. Appendix 1 to this document outlines the complex set of allegations

[1] The coupon crew is also referred to as the "corrosion monitoring crew"; to avoid confusion with the other parts of CIC, we generally use the term "coupon crew" throughout this report.

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gathered from a variety of sources and provides our conclusions regarding each specific allegation.[2]

Our overall conclusion is that there is an atmosphere in the CIC group that chills reporting of HSE concerns, especially among several employees of the coupon crew. Some, but not all, of these employees fear retaliation for raising HSE concerns as a consequence of the events surrounding HSE-1838. We believe that this situation evolved out of the climate created by CIC management in the context of a chain of events that began with the transition to single operatorship after the BP-ARCO merger. Principally responsible for the creation of this climate is the current head of the CIC group, *[the CIC manager]*, who is an aggressive manager whose approach can be summed up in the term "extreme performance management." Based on what we have seen in documents and learned in interviews, *[the CIC manager]* aggressively pushes contractor management to reach certain performance metrics. In many ways, this has had benefits in terms of the CIC group's performance – while *[the CIC manager]* has many detractors, even his detractors agree that the CIC program is technically very effective and *[the CIC manager]* has exceptional technical skills.

But *[the CIC manager]*'s high-pressure, metric-driven approach to management had the side effect of creating an environment where contractor management has an incentive to drive reporting underground. If the number of HSE incidents is treated as just another metric, and a manager like *[the CIC manager]* demands that the metric be met and is intolerant of situations where it is not met, there is inevitably a pressure not to report incidents. This kind of pressure can result in an intimidating environment when it is compounded, as it was here, by the actions of contract management in response to HSE concerns, in this case, the HSE-1838 concern surrounding the crew reduction.

Similarly, *[the CIC manager]*'s aggressive style deterred contractor management from standing up to *[the CIC manager]* in a case where one of his demanded changes, the reduction in the size of the coupon crew from 8 to 6, was based on a process that did not adequately address the good-faith concerns raised by a variety of sources, particularly those on the coupon crew who were directly affected. *[The CIC manager]* dictated that the size of the coupon crew be reduced to correspond to his metric – that coupon pulls had been reduced 25% – which he believed justified this change. The contractors were forced to conform behavior to his demands regardless of the impetus for the demands. We believe the "25% reduction in pulls" metric led to pressure on contractor management to implement a policy that has not been successful and has contributed to the negative environment in the coupon crew, which has generated the accusations embodied in HSE-1838 and many other criticisms of the corrosion program.

[2] To keep this report to a manageable level, the Appendix 1 conclusions are presented in a summary fashion; we can provide a more detailed analysis of specific allegations if more detail is needed.

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The situation was exacerbated by the missteps of contractor management, particularly the manager for the contractor ASRC, *[name redacted]*. *[The AES manager]* was chiefly responsible for the coupon crew being told that BPXA management had approved replacing the entire crew if they did not stop pushing back on the changes to their program, and for the employee primarily associated with HSE-1838, *[the CIC worker]*, being informed that he could have been fired for raising HSE concerns in the manner that he did.

Finally, the climate of perceived intimidation and threatened retaliation affecting the coupon crew was exacerbated by the elimination of significant overtime for the crew. After HSE-1838 was filed, some individuals on the crew complained that excessive overtime was being required to manage the growing backlog of coupon pulls that resulted from the crew reduction, and that the amount of overtime in turn created potential safety issues. In response to this complaint, BPXA and contractor management eliminated all overtime for all coupon-pulling (1.5 hours were restored for other activities but were later eliminated). While management believed that they had to respond to the potential safety issues raised by the overtime complaint, the crew perceived that this was another instance of retaliation for raising an HSE concern.

We want to emphasize that it was not *[the CIC manager]*'s or the contractor's management's intent to intimidate or retaliate against any employee raising HSE concerns. But the threats to fire the whole crew or *[the CIC worker]*, which were discussed by management, should not have gone beyond the offices of the participants. Thus, a legitimate chill on reporting HSE concerns exists among the workers, and is an unfortunate byproduct of *[the CIC manager]*'s management style and actions in this chain of events.

There have also been a number of serious allegations made regarding the integrity of the CIC program as a whole, principally including various forms of data falsification. Our investigation did not uncover any evidence to suggest that such falsification was actually occurring. Rather, we believe that these accusations are based on an inaccurate view of certain facts regarding the CIC program that, when combined with the very negative view of BPXA management held by some individuals, led them to interpret the facts in the most negative light possible. Still, our review of the program would not necessarily have been sufficient to uncover possible fraud in handling the corrosion data being generated by the CIC program, the foundation on which corrosion control decisions are based. We do not possess the requisite technical skills to draw such conclusions. As a result, we recommend that the Company conduct a thorough audit of the corrosion program's database and operations, including MIMIR, as a way of resolving this issue with certainty. Given the significant changes made to CIC operations in the past few years, such as the implementation of MIMIR, such an audit may be useful to the CIC program in any event.

This report will begin with an overview of the structure of the CIC program relevant to our investigation, and then turn to the events surrounding the coupon crew, particularly HSE-1838, that led to the chill that exists with some employees in that group today. It will then

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address some of the specific allegations made regarding the CIC program – particularly the allegation of data fraud – to assess their merit and to explain what may have prompted individuals to make these claims. Finally, the report concludes with recommendations to address these issues and to correct the problems identified through our investigation.

STRUCTURE OF CIC PROGRAM

Due to the corrosive conditions present at the Greater Prudhoe Bay ("GPB") oilfield and the age of the field, corrosion control is and has been a major issue for BPXA. As a result, the Company devotes significant resources to control corrosion at GPB. The scope of the program is described in detail in the CIC group's annual report to ADEC.[3] To summarize, CIC's total expenditure of funds in FY 2003 was $53.8 million.[4] This represents an $8.0 million increase from 2002.[5] And the activities of CIC are extensive: there are approximately 7400 weight-loss coupons pulled per year;[6] the chemical mitigation program uses 2.52 million gallons of corrosion inhibitor per year;[7] and, on average, there are more than 100,000 inspections for internal and external corrosion at various points across the Slope.[8] While we do not intend to reproduce the discussion contained in the ADEC report here, some overview of those parts of the CIC program relevant to our investigation is necessary to provide context to this report of our investigation.

I. Overview of CIC Operations

The CIC program can generally be described as a three-part program, each part of which involves a different aspect of corrosion monitoring and control. This program is overseen by on-Slope BPXA managers, *[name redacted]* and *[name redacted]*, who report to *[the CIC manager]* in Anchorage. The engineering function related to this effort is conducted from Anchorage, where the corrosion engineers are based. The first part of the program is the monitoring program which includes the weight-loss coupon program and ER (Electrical Resistance) Probes, to which this report will devote significant attention. (This part is the source of most of the allegations made about CIC.) The second part of the CIC program is the chemical mitigation program. The third part is inspections, including the non-destructive examination ("NDE") program. Currently, these three parts are tracked through the "MIMIR" database, the comprehensive

[3] Annual Report to Alaska Department of Environmental Conservation, Commitment to Corrosion Monitoring Year 2003 (March 2004) ("2003 ADEC Report").
[4] *See* Email from *[name redacted]* to *[name redacted]* re: Verification of the Alaska Location report (Feb. 27, 2004 6:22 PM). Note that we have relied on the data provided to us by CIC staff and have not independently reviewed the underlying data. While we did not encounter any reason to believe that this data was not accurate, such questions could be resolved through the comprehensive audit of the CIC program we recommend.
[5] Interview of *[name redacted]* (August 24, 2004).
[6] 2003 ADEC Report at 16.
[7] 2003 ADEC Report at 73.
[8] *See* Email from *[name redacted]* to *[name redacted]* re: Verification of the Alaska Location report (Feb. 27, 2004 7:11 PM); *see also* 2003 ADEC Report at 84 (35,000 external inspections in 2003) and at 90 (60,000 internal inspections in 2003).

computer program for the entire corrosion program, which has recently been implemented to provide greater sophistication in the CIC program. Based on the information developed through the inspection program, requests for corrective actions are issued to Operations. Once these requests are in the form of a Pipeline Modification Process ("PMP"), Operations must take action (e.g. pipe replacement) to address a recognized corrosion problem by a certain time.[9] These PMPs are taken very seriously, and there is management pressure to have corrective action implemented by the prescribed time.[10] CIC also conducts a weekly meeting to which state agencies are invited, to monitor and address corrosion issues; provides an annual report to state agencies; and hosts a multi-day annual meeting, to which state agencies are invited, to discuss the corrosion program.

A. Coupon program

The coupon program entails the insertion and removal of weight-loss coupons in pipes, valves and other fittings at locations inside and outside Prudhoe Bay facilities in order to monitor the corrosion of the equipment. The coupon crew inserts and removes coupons on a defined schedule, which varies depending on the location and service (flow- 3 months, well- 4 months, seawater or produced water- 6 months) and the monitoring and inspection results for the equipment in question. There are about 1500 points around the field, of which most are monitored several times a year.[11] The coupons, which are stamped with a unique identification number, are provided to the crews in envelopes with the corresponding identification numbers. When the coupons are inserted in the field, their location is noted on the envelopes, which are returned to the CIC office. On removal, the locations of the coupons are checked against the notes on the envelopes and the coupons are returned to their respective envelopes. The crew will "field grade" or make a visual inspection of the coupons on a scale of "low, medium, to high corrosion" in order to immediately flag any serious corrosion. On their return to the office, the coupon crew will enter into the MIMIR system the identification numbers, locations, and initial observations for the pulled coupons. The coupons are then sent to an outside laboratory, Enviroscience, which is in Texas. Enviroscience weighs and closely examines the coupons[12] and adds the results of their testing directly to the MIMIR system through a remote connection to the BPXA computer system.[13] The coupon crew typically does not see these results, and has no ability to alter the testing results entered by the laboratory.

AES is the contractor that staffs and manages the crew that does the coupon-pulling work. This work is widely recognized as the most physically demanding and high risk job within CIC due the use of the heavy, awkward tools (weighing from 60 to over 100 lbs.) on high

[9] Interview of *[name redacted]* (July 26, 2004).
[10] Interview of *[name redacted]* (August 20, 2004).
[11] 2003 ADEC Report at 15-16.
[12] Interview of *[name redacted]* (July 27, 2004).
[13] Interview of *[name redacted]* (July 28, 2004).

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pressure pipes (up to 3,500 lbs. psi), often in difficult-to-reach locations and in extreme arctic conditions.[14] Among the AES employees who perform the work, almost all are trying to move to other positions, which are less high risk and physically demanding and often pay more.[15] (A number of AES employees that have done coupon pulling in the past observed that it makes little sense that the coupon crew should be paid less and probably should be paid more than many other AES positions in CIC).[16]

One of the key issues presented by the coupon-pulling program is the "backlog" of coupons. Each coupon is assigned a preferred pull date, and the coupon crew is given a "window" of 15 days on each side of the pull date to pull each coupon.[17] After the optimal window passes, there is another period during which the coupon can still be pulled. After this period passes the coupon is considered "missed" and is dropped from the schedule, to be rescheduled in the future.[18] Since the reduction of the coupon crew from eight workers to six, a backlog of pulls has generally been a perceived problem. The existence of this backlog has created stress for some of the crew and a sincere loss of pride in their work because they feel they are never able to complete it as in the past (others are not as concerned, viewing this as a management issue that is not really their problem).[19] The backlog as of August 23, 2004 was over 180 pulls;[20] a two-man crew does approximately 10-12 pulls a day[21] and hundreds of pulls are added monthly.[22]

For triage purposes, coupons are assigned a priority level of 1, 2, or 3, with 1 being the highest priority. While there is a backlog of coupons, the crew gets the priority 1 coupons and most of the priority 2 coupons; some of the priority 3 coupons slip into the backlog.[23] While we understand that there had not been any coupons "missed" at the time of our last interviews, we

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[14] Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (July 26, 2004); Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (July 26, 2004).
[15] Interview of *[name redacted]* (August 20, 2004); Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (July 27, 2004).
[16] *See, e.g.,* Interview of *[name redacted]* (August 21, 2004); Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 20, 2004).
[17] Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (July 27, 2004).
[18] Interview of *[name redacted]* (July 28, 2004).
[19] *See, e.g.,* Interview of *[name redacted]* (August 19, 2004) (pressure to get backlog done); Interview of *[name redacted]* (August 19, 2004) (same); Interview of *[name redacted]* (July 27, 2004) (backlog a management issue); Interview of *[name redacted]* (August 19, 2004) (same).
[20] Interview of *[name redacted]* (July 29, 2004); Interview of *[name redacted]* (August 23, 2004).
[21] Interview of *[name redacted]* (August 23, 2004) (stating it is hard to hit 12-13 pulls every day).
[22] Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (August 23, 2004).
[23] Interview of *[name redacted]* (July 27, 2004) (explaining all priority 1 pulls for July done; backlog is priority 2 and 3 pulls).

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were informed that this might change in the near future.[24] Even if misses are not occurring, data collected late does not give optimum corrosion information.[25]

Failure to pull a coupon in a "red zone," or an area where it is dangerous to pull a coupon (due to hazards caused by height, lack of safety protections, or weather conditions), is another reason a pull may not occur as scheduled.[26] This shifts the burden to the corrosion engineers to determine if the particular coupon provides critical information and if so, to ensure that the access problems are corrected to allow the pull to be done safely.[27] The coupon crew members uniformly stated they can refuse to pull a coupon because they determine an area to be a "red zone," and that they are not pressured to pull coupons until the safety issues are resolved.[28]

B. Chemical mitigation program

The second major program that CIC handles is the chemical mitigation program. Using data on the MIMIR system from the weight loss coupon monitoring program, the inspection program, production data and other information (e.g., the amount of water produced in a given line), the chemical mitigation program adjusts the amount of anti-corrosive chemical that is injected into various equipment in order to keep the corrosion at a targeted rate of less than 2 mils per year.[29] This program has become more sophisticated in its attempt to manage the effects of corrosion, moving from batch treatments, involving crews injecting quantities of chemicals into certain wells at particular times, to using continuous injection to maintain the concentration of chemicals at the necessary levels to inhibit corrosion.[30] As a result of these efforts, the average corrosion rate for 2003 across GPB is approximately a factor of 10 lower than the corrosion rates from the early 1990's.[31]

The job of the AES chemical operators, who monitor and adjust the chemical injection, is widely considered by AES employees to be more desirable than that of the coupon-pulling crew.[32] AES also operates the infrastructure of bulk storage tanks and chemical delivery trucks necessary for the program.[33]

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[24] Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 19, 2004). *See also,* email from *[name redacted]* to *[name redacted]* (August 23, 2004).
[25] Interview of *[name redacted]* (July 26, 2004).
[26] Interview of *[name redacted]* (August 23, 2004).
[27] Interview of *[name redacted]* (August 19, 2004).
[28] Interview of *[name redacted]* (August 18, 2004).
[29] Interview of *[name redacted]* (August 24, 2004).
[30] Interview of *[name redacted]* (July 27, 2004).
[31] 2003 ADEC Report at 45.
[32] Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (August 19, 2004).
[33] Interview of *[name redacted]* (July 27, 2004).

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C. Non-destructive examination/X-ray program

The third leg of the CIC program is the inspection program, including radiographic or x-ray, digital radiographic, tangential radiography, ultrasonic, guided wave ultrasonic, and electromagnetic pulse testing, or non-destructive examination (NDE). The current operator of this program, CANSPEC, took over in 2002, after the former contractor, a subsidiary of ASRC, did not have its contract renewed by BPXA as a result of the falsification of inspection data by some of its inspectors.[34] As noted above, CANSPEC crews inspect more than 100,000 points per year. As a result of the inspections, specific locations in a particular pipe are assigned a rank from "A" to "F", with "F" being the worst condition.[35]

D. MIMIR

The MIMIR system was implemented beginning in 2002 and represented a significant expenditure of resources. It presently manages monitoring and inspection data, production data, coupon locations and pull schedules, and chemical injection data. At the time the Prudhoe Bay field went to single operatorship, there were several legacy databases that needed to be combined.[36] Thus, in the transition to MIMIR, a common nomenclature had to be assigned to common activities and data had to be "scrubbed" as these databases were reviewed and combined. While, as we have been informed, no data was removed in the process, some may have the impression that data was being discarded.[37] The MIMIR system, however, allows the user to always go back to original data even if changes are made. For example, if a coupon crew member realized that the location for a coupon pull was incorrect (which we are informed happens on occasion), he could contact *[the CIC manager]*'s assistant to make this change. The accurate data would rule, but the inaccurate data would be maintained and can be queried. Any changes on the system by anyone create an events log that can also be queried. Only *[the CIC manager]* and MIMIR's architect, *[name redacted]*, have full access to the system; however any of their activity is also logged by the internal security checks built into the system.[38]

E. Responses to indications of problems

When inspection data indicates that there is pipe or other equipment that has become sufficiently corroded to need repair, a PMP is generated and sent to Operations. Operations then decides how to address the problem, which can involve one of several options: pipe can be replaced, sleeved, derated, or taken out of service completely.[39] In this context, "derating" means calculating the operating pressure, flow rates, and other parameters at which the pipe is

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[34] Interview of *[name redacted]* (July 29, 2004).
[35] Interview of *[name redacted]* (July 27, 2004).
[36] 2003 ADEC Report at 11.
[37] Interview of *[name redacted]* (July 28, 2004).
[38] *Id.*
[39] 2003 ADEC Report at 10-11.

safe to operate and then limiting its operation to stay within the new parameters.[40] This process of ensuring that the pipe is "fit for service" is done to be consistent with industry standards recognized and used around the world.[41] While Operations ultimately determines how to fix the problem, the schedule on which it is done is negotiated with CIC and is not set at Operations' convenience.[42] As noted above, PMPs are carefully tracked.

F. Interaction with state agencies

The CIC Group has reported to ADEC annually regarding corrosion issues for the past four years, a process that involves a very detailed report on the activities of the CIC Group as well as semi-annual "meet and confer" sessions. ADEC retains its own independent consultant to review and critique BPXA's report. This process is governed by a 2000 "Work Plan," which is provided as Appendix 2 to the 2003 ADEC Report. The most recent meet and confer activities took place on the North Slope during the week of August 16, 2004. We were also informed that ADEC staff are invited to participate in the weekly corrosion team meetings (described below) and occasionally do so.[43]

G. Weekly meetings to assess corrosion

Every Wednesday there are meetings of approximately 20 people from the CIC group to assess and make decisions about the data from the Slope regarding pipes that have corrosion. The engineers at the Wednesday meetings are CIC employees, with designations by locations, operations, and by service (e.g., produced water).[44] These meetings examine computer-generated layouts of all of the data received, and any data showing greater than a 2 mil loss per year dictates that a decision be made as to what to do about that equipment.[45] The engineers review MIMIR data involving probe and coupon results, NDE and physical inspections, frequency and location of data of monitoring, chemical deliveries and rates of injection, actual production data, and scheduling.[46] The engineers make decisions about scheduling of monitoring, injections of chemicals and "fit for service" issues based on a review of all of this data.

There is a watch list of problem areas that changes from week to week, and each week three to four lines will go off the list because of various changes, such as a drop in the water content or an increase in the use of anti-corrosion chemicals, resulting in alleviation of the

[40] Interview of *[name redacted]* (July 28, 2004).
[41] Interview of *[name redacted]* (August 24, 2004)
[42] *Id.*
[43] *Id.*
[44] Interview of *[name redacted]* (August 20, 2004).
[45] Interview of *[name redacted]* (July 29, 2004).
[46] Interview of *[name redacted]* (August 20, 2004).

problem.[47] Problem lines get frequent attention in these meetings. For example, the chemicals on Y-36 are adjusted each week, because that line is viewed as a problem line.[48]

II. CIC Management Structure

The corrosion program is a very large program of about 150 employees and contractors,[49] and is overseen by *[the CIC manager]*, who took this position about 5 years ago. The corrosion program is independent of operations and reports upward through *[name redacted]*, Manager of Maintenance and Reliability.[50]

A. BPXA CIC management

[The CIC manager], the head of the CIC group, is based in Anchorage along with his team of engineers. *[The CIC manager]* also has subordinates, who manage the CIC program on the Slope, alternates *[name redacted]* and *[name redacted]*.

B. Contractor management

[The CIC manager] oversees the operation of a number of contractors, both personally and through the activities of his subordinates. There are a number of contractor companies performing CIC-related functions on the Slope. One is AES, which performs many of the CIC functions, including corrosion monitoring and chemical injection and handling. AES is the successor to an earlier company, APC, that performed the same function on the Slope and changed its name several years ago. For convenience, we will use "AES" throughout to refer to either AES or APC. AES is part of ASRC, which provides other contracting services on the North Slope. AES has a manager based in Anchorage, *[the AES manager]*, who oversees two Slope-based subordinates, *[name redacted]* and *[name redacted]*. *[An AES supervisor]*, who formerly was one of the Slope-based managers, has temporarily been moved to Anchorage to assist *[the AES manager]* in interfacing with *[the CIC manager]*.[51]

The second major contractor working for CIC on the Slope is CANSPEC, which performs the inspection work. CANSPEC is managed by *[the CANSPEC manager]*, who is based on the Slope. *[Name redacted]* is *[the CANSPEC manager]*'s assistant and manages the CANSPEC operations when *[the CANSPEC manager]* is not present.

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[47] Interview of *[name redacted]* (July 29, 2004).
[48] *Id.*
[49] Interview of *[name redacted]* (July 27, 2004).
[50] *Id.*
[51] Interview of *[name redacted]* (July 29, 2004).

Note: redactions indicated in italic text in brackets

HARASSMENT AND INTIMIDATION ISSUES

There are a number of allegations regarding claims of harassment and intimidation, which primarily focus on the coupon crew. In our view, the current situation is one where certain individuals on the coupon crew feel intimidated about reporting HSE issues. This situation evolved primarily as a consequence of events before and after HSE-1838 was raised on March 2, 2003. HSE-1838 was raised due to concerns about a reduction in the staff of the coupon crew from eight to six workers. This change was prompted by *[the CIC manager]*'s insistence that AES reduce its crew size by 25% to correspond with his metric that pulls had been reduced by 25%. He forced this decision, choosing to ignore managers and workers raising problems with his metric or so unsettling managers that they failed to press problems with him, believing it was better to "go along" than suffer the consequences of being considered as someone who is not on the "team."[52]

A secondary factor that contributed to this negative atmosphere is the inherent tension between BPXA's policy of reporting every HSE incident and BPXA's stated goal of reducing HSE incidents to zero. BPXA's goal is certainly laudable, but can cause problems in the hands of an aggressive manager like *[the CIC manager]*, who pushes contractors very hard to hit performance metrics and threatens contract loss on a regular basis. The inherent tension between "100% reporting" and "zero incidents" requires a manager who is able to reduce that tension through his management style; regrettably, instead *[the CIC manager]* exacerbated this tension. Moreover, *[the CIC manager]*'s particular approach – requiring contractors to perform his way (or else) – placed intense pressure on contractor management. Some of the contract managers could not handle this pressure, and acted in ways that contributed to the difficulties in CIC.

We will focus first on the more general issue of reporting HSE incidents and then move to discussing the events surrounding HSE-1838.

A. BPXA reporting policy and goals for HSE incidents

BPXA's policy regarding reporting is very clear: all HSE incidents are to be reported, and there are a variety of ways that employees can use to report those incidents, including an anonymous hotline. We saw posters on various bulletin boards and in conference rooms on the North Slope setting out the policy. BPXA policy is also that any employee may stop any job due to safety concerns, and "safety first" is repeatedly preached by BPXA management.[53] To a person, BPXA employees (as distinguished from contractor employees) felt absolutely comfortable raising HSE concerns or issues.[54] And the CIC employees we spoke to uniformly

[52] *See, e.g.,* Interview of *[name redacted]* (August 23, 2004); email from *[name redacted]* to *[name redacted]*, June 30, 2003; Interview of *[name redacted]* (July 29, 2004); Interview of *[name redacted]* (August 24, 2004).
[53] Interview of *[name redacted]* (August 20, 2004).
[54] *See, e.g.,* Interview of *[name redacted]* (August 18, 2004); Interview of *[name redacted]* (July 28, 2004); Interview of *[name redacted]* (August 18, 2004).

stated that *[the CIC manager]* expresses the same message, that all incidents should be reported.[55]

It should be noted that our perception was that safety is a high priority for BPXA, and employees with experience in other oilfield facilities were emphatic that, whatever differences they may have with management on other issues, BPXA's commitment to safety is sincere. According to one PACE employee, the safety situation at the BPXA facilities on the Slope is "a hell of a lot better" than anywhere in the lower 48.[56]

Indeed, BPXA makes no secret of the fact that its goal is zero incidents. "Safety first" is a pronounced culture on the North Slope. Although laudable, there is a danger that the pressure to reach the metric of zero incidents could result in driving reporting underground. This is particularly true if BPXA managers, and through them contract managers, are managing to the metric, as was occurring in CIC, rather than towards the goal of a safer workplace. BP is aware of this natural tension and actively manages it. *[The CIC manager]*, however, appeared to manage primarily to the metric rather than the goal of a safer workplace. *[The CIC manager]*, for example, told *[the AES manager]* that AES had better not "screw-up his safety record."[57] Other contractors felt that *[the CIC manager]* would pull their contract if the number of reportable HSE incidents rose.[58]

B. General contractor management issues

Many of the BPXA employees we interviewed stated that they personally feel comfortable reporting HSE issues, but that the same may not be true for contractors.[59] While we did not comprehensively interview employees from every contractor on the Slope, the information we did receive suggested, anecdotally, that contractor management may take BPXA's message of emphasizing safety to an extreme. For instance, a BPXA employee related an incident to us in which an employee of a contractor, VECO, was involved a vehicle accident with a BPXA employee.[60] The BPXA employee had bumped the vehicle of the VECO employee, and there was no damage. The incident was reported, and VECO management reportedly wanted to send the VECO employee off the Slope for a week without pay pursuant to its accident policy, even though it was not the employee's fault and there was no damage.

While we do not have firsthand verification of this story, it is merely an illustration of a perception that is very common on the Slope: while BPXA employees do not fear retaliation,

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[55] Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (July 27, 2004).
[56] Interview of *[name redacted]* (August 18, 2004).
[57] Interview of *[name redacted]* (August 24, 2004).
[58] Interview of *[name redacted]* (July 27, 2004).
[59] *See, e.g.*, Interview of *[name redacted]* (August 18, 2004); Interview of *[name redacted]* (July 28, 2004); Interview of *[name redacted]* (August 18, 2004); Interview of *[name redacted]* (August 24, 2004).
[60] Interview of *[name redacted]* (August 20, 2004).

some contractor employees do as a result of the actions contractor management has taken in response to BPXA's policy. As we learned through our interviews, these kinds of issues are present in the CIC group contractors AES and CANSPEC. Contract management in the CIC group is leery of losing their contracts if HSE recordables increase.[61] It should also be noted that contractor employees are negatively impacted when their companies lose a contract; while many may be rehired by the new company that gets the contract, that is not always the case, and there is substantial disruption even for the ones that get rehired.[62] Thus, threats of terminating a contract can cause significant concerns to employees.

A good example of the kind of pressures contractors are under is the events surrounding the Deadhorse clinic, which was one of the allegations we were asked to investigate. It was widely thought by both BPXA and contractor employees, within and without the CIC group, that contractors were sending their employees to the Deadhorse clinic to avoid reporting workplace injuries.[63] Sending employees to Deadhorse seemed to be a response to the pressure from BPXA management to reduce OSHA recordable incidents, which are considered to be more serious injuries. These contractors shared the view, which is widely-held among those we interviewed, that the BPXA clinic ordered unnecessary prescription medication or unnecessary medevacs, which automatically make an incident an OSHA recordable.[64] For instance, AES had a policy in the past that employees should go to the Deadhorse clinic, rather than the BPXA clinics, if they were injured but it was not an emergency situation.[65]

While we did not investigate the treatment decisions made by BPXA physician assistants ("PAs"), it was a common perception among contractors that their decisions created unnecessary OSHA recordable incidents, and several AES managers told us that the decision to avoid BPXA clinics was to allow them to manage the treatment of their employees without client "interference."[66] While this was the rationale for the policy, AES managers conceded that the policy was not explained well to employees, which may have confused them about the intention behind the policy and may have led them to believe that reporting injuries in general was being discouraged.[67] In fact, according to *[name redacted]*, who manages the Prudhoe Bay Field, injuries are reported whether the employee goes to a BP clinic or another clinic.[68] The sole difference is whether the treatment causes the injury to be an OSHA recordable, which is a metric BP carefully tracks because of its implications on safety.

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[61] Interviews of *[name redacted]* (August 24, 2004) and *[name redacted]* (July 27, 2004).
[62] Interview of *[name redacted]* (August 19, 2004)
[63] *See, e.g.,* Interview of *[name redacted]* (July 28, 2004);
[64] Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 24, 2004).
[65] Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (August 24, 2004).
[66] Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 24, 2004).
[67] Interview of *[name redacted]* (July 27, 2004).
[68] Telephone conversation with *[name redacted]* (September 29, 2004).

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AES has reversed its Deadhorse policy:

> Just to clarify a change to AES policy regarding the use of BPXA Medical Facilities, the following will be adhered to: AES personnel working on the BPXA lease are to use the BPXA medical facilities for all medical attention, regardless of nature or origin, at all times. The only exception to this is if an emergency dictates use of a closer facility, such as ConocoPhilips or the Deadhorse clinic.[69]

AES management attributed this change in policy to the fact that BPXA has replaced the contractor that is running the clinics and the new contractor, Beacon, does not have the same reputation for unnecessary treatment.[70]

C. CIC management and reporting issues

We believe that CIC management has encountered problems due to the aggressive management style of *[the CIC manager]*, combined with what are universally described as his extremely poor people skills. In fairness to *[the CIC manager]*, a number of individuals stated that he has improved in this regard[71] – but the lingering impacts of his past history contribute to the management issues that persist in CIC to this day. Indeed, even though *[the CIC manager]*'s personal skills have arguably improved, he still exercises extensive involvement in the operations of AES. *[The CIC manager]* is perceived to be much more involved in management of the contractors than other BPXA managers.[72] One former AES manger said *[the CIC manager]* was constantly threatening to not renew AES's contract.[73] This gives him significant control of CIC's operations and leverage over the contractors. Many persons we spoke to referred to CIC as *[the CIC manager]*'s "kingdom" and *[the CIC manager]* as "King *[name redacted]*." Criticism of *[the CIC manager]*'s management style is ubiquitous.

[The CIC manager]'s abrasive style is documented in the following e-mail to contractor management:

> Over the last few days BPXA has received a number of requests from [AES] for additional manpower on the North Slope to cover our current workload and a relatively small increment for the future. I am struggling to understand why

[69] Email from *[name redacted]* to *[name redacted]*; *[name redacted]* re: AES use of BPXA Medical Facilities (Aug. 9, 2004).
[70] Interview of *[name redacted]* (August 24, 2004).
[71] Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (July 27, 2004).
[72] Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 24, 2004).
[73] Email of *[name redacted]* to *[name redacted]* (June 30, 2003). We have tried to contact *[name redacted]* for a telephone interview and have been unsuccessful in repeated attempts to contact him.

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> [AES] thinks the response will be anything other than "NO!" or even "HELL, NO!" and therefore why we are being pestered with these requests.[74]

Similar views concerning *[the CIC manager]*'s management style were related to us by *[the CANSPEC manager]*, the current CANSPEC manager on site. *[The CANSPEC manager]* stated that *[the CIC manager]* has a very intimidating management style, and noted that approximately one-third of the CANSPEC employees do not raise issues because they fear either personal retaliation or loss of the contract.[75] *[The CANSPEC manager]* himself may well have contributed to these fears, as he explains BPXA's policy that all incidents should be reported to his employees, but also explains to them that HSE incidents may have the effect of losing the HSE contract, and tells the employees that they are intelligent people and can make the right decision.[76] *[The CANSPEC manager]* defended this message as simply being a realistic response to *[the CIC manager]*'s management, pursuant to which *[the CANSPEC manager]* believes the CANSPEC contract is in constant danger of being terminated by *[the CIC manager]* if HSE reportables increase. *[The CANSPEC manager]* also explained that BPXA management pressured him to strongly discipline a CANSPEC employee who had injured himself (a minor hand cut that required a few stitches); this pressure did not come from *[the CIC manager]*, but from another BPXA manager, *[name redacted]*, who stated in a formal "root cause analysis" meeting between BPXA and CANSPEC management to discuss this incident that the employee should be strongly disciplined.[77] It is likely that this incident is well known among CANSPEC employees and it cannot engender a strong desire to report incidents, notwithstanding BPXA policy. It should be noted, however, that a number of CANSPEC employees we spoke to stated that they did not have any concerns about reporting HSE incidents.

Indeed, *[the CIC manager]* sent an email instructing his managers to make sure that his employees stated that they were comfortable reporting any and all HSE issues through any and all means in connection with an upcoming visit by *[name redacted]* to the Slope:

> We need the very best HSE performance possible on this trip, in particular, anyone that *[name redacted]* talks to needs to say that they know they can, and do report any and all HSE concerns via any and all channels.[78]

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[74] Email from *[name redacted]* to *[name redacted]* et al. re: APC Requests for Additional Manpower (Dec. 6, 2001 9:17 AM).
[75] Interview of *[name redacted]* (July 27, 2004).
[76] Interview of *[name redacted]* (July 27, 2004). *[Name redacted]* specifically confirmed this statement during our interview.
[77] Interview of *[name redacted]* (July 27, 2004). This account was confirmed by *[name redacted]*'s assistant, who was also present at the meeting. Interview of *[name redacted]* (August 20, 2004).
[78] Email from *[name redacted]* to *[name redacted]* re: FYI: *[name redacted]*'s Slope Trip Next Week (March 30, 2004).

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While the text of this email is certainly amenable to the interpretation that *[the CIC manager]* was attempting to influence what the workers said, none of the workers we showed the email were concerned by it.[79]

Our assessment of the management situation in CIC is that the extreme aggressiveness of *[the CIC manager]* in pushing contractors to hit his chosen performance metrics (including HSE metrics) and the weakness of contractor management combined to create an environment that chilled reporting and caused some employees to fear retaliation, as illustrated most clearly by the chain of events surrounding HSE-1838.

D. Events leading up to HSE-1838 and the climate of intimidation in the coupon crew.

The current dysfunctional situation in the coupon crew is best understood as the culmination of past decisions and a culture where contractor management was intimidated by *[the CIC manager]*, and as a result did not manage their employees as well as could be hoped. In one case, contractor management affirmatively threatened a worker's job for being involved in filing a concern with the HSE Committee, although this threat was never acted on.

1. Single operatorship and the changes to the coupon crew

The genesis of these events comes from the consolidation of the east and west sides under a single operator on the North Slope, which began in 2000. During this transition, there was a major effort to "rationalize" the coupon-pulling program and the number of pulls was reduced, as corrosion engineers determined a number of coupon locations were producing unnecessary or redundant data.[80] At the same time, there were a number of changes to the work environment and activities of the coupon crew that engendered resentment on the part of the workers. This resentment was largely prompted by the decision to centralize CIC operations on the east side of the field, which required the workers who had been on the legacy BPXA side of the field to relocate to the east side.[81] This caused several sources of discontent, including the fact that the workers now had to drive longer distances in order to perform pulls on the west side. In addition, the workers had to equip themselves with twice as many coupon-pulling tools and valves given the differences in the field fittings on the two sides. The workers also had to move to less desirable accommodations on the east side of the field, where many employees had to share rooms (they had not had to before), and were no longer able to stay overnight at some of their pull locations, e.g., Milne Point. Finally, the coupon crew had to perform field-grading duties and enter data into the MIMIR system, tasks that were formerly performed by data entry

[9] *See e.g.*, Interview of *[name redacted]* (July 27, 2004).
[0] Interview of *[name redacted]* (August 24, 2004).
[1] *See, e.g.* Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 19, 2004);
nterview of *[name redacted]* (August 21, 2004).

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assistants.[82] This data entry function could be time consuming with little perceived benefit to the coupon crew, and engendered widespread frustration with MIMIR, which was in its early stages of implementation.[83]

The worker opposition was apparently perceived as bad enough by *[the CIC manager]* that he gave AES the authorization to fire the entire coupon crew and replace them with new workers,[84] a statement that AES management unfortunately chose to share with its workers.[85] That statement was widely known by many persons we interviewed.[86] The impacts of such statements by BPXA management, and the poor judgment of AES management in conveying such sentiments to their workers, helped to lay the groundwork for the hostile climate that was later to emerge in the coupon crew. In this environment, *[the CIC manager]* decided to reduce the size of the coupon crew, a decision that was a source of vocal discontent and opposition from the workers.

2. Reduction in staff from eight to six workers

It is not clear exactly what motivated *[the CIC manager]* to insist that the coupon crew be reduced from eight workers to six; during our interview of him, he told us that there was no budget pressure, as the CIC budget was increasing at this time.[87] It appears to have been driven by a metric he developed that total coupon pulls had been reduced by 25%, which he believed had to translate into a 25% reduction crew size. This change began as a suggestion from *[the CIC manager]* to *[name redacted]*, the AES manager:

> Here is a perfect example of where you no longer have the workload that you used [*sic*] yet the number of crew members is the same, if not slightly higher . . . The data clearly shows that the average number of pulls per month has decreased by 20-30% since 2000 . . . Given that we have 4 crews working (2 per week) we

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[82] Interview of *[name redacted]* (August 18, 2004).
[83] *See, e.g.,* Interview of *[name redacted]* (August 20, 2004), Interview of *[name redacted]* (August 19, 2004) and Interview of *[name redacted]* (August 21, 2004).
[84] While some sources contend that *[name redacted]*'s statement was made in the context of employees raising safety issues, as *[name redacted]* did in the text of HSE-1838, we do not believe that to be the case; this statement appears to have been made to AES management in the context of the worker opposition to consolidation of CIC operations and the increase in their duties. It was also not made in the form of an email as *[name redacted]* has suggested but evolved from a discussion with *[name redacted]* of options. *See* Interview of *[name redacted]* (August 24, 2004). *See* Interview of *[name redacted]* (August 19, 2004).
[85] *See*, Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 24, 2004).
[86] *See, e.g.,* Interview of *[name redacted]* (August 21, 2004).
[87] Interview of *[name redacted]* (August 24, 2004).

> could reduce this to 3[,] save 25% on the cost and should still be able to keep up with the workload based on 2000 performance.[88]

Some at AES questioned this data. In an email responding to *[the AES manager]*'s request for comments, *[name redacted]*, an AES supervisor, strongly criticized *[the CIC manager]*'s methodology and suggested that he was afraid to take his concerns to BPXA management:

> YES I would like to make Comments!!! I'm sure *[the CIC manager]* is smart enough to know these facts, but they don't help to bolster his case so he chooses not to use them. This is only a partial list, when *[name redacted]* gets here we will look at the numbers *[the CIC manager]* used.
>
> * * *
>
> In 2000 the EOA coupon crew had Data entry people (*[name redacted]* ...) Now they do all there [*sic*] own data entry.
> In 2000, the EOA crews didn't do any of the Shipping of the coupons.
> In 2000, the EOA crews didn't do any Field grading of the coupons.
>
> * * *
>
> In 2000, the WOA crews didn't loose [*sic*] 4 man-hours per day driving back and forth to there [*sic*] living quarters.
>
> * * *
>
> In 2000, we didn't have as many test sites as we do now.
> In 2000 we weren't supporting North Star
> In 2000 we didn't have L & V pads
>
> * * *
>
> I wrote an email to *[the CIC manager]*, *[name redacted]* and you, however before sending it, I decided, I still need a job! I think it is very unprofessional of *[the CIC manager]* to send out only part of the facts when, I'm sure knows better.
>
> <u>If *[the CIC manager]* want [*sic*] to honestly find out about productivity, We need to compare apples with apples.</u>[89]

[88] Email from *[name redacted]* to *[name redacted]* re: APC Coupon Crew Workload (May 30, 2002) (email has been reformatted for clarity).

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It is unclear if these specific objections were transmitted to *[the CIC manager]*. But *[the CIC manager]* explained that he had heard from *[the former AES manager]* that he did not agree with the 25% metric.[90] There were also regular meetings between *[the CIC manager]* and *[the AES manager]* on this and other issues. If *[the AES manager]* did not specifically raise *[name redacted]*'s comments, we believe it was because he was intimidated by *[the CIC manager]* or believed it would be futile given that *[the CIC manager]*'s suggestion was really a directive. *[Name redacted]* observed that during this period he suffered from guilt by association because he supported *[the former AES manager]* when his positions were legitimate and *[the former AES manager]* was not viewed by *[the CIC manager]* to be a "team player."[91]

The change from eight to six workers was important to *[the CIC manager]*. In our interview with him, he stated that while he began to focus on the issue in mid-2002, he became increasingly frustrated that he could not get the contractor to look into the issue until 2003. He talked with both *[the former AES manager]* and *[the AES manager]* about the issue, but because *[the AES manager]* was relatively new, *[the CIC manager]* relied principally on *[the former AES manager]*, who was resistant to change.[92] Therefore, in an email from early 2003 he emphasized that he had raised this issue in 2002 and wanted AES to look at it:

> As discussed, please find attached a chart showing the level of weight loss coupon pulls over the last few years. As can be seen from the chart, the average monthly pull rate has dropped from an average of 1000 per month in 2000 to ~750 per month in 2001/2002. Based on this trend, I requested [AES] look at the coupon crew level in mid-2002 - is 4 crews still appropriate given the reduction in work load, pull rate reduction, and in moving from twice weekly to weekly ER probe readings.
>
> It should be noted that the considerable variation in coupon pulls per months suggests that there is an opportunity to level the work load/schedule, more than is current practice.[93]

In this email, *[the CIC manager]* also provided a detailed list of items to be included in the transition plan for this change, including specific regimens for cross-training of AES employees, (which certain members of the coupon crew thought to be foolish because of the

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[89] Email from *[name redacted]* (APC) to *[name redacted]* re: APC Coupon Crew Workload (June 19, 2002) (emphasis in original) (some reformatting of email).
[90] Interview of *[name redacted]* (August 24, 2004).
[91] Interview of *[name redacted]* (August 23, 2004).
[92] Interview of *[name redacted]* (August 24, 2004).
[93] Email from *[name redacted]* to *[name redacted]* re: Corrosion Crew Transition from 4 to 3 (Feb. 2, 2003). The reference to "4 to 3" is to the number of crews; there are two workers on each crew, so this reduction was from eight workers to six. For consistency, we refer to the number of workers, rather than the number of crews, in this report.

physical barriers associated with coupon-pulling[94]), a specific implementation date and the following statement of "expectation": "The transition plan consists of clearly identified actions, dates, and deadlines so that individuals can be held accountable for implementation."[95] It seems clear from this email that *[the CIC manager]* was pushing for this change, and had definite ideas about what it should involve and how it should come about. At the same time, *[the CIC manager]* admits that his 25% reduction metric was "a raw number at a high level"; he did not, for example, consider issues about the fact that "not all pulls are equal," (depending on the locations and difficulties associated with eliminated pulls, there may or may not have been a 25% reduction in the time needed to do the reduced number of pulls).[96]

AES management proceeded with this plan; *[an AES supervisor]*, who succeeded *[the former AES manager]* and had no experience in pulling coupons, prepared the transition plan requested by *[the CIC manager]*. The change was to be implemented despite the objections of the coupon crew, who believed that the plan did not accurately describe the work issues involved in making this change.[97] Most notably it did not consider that coupon pulling was only part of the crew's workload (a recent analysis by *[an AES supervisor]* found that pulling coupons amounted to only 40% of the crew's workload), that time involved in coupon pulls varies dramatically from location to location, that consolidation greatly increased travel time to the west side pulls and that the new wells (e.g., L and V pads) and pulls were being added. Many of these concerns were raised as early as June 19, 2002 by *[name redacted]*'s email and went unheeded.[98] *[An AES supervisor]*'s draft transition plan made only passing reference to these issues:

> The purpose of the plan to transition the Corrosion Monitor Crew (CMC) from 4 crews of 2 to three crews of 2 stems from a reduction in Weight Loss Coupon (WLC) pulls per month over the last 2 years approximating a 25% reduction. While many other factors directly affect the workload/daily activities of the CMC, we believe at this time the transition can occur with success. Outlined below is a generalized plan for the transition, including completion dates. Responsible parties for all actions are *[an AES supervisor]* and *[name redacted]* (AES Supts).[99]

In the email transmitting this plan to *[the CIC manager]*, *[an AES supervisor]* stated "I will make any changes you feel are warranted."[100]

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[94] Interview of *[name redacted]* (August 20, 2004).
[95] *Id.*
[96] Interview of *[name redacted]* (August 24, 2004).
[97] Interview of *[name redacted]* (August 20, 2004); Interview of *[name redacted]* (August 21, 2004).
[98] If there was an email or other written response to *[name redacted]*, we have not seen it.
[99] Draft Transition Plan at 1 (attached to email from *[name redacted]* to *[name redacted]* (Feb. 2, 2002)).
[100] *Id.*

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The MOC briefing prepared by BPXA CIC managers does not address these other tasks, and justifies the change based on the purported reduction in number of pulls:

> The proposed reduction in coupon crew from 8 FTE to 6 FTE reflects the reduction in work scope resulting from the rationalization of the coupon program between the heritage East and West operating areas at Greater Prudhoe Bay. In moving from 8 to 6 FTE the intent is simply to return the workload to that seen in 2000, there is no significant increase in expected work load or activity on the basis of pulls per crew per day.[101]

While this briefing suggests that AES was requested to look into the issue – "[AES] have been asked to review the present 8 FTE coupon crew to determine whether the crew man-power level can be reduced by 25%,"[102] an email suggests that this was less a request and more of a directive:

> One other thing, we need to get commitment from AES (*[the AES manager]*), that they will commit to make this successful, versus just doing what we request and expressing doubt.[103]

And the MOC Briefing does not acknowledge concerns regarding the potential coupon backlog:

> The current coupon pull backlog is zero. A zero coupon backlog is the normal mode of operation, as can be seen from the data below in the second-half of 2002 there were only 2 weeks with a non-zero backlog.[104]

This focus on the second half of 2002 is curious, given that *[the CIC manager]* had made much of the backlog problem in an email sent to AES in the first half of 2002:

> Please hold a crew over and get caught-up by the 1st week of March, however, in agreeing to this I am expecting a more pro-active management of the coupon program by [AES] for the future. *[Name redacted]* et al have significantly reduced the coupon program over the past 12 months and in the years prior for that matter and have reduced the workload by moving to RDC as opposed to manual readings, yet we continue to run into these backlog issues . . . If the backlog moves back-up over 50 or so, or you ask me to hold over crews to keep

[101] Organizational MOC Briefing: APC Corrosion Monitoring Crew Staff Reduction at 3 (attached to email from NSU, CIC TL to *[name redacted]* and *[name redacted]* re: CIC MOC (March 22, 2003)).
[102] *Id.* at 2.
[103] Email from *[name redacted]* to *[name redacted]* and *[name redacted]* re: CIC MOC (March 22, 2003)
[104] Organizational MOC Briefing: APC Corrosion Monitoring Crew Staff Reduction at 3 (attached to email from NSU, CIC TL to *[name redacted]* and *[name redacted]* re: CIC MOC (March 22, 2003)).

> up with the workload I am going to want to know why and the answer better be a good one![105]

By way of comparison, after 18 months of the coupon crew being reduced to 6, the backlog exceeds 180 pulls as of August 23, 2004.[106]

It seems clear from these documents that *[the CIC manager]* had decided that the reduction in coupon pulls should lead to a reduction in force on the coupon crew, and he was not inclined to listen to dissenting views. Crew members accurately predicted that it would result in a significant increase in the backlog. We were informed by an AES manager that even though the first audit of the MOC showed that the change was successful, a more recent one may show a different result.[107]

[The CIC manager] contends that "it was a wise decision still to reduce the crews." He states that in addition to telling the contractor to "figure out how to do it," he also claims that he told them to incorporate into the plan "how they'll unwind it if it doesn't work." While the MOC and the other documentation connected with the crew reduction refer to the fact that "(a)n overall contingency plan will be in place if the change isn't successful," the documentation refers to such measures as borrowing other workers or holding over crews but nowhere suggests that it was being done on a trial basis, or that returning to 8 crew members was an option.[108] In any event, *[the CIC manager]* states that "he doesn't remember what would be the exit plan, or what criteria would trigger it."[109]

Recall that during the period of implementation of the crew reduction, *[the CIC manager]* continued to press AES management to make the reduction. *[The former AES manager]*, who opposed it, was in his belief "run off" the North Slope by *[the CIC manager]*.[110] *[The former AES manager]*'s belief was widely held among the coupon crew.[111] Moreover, in discussions with *[the AES manager]*, *[the CIC manager]* gave *[the AES manager]* permission to get rid of the whole crew if they did not stop complaining about the changes.[112] *[The AES manager]* conveyed this threat to *[name redacted]* and *[an AES supervisor]*, who replaced *[the former AES manager]*, and the crew learned of this.[113] *[The AES manager]* stated that he also

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105 Email from *[name redacted]* to *[name redacted]* (APC) et al re: Coupon Pull Backlog Plan (February 10, 2002).
106 Interview of *[name redacted]* (August 23, 2004).
107 Interview of *[name redacted]* (July 29, 2004).
108 Organizational Management of Change Process, "APC Corrosion Monitoring Crew Staff Reduction" (March 2003)
109 Interview of *[name redacted]* (August 24, 2004).
110 Email from *[name redacted]* to *[name redacted]* (June 30, 2003).
111 Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (July 27, 2004).
112 Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 24, 2004).
113 Interview of *[name redacted]* (August 21, 2004); Interview of *[name redacted]* (August 23, 2004).

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told two crew members, including *[the CIC worker]*, in February 2003 that he had this authority.[114] It is in this atmosphere that HSE-1838 developed.[115]

3. HSE-1838 and subsequent events

On March 4, 2003, *[the concerned BPXA employee]*, a BPXA PACE employee not assigned to CIC, submitted HSE Concern No. 1838 ("HSE-1838") to the HSE Committee. The HSE Committee is made up of employees and managers and attempts to resolve any HSE concerns raised by individual employees. While the HSE Committee allows employees to submit concerns anonymously, typically employees submit their names. The HSE Committee meets weekly and discusses the "concerns" raised by anyone. When new concerns are brought up, one or more persons on the committee volunteers to work them. Typically, HSE concerns are worked by the investigating committee members until they reach closure with the originator of the concern. In the case of HSE-1838, the committee members responsible for investigating are *[name redacted]*, the Area Manager for GC-2, and *[name redacted]*, a PACE electrician.[116]

[The concerned BPXA employee] submitted this concern on behalf of anonymous employees from the coupon crew because he claimed the employees involved feared to raise their concerns. *[The concerned BPXA employee]* is considered by some employees to be an advocate of safety issues, although a number of persons indicated that *[the concerned BPXA employee]* does not always get his facts right.[117]

HSE-1838 reads as follows:

> The corrosion monitoring crew will soon be reduced to 6 staff down from 8. Their duties include pulling corrosion coupons and working with other crews such as the chemical crew when requested. They now pull over 5800 coupons per year averaging 6 to 8 per day. The total number of pulls was recently reduced, but new wells on S, L, V and W pads and recently repaired wells on H-pad actually added 32 coupon pulls. H-pad wells were added after the blowout of the S-riser on the H21 well, which resulted in a spill, fortunately there were no injuries. The failure

[114] Interview of *[name redacted]* (August 24, 2004).
[115] Some of the factors contributing to the filing of HSE-1838 and the allegations in this matter are similar to those factors underlying the concerns about operational integrity identified and addressed in the ORT Report. There, management had "not effectively communicated how workers' concerns have been included in decision-making processes hence trust in management has eroded." ORT Report pp. 5, 9. In the present matter, contractor employees' concerns were ignored. This is at odds with one of the recommendations of the ORT Report that management "works with employees to develop both short and long term solutions to their staffing level concerns." *Id.* at 7. As in both matters, the failure to resolve workers concerns results in some workers choosing to raise their concerns outside the company. *Id.* at 9.
[116] Interview of *[name redacted]* (July 28, 2004); Interview of *[name redacted]* (August 18, 2004).
[117] *See, e.g.*, Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (July 28, 2004).

> was encouraged by BPXA management's decision to reduce monitoring and chemical injection of the H-pad wells because the chemical injection fittings were not in the best location for injection. Management decided to run without injection or monitoring for an unspecified period of time (run-to-failure), until the injection points could be modified. The number of pulls per day can be reduced when workers encounter poor weather conditions, frozen wells, new recording duties and travel time to distant worksites. Coupons: WOA 200+ every 3 to 4 months, EOA 200+ every 3 to 4 months, Endicott 97 every 3 months, Milne 100 every 4 months, NorthStar 35 every 3 months. With the present staff, the crew is currently 1 month behind. The backlog is expected to increase with a further reduction in manpower. To reduce the staff workload, it was suggested by BPXA management to not rebuild the pulling equipment as often, rebuild the equipment on site in the workers van to reduce down time and possibly not pressure test the equipment. The worker's van does not have pressure test equipment installed. This obviously would increase the potential for equipment failure resulting in equipment damage, environmental spills and injury to workers. The workers are exposed to pressures of up to 2000# and average pressures of 400# to 1500#. BPXA management has requested the pull rate be increased to 17-18 per day. Pressure has been applied to the workforce to comply. The workers have communicated their concerns, but have not received relief. One statement from BPXA management to the APC management was "I give you permission to get rid of the entire crew and hire a new crew. We will have a learning curve and it will take time to train the new employees, but we will be able to handle it." The reduction in manpower and increase in workload is BPXA management's attempt to cut costs to increase profit. The workers have not received improvements in equipment, time, help or conditions to help meet these goals. The workers will continue in their current positions because they are trying to make a living. They are afraid their jobs are now in jeopardy because they have spoken up. The workers do not know I am sending this communication to you. They are afraid to take their concerns any further.

HSE-1838 came as a surprise to *[the CIC worker]*, who stated that he did not know *[the concerned BPXA employee]* was going to file the concern with the HSE Committee, and certainly not so quickly (although he stated that he anticipated that *[the concerned BPXA employee]* was going to make it public somehow).[118] *[The CIC worker]* stated that he has known *[the concerned BPXA employee]* for years and they discussed complaints leading to HSE-1838 over meals and during work over a one-to-two week period. During that time, vestiges of a CIC shop remained on the west side, and *[the concerned BPXA employee]*'s shop was next door. *[The CIC worker]* stated that *[name redacted]* may have been present during some of the

[118] Interview of *[name redacted]* (August 19, 2004).

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conversations. *[The CIC worker]*'s complaints primarily centered on the crew reduction and were last discussed with *[the concerned BPXA employee]* over lunch on Monday, March 3, 2003. According to *[the CIC worker]*, HSE-1838 went out on Tuesday.[119]

AES contract management reacted very poorly to HSE-1838, perhaps based on their view that *[the CIC worker]*, who they suspected was involved in drafting HSE-1838, was a frequent complainer (a view shared by some of *[the CIC worker]*'s colleagues).[120] In any event, *[name redacted]*, the AES manager, told *[an AES supervisor]*, *[the CIC worker]*'s supervisor, that he wanted to fire *[the CIC worker]* for being involved in filing HSE-1838.[121]

When *[an AES supervisor]* went to speak on Wednesday morning to *[the CIC worker]* about HSE-1838, *[name redacted]*, another member of the crew, was in the room, and *[an AES supervisor]* asked *[name redacted]* to leave so he and *[the CIC worker]* could speak alone.[122] *[The CIC worker]* stated that *[an AES supervisor]* was agitated when he made this request, and then threw down HSE-1838 on the desk, which was the first time that *[the CIC worker]* had seen it.[123] According to *[the CIC worker]*, *[an AES supervisor]* stated that "*[the AES manager]* wants somebody fired over this" and that he also said that he had calmed *[the AES manager]* down, but *[the AES manager]* had wanted to fire *[the CIC worker]* and that AES was going to lose the contract.[124] According to *[the CIC worker]*, *[an AES supervisor]* talked to *[the AES manager]* on his cell phone while *[the CIC worker]* was outside the room. After this conversation, *[an AES supervisor]* told him not to worry, that "*[the AES manager]* has calmed down and things will probably be okay."[125]

Obviously, the initial desire of *[the AES manager]* to fire *[the CIC worker]*, the decision to confront *[the CIC worker]*, and *[an AES supervisor]*' decision to share *[the AES manager]*'s remarks with *[the CIC worker]*, were major errors of judgment by both AES managers. It should be noted that AES management did not carry out *[the AES manager]*'s threat, and *[the CIC worker]* advised us that he was never in fear for his job.[126]

[An AES supervisor] told *[the CIC worker]* that he believed there were a number of factual errors in the HSE-1838 filing, and *[the CIC worker]* agreed with this. *[The CIC worker]* also told *[an AES supervisor]* that he wished *[the concerned BPXA employee]* had given him a

[119] *Id.*
[120] Interview of *[name redacted]* (August 18, 2004).
[121] Interview of *[name redacted]* (August 23, 2004).
[122] *Id.*
[123] Interview of *[name redacted]* (August 19, 2004).
[124] *[Name redacted]* stated to us that he did not think it was appropriate to fire people over an HSE concern, and that he was particularly surprised to hear this from *[name redacted]*, who used to be the safety person on the corrosion team.
[125] *Id.*
[126] Interview of *[name redacted]* (August 19, 2004).

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draft before filing the concern.[127] In our discussions with *[the CIC worker]*, he identified numerous errors in the HSE-1838 allegations including these principal ones:

- The statement that chemical injection was discontinued at H-21 was wrong.
- *[The CIC worker]* had never heard about the idea of "run-to-failure" and had never discussed this with *[the concerned BPXA employee]*, or anyone else.
- The estimate of 200 pulls every three to four months on the Western Operating Area was incorrect. That is the figure for every month. The same is true for the 200 pulls every three to four months figure for the Eastern Operating Area.
- BPXA never suggested that the coupon-pulling equipment not be rebuilt as often, and not be pressure tested. *[The AES manager]* of ASRC had asked the crews whether it was necessary to rebuild the equipment every 6 months, and whether it could be pressure tested in the trucks.[128] In fact, the equipment is routinely rebuilt more frequently, and is pressure tested in CIC's shop.
- *[The CIC worker]* was not sure where the statement that BPXA management asked the crew to increase the pulls to 17 or 18 per day had come from, and he had never said it.
- *[The CIC worker]* was not sure if pressure had been applied to the workforce to comply with increased pulling requirements; pressure was applied to perform the new responsibilities that were being placed on the coupon crew, e.g., MIMIR data entry, by *[the CIC manager]*'s ultimatum to fire crew if they didn't do them.
- As noted above, *[the CIC worker]* also said he did not fear he would lose his job.

[The CIC worker] observed that *[the concerned BPXA employee]* did not take notes when he explained corrosion issues to him, which may explain the inaccuracies in HSE-1838.[129]

[An AES supervisor] asked *[the CIC worker]* to withdraw HSE-1838 from the HSE committee, until the factual errors could be corrected, which *[the CIC worker]* agreed to do. *[The CIC worker]* waited until *[an AES supervisor]* left the office, and then called *[the concerned BPXA employee]* at home to ask him to withdraw the concern, which he did. While *[the concerned BPXA employee]* has alleged that *[an AES supervisor]* monitored this call,[130]

[127] *Id.*
[128] To put *[name redacted]*'s suggestion in context, crews working on the east side before consolidation had been pressure testing and rebuilding their equipment in the field or their trucks. Interview of *[name redacted]* (August 21, 2004). The crews working on the west side were not doing this. Interview of *[name redacted]* (August 22, 2004).
[129] *Id.*
[130] Interview of *[name redacted]* (July 23, 2004).

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both *[the CIC worker]* and *[an AES supervisor]* deny this.[131] We believe that *[the concerned BPXA employee]* is in error on this point and misunderstood *[the CIC worker]*, who explained to us that he told *[the concerned BPXA employee]* that *[an AES supervisor]* had been in the room with him at one point.[132]

[The concerned BPXA employee], believing that *[the CIC worker]*'s job was in jeopardy – and there is no dispute that it was threatened by *[the AES manager]* at one point – contacted *[name redacted]*,[133] who is the PACE HSE representative on the HSE Committee, to ask for the withdrawal of the concern.[134] According to *[the CIC worker]*, *[the concerned BPXA employee]* never asked him why he was trying to withdraw the HSE concern, and *[the CIC worker]* thinks that *[the concerned BPXA employee]* knew without asking that there had been some pressure.[135] But there was no specific discussion of this issue. The HSE Committee initially agreed, but later was told by BPXA management that the issue needed to be investigated due to the allegation of a threat of retaliation.[136]

As one of the HSE Committee members working HSE-1838 indicated, the allegations of retaliation made this very different than the typical HSE Committee issues; as a result, when they learned that *[name redacted]*, an outside consultant for BPXA who investigates worker HSE complaints, was investigating the issue, they basically stopped their efforts.[137] Based on his efforts, and the fact that BPXA management instituted harassment training to address the issue of retaliation, *[name redacted]* concluded that the issues had been resolved and *[name redacted]* informed *[the concerned BPXA employee]* of this.[138]

[The concerned BPXA employee], however, was not convinced, and continued to argue that the issues raised in HSE-1838 had not been resolved.[139] Thus, the two HSE Committee investigators, *[name redacted]* and *[name redacted]*, continued to work the issue. *[Name redacted]* attempted to get the situation with *[the concerned BPXA employee]* to closure, but was unable to.[140] *[Name redacted]* was reluctant to close the HSE concern until he had an opportunity to address some of the safety-related issues implicated by the concern. He has now

[131] Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (July 29, 2004).
[132] *Id.*
[133] We were not able to schedule *[name redacted]* for an interview while we were on the North Slope. We called him from Anchorage and requested that he agree to a telephone interview by us, but he did not feel comfortable speaking by telephone. He would agree to an in-person interview, if a PACE steward was present, but this could not be arranged.
[134] Interview of *[name redacted]* (July 23, 2004).
[135] Interview of *[name redacted]* (August 19, 2004).
[136] Interview of *[name redacted]* (July 23, 2004).
[137] Interview of *[name redacted]* (August 18, 2004).
[138] *See* email from *[name redacted]* to *[name redacted]* re: FW: HSE Concern #1838 Corrosion Staff issues (August 30, 2003).
[139] *See* email from *[name redacted]* to *[name redacted]* re: MOC for Crew Changes (September 10, 2003).
[140] Interview of *[name redacted]* (July 28, 2004).

done so, and made a number of suggestions to improve safety in this work, which apparently were well-received by BPXA CIC management.[141] However, because *[the concerned BPXA employee]* remains unconvinced that the issues are adequately resolved, the decision whether to close HSE-1838 remains at a standstill.[142]

[Name redacted] stated that he believed that while the workers have not actually been retaliated against, some of them fear retaliation due to the way HSE-1838 was handled, and even if these concerns are not entirely valid, they will probably never be entirely put to rest.[143]

4. Overtime issues and perceived retaliation

In light of the crew reduction and the typical backlog associated with the harsh winter weather conditions, in July of 2003 *[an AES supervisor]* approved a 17-hour per day schedule for the coupon crew, which included 6.5 hours of voluntary overtime, in order to catch up with the backlog.[144] It is worth noting that the MOC completed only a few months before concluded that the reduction would not cause a backlog.[145] While some of the employees told us that they liked having this much overtime, *[name redacted]*, an AES supervisor, determined that this schedule was too demanding and limited the overtime to 4.5 hours a day, as reflected in his change-out notes:

Subject	Author	File Code	Date	[illegible]
Reduced Corrosion Monitoring hours	*[name redacted]*	Corrosion Monitoring Info.	8/14/2003	I have reviewed the Corrosion Monitoring hours, I know *[the AES manager]* wasn't happy about the crews working back-to-back 17's. I got a copy of Kupruak's [*sic*] policy, they won't let employee's work more than a 15 hour day on a consecutive basis. Based on that policy I reduced the C.M. daily hours to 15 per day. I feel like this is a reasonable amount on a continuous basis, however, I have told the crews if they feel they are getting run down to take a day off.

[141] Interview of *[name redacted]* (August 18, 2004).
[142] *Id.*
[143] Interview of *[name redacted]* (August 18, 2004).
[144] Interview of *[name redacted]* (August 23, 2004).
[145] Organizational MOC Briefing: APC Corrosion Monitoring Crew Staff Reduction at 3 (attached to email from *[name redacted]* to *[name redacted]* and *[name redacted]* re: CIC MOC (March 22, 2003)).

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Later, *[the concerned BPXA employee]* appears to have raised some concerns regarding the 17-hour days the crews had been working (an issue that AES management had already addressed). He wrote in a September 10, 2003 email to *[name redacted]*, who was investigating HSE-1838, that:

> BPXA has yet to operate with the planned reduced staff. The current staff are working 17 hour days and other workers from other groups are staying over on their off shift to keep up. The plan does not work, it creates stress and overworks the workers.[146]

BPXA CIC management did not agree with this assessment, believing that the overtime was the result of factors other than the crew reduction, which were coming under control:

> A corrosion monitoring crew lead broke his arm the first week of June and just got back to work yesterday[.] His position was backfilled by having other crew members work extra time[.] The crews have put in overtime over this summer. Contributing factors: Injured crew member[;] Special projects which have now tapered off and we are going to control better and ensure focus is on core work[;] Smart Pigging campaign manpower support[.][147]

[The concerned BPXA employee] noted in a December 30, 2003 email to *[name redacted]* that the coupon crew was still working overtime. A directive came from BPXA management that the coupon crew was not to work overtime, in light of the concerns being raised by *[the concerned BPXA employee]* and others. The AES supervisor's change out notes document this directive:

Subject	Author	File Code	Date	Notes
No more overtime for the Corrosion crew	*[name redacted]*	Corrosion Monitoring Info.	1/5/2004	I was told *[the concerned BPXA employee]* has written another letter to *[name redacted]* and *[name redacted]*, stating one of the corrosion monitoring has complained about working overtime to try to keep up with the schedule. *[Name redacted]* said he didn't [*sic*] them working overtime and he wanted us to hold to a strict 6 man crew, no pulling them off to do other things.

146 Email from *[name redacted]* to *[name redacted]* re: MOC for Crew Changes (Sept. 10, 2003).
147 Email from *[name redacted]* to *[name redacted]* and *[name redacted]* re: FW: MOC for Crew Changes (Sept. 11, 2003).

Note: redactions indicated in italic text in brackets

This overtime decision was conveyed to the crew by *[an AES supervisor]* at a toolbox meeting. *[An AES supervisor]* was frustrated by the complaints regarding overtime because he had argued for allowing the crew to work the overtime, felt that he was blindsided and was being criticized by management; he expressed this frustration to the crew.[148] He told the team overtime was rescinded because of safety criticism of the number of overtime hours. Sometime after the original overtime cut-off, he was able to get the crew 1.5 hours of overtime daily if it could be tied to valve work and not coupon pulling, but *[the CIC manager]* and *[name redacted]* discontinued this overtime a few months ago.[149]

We should add that most of the workers on the coupon crew were very happy with the overtime.[150] As a general matter, overtime is something that the workers want to have, because it allows them to make as much money as possible during their time on the Slope, where there is little else to do.[151] Given this reality, the coupon crew was displeased with the decision to eliminate overtime and viewed it as retaliation for the concerns raised by some of the workers – particularly in light of *[an AES supervisor]*'s comments, which may have supported this perception. Both BPXA and AES management stated that this decision was not retaliation, as it was necessary to stop the overtime while assessing whether it presented a safety issue.[152]

In addition, *[the CIC worker]* was understood by many to be the person on the crew who was complaining about the overtime being worked. Both AES and BPXA management understood that the decision to no longer permit overtime could potentially cause worker-to-worker harassment directed at *[the CIC worker]*, and explained that they took steps to prevent this.[153] Based on our discussions with the coupon crew, it does not appear that such worker-to-worker harassment occurred. *[Name redacted]*, who was formerly on the coupon crew and was on the Slope at the time the decision was made, called *[the CIC worker]* at home to get an explanation for what had happened. But both men described this call as cordial.[154] *[The CIC worker]* said that he has not been harassed because the overtime was cut off.[155]

It is our understanding that AES may have persuaded BPXA management to begin allowing some overtime for the coupon crew again and discussions are ongoing about adding a crew member.

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[148] Interview of *[name redacted]* (August 23, 2004).
[149] *Id.*
[150] *See, e.g.*, Interview of *[name redacted]* (August 20, 2004).
[151] *See, e.g.*, Interview of *[name redacted]* (August 18, 2004).
[152] Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 24, 2004); Interview of *[name redacted]* (August 24, 2004).
[153] Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 24, 2004); Interview of *[name redacted]* (August 24, 2004).
[154] Interview of *[name redacted]* (August 19, 2004); Interview of *[name redacted]* (August 20, 2004).
[155] Interview of *[name redacted]* (August 19, 2004).

5. Current situation in the coupon crew

Based on our interviews with the coupon crew, there are several employees who fear reporting HSE issues because of potential retaliation. This is not surprising, given that an AES manager, *[the AES manager]*, stated that he wanted to fire *[the CIC worker]* for being involved in raising HSE-1838, and this threat is known by the entire crew, as well as workers in CIC outside of the crew. While that threat was never carried out, and it is unclear to what extent, if any, *[the CIC worker]* was ever actually retaliated against, it should come as no surprise that workers, whose livelihoods depend on their work, would be intimidated by the threat alone, whatever happened later. Also they believe *[the former AES manager]* was run off and *[the CIC manager]* gave AES permission to fire the entire crew. Finally, overtime was eliminated, which some crew members tie directly to raising a safety issue, and the total elimination of overtime in the face of an expanding backlog caused some to view it as being punitive. Such actions are not easily undone, once done; it seems likely, as a BPXA employee who investigated HSE-1838 told us, that these fears will probably never go away completely, even if they are not entirely valid.[156]

E. Conclusions regarding harassment

[The CIC manager]'s management style has created a negative atmosphere within CIC that led to widespread employee discontent within the coupon crew and the HSE-1838 concern. Because of frustrations associated with trying to implement *[the CIC manager]*'s directives, AES management made inappropriate comments to the coupon crew (e.g. *[the CIC manager]* has given us permission to fire the whole crew), which, coupled with *[the AES manager]*'s response to HSE-1838 ("fire *[the CIC worker]*"), which is well known within and outside the coupon crew, created a chill in the workplace. This was exacerbated by the handling of the overtime issue, which reinforced in some workers' minds that raising HSE concerns can only lead to problems. On a more general level, *[the CIC manager]*'s message (and possibly that of other BPXA managers across the North Slope) to contractor management to make the HSE incident metrics look good or else face possible loss of their contract creates a tension between reporting all incidents (BPXA's policy) and driving reporting underground. This problem may be more acute in the CIC group, as AES has only a one year contract, and as a result AES management perceives *[the CIC manager]* to have considerable leverage over AES.[157] CANSPEC management also feels intense pressure.[158]

ALLEGATIONS REGARDING FRAUD IN THE CIC PROGRAM

Nothing we learned in our investigation suggests that the field is, as a general matter, unsafe or prone to catastrophic failure. This does not mean from time to time there will not be

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[156] Interview of *[name redacted]* (August 18, 2004).
[157] Interview of *[name redacted]* (August 24, 2004).
[158] Interview of *[name redacted]* (July 27, 2004).

incidents given the age of the field and the many miles of piping, despite BPXA's best efforts. Based on our review of the specific allegations raised regarding the corrosion program, it does not appear that the allegations regarding fraud in the CIC program are correct. What we discovered, however, is that while the allegations of data fraud in the corrosion program were not accurate, they contain enough factual content that, when heard by employees at second- or third-hand, was enough to convince some individuals that the allegations had substance. These concerns are also animated in part by the negative atmosphere existing among workers in parts of the North Slope and the fact that there have been major, relatively recent incidents on the North Slope – for instance, the H-21 blowout, the Y-36 spill, and the A-22 explosion. Contributing as well are other field conditions, such as the failure to re-insulate pipe after external corrosion inspections and an apparent preference by Operations to derate, rather than replace, problem pipe, which suggests to some that significant problems are not being addressed.

Our review of documents and interviews of witnesses suggested the origin of these allegations and why they had become concerns to individuals like *[the concerned BPXA employee]*. This section of the report summarizes the key allegations regarding the CIC program and provides our conclusions regarding them. While we found no evidence of falsification or other forms of corruption in the corrosion program – indeed, as noted above, everyone we spoke to with full knowledge of the scope of the program lauded it as technically excellent – our review in no way reached the level of detail that would be obtained by a comprehensive audit of the corrosion program's data system. As a result, in our recommendations below, we advise BPXA to consider performing a thorough audit of the corrosion program's data system. We understand that no such audit has yet been performed,[159] and given the number of changes to the corrosion program in recent years, including most significantly the implementation of MIMIR, such an audit appears advisable. Moreover, given the critical importance of this program to the future of BPXA's operations, such an effort appears prudent in any event.

This section begins by explaining some of the conditions and events at the field that have led to the perception among some workers that the field is unsafe. It then turns to the specific allegations regarding the corrosion program.

I. General condition of field

As a threshold matter, it is generally perceived by interviewees that there are inherent dangers involved with the production of oil on the North Slope that contribute to the perception of risk. The operations at Prudhoe Bay involve thousands of segments of piping and other equipment, many of which are under pressure and are exposed to corrosive and erosive elements

[159] Interview of *[name redacted]* (August 24, 2004).

and, consequently, could fail. Moreover, the field is now 27 years old and there is a belief that in the mid-90s the field was not well maintained as BPXA was evaluating its useful life.[160]

The failure of H-21 is also a well-known failure. A former BPXA CIC manager, *[name redacted]*, made the decision to stop monitoring the corrosion coupons at a number of wells, including H-21, because the coupons were located upstream of the chemical injection point and thus did not give useful data on the effectiveness of the corrosion inhibitor. Although the H-21 incident was primarily caused by failures in the inspection program, continuing to monitor the H-21 coupon might have provided some additional early information regarding the corrosion that caused the failure.[161] Such monitoring may have prevented the incident because it could have caught the corrosion that was missed by the inspection program, which had inspected the pipe before the incident, but did not examine the section of the pipe that blew.[162] *[The CIC manager]* candidly admitted that this was a "program failure," and the approximately 30 wells similar to H-21 had their injection points relocated and were inspected, which should prevent future problems.[163] But when an incident like H-21 occurs – where the decision to stop monitoring might be perceived to have contributed, in at least some measure, to a pipe failure – it is natural for workers and other observers to raise questions and concerns regarding monitoring decisions at other locations, including the decisions to discontinue many coupon pulls and to expand the intervals between other pulls over the last few years. It is events like this that, in our view, drive many of the suspicions concerning the effectiveness of the corrosion program and the specific corrosion allegations we investigated.

Such concerns are magnified by some of the decisions made regarding facility management. For instance, rather than replacing pipe, Operations often opts to derate the pipe. Derating a pipe is a formal procedure used to ensure that operating pressures are not increased to a level that is unsafe because of corrosion.[164] While this practice may be appropriate from a technical and business standpoint, it causes concerns on the part of some employees, who hear that a certain pipe is "not fit for service", but remains in service. "Not fit for service" simply means that the pipe is not fit at a certain operating pressure and flow rate. Once derated, the pipe is again fit for service, but to some employees, once a pipe is unfit, it is bad pipe that should be replaced; hence the belief by some that the field has a lot of bad pipe. Similarly, the fact that insulation is not replaced in numerous places where corrosion inspections have been done contributes to concerns about the quality of maintenance and integrity practices. This issue may well be one of perception, rather than reality, because there may be excellent technical reasons underlying the decision to manage a given corrosion issue through derating.[165] ; but these

[160] Interview of *[name redacted]* (August 18, 2004).
[161] Interview of *[name redacted]* (August 24, 2004).
[162] Interview of *[name redacted]* (August 24, 2004); Interview of *[name redacted]* (July 27, 2004).
[163] Interview of *[name redacted]* (August 24, 2004).
[164] Telephone Conversation with *[name redacted]* (October 11, 2004).
[165] Telephone Conversation with *[name redacted]* (October 11, 2004).

perceptions if not addressed, can lead to the kinds of problems that occurred in the HSE-1838 context.

II. Specific allegations regarding the CIC program

Given the nature of these allegations, which are very fact- and incident-specific, we will address each of the major allegations in turn. Appendix 1 to this report summarizes the allegations we knew of at the time of the investigations, and explains our views on each of them.

Workers are pressured to falsify corrosion monitoring reports. One method was to send the contract crews to monitor and report on known lines with little or no corrosion to dilute the overall findings of corrosion.

The individuals we spoke to uniformly stated that they had not been pressured to falsify data in this way. The corrosion crew workers stated that they were not involved in falsification of coupon reports, and that given the nature of their duties, it would be impossible for them to do so.

We believe this allegation may have emerged the concerns, like those expressed to us by one of the CANSPEC technicians we spoke to, that the inspection crews spend a significant portion of their time monitoring lines and inspection points that have repeatedly been proven to be in good condition.[166] Similarly some coupon crew members observed that certain coupons were regularly pulled and showed no corrosion. As a technical matter, there may be good reasons for such monitoring, and the workers we spoke to acknowledged that these areas of good lines are monitored less frequently than the lines that are in worse condition.[167] Another CANSPEC employee informed us that they have discretion in selecting inspection points while at certain facilities – and, in such cases, the technician tries to find the points of maximum corrosion.[168] We were told repeatedly by workers in the inspection and coupon crew that everyone looks for corrosion; it justifies their jobs.[169] Still, this allegation illustrates what can happen when workers do not understand the reasons underlying decisions made regarding corrosion monitoring.

It is also alleged that the worst data are pulled from the reporting for the same purpose.

No one we spoke to thought that bad data was being dropped from the system.[170] According to the individuals we spoke to, the MIMIR system maintains an audit trail that logs changes to the system and identifies who made them. In addition, MIMIR is a limited access

[166] Interview of *[name redacted]* (July 27, 2004).
[167] Interview of *[name redacted]* (August 20, 2004).
[168] Interview of *[name redacted]* (August 19, 2004).
[169] *Id.*
[170] *See, e.g.,* Interview of *[name redacted]* (August 23, 2004), Interview of *[name redacted]* (August 19, 2004).

system, where most employees have limited privileges to remove or alter data.[171] The exceptions are *[name redacted]*, who runs the system, and *[the CIC manager]*, both of whom have unlimited access.[172] According to individuals familiar with MIMIR, falsification of data in the manner alleged would require the cooperation and conspiracy of numerous Anchorage-based corrosion engineers and managers, which seemed very unlikely to most.[173] The only person making this allegation was *[the concerned BPXA employee]*, who claimed he knew BPXA employees in Anchorage who would validate this theory. He did not give us the names and we were not able to find any support for his claims.[174] In addition, several individuals stated that there would not have been any motivation to engage in such fraud, since all it would do is guarantee a pipe failure at some point in the future, and the costs of responding to the failure would far outweigh any short-term benefit associated with making the field condition look better than it is.[175] For example, over $1 million was spent in cleaning up the Y-36 spill alone.

Again, however, there are a number of facts that suggest the origin of this allegation. During the MIMIR implementation, the legacy ARCO and BPXA databases needed to be combined. This process required "data scrubbing" to make the data fit the new format. In addition, due to the differences between the old systems, not all of the same information is available for every "F-rank" pipe in the system.[176] Based on our discussions with the MIMIR developer, however, no data was lost during this process.[177] Auditing MIMIR and the corrosion data gathering and retention system should put this allegation to rest.

Additionally, it appears from our interviews that some of the information in the MOC for the coupon crew reduction has, at least in part, fed these suspicions. When we asked *[name redacted]*, one of the HSE-1838 investigators, about data falsification, he referred to "documents" that he had been shown that contain "falsifications." When he later provided us with these documents, they turned out to be related to the MOC. *[The concerned BPXA employee]* in his interview also pointed to the MOC as an example of BPXA's alleged falsification of information.

Coupons receive anti-corrosion chemical treatment that distorts results.

We did not find evidence of this. The coupon crew universally denied (and ridiculed) this suggestion, stating that they would have no motive to do so, that such a treatment would have no benefit (the chemicals do not stay on the metal long; this is why continuous treatment is

[171] Interview of *[name redacted]* (August 20, 2004).
[172] *Id.*
[173] Interview of *[name redacted]* (August 23, 2004); Interview of *[name redacted]* (August 23, 2004).
[174] Interview of *[name redacted]* (July 23, 2004).
[175] Interview of *[name redacted]* (August 24, 2004); Interview of *[name redacted]* (August 20, 2004).
[176] Interview of *[name redacted]* (July 27, 2004); Interview of *[name redacted]* (August 18, 2004); Interview of *[name redacted]* (August 23, 2004).
[177] Interview of *[name redacted]* (August 20, 2004).

needed for pipes), and that they had never heard of this occurring. There was a test program several years ago that involved coating the housings into which the coupons are placed with a protective spray-on coating to see if the coating helped reduce corrosion; perhaps this was the source of this allegation.[178]

Agency inspectors are directed to inspect only good areas of the pipeline.

We did not find evidence of this. The coupon crew and others we spoke to stated that inspectors can, and do, go wherever they want when inspecting facilities on the Slope. Moreover, the inspectors can and occasionally do attend the weekly corrosion meeting, which discusses problem areas of pipe. One employee, however, provided us with an email from management asking that clean, convenient locations be chosen for demonstrations of coupon-pulling for state inspectors. While this email appears to us to have no sinister motivation, the existence of such emails provides fertile ground for rumors and allegations concerning such practices, particularly given the atmosphere of distrust that exists within parts of CIC and other parts of the North Slope.[179]

Necessary repairs were being delayed beyond the projected critical time for piping and associated equipment to the extent that it has now become a hazard for workers and that procedures are being used to hide these problems from higher management.

CIC provides a PMP to Operations identifying areas of the pipe that need to be repaired and providing a deadline to address the issue. When Operations receives these PMPs, it deals with the issue in a variety of ways, which include fixing the pipe, derating the pipe, or taking it out of service. It is our understanding from BPXA supervisors that the need to take corrective action before the deadline specified in the PMP is taken seriously: in fact, one manager stated that he has taken employees off of production-related tasks in order to meet a PMP deadline to fix a pipe that, in his option, had a low risk of causing a spill.[180] However, we are not technically qualified to evaluate the adequacy or timing of repair decisions.

What our interviews did reveal is that some employees may not understand the way these issues are being managed, and see only that pipe that some people perceive to be in bad condition remains in service, leading to a perception of unsafe pipe.[181] In addition, we heard that *[the concerned BPXA employee]* had alleged that there was an issue with document falsification at GC-2, where PMPs were not issued for certain repairs that needed to be done. *[Name redacted]*, the manager of GC-2, explained to us that PMPs were not issued because the affected

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[178] Interview of *[name redacted]* (August 21, 2004).
[179] Email from *[name redacted]* to *[name redacted]* (APC) re: ADEC visit – WLC Pull and ER Probe (Aug. 4, 2004).
[180] Interview of *[name redacted]* (August 20, 2004).
[181] Interview of *[name redacted]* (August 21, 2004).

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pipe was going to be removed from the facility, which it was.[182] These kind of misunderstandings, in an atmosphere of distrust, can easily trigger an allegation of bad pipe in service.

> *Decreasing the amount of coupon pulls has jeopardized the condition and safety of the field.*

There have been a number of coupon pulls eliminated, apparently for good reason. Yet in an atmosphere of distrust, this can easily be interpreted as a way for BPXA to save money, particularly when it was tied to the elimination of 2 coupon crew jobs, generating the allegation that a less vigorous corrosion program results. It is apparent that the reasons for the pulls being eliminated was not carefully explained to the coupon crew, nor how their work relates to the overall corrosion program. Indeed, given the fact that there is a perception that the H-21 incident was contributed to, at least in part, by the decision to stop monitoring, it is easy to see why some employees might have concerns that similar results will occur when other pulls are discontinued.

During our inquiry, we did not learn anything that suggested to us that the reductions in the number of coupon pulls has jeopardized the condition or safety of the field, as *[the concerned BPXA employee]*, for instance, has alleged. *[The CIC manager]* and others explained that the coupon-pulling program had been rationalized and that certain pulls were eliminated as unnecessary and the frequency of pulls was decreased.[183] This is consistent with the anecdotal information we were provided by many current and former workers on the coupon crew, who suggested that many of the coupons they pulled in the past had little or no visible corrosion evident when they were removed from the pipes. While this is not dispositive, and we are not expressing a technical opinion on the condition of the field, we did not discover anything that suggested that decreasing coupon pulls, as a general matter, compromises safety or causes worker concerns. We were also told that if an eliminated pull was determined to provide important data, it would be reinstituted and that money did not enter into this decision.[184] The BPXA Operations people we talked to expressed a good deal of confidence in CIC.[185]

Our findings on this point are consistent with similar ones in the ORT Report:

> 3.2.18 Management has extended inspection intervals on some equipment based on history and engineering judgment. However, the basis for these decisions has not always been well documented or effectively communicated to field personnel, many of whom view these deferrals as largely budget driven.[186]

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[182] Interview of *[name redacted]* (July 28, 2004).
[183] Interview of *[name redacted]* (August 24, 2004).
[184] Interview of *[name redacted]* (August 19, 2004).
[185] Interview of *[name redacted]* (August 20, 2004).
[186] ORT Report, p. 25.

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Our recommendation to better inform the coupon crew and others in CIC on this and other issues is similarly consistent.

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CONCLUSIONS AND RECOMMENDATIONS

I. Conclusions

- We believe some employees on the coupon crew experience an unintended chilling effect on reporting HSE concerns. This is a consequence of events that occurred before and after HSE-1838. Secondarily, the reluctance to raise HSE concerns is present but less pronounced in other parts of CIC, such as CANSPEC, as a consequence of the competing pressures of reporting HSE incidents while contractor performance is being judged in part on the number of recordable incidents. The perception of those that we interviewed is that this pressure is also found among contractors outside of the CIC group. An example involved contractor use of the Deadhorse Clinic to avoid OSHA recordables, which was one of the allegations we investigated. These contractors directed their employees to use the Deadhorse Clinic rather than the BP clinics, when injured, to control their recordable incidents. At least one contractor has rescinded this directive. BP is aware of the natural tension that exists between reporting and contractor performance. Its culture is one of safety first and BP actively manages to avoid the unintended consequences of implementing laudable policies targeted at reducing workplace injuries.

- Problems have shown up in CIC, which we believe can be attributed to *[the CIC manager]*'s management style. While his hard-charging, "extreme performance management" approach has probably made the CIC program more effective, his demands for performance to metrics of his choosing, even in cases where those metrics may not be soundly based (e.g. the reduction of coupon crew from 8 to 6), and treatment of HSE incident numbers as just another performance metric that contractors must hit (or else) creates discontent within the organization. This discontent manifests itself in a variety of ways, such as HSE 1838. We found evidence of managers forcing the adoption of decisions made by *[the CIC manager]* regardless of their reservations over them and line worker complaints about them, largely because of *[the CIC manager]*'s overbearing management style, which does not countenance debate and open discussion. We did not find any evidence that *[the CIC manager]* tells people not to report HSE incidents – it was universally acknowledged that he said to report – but his pressure on contractor management to hit performance metrics (e.g. fewer OSHA recordables) creates an environment where the fear of retaliation and intimidation could and did occur. The questionable quality of contractor management in CIC contributes to this problem.

- We did not find any evidence that the allegations regarding data fraud in the CIC program had merit, although our review did not rise to the level of a comprehensive audit of the CIC program's data system. Our investigation, however, revealed that there were facts relating to these allegations, which, when viewed in the negative light used by critics of the Company, allow negative inferences to be drawn.

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II. Recommendations

To address the chill associated with HSE-1838 and the anxiety of some contractor employees and contractors over reporting HSE concerns, we recommend the following:

1. Transfer *[the CIC manager]* from a management to a technical position. This will remove him from management of the corrosion program, while allowing BPXA to continue to utilize his impressive technical skills.

2. Direct ASRC to take *[the AES manager]* out of the management chain for CIC. This will move out of the CIC program a manager who is not considered particularly effective and send a message that a threat to fire an employee for raising an HSE concern will not be tolerated even if the threat was not carried out.

3. Evaluate and implement appropriate measures to improve morale in the coupon crew. Such measures could include the following: request that ASRC increase the size of the crew back to 8; evaluate whether additional administrative support for the coupon-pullers is needed; reassess the overtime limitations to determine if a total ban on overtime is necessary or appropriate; review pay for the crew to ensure it is in line with the risks and physical demands of the job, and; investigate ways to improve work load and scheduling issues for the coupon crew.

4. Review contracts with CIC contractors that are less than 3 years in length and consider extending them to at least 3 years to reduce the perception that a BPXA manager has de facto control over the contractor as a consequence of the contract constantly being up for renewal.

5. Better educate BPXA managers, contract managers, and contractor employees that the HSE metrics dealing with reportable incidents are only tools to reach the laudable goal of a safer and an environmentally better workplace, not an end unto themselves.

6. Strengthen the process used to address issues related to intimidation and retaliation and make the procedures used to investigate allegations more formal. Currently, allegations of retaliation and intimidation are handled ad hoc. The HSE Committee does not address these issues, and while *[name redacted]* does investigate some allegations, there is no formal process to track an allegation from beginning to closure, nor is there a centralized record system to find records of current or past complaints of incidents or the actions taken to address them.

To improve confidence in the corrosion program and address allegations of falsification and manipulation of corrosion data, we recommend:

1. Undertake a focused review to assess the corrosion program data systems, which should examine the data system (MIMIR) itself, procedures for gathering, documenting and inputting

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data, and how corrosion engineers and others access the data and use it. The purpose of this review would be to address allegations of corrosion data falsification.

2. Better educate the employees within CIC (and possibly across the entire North Slope) as to the overall corrosion program to reduce confusion over its goals and actions. If a major incident occurs, it is imperative to thoroughly explain its causes and BPXA's responses to limit the rumors and potentially inaccurate information that otherwise will be circulated on the North Slope.

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Appendix 1

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STATUS OF ALLEGATIONS[1]

1. BP is a European company that does not take the same positive view of whistleblowers as American companies.

   Status: BP's formal policies strongly encourage reporting of any and all HSE concerns. The problems that arise come not from an animus towards whistleblowers, but from a sometimes results-oriented management model that pressures contractors to hit defined HSE targets, with the attendant risk of driving reporting underground.

2. BP dismisses complaints because it is not in the economic best interests of the Company to listen to them.

   Status: BP employees generally expressed confidence that they can raise HSE concerns or stop a job if they feel it is unsafe. Some contractor employees expressed concern over raising HSE concerns, but generally indicated a willingness to stop a job if it was unsafe.

3. BPXA has offered management harassment training since 2003, but the threats continue. BP has never reported on any investigation of threats originating from BP or contract management.

   Status: BPXA continues to do training and investigates any harassment complaints. This spring it investigated concerns relating to the North Slope Lab and acted upon the findings. One of the recommendations in the Report is to make the process of investigating complaints more formal.

4. BPXA, *[name redacted]*, and the HSE committee have yet to admit that Company policies have been violated.

   Status: We believe this allegation relates to the letter sent by BPXA (*[the former GPB field manager]*, July 20, 2004) in response to the Lab incident, which some have criticized as not admitting that policies were violated.

5. Pulling equipment maintenance deferred to reduce down time and possibly not pressure test the equipment.

   Status: We believe this allegation is unfounded. The pulling equipment is on a mandatory 6-month rebuild schedule, but it seldom, if ever, makes it to this scheduled interval before being rebuilt due to wear and tear on the job. According to the coupon crew, the equipment is adequately pressure tested and they would not work with equipment not tested. We believe that this allegation comes from suggestions made in

[1] These allegations are derived from 7/20/04 list prepared by *[name redacted]* of BPXA from a variety of sources including communications of *[the concerned BPXA employee]* and *[name redacted]*.

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the past by contract managers to service the pulling equipment in the vans used by the workers to take them to the pull locations. Workers on the east side had been doing tool servicing in their vans prior to the consolidation of the east and west sides. These suggestions were never adopted, and the tools are serviced at an equipment shed that is part of CIC's offices on the east side.

6. Pull rate increased to 17-18 per day with no improvements in equipment, time, help, or conditions to help meet those goals.

   Status: This allegation appears in HSE-1838 and *[the CIC worker]* has said he does not know where the author of HSE-1838 came up with this number. We believe this allegation is unfounded, as coupon crew employees told us that they had not been given specific coupon targets or pressure to make a certain number. The backlog in the coupon program does, however, create pressure on employees, whether that pressure is self-inflicted (because the workers take pride in their work and want to get the job done) or from contractor management due to pressure by BPXA management (we have seen evidence that, in the past, BP management pressured contractor management to eliminate the backlog).

7. BPXA possibly reducing monitoring by removing probes to compensate for the reduced workforce or falling behind on monitoring because of the reduced workforce.

   Status: BPXA has reduced the number of corrosion monitoring sites, which has been explained to us as a rationalization of the process due to the consolidation of the two sides of the field and improvements in the structure of the corrosion monitoring program. While we are not in a position to opine on whether or not the reduction in pulls is consistent with sound corrosion management, the intent behind the decrease in monitoring and its implications for the program are not understood by (and may not have been explained to) the workers, who may thus worry that important data is being sacrificed in the interest of cost control. The corrosion engineers we spoke to insisted that the reductions in pull locations occurred because data from the particular locations showed those pulls to be unnecessary. There is currently a substantial coupon-pulling backlog.

8. Over many years, personnel and contractors report that the facilities suffered from corrupt practices in the corrosion monitoring and control program to cut expenses. (It is reported that intimidation and harassment in the program has been rampant. There also are reports that the program has been tainted by instances of contractor kickbacks/bribery in exchange for silence on the monitoring and control program.)

   Status: We found no evidence to support these allegations.

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9. Proper corrosion control, detection, monitoring, and repair procedures were often being ignored in favor of cost saving.

   Status: It is true that GPB has been under cost pressure, and that the corrosion group management has placed significant pressure on contractors to reduce costs. We are not in a position to opine whether cost reductions jeopardize the integrity of the corrosion program. We would note that the budget for the corrosion program has been increasing and for 2003 BPXA spent $53 million.

10. Numerous corrosion experts under the CIC Division over the past half dozen years warn of cost cutting, causing serious corrosion damage to the flow lines and systems.

    Status: The originator of this statement did not identify who these "corrosion experts" are and we were unable to locate them. We did interview a number of employees working in the Flow Stations and Gathering Centers who were laudatory of the pipe replacement work and corrosion efforts they are seeing within their facilities.

11. High injury rate due to equipment design and poor probe placement on the WOA lines, understaffing which created stress, injury, and reduction of corrosion monitoring.

    Status: We have been informed by a number of employees that where corrosion monitoring coupons are placed on the west side results in much more difficult pulling locations than on the east side. Coupon-pulling is also universally viewed as a tremendously physical job that takes a toll on the bodies of the workers. Also, the reduction in the coupon crew and the attendant backlog has caused stress for certain workers. We have been told by AES management that a lighter tool is being evaluated. Also, so-called red zone pulls, which are pulls in unsafe locations, are being identified and the pulls suspended until the access can be improved.

12. Workers are pressured to falsify corrosion monitoring reports. One method was to send the contract crews to monitor and report on known lines with little or no corrosion to dilute the final severity of the corrosion.

    Status: The coupon crew stated that they were not involved in falsification of corrosion monitoring reports, and that given the nature of their duties, it would be impossible for them to do so. One of the inspection workers did express concerns regarding the fact that there was so much monitoring of lines that had repeatedly been proven to be good. The good lines are monitored less frequently than the bad lines, however, and there may be good technical reasons for the monitoring that is done.

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13. It is also alleged that the worst figures are pulled from the reporting data for the same purpose.

    Status: No one we spoke to thought that bad data was being dropped from the system. This allegation may have come from the implementation of MIMIR, which involved a "data scrubbing" process to fit the data to the new format. The MIMIR developer assured us that no data was lost during this process.

14. Corrosion blending on S-risers.

    Status: We did not find evidence of this. We were informed that data is sometimes averaged or blended as part of the process of delineating the extent of corrosion damage in a given area.

15. BPXA misrepresented corrosion history leading to the May 27, 2003 GC-1 Spill.

    Status: This was not specifically commented on by any of the interviewees, although interviewees generally denied that false information was being presented to the State.

16. BPXA delivered to ADEC a false timeline spreadsheet of corrosion-monitoring program for the rupture site of the May 3, 2003 oil spill.

    Status: This was not specifically commented on by any of the interviewees, although interviewees generally denied that false information was being presented to the State.

17. The experts claim that BPXA is manipulating the corrosion field data that is reported to the authorities.

    Status: We found no evidence of manipulation. This does not mean that CIC in presenting corrosion information to the State does not put a positive spin on the data. One interviewee noted that he observed this occurring, but the State appears to have full access to the data, has regular corrosion meetings with CIC, has the opportunity to attend the weekly corrosion meeting that discuss key corrosion issues and conducts inspections. It should have ample capability to evaluate the corrosion data it receives.

18. Coupons receive anti-corrosion chemical treatment that distorts results.

    Status: We did not find evidence of this. The coupon crew universally denied (and ridiculed) this suggestion, stating that they would have no motive to do so, that such a treatment would have no benefit (the chemicals do not stay on the metal long; this is why continuous treatment is needed for pipes), and that they had never heard of this occurring. There was a test program several years ago that involved coating coupons with a protective coating to see if a pipe could be protected in that way; perhaps this was the source of this allegation.

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19. Agency inspectors are directed to inspect only good areas of the pipeline.

    Status: We did not find evidence of this. The CIC workers and others we spoke to stated that State inspectors can, and do, go wherever they want when inspecting facilities on the Slope. One employee, however, provided us with an email from management asking that clean, convenient locations be chosen for demonstrations of coupon-pulling for state inspectors. While this email appears to us to have no sinister motivation, the existence of such emails provides fertile ground for rumors and allegations concerning such practices.

20. BPXA knew for several years that the low-lying Caribou Crossing Large Diameter Flow line was rapidly corroding and needed to be dug up, inspected, and repaired. Action was deferred.

    Status: We are not in a position to opine on the technical aspects of the inspection, monitoring, and mitigation program. We heard from many employees, however, that external corrosion is an issue, that there are problems with pipe insulation, and that many areas of the pipe have had insulation removed for inspection but not replaced. The existence of such conditions may be the reason some employees believe that this problem is not being addressed. This particular pipe, the Y-36 line, is well known for having corrosion problems and is carefully monitored.

21. Necessary repairs were being delayed beyond the projected critical time for piping and associated equipment to the extent that it has now become a hazard for workers and that procedures are being used to hide these problems from higher management.

    Status: CIC provides a PMP to Operations identifying areas of the pipe that need to be repaired and providing a deadline to address the issue. When Operations receives these PMPs, it deals with the issue in a variety of ways, which includes replacing the pipe, putting on a sleeve, derating the pipe, or taking it out of service. Operations in consultation with CIC determines the repair option predicated on a variety of factors. Timing of the repair is carefully monitored. Some employees may not understand the way these issues are being managed, and see only that pipe thought by some to be in bad condition remains in service, leading to a perception of unsafe pipe.

22. AES Probe pulling crew representative stated upper management showed his crew an internal BPXA report stating that they only worked a couple of hours each day. Management emphasized that the report that the probe pulling crew was overworked and had worked long hours to catch up on monitoring were not true.

    Status: Some of the coupon crew members were highly critical of the data supporting the MOC for the reduction in the coupon crew from 8 members to 6, believing that it did not take into account all of the work that they are required to do. The crew did work

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substantial overtime to catch up with the coupon-pulling backlog in the summer of 2003. Overtime was eliminated in January 2004 and there is now a substantial backlog again.

23. The data *[name redacted]* used in the investigation of HSE-1838 was manipulated to deceive and hide the truth.

    Status: This is probably the same data underlying the MOC. From our review of the MOC, it did not address concerns being raised by workers as to why the crew reduction was not justified.

24. *[The CIC manager]* personally benefits from improved safety and/or corrosion metrics.

    Status: This is probably a fair statement for any manager, and it is clear that *[the CIC manager]* strongly pushes the CIC program to hit certain safety and corrosion metrics. We did not, however, find any evidence that this type of benefit led to any sort of fraudulent activity on his part. For instance, *[the CIC manager]* stated that he has no incentive to present misleading corrosion data, because it would ultimately be discovered when an incident occurred, and the problems caused by that would far outweigh any benefits associated with portraying the field as better than it is, a point that was very plausible. This point was also made by a number of other interviewees.

25. There were injuries due to the equipment and orientation of the probes specific to the WOA. Some injuries were not reported to the medical office for fear of losing one's job.

    Status: There have been injuries resulting from coupon pulling, and the WOA is probably more risky due to the location of the probes. At least one contractor took an injured employee to the Deadhorse clinic, and another was instructed to go, but did not. Contract management had instructed the employees to go to Deadhorse; reporting issues may have motivated this. It was a commonly-held view among the people we interviewed that contractors were directing employees to the Deadhorse clinic because of concerns the BP clinic was being overly conservative in its treatment, causing the number of OSHA reportable incidents to escalate. While AES, for instance, had instructed its employees to use the Deadhorse clinic, that policy has been changed.

26. *[The CIC manager]* and the CIC group pulled the monitoring on wells which led to the H-21 blowout and an environmental spill. After the spill, the monitoring was resumed.

    Status: This appears to be partially true. The coupon monitoring at this location was stopped because it was upstream of the injection point and was therefore not providing data regarding the effectiveness of the chemical injection. Although the primary cause of the H-21 incident was failure to inspect the part of the S-riser that failed, it is possible that had the coupon monitoring continued, it would have provided some advance warning of the failure. Within 60 days after the failure, the injection points were fixed on this and

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a number of similar wells. We have been told by BP corrosion team supervisors, including *[the CIC manager]*, that the H-21 incident was the result of "program failures" at CIC.

27. BP's corrosion monitoring program has reduced the number of corrosion probe pulls by extending the time frequency intervals for the pulls.

Status: This is true. We have been informed by CIC managers that this is because less-frequent pulls were appropriate for certain lines. Corrosion engineers have informed us that there are a number of factors affecting the decision to remove a coupon location from the pull schedule, including eliminating redundant locations on the same line, greater use and effectiveness of chemical mitigation, and greater use of other inspection techniques, such as X-rays. CIC crew members have stated that this makes sense from their field observations, where many coupons showed little or no corrosion when pulled. Nevertheless, this is another example of a field decision that can easily be construed by some as a reduction in BPXA's commitment to control corrosion.

28. L&V wells are still not monitored. Endicott has 12 probes not checked for at least one year.

Status: We have been told by *[name redacted]*, an on-Slope BPXA CIC Supervisor, that coupons are now being pulled from these wells.

29. Independent corrosion experts, who were all formerly contractors working on Prudhoe Bay, have resigned their positions over the last few years allegedly due to their growing worries over the potential for a serious incident on the field.

Status: We have been told by one person that an operator, *[name redacted]*, resigned because of concerns over pipe integrity. Others suggested this was not why he resigned. We have tried to contact *[name redacted]* to interview him and have been thus far unsuccessful. We are aware of no other persons who could possibly fit this description.

30. Several hundred inspection points had been overlooked by our corrosion inspection program and people were being held over to work 3 weeks with one off to correct the deficiencies.

Status: This point was not raised by any interviewees, even though our questions of them were designed to elicit such information.

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31. *[The CIC worker]*, CIC, was pressured to request HSE concern 1838 be pulled immediately. *[The CIC worker]* was requested to meet with management in Anchorage to explain his actions.

    Status: While *[the CIC worker]* voluntarily agreed to request HSE-1838 be pulled because of some inaccuracies in the concern, with the knowledge a corrected version could be refiled, his job had been threatened. He did not go to Anchorage to discuss this issue.

32. In response to HSE concern 1838, *[the CIC manager]* threatened to fire these guys. The AES boss told workers that AES will now lose its contract.

    Status: While we have been able to substantiate *[the CIC manager]*'s threat to fire the entire crew, it appears that this was not made in connection with HSE-1838, but earlier regarding additional duties and consolidation of the corrosion crew. *[The CIC manager]* had given AES authority to replace the entire coupon crew prior to HSE-1838. Initially, *[the AES manager]* of AES indicated he wanted *[the CIC worker]* fired over HSE-1838, but he quickly relented. *[An AES supervisor]* of AES did indicate to *[the CIC worker]* his concern over the contract.

33. Six disciplinary letters in five weeks written on the BP field crew in the WOA while there were no discipline letters written in the EOA. BP management is retaliating for the safety and mechanical integrity concerns brought up by this crew.

    Status: *[Name redacted]* is investigating this issue and we did not examine it extensively. To the extent interviewees addressed this issue, they denied the letters were issued to retaliate for safety and mechanical integrity concerns brought up by these individuals.

34. A former corrosion staff member was fired for insisting that the downhole production tubing monitoring program continue.

    Status: We did not find any interviewee, beside *[the concerned BPXA employee]*, who was aware of this incident, if it occurred and we were not given the name of the individual. We were told that down-hole monitoring stopped six years ago.

35. *[Name redacted]* stated that the workers only feel comfortable because so much attention has been placed on their issues; the workers fear delayed retaliation.

    Status: Some workers in the coupon crew fear reporting issues because of what happened to *[the CIC worker]* and how overtime was treated.

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36. *[The CIC manager]* wrote a memo that indicated the corrosion workforce increased by 50%; he neglected to say that the WOA and EOA monitoring staff and duties were combined, resulting in a net reduction in staff.

    Status: We have not seen this memorandum; this allegation may refer to the MOC or other documents. It is clear that *[the CIC manager]* believed that the coupon crew could be reduced due to the consolidation of GPB. It is also clear that others disagree with that and their concerns were not properly evaluated.

37. Between the time that he became CIC Team Lead and December 2002, *[the CIC manager]* displayed behavior to *[the former AES manager]* and other CIC staff that qualifies as workplace harassment.

    Status: It is clear that *[the CIC manager]* had disputes with both *[the former AES manager]* and *[the AES manager]*. *[The CIC manager]*'s style is universally characterized as harsh, so it is likely that he was hard on these two people. The people we spoke to, however, stated that neither *[the AES manager]* nor *[the former AES manager]* were effective managers, which may have contributed to this conflict. We were unsuccessful in our efforts to contact *[the former AES manager]* for an interview but are aware of his views concerning *[the CIC manager]* that are expressed in his email to *[the concerned BPXA employee]* dated June 30, 2003.

38. It was not uncommon for *[the CIC manager]* to become upset if a project was falling behind schedule and display intimidation tactics and disrespectful verbiage.

    Status: This is from *[the former AES manager]*'s email. By all accounts, *[the CIC manager]* can be abrasive and is totally focused on achieving business results. This allegation seems quite plausible, although some believe that *[the CIC manager]* has improved in this area.

39. *[The CIC manager]* insinuated that he would cancel the AES contract on several occasions if the objectives he outlined were not achieved and threatened to fire *[the former AES manager]*.

    Status: This is from *[the former AES manager]*'s email. We heard from several individuals that AES was threatened with contract termination for performance reasons.

40. *[The former AES manager]* resigned because of *[the CIC manager]*'s belief that he was not competent.

    Status: The consensus of the vast majority of those we spoke to is that *[the CIC manager]* ran *[the former AES manager]* off the Slope, although other individuals believed that *[the former AES manager]* left for reasons unrelated to *[the CIC manager]*.

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In any event, none of the people we spoke to viewed *[the former AES manager]*'s departure as any great loss, as he was not a highly regarded manager by his peers, supervisors or subordinates.

41. *[The CIC manager]* wrote an email to *[name redacted]* stressing that his employees tell her that they feel free to report any and all HSE issues.

Status: The people we spoke to about this email (March 30, 2004) viewed this merely as "*[the CIC manager]* being *[the CIC manager]*" and being very clear about his expectations. The employees we spoke to stated that *[the CIC manager]* emphasizes the importance of reporting.

42. *[The former GPB field manager]* was very hostile towards *[the concerned BPXA employee]* during Compliance Agreement discussions at the BP/PACE Labor/Management Meeting on 4/8/2004.

Status: This meeting was described by a number of participants as being highly productive until the end when *[the former GPB field manager]* and *[the concerned BPXA employee]* had a disagreement over the status and veracity of certain allegations *[the concerned BPXA employee]* was raising. In general, *[the former GPB field manager]* received very high marks as the GPB field manager.

43. *[Name redacted]* wrote a hot email to *[the concerned BPXA employee]*.

Status: We did not have the opportunity to interview *[name redacted]* who we understand is a PACE member.

44. *[The former PACE president]*'s behavior is such that if someone brings up a health and safety issue, his behavior is not good; his memos are awful.

Status: [The former PACE president] was almost universally praised by PACE members and BP managers whom we interviewed.

45. *[The CIC manager]* is brutal, and screams and shouts at contractors.

Status: We have been informed that *[the CIC manager]* had very poor communications skills, but has recently been improving. This is a very common perception.

46. Jeanne Pascal has heard nothing good about *[the CIC manager]*.

Status: We heard many positive things about *[the CIC manager]*. He is viewed as having top-notch technical skills, and not all employees were affected by his personal style. He is also described as being very committed and an exceptionally hard worker.

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47. *[Name redacted]* wrote bad emails to *[name redacted]* and others.

    Status: Our investigation did not address the *[name redacted]* issues. Mr. Gaynor and Ms. Dinkins intended to do a phone interview of *[name redacted]* when his attorney, through Ms. Pascal, sent Ms. Dinkins certain documents. Ms. Dinkins has not yet received the documents. We were informed that there were disagreements within PACE over *[name redacted]* holding himself out as a PACE representative when making certain public allegations against BPXA.

48. *[The CIC manager]*'s work ethics/hours are poor. *[The CIC manager]* typically works from 10am - 2pm "because that's the kind of guy he is".

    Status: This is almost certainly false. *[The CIC manager]* is universally described as an extremely hard worker.

49. After HSE-1838 was filed, *[the concerned BPXA employee]* received a call from *[the CIC worker]*, who requested that he retract the concern, stating that the information in it was not accurate. The worker's supervisor was sitting next to *[the CIC worker]* and monitoring the call. *[The concerned BPXA employee]* asked him if he felt his job was in jeopardy and he said yes.

    Status: [The CIC worker] did call to retract HSE-1838, but both he and his supervisor stated that the supervisor did not monitor the call. *[The CIC worker]* stated that he did not believe his job was in jeopardy at the time of 1838 (although he had been threatened with being fired).

50. Contract workers are instructed at *[the CIC manager]*'s direction not to report to BOC for injuries. Reference two contract workers (*[name redacted]* and *[name redacted]*) who were injured and sent to Deadhorse doctors.

    Status: AES made a practice of instructing its workers to go to Deadhorse; but we found no evidence that *[the CIC manager]* was involved in this decision. Nevertheless, *[the CIC manager]*'s abrasive management style and threats of contract termination for poor performance, including not meeting HSE metrics, may have motivated AES to start using the Deadhorse Clinic. As explained in the report, sending workers to the Deadhorse Clinic was not done to avoid reporting but to manage OSHA recordables, perhaps motivated in part by concerns about the treatment decisions made by the BP medics. One of these workers, *[name redacted]*, did not go to Deadhorse and went to the BP clinic; he was not reprimanded for this. The contractor has now changed its policy and its employees are instructed to report to the BP clinics.

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51. PE experts expect a catastrophic event at BP Prudhoe facilities.

    Status: Our inquiry of CIC personnel did not reveal this kind of concern. To the extent that their have been pipe failures in the past, however, the individuals we spoke to suggested that there is always a risk of such events. But the people we spoke to generally believe that the CIC program does a good job of monitoring, assessing, and mitigating these risks. There were, however, a number of employees who expressed concerns regarding working on certain areas of pipe, concerns about external corrosion, and concerns about valve maintenance. A thorough technical audit of the CIC program would be necessary to evaluate the actual risks related to a catastrophic failure at Prudhoe Bay.

52. Retaliation activity within the PACE union and towards *[name redacted]* (email from *[the former PACE president]*, evicted from meeting by *[name redacted]*, speeding ticket, computer privileges), *[name redacted]* email.

    Status: See the response to number 47.

53. *[The former GPB field manager]* uses *[the former PACE president]* as a "guard dog" to talk to those he doesn't like. Jeanne Pascal said she believes this has created a "hostile work environment." *[The former GPB field manager]* uses *[the former PACE president]* to "muscle people". *[The former GPB field manager]* uses *[the former PACE president]* as a "junkyard dog to hush up the Unions."

    Status: [The former PACE president] denied this, and the PACE members, with the possible exception of *[the concerned BPXA employee]*, we spoke to supported him in this position. While there are differences of opinion within the union on how to handle certain issues, the individuals we spoke to expressed great respect for *[the former PACE president]*, particularly his integrity. *[The former PACE president]* resigned his position in June 2004 as the President of PACE because he is tired of these kinds of criticisms.

54. *[The former GPB field manager]* and *[the former PACE president]* have been discussing having the union put pressure on the union members to vote to tell Jeanne Pascal to terminate the Compliance Agreement.

    Status: We found no PACE members we interviewed, with the exception of *[the concerned BPXA employee]*, claiming any knowledge of this. At least one PACE member said it was never discussed at any PACE meeting.

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55. "There is a lot of intolerance and hostility member-to-member within the union."

Status: The PACE members we spoke to denied this, although they noted that there had been a significant controversy within the union regarding whether *[name redacted]* was authorized to represent himself as speaking for PACE.

56. *[The former PACE president]* has retaliated against *[the concerned BPXA employee]*. *[The concerned BPXA employee]* had previously expressed safety concerns. *[The concerned BPXA employee]* was called into a meeting with *[the former GPB field manager]* in March 2004. During that meeting, *[the former PACE president]* told *[the concerned BPXA employee]* to shut-up, that BP's shareholders will lose value and the union will lose members if he does not keep quiet.

Status: We did not ask *[the former PACE president]* directly about this meeting. *[The former PACE president]* resigned in June 2004 as PACE's President.

57. There is no oversight of the CIC Division.

Status: This does not appear correct as stated, since *[the CIC manager]* reports to *[name redacted]* and in our discussions with her, she indicated that she does monitor *[the CIC manager]*'s performance. ADEC also receives an annual report of the corrosion program, attends corrosion meetings and sends inspectors to the North Slope. Many individuals did state, however, that *[the CIC manager]* has a great deal of autonomy and manages CIC as his "kingdom."

58. Corrosion program audits itself.

Status: Our interviews indicated that there has not been a technical audit of the CIC program for at least a few years now; as we note in our recommendations, a review of the corrosion program data systems is probably a useful exercise given the serious allegations raised about CIC.

59. Workload of the coupon crew has increased significantly and is at a level that creates risk to the individuals and operational integrity.

Status: Based on our investigation, the coupon crew was limited to working no overtime as of January 2004, in response to complaints of this nature. Several months thereafter, the crew was given up to 1.5 hours a day of overtime if the work was valve related, not coupon-pulling related. This overtime was rescinded a few months ago. We should add that most of the coupon crew loved working overtime.

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60. VECO crew told there is a zero tolerance policy on spills. Any spill reported will result in a disciplinary letter to the reporting employee. This will result in no more spill reports.

    Status: We discuss the tension between encouraging reporting and ramifications that flow from reporting in the body of our report. Policies, no matter how laudable, have to be carefully reviewed to determine if the unintended consequences of a policy are negative. We understand that some employees had the perception that there had historically been a "zero tolerance" policy on spills, and such a perception can drive spill reporting underground. Our interviews showed that contractors' policies were often more stringent than BPXA's (e.g., VECO sending employees home without pay for minor traffic infractions) but that the workers would often attribute such policies to BPXA. The employees we spoke to were generally more comfortable with spill reporting today than they were in the past, but the tension between reporting and its potential consequences remains an issue.

61. *[Name redacted]* interviewed only two AES workers on the coupon crew during the investigation of HSE Concern 1838. *[name redacted]* also contacted *[name redacted]*, the PACE HSE rep assigned to the issue and tried to convince *[name redacted]* to drop the HSE concern.

    Status: Whether *[Name redacted]* interviewed only two AES workers on the crew is immaterial as we interviewed almost all crew members, as well as many former crew members regarding HSE-1838.

62. BP recently tried to get out of the compliance agreement early but EPA did not allow this. Based on information received by EPA it was determined statements from *[name redacted]* regarding BP's compliance to EPA were possibly false and required investigation. BP management was embarrassed and is now placing pressure on the Union. These meetings (BP/PACE Labor/Management Meeting) are designed to pressure workers to remain silent, adopt a neutral position or support BP's position to gain influence with EPA.

    Status: See the response to number 54.

63. *[Name redacted]*'s decision not to return to the North Slope is extremely chilling on other employees.

    Status: See the response to number 47. No interviewee mentioned any chilling effect from *[name redacted]* not returning to the North Slope with the possible exception of *[the concerned BPXA employee]*. After a request from Jeanne Pascal early in the interview process, we desisted from asking any specific questions regarding *[name redacted]*.

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64. Supervisors are telling contractors that they will get fired if they do not keep their lips zipped and quit bringing up health and safety problems.

Status: We did not find any basis for this allegation, as stated, although as we note in the body of the report, there is evidence to suggest that contractor management has, in the past, made statements regarding threats to fire employees and potential loss of contracts due to increases in HSE incidents.

65. A lot of the people who are going outside the Company think there is no place to go inside the Company. There is no one they feel safe talking to.

Status: We can confirm that certain individuals believe the only way to force BPXA to address issues is to go outside the Company. This view is the minority view.

66. People are making patchwork repairs but at some point they are not going to know where to make the patches and something bad will happen.

Status: The majority of employees we spoke to disagreed with this allegation, although there were a few who were not comfortable with the practice of sleeving pipes or derating pipes.

67. Employee concerns are not making their way up through the ranks and people do not know how to get their concerns up through the ranks. People are leaned on not to express concerns.

Status: These issues are discussed in detail in the body of our report.

68. Hostile work environment and retaliation is ongoing today.

Status: These issues are discussed in detail in the body of our report. It is certainly BPXA's policy for this not to happen and management seriously addresses allegations of specific behavior when it learns of them. BPXA supervisors communicate BPXA policies in this regard on a regular basis.

69. *[Name redacted]* interviewed only one of four people in response to a corrosion complaint.

Status: See our response to allegation 61.

70. For four years, workers on the coupon crew raised safety concerns with their supervisors. AES and BP management ignored them and in some cases intimidated the crew for raising concerns.

Status: These issues are discussed in detail in the body of our report.

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71. "The workers remain in fear of loosing their jobs. Even this week, the workers are still receiving the same threats; 'BP will cancel our contract if you continue'. The workers have stated several times, as long as we are working the issue they probably will not be fired, but soon after the attention dies away they will be targets."

    Status: These issues are discussed in detail in the body of our report. Our recommendations are intended to address the chill discussed in our report.

72. *[Name redacted]* stated in a recent Labor/Management meeting only one worker had an issue, the worker is satisfied and the concern should be closed. When *[the concerned BPXA employee]* informed him of the current status and that other workers were also involved, he threw his hands in the air and stated we should have more meetings.

    Status: These issues are discussed in detail in the body of our report. There has been a difference of opinion over when HSE-1838 should be closed. This is a decision that the submitter and the HSE Committee will have to make.

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9

BP Concerns/Comments on the Final Draft Coffman Engineers Report

Corrosion Monitoring of Non-common Carrier North Slope Pipelines
ADEC Contract Number 18-6000-02

Introduction

In the original discussions with ADEC, the intent of the process to fulfill the Corrosion Monitoring commitment under the charter was supposed to be a collaborative and cooperative effort, and this is still BP's preferred approach. However, the nature of the comments and style of the Coffman Engineers Final Draft report, that BP believes is misleading, has forced BP to respond to their Final Draft.

This document highlights our concerns regarding misperceptions or misinterpretations we feel have been made in the review of our report. We are willing to review and revise sections of BP's report where there are valid issues, however, our impression is that overall the review of our report was biased and unduly negative. This paper details BP's main objections and comments on the Coffman Engineers Final Draft Report but, as noted above, we would have, and still would prefer to work differently with ADEC on this issue.

General Observations

- The whole tone of the report seems extremely negative, and is inconsistent with prior conversations and discussions with ADEC in which the fulfillment of the commitments II A 6 and 7 was envisioned as being a constructive and collaborative effort between the companies and the state.
- The Coffman report presents many negative findings and characterizations, and very few positive references to BP's report or its content. This does not appear to be a balanced review of the document or it's content when there are many positive trends reported.
- The fulfillment of the charter commitment was intended to be done in consultation with ADEC and to date there has been no consultation with Coffman regarding the Coffman report so that any questions from the Coffman engineers could be addressed. This is the process proposed in the Coffman Technical Proposal.
- The report is inconsistent with the initial feedback from ADEC.
- Many of the recommendations/comments are worded as if the report is a compliance document that is enforceable. It would be more appropriate if the report was worded as a request for more information and suggested actions or options to be investigated.

Front Cover

- Milne Point is misspelled on the front cover.

Executive Summary

- **Paragraph 2** implies that BP has not reported openly – such an implied accusation needs to be substantiated as the contents of the report, by any reasonable measure, provide the information necessary for a qualitative understanding. Also, as noted in the Coffman report 'The BPXA Report was comprehensive in scope' which indicates there was more than adequate information to conduct a qualitative assessment.
- **Paragraph 2** states that it is difficult to develop a qualitative understanding of the BP program based on the report yet the Coffman Engineers report provides a section entitled 'Corrosion Control Strategy' on page 3 through page 5 or approximately 20% of the overall report length.

- **Paragraph 2** is critical of the performance metrics used in the BPXA report. However, the performance management metrics presented in the BPXA report are accepted statistical process control (SPC) metrics found in any quality process such as the ISO series or in the general performance management literature such as that provided on the web by National Institute of Standards and Technology (NIST), Statistical Engineering Division (SED), Engineering Statistics Handbook, www.itl.nist.gov/div898/handbook. In general, SPC provides many performance management tools and reporting methodologies including, but not limited to, non-conformance ratios such as those given in the BP report, Engineering Statistics Handbook Section 6.3.3.2. This performance management methodology contrasts with the three references provided by Coffman Engineers,

    ISO 8044 which is a list of corrosion terms and definitions in four languages that does not include the terms 'Performance Management' or 'Metric.'

    ASTM G15 is a similar list of corrosion terms and definitions as ISO 8044 and is also silent on the terms 'Performance Management' or 'Metric.'

    NACE RP0690 is a recommended practice that defines the data fields for a database system designed to assess the compatibility of engineering materials for a wide range of environments. Again, it is not designed for performance management of a corrosion control program.

- **Paragraph 2**states that the report and presentation contain no discussion of the underlying program strategy. However, the corrosion management strategy matching pipeline life to field life is very clearly stated and referenced on pages 810 which provides specific targets and discusses the relationship between monitoring, inspection and overall corrosion management, pages 24-26 discuss the inspection program in detail and slides 3-6 summarized the information for the Meet and Confer session in April 2001 as 'Maintain existing infrastructure throughout existing field life, (for) future satellite development (and) future gas production' With the aspiration of 'No Harm, no accidents, no damage to the environment.'

- **Paragraph 3**As discussed in the presentation, the corrosion mechanism, which if uncontrolled, presents the greatest potential for environmental impact is internal corrosion from CO_2. With the control of internal corrosion the next most impacting corrosion mechanism is external corrosion. Therefore the statement that 'external corrosion inspection level is not consistent with the relative risk' is misleading since the internal inspection program is an integral part of the internal corrosion management program as a whole. This is an area where if Coffman Engineers had taken the opportunity to consult with BP staff, clarification would have improved the content of the Final Draft.

- **Paragraph 4**Knowledge of the corrosion inhibitor efficiency and/or baseline corrosion trend is of limited utility since the effectiveness of the program is demonstrated by low corrosion rates and ultimately by lower repair and leak/spill rates, not from corrosion inhibitor efficiency. This recommendation should be amended, again, it is an area where if Coffman Engineers had taken the opportunity to consult with BP staff, clarification would have improved the quality of the Final Draft.

- **Paragraph 7**'...does not provide the necessary information for a detailed technical analysis...' There is no requirement for BP to provide such information nor is it within the scope of work defined for Coffman. As defined in the Work Plan, the Meet and Confer sessions are to provide a 'summary overview' and the annual report is to provide 'metrics which depict or characterize' issues, no fixed format was prescribed. The RFP from ADEC requests Coffman to 'Perform a comprehensive technical analysis of the specific information presented in the reports...' in paragraph (c) of the scope of work and in

Coffman's Technical Proposal Task 1 is defined as 'A comprehensive technical analysis of the March 2001 reports provided by PAI and BPXA be made. The primary source of data for these analyses will be the reports provided by BPXA and PAI.'

- **Omission** At the very end of the Coffman report it states 'The corrosion program results outlined in the report submitted to ADEC demonstrate a clear commitment by BPXA to mitigate corrosion and its impact to the environment and the field assets.' This is a very significant finding yet is omitted in its entirety from the Executive Summary.
  There is therefore a lack of balance in the report. A balanced report would have commented on both the positive and the negative findings and therefore have supported those activities that should be perpetuated as well as identifying potential gaps.

- **Errors/Inaccuracies** There are numerous misperceptions, misinterpretations and technical mistakes in the Coffman report, these are detailed below.

Commitment to Corrosion Monitoring- Page 3

- **Paragraph 1** The actual wording from the Charter Agreement is ' BP and ARCO will, in consultation with ADEC, develop a performance management program for the regular review of BP's and ARCO's corrosion monitoring and related practices for non-common carrier North Slope pipelines operated by BP or ARCO.'

Corrosion Control Strategy- Page 4

- **Monitoring and Inspection- Paragraph 2** The inference in the last sentence is incorrect, the target or action limit is any detectable corrosion activity found in the inspection data, not greater than 10 mils as reported by Coffman.

- **Mitigation – Paragraph 6** states that the target inhibitor concentration is 150 ppm, this is incorrect. The system is controlled to a corrosion rate of 2 mpy and sufficient corrosion inhibitor is added to achieve that target. The resultant average field wide corrosion inhibitor concentration happens to be ~150 ppm for 2000 but, as can be seen from Table 7 of the 2000 BP Report this value has changed over time as the corrosivity of produced fluids at GPB has changed.

Corrosion Program Status- Page 5

- **Risk – Paragraph 1** 'Judgment or experiential based protocols suffer from a lack of continuity; oil fields with production lifetimes in excess of half a century or more require a codified set of protocols...' This is an opinion of Coffman but is stated as a fact. Programs benefit from regular review/changes and our programs are always being revised to keep pace with changing field conditions.

- **Internal Corrosion Control – Paragraph 1** '...only the percentage of inspections which show increases in damage is reported; not the magnitude of the wall loss.' BP was charged with reporting corrosion-monitoring data. Magnitude of wall loss is of limited utility in the management of corrosion and as such was not included in the Work Plan for reporting on inspection results, reference Part 2, Section E of the Work Plan.

  Fitness-for-Service (FFS) efforts, where magnitude of wall loss is clearly an important consideration, are reported under the leak, save and repair metric again as per the Work Plan, Part 2 Section F. Corroded areas are evaluated for FFS to recognized industry standards.

Corrosion Program Status- Page 6

- **Internal Corrosion Control– Paragraph 1** 'No attempt is made to quantify the possible extent...' The word 'quantify' should be replaced with 'report' as BP did quantify it, but did not report it directly. However, this seems to be an unnecessary criticism on the part of Coffman as the Final Draft report then goes on in the following paragraph to note 'Inspections have not detected any appreciable increase due to lower than normal inhibitor concentration in the three phase piping.'

- **Monitoring and Inspection** Table 13 of the BP 2000 Report shows the Leak/Save history for the last 5 years and the leak cause for the year 2000. The Coffman Report then finds fault with the BP 2000 Report for not reporting pre-2000 leak causes. However, it is clear from the scope Work Plan Scope agreed with ADEC that the detailed leak causes are only required for the prior calendar year – see introductory comments for Section 2 of the Work Plan.
- **Mitigation – Paragraph 1** The reasons for the use of different corrosion inhibitors across the field is discussed on page 31 of the 2000 BP Report and again on slide 21 of the April Meet and Confer session.

Recommendations

- **Recommendation 1** As discussed earlier the recognized industry standards and practices given as examples by Coffman Engineers are of little relevance to the overall Charter Agreement commitment of agreeing a performance management program and performance metrics. The examples given by Coffman are,

  ISO 8044 which is a list of corrosion terms and definitions in four languages that does not include the terms 'Performance Management' or 'Metric.'

  ASTM G15 is a similar list of corrosion terms and definitions as ISO 8044 and is also silent on the terms 'Performance Management' or 'Metric.'

  NACE RP0690 is a recommended practice that defines the data fields for a database system designed to assess the compatibility of engineering materials for a wide range of environments. Again, it is not designed for performance management of a corrosion control program.

  Therefore this recommendation should be deleted or modified, to reflect the agreed action plan from Meet and Confer II.

- **Recommendation 5** This is not a recommendation but series of questions and/or requests for additional information or clarification, therefore, this recommendation should be deleted.
- **Recommendation 6** This recommendation has only limited utility in improving the performance of the corrosion inhibition program since the calculation of corrosion inhibitor efficiency is not used in corrosion management where it is the corrosion rate that is controlled. BP manages to a corrosion rate and demonstrates the value of the inhibitor program by the corrosion monitoring and inspection programs, leaks/saves and repair rates not by the corrosion inhibitor efficiency, which is measure useful primarily for comparing corrosion inhibitor products.

  Also, coupon removal from live systems should never be undertaken lightly and only done where the value of the data justifies the associated risk. We will never expose our workforce to unnecessary risk and therefore given the dubious nature of the data that would be generated this is an unnecessary risk and will not be undertaken.

- **Recommendation 7** This recommendation appears to confuse two different aspects of the coupon program. The 'no meaningful data' refers to the fact that these coupons are upstream of the chemical injection location on the 3 phase production system and therefore do not reflect the inhibited system corrosivity – this is clearly explained on page 11 of the BP 2000 Report. The under-reported corrosion rate refers to the coupons in the produced water system, page 10, and is as a consequence of the time required to buildup surface deposits on newly installed coupons, this is being addressed through the doubling of the exposure period.

It appears that two different issues and two different systems are being confused and therefore the recommendation should be deleted.

- **Recommendation 9**This is beyond the agreed scope of the report Work Plan that very clearly states that the report should cover the prior calendar year – introduction to Section 2 of the Work Plan – and therefore should be removed. The data for 1996 onward for leak/saves and other metrics was provide voluntarily as a courtesy and to help provide context.
- **Recommendation 10**Again, as per recommendation 9, this is beyond the scope of the agreed reporting guidelines included in the Work Plan and therefore should be removed.
- **Recommendation 11**This data is not generated and therefore cannot be reported. The data is not generated because it provides no additional useful information that would help in improving the corrosion control in the produced water system since the partitioning characteristics of the upstream inhibitor are predefined and unalterable. Therefore this recommendation should be removed.
- **Recommendation 14**This recommendation needs to be clarified, as the wording is unclear as to what is being recommended. If Coffman Engineers is requesting an understanding of how BP allocates resources then it is unacceptable as it is BP's responsibility based on our broad definition of risk and cannot be discussed with Coffman/ADEC.

  Additionally, one of the standards used as an example, ASTM 2081 Standard Guide for Risk Based Corrective Action, is not relevant as the scope of the document is for '...conducting risk-based corrective action (RBCA) at chemical release sites based on protecting human health and the environment. The RBCA is a consistent decision-making process for the assessment and response to chemical releases.' Therefore the standard is not relevant for the intended application.

Conclusions– Page 10

The conclusions should be re-written to reflect the issues/concerns raised in the prior notes and points with the exception of the last paragraph which should also be included in the Executive Summary. Of particular concern, and noted elsewhere,

- Coffman were requested to conduct a 'technical analysis' of the data presented in the report and this has not been done as per the RFP from ADEC or Coffman's technical proposal. The Coffman Final Draft appears to be more of a critique than an objective analysis of the BP 2000 report.
- The metrics presented in BP's 2000 report are well-understood measures for process control and improvement that Coffman have made no attempt to understand or improve upon. Instead, Coffman has chosen to cite 3 irrelevant standards in the recommendations.
- Coffman's report could have been improved substantially if BP had been consulted for clarification/explanation. This is exemplified by the repeated reference to inhibitor concentration and efficiency as opposed to the resultant corrosion rate, which is actually the most important parameter in reducing spills and the environmental impacts of corrosion.

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Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Final Draft

Technical Analysis

Of

BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami and Miline Point

Submitted by

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ADEC Contract Number – 18-6000-02

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2000 corrosion program report submitted by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the April 2000 Meet & Confer session. The goal of this review is to examine the corrosion program report, attempt to gain a qualitative understanding of BPXA's corrosion control program and identify initial recommendations for improvement to the content and extent of topics covered..

BPXA stated intent is to "to report openly, good or bad..." the results of its corrosion management programs. However, the reporting style makes it difficult to develop a qualitative understanding of the basis for their corrosion strategy. Program results have been reduced and factored; conclusions are hard to report without making inferences with regard to the underlying reasoning and strategy. The metrics chosen to report results make comparisons to industry peers difficult to quantify. No discussion of the underlying program strategy is included other than to say "Our corporate goals are no accidents, no harm to people and no damage to the environment". With these limitations in mind, the focus of this review concentrated on the Greater Prudhoe Bay (GPB) pipelines. Similar findings can be applied to the field data presented in the report.

External corrosion is the most immediate threat to pipeline integrity for BPXA. External corrosion under insulation was reported as the cause for both leaks in 2000 (table 12) and there have been two additional leaks in 2001 due to external corrosion. Repairs due to external corrosion outweigh repairs due to internal corrosion by 4:1 (table 11). Tables 1 and 2 show 13,274 inspections were made for external corrosion while 20,420, or ~50% more, inspections were done for internal corrosion. External corrosion inspection levels are not consistent with the relative risk of an internal vs. external corrosion event.

Internal corrosion rates increased in 2000 in well flow lines, drillsite gathering lines, and produced water injection lines (figure 1). The actual magnitude of the corrosion increase is not reported and subsequent damage to the pipe wall due to increased corrosivity is not quantified. Seawater distribution lines showed a small decrease in corrosion rates. Figure 1 reports the results for the internal corrosion program as an "Annualized percentage of coupons with corrosion rates <2 mpy". No differentiation between weight loss and pitting corrosion are discussed. It is also reported that some coupons were removed from its system in 2000 because "a number of coupons are installed upstream of the chemical injection location and therefore provide no meaningful data". Without knowing the baseline corrosion trend within its production system it is difficult to judge the effectiveness or value of its inhibition program.

Erosional mechanisms are well characterized and are controlled by modifying the production parameters on wells likely to produce velocities and/or solids in excess. No statistics on the extent of erosion corrosion defects was reported.

Lastly, the Work Plan required a "Summary overview of ongoing structural concerns". Structural issues beyond corrosion were not addressed in either the report or the presentation. The corrosion group will need to coordinate with those tasked with maintaining pipeline structural integrity in order to address the confluence of corrosion and structural concerns.

While the BPXA report and presentation materials where an initial attempt to meet the expectations outlined in the Commitment to Corrosion Monitoring plan, it does not provide the information necessary for detailed technical analysis. BPXA and ADEC have committed to better define reporting metrics and definitions for future reports. International standards are available as a starting place for discussion of appropriate reporting metrics.

COMMITMENT TO CORROSION MONITORING

The Charter agreement between the State of Alaska, BPXA and PAI required the development of a "performance management program for the regular review" of the corrosion monitoring and related practices for the non-common carrier North Slope pipelines. As a result of the subsequent meetings, the annual reporting requirements were defined as follows:

A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.

B. A general overview of the previous year's monitoring program.

C. Metrics which depict coupon and probe corrosion rates.

D. Metrics which characterize chemical optimization activities.

E. Metrics which depict the number and type of internal/external inspection done and, as applicable, the corrosion increases/rates and corresponding inspection intervals.

F. Metrics which characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.

G. Metrics which depict the numbers and types of corrosion and structural related spills and incidents

H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meeting described above.

ADEC contracted with Coffman Engineers, Inc to provide a technical analysis of the information presented in the annual report and determine if there any specific corrosion or pipeline structural issues which warrant further review or corrective action. In addition to the annual report, Coffman reviewed the presentation materials from the April 2001 Meet and Confer Session.

CORROSION CONTROL STRATEGY

This section outlines the strategy presented in the report and presentation. It is divided into Internal and External corrosion and describes the monitoring, inspection and mitigation components. The current program status is presented in a subsequent section.

Internal Corrosion Control

Monitoring & Inspection

BPXA uses probes and coupons to monitor internal corrosion throughout the field. Information on how the coupons are analyzed and how the data is weighted is not presented. The target, or action, limit for coupons is stated as 2 mils per year (mpy). The target, or action, limit for probes is based on location and is between 0.5 mpy and 10 mils per year.

They also employ manual and automated RT and UT inspection techniques. The report discusses the limitations of the various inspection methods. Wall losses less than 10 mils (0.010") are difficult to detect. The typical amount wall loss upon first detection is not reported. The target, or action, limit for inspection is "zero detectable corrosion," which is inferred to mean something greater than 10 mils.

The data generated from the monitoring and inspection programs is reviewed weekly and in depth reviews are made at the end of each quarter. If target values are exceeded, there is an investigation and possible mitigation.

Lastly, BPXA discusses the use of Magnetic Flux Leakage (MFL) pigging technology. MFL pigging allows an operator to inspect the entire length of pipe for both internal and external corrosion indications and would be a significant tool for determining the corrosion baseline and corrosion rates for a given pipeline or pipeline sections. There is very little discussion about the MFL pigging strategy (location, frequency, results, etc.).

Mitigation

Internal corrosion at BPXA is controlled primarily by corrosion inhibitor application and secondarily by erosional velocity controls and well start-up procedures (slide 6). There are also a host of other engineering tools, such as design, material selection, coating selection, etc.

Chemical optimization is an on-going task for BPXA. As promising new inhibitors are developed they are tested on a small scale initially, followed by a larger scale test, and if successful, used within the facilities. Several products have been developed in the past years. The target values for inhibitor concentration is 150 ppm

External Corrosion Control

External corrosion under wet insulation is a concern for all North Slope producers. All the pipelines are above ground and the vast majority is insulated. Snow and water can be forced under the insulation where pipe segments are joined and field applied insulation was installed. These areas are known as weld-packs. When the line is warm and the water trapped under the insulation is above freezing, oxygen corrosion cells can form. Corrosion under insulation is likely to require an ongoing commitment throughout the life of the field. BPXA will have to validate an effective repair method in order to eliminate this as a fixed cost of operation.

Monitoring & Inspection

Presently, there are no monitoring techniques used for this corrosion mechanism. This places greater emphasis on the inspection program. Inspection methods for corrosion under insulation are radiographic and visual. TRT (tangential radiography), C-arm fluoroscopy and MFL smart pigging, eddy current, and digital radiography are used in conjunction with visual inspection to detect corrosion under insulation. The weld-pack locations are externally identifiable so the precise location of possible corrosion cells is easily ascertained. This mechanism can be expected to be active through-out the rest of the field life. In addition, BPXA is also using two technologies for inspecting the below grade, cased pipeline crossings; electromagnetic and guided wave inspection.

Mitigation

Draining the weld-pack, refurbishing the seals to eliminate water ingress, and replacing the saturated insulation are the primary mitigation methods. Repair requires the exclusion of oxygen saturated water from contact with the external pipe wall. External corrosion under insulation may be prevented by the redesign of the weld-pack to prevent water/oxygen ingress, application of inhibitor doped greases, or organic coatings, like tape systems and epoxies may help. In addition, weld-packs that have been repaired need to be inspected to verify the method is an adequate long term solution. A more in-depth review of the measures taken in the past by BPXA would be necessary before any sort of recommendation could be formulated.

CORROSION PROGRAM STATUS

Risk

With the exception of corrosion under insulation (pg31), the report does not discuss risk assessment protocols or risk based inspection. BPXA appears to use some form of risk based resource allocation method but the details are not reported. Judgment or experiential based protocols suffer from a lack of continuity; oil fields with production lifetimes in excess of half a century or more require a codified set of protocols otherwise the program changes when key personnel move on. BPXA may have codified its risk assessment strategy but it is not reported.

Internal Corrosion Control

Internal corrosion rates at GPB have increased in every service category except seawater in 2000 (Fig 1). It was reported that seven (7) repairs and 63 saves were recorded due to internal corrosion in 2000 (Table 11 and 12). BPXA reports its inspection results for internal corrosion as "percent of inspection increases" (see fig.4). Unfortunately only the percentage of inspections which show increases in damage is reported; not the magnitude of the wall loss.

BPXA reports a loss of corrosion control due to under-treatment with corrosion inhibitor in 2000 (pg 23). The loss of control is attributed to damaged corrosion inhibitor chemical (the active ingredients precipitated out of solution and plugged the injection tubing) and to manpower reductions incurred during the reorganization. Reportedly, these issues have been rectified and they expect to be back on-track in 2001. BPXA states damage due to these corrosion rate increases were probably limited to on pad piping because off-pad piping is protected by the redundancy inherent in wellhead injection. The actual inhibitor concentration achieved in each gathering line is not reported, however the overall concentration would be lower. No attempt is made to quantify the possible extent of internal pipe wall loss due to this corrosion rate excursion. It would be beneficial to understand how the coupon and probe rates varied during this episode and whether or not inspection results saw correlative increases in pipe wall damage.

Coupon data by service class were summarized in a series of bar graphs (figure 1). The vertical axis is scaled as Annualized percentage of coupons <2 mpy. Increases in corrosivity appear as decreases in bar height. The report states that corrosion rates are increasing in the three-phase gathering system and the produced water distribution system. Figures 4 and 5 show the inspection results for internal corrosion. Increases in pipe wall damage were noted for both of the injection service categories depicted, while inspections finding increased internal damage on three-phase piping remain flat. Inspections have not detected any appreciable increase due to lower than normal inhibitor concentration in three-phase piping. The increases in the downstream produced water system could be due to the reported inhibitor under-treatment even though the three-phase piping has shown no such change.

Monitoring & Inspection

BPXA used 8,970 coupons in 2000 down from 11,574 in '97. The reduction is explained by the following:

- changes in pull frequencies in the produced water system not a reduction in locations,
- reduction in the number of coupons in the production well lines, primarily upstream of chemical injection, and
- wells that are in long term shut-in.

The number of coupon locations per service category (PW/SW/3-phase, etc;) would be beneficial for clarifying performance of the coupon monitoring program. No discussion of how coupons are analyzed is reported. Coupon grading requires a subjective, judgment-based, analysis of the coupon surface condition (pitting) as well as a weight loss measurement. There are also several Industry Standards relevant to corrosion coupon use in oil field applications.

Table 13 reports "Leaks and Saves" by year but the cause of the leaks is not reported (except for 2000) so conclusions can not be made about the historical probability of a leak due to internal vs. external causes.

Mitigation

BPXA runs an extensive program of corrosion inhibitor development. Table 6 shows the progression of corrosion inhibitor products over time. Six inhibitor formulations were used across the GPB in 2000. Why different inhibitors are used in different areas is not reported. Table 7 shows the produced water volume treated and the inhibitor concentration per year. The inhibitor concentration required for mitigation has risen from a low of 106 ppm in 1996 to a high of 149 ppm in 2000. BPXA reports that though water volumes remain relatively flat, water-cuts have increased along with flow velocities (increased gas handling is cited) requiring an increase in inhibitor concentration over time. Continuous trials are run seeking to improve inhibitor performance and cost effectiveness.

External Corrosion Control

There are approximately 185,000 weld-packs at GPB. Slide 4 states the two corrosion related pipeline leaks it experienced in 2000 were due to external corrosion under insulation. Inspections in the year 2000 identified approximately 500 locations (out of 13,274 inspected) where damage increased due to external corrosion under insulation. Figure 3 shows that for the last four years between 4% and 8% of all the locations inspected with TRT yielded external corrosion damage. Table 8 displays the recur frequency for external corrosion under insulation inspections, assigned only by pipeline operating temperature.

During 2000, BPXA repaired 28 locations due to external corrosion and only 7 locations due to internal corrosion. External corrosion will require an ongoing commitment of resources by BPXA for the life of the field. The inspection effort appears to be changing the focus from, off-pad, cross-country lines to the on-pad weld packs. In 2000, BPXA inspected 7,632 on-pad locations and 5,642 off-pad locations.

While it is difficult to be exact, it appears there have been inspections on ~70,000 weld-packs, or 38% of the total (185,000) and ~5% show pipe wall damage detected. Of the 500 locations found in 2000, there were 28 repairs, or ~5% of damaged locations. If the same percentages are applied to the remaining population there are approximately 5,700 weld-packs with pipe wall damage and almost 300 repairs to be made.

There are 1,800 below grade, cased piping segments in 350 crossings. During 2000, 200 to 300 segments were inspected and there were 3 segments either replaced or repaired. It is unclear what the total number of inspected segments overall, only 2000 inspections were reported. Extrapolating the 2000 results to the entire population, there appears to be several areas that will require repair in this category of pipe.

RECOMMENDATIONS:

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. Results should be reported by BPXA to ADEC in a format consistent with industry recognized standards or practices. Guidelines are available from international standards organizations and those listed below are provided as examples.

    - NACE RP0690 Standard Format for Collection and Compilation of Data for Computerized Material Corrosion Resistance Database Input
    - ASTM G15-99b Standard Terminology Relating to Corrosion and Corrosion Testing
    - ISO 8044:1999 Corrosion of Metals and Alloys: Basic Terms and Definitions

2. Inspection and monitoring data need to be reported by service category and a definition of each service category needs to be supplied. The service category definitions used by BPXA should be agreed upon and remain consistent. For instance, the corrosion data gathered for a pipeline that has been on produced water injection for 100% of its service life will have a different corrosion history than a pipeline that has seen only de-oxygenated sea water for 100% of its service life. Pipelines may see service as producers or injectors; carry produced water, seawater or some mixture thereof. The rules used by BPXA to assign service categories for well inspection and monitoring programs need to be understood. The coupon database should include the well service history. The service category (production, injection, or shut-in) that predominates during the coupon exposure period should be used.

3. Results of coupon monitoring for a given service category (i.e. produced water injection wells) should be linked to the inspection results for produced water injection wells. Service category definitions used by the monitoring program need to be the same service category definitions used by the inspection program. For instance BPXA lumps all of the internal corrosion coupon results reported in slide 9 into a service category called "Well Line" yet the inspection results reported on slide 11 are divided into "3-phase Production" and "PWI/SWI Supply". This lumps wells and gathering lines in the inspection results making any correlation between monitoring results and inspections results impossible to discern.

4. BPXA should include the results of smart pig runs in its report if smart pig runs were made on non-common carrier pipelines. Table 3 reports smart pigs were run on non-common carrier pipelines in the GPB but does not report the results of these runs. The results of these inspections should be used to verify the corrosion mechanism and the extent of any corrosion networks. A histogram (i.e. frequency vs. pipe-wall penetration) of the corrosion anomalies detected from each run would be useful. When pipelines are smart-pigged more than once, the differences from run to run could be used to establish corrosion rates. Smart pigging is the only inspection technique capable of looking at the whole internal and external corrosion picture.

5. Some questions which arise after reading the report are; does BPXA pig every non-common carrier pipeline of suitable diameter? Are there plans to install/configure EOA pipelines for smart pigs? Are baseline smart-pig runs performed on newly commissioned lines? How are lines selected for smart pigging and what is the recur frequency of inspection? What were the service categories of the lines inspected and how did this inspection data compare to that gathered by other inspection techniques? Did coupon data detect a correlation with any damage discovered by pigging? Is the corrosion damage morphology consistent with the postulated corrosion mechanism?

6. Coupons should be re-installed upstream of corrosion inhibition injection locations in a statistically representative sample of production wells. BPXA removed coupons located upstream of inhibitor injection points (pg 11) stating these locations provided "no meaningful data". The inhibited corrosion rate needs to be

measured against the uninhibited corrosion rate to determine the inhibitors efficiency.

7. Coupon access fitting locations need to be changed to reflect an improved understanding of the corrosion mechanism. BPXA reported that coupons under-reported corrosion rates or provided "no meaningful data" (page 11). These ambiguous results are consistent with an under-deposit corrosion mechanism. BPXA is missing a piece of the bigger corrosion picture and may miss significant, localized changes in the production stream baseline corrosivity.

8. BPXA should report how coupon results are analyzed. The report makes no reference to pitting corrosion rates. If pitting is not a concern or has never been implicated in a corrosion failure in the GPB then that should be stated. Pitting is a corrosion concern for typical oil field operations. The following is a sample of industry standards related to corrosion coupons:

    - ASTM G4-95 Standard Guide for Conducting Corrosion Coupon Tests in Field Applications
    - ISO 11463:1995 Corrosion of Metals and Alloys: Evaluation of Pitting Corrosion
    - ASTM G1-90 (1999)e1 Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens
    - NACE RP0775 Preparation, Installation, Analysis, and Interpretation of Coupons in Oilfield Environments
    - ASTM G46-94(1999) Standard Guide for Examination and Evaluation of Pitting Corrosion

9. Include a historical Leak/Repair history from field start-up to the present. Leak/Repair history is a traditional means of gauging program effectiveness over time. A table that listed leaks, by cause and repairs by pipeline, would be useful for placing the results reported for 2000 into a historical context. Additional items that would be beneficial include volume of spill, identified corrective actions, and implementation of corrective actions.

10. Include a table or diagram that reports the historical inhibitor concentration for each cross-country production gathering line. BPXA reports under-treating with corrosion inhibitor due to mechanical and personnel problems (page 13). Corrosion damage is cumulative over the life of the asset and under-treatment results in increased pipe wall loss.

11. Report residual inhibitor concentrations in produced water streams. Residual inhibitor concentrations should be measured on a regular basis in the produced water fluid stream since credit is taken for the inhibition effect of the residuals. If corrosion inhibitor is injected to protect injection water distribution systems include those program details as well.

12. Maintenance pigging is a part of the corrosion mitigation effort. The pipelines which are maintenance pigged and the maintenance pigging intervals should be reported.

13. Provide a histogram of external pipe-wall defect penetration by year (frequency vs. pipe-wall penetration). The report shows 20,420 internal inspections (Table 1 and 2) and 13,274 external inspections done in 2000. The two reported leaks in 2000 were due to external causes and there are still approximately 500 locations discovered each year with increasing damage. Are the inspection resources allocated in proportion to the risk of an occurrence?

14. Develop a flow diagram detailing the decision making process or risk-based strategy used to allocate inspection, monitoring, and inhibition resources. If possible, reference a third party standard or practice (i.e. ASTM 2081-00 Standard Guide for Risk-based Corrective Action or API PUBL 581 Risk-based Inspection Base Resource Document First Edition).

15. Provide a summary in the next report of significant structural concerns impacting non-common-carrier pipelines. Provide a historical look at leaks/repairs due to structural reasons from field start-up to present.

CONCLUSIONS

The reporting style and corrosion metrics used in the subject report make it difficult to develop a qualitative understanding of the basis and underlying strategies employed by BPXA. ADEC and BPXA have committed to better define the metrics used for reporting. The BPXA report was comprehensive in scope but lacked sufficient data for a technical analysis. Industry recognized metrics are necessary to make peer to peer comparisons of program results.

External corrosion-under-insulation is the corrosion mechanism with the highest probability of producing a leak in near future. While the external corrosion program is ongoing, it may not be receiving the appropriate resources; repairs due to external corrosion exceed those due to internal corrosion by 4:1 and both leaks reported for 2000 were due to external mechanisms. Time will tell if the inspection recur frequency (table 8) for external repairs is appropriate; tracking external corrosion increases by recur interval would validate this approach.

Internal corrosion rates increased in 2000 in production gathering systems and produced water injection systems. Inhibitor concentrations necessary for corrosion control are increasing (table 7). BPXA has identified and corrected issues leading to low inhibiter concentrations that may have resulted in increased damage to piping. There have been corrosion inhibitor quality issues (pg 23) that have impacted inhibitor injection concentration compliance. Inhibitor concentrations over time need to be reported by pipeline; reporting aggregate averages does not allow for technical analysis of the program merits. Details of how BPXA analyzes coupons need to be reported. No mention of coupon pitting measurements was made. Coupons removed from locations upstream of injection locations need to be re-installed in a statistically representative number of locations.

Structural issues were not discussed and need to be included in future reports. Pipeline sagging due to support member frost-jacking, wind induced vibration, subsidence, and snow loading in pipelines already at risk due to pipe-wall thinning need to be addressed.

The corrosion program results outlined in the report submitted to ADEC demonstrate a clear commitment by BPXA to mitigate corrosion and its impact to the environment and the field assets. The adoption of mutually agreed upon metrics for reporting and additional technical detail in the next reporting cycle will eliminate many of the issues raised by this review.

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Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami and Milne Point

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BPXA has demonstrated a clear commitment to corrosion control. BPXA has developed a comprehensive program of monitoring and inspection. Reported results indicate internal pipeline corrosion trends for GPB West have been steadily improving since 1993 and are currently at their lowest levels in 12 years. BPXA has made a significant commitment to corrosion inhibitor testing and development, as well as reducing the number of products to a more manageable selection.

BPXA reports coupon corrosion rates as "Annualized Percentage < 2 mpy." These coupon corrosion rates increased slightly in 2000 for well flow lines, drill site gathering lines, and produced water injection lines; while they decreased slightly in the seawater injection lines. The average magnitude of the coupon corrosion rate change is not presented, however the majority, 85+%, has rates below the 2mpy threshold. BPXA has analyzed the causes relating to the coupon corrosion rate increases and has taken steps to reverse the trends.

Compared to 1999, inspection results for well lines show increases in the number of locations reporting damage to the pipe wall in all injection (PW/SW/MI) service categories; conversely three-phase production well lines are relatively flat and are at their lowest levels in the period reported (1995-2000).

Presently, external corrosion is a significant risk to pipeline integrity for BPXA. External corrosion under insulation was reported as the cause for both leaks in 2000 and two additional leaks in 2001. The need for additional resources for external corrosion management should be re-examined.

The BPXA report and presentation materials were a positive step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan. BPXA and ADEC have committed to better define reporting metrics and definitions for future reports.

COMMITMENT TO CORROSION MONITORING

The Charter agreement between the State of Alaska, BPXA and PAI required the development of a "performance management program for the regular review" of the corrosion monitoring and related practices for the non-common carrier North Slope pipelines. As a result of the subsequent meetings, the annual reporting requirements were defined as follows:

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F. Metrics which characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.

G. Metrics which depict the numbers and types of corrosion and structural related spills and incidents

H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meeting described above.

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CORROSION CONTROL STRATEGY

This section outlines the strategy presented in the report and presentation. It is divided into internal and external corrosion strategies and describes the monitoring, inspection and mitigation components. The current program status is presented in a subsequent section.

Internal Corrosion Strategy

Monitoring & Inspection

BPXA uses probes, coupons and numerous inspection methods to monitor internal corrosion throughout the field. It is unclear how the coupons are analyzed and how the data are weighted. The target, or action, limit for coupons is 2 mils per year (mpy). The target, or action, limit for probes is based on location and is between 0.5 mpy and 10 mils per year.

BPXA employs manual and automated RT and UT inspection techniques. The report discusses the limitations of the various inspection methods and BPXA has a clear understanding of their strengths and weaknesses. Wall losses less than 10 mils (0.010") are difficult to detect reliably using RT. The target, or action, limit for inspection is "zero detectable corrosion."

The data generated from the monitoring and inspection programs are reviewed weekly and in-depth reviews are made at the end of each quarter. If target values are exceeded, there is an investigation and possible repair/replacement/mitigation.

Lastly, BPXA discusses the use of Magnetic Flux Leakage (MFL) pigging technology. MFL pigging allows an operator to inspect the entire length of pipe for both internal and external corrosion indications and can be a significant tool for determining the actual fitness for purpose of a pipeline. In future reports, a more in-depth discussion about the MFL pigging strategy (location, frequency, results, etc.) would be helpful.

Mitigation

Internal corrosion at BPXA is controlled primarily by corrosion inhibitor application and secondarily by erosional velocity controls and well start-up procedures (slide 6). Other engineering tools, such as design, material selection, coating selection, etc., are also used by BPXA to control corrosion.

Chemical optimization is an on-going task for BPXA. As promising new inhibitors are developed they are tested on a small scale initially, followed by a larger scale test, and if successful, used within the facilities. Several products have been developed in the past years. BPXA's strategy is to inject inhibitor volumes until coupon corrosion rates of less than 2 mpy are achieved.

External Corrosion Strategy

External corrosion under wet insulation is a concern for all North Slope producers. The vast majority of pipelines is above ground and thermally insulated. Snow and water can be forced under the insulation where pipe segments are joined and field applied insulation was installed. These areas are known as weld-packs. When the line is warm and the water trapped under the insulation is above freezing, corrosion cells can form. Corrosion under insulation is likely to require an ongoing commitment of resources throughout the life of the field.

Monitoring & Inspection

BPXA is currently managing 1/3 of a million weld-packs (slide 15) between GPB and ACT. Presently, there are no monitoring techniques used for this corrosion mechanism. This places greater emphasis on the inspection program. Inspection methods for corrosion under insulation are radiographic and visual. TRT (tangential radiography), C-arm fluoroscopy and MFL smart pigging, eddy current, and digital radiography are used in conjunction with visual inspection to detect corrosion under insulation. The weld-pack locations are externally identifiable, so the precise location of possible corrosion cells is known in advance. This mechanism can be expected to be active throughout the rest of the field life. In addition, BPXA is also using two new technologies for inspecting the below grade, cased pipeline crossings; electromagnetic and guided wave inspection.

Mitigation

Refurbishment of the weld-pack requires the exclusion of oxygen saturated water from contact with the external pipe wall. The primary refurbishment method is to drain the weld-pack, refurbish the seals to eliminate water ingress, coat the pipe, and replace the saturated insulation. A more in-depth review, of past BPXA measures taken, would be necessary before recommendations could be formulated.

CORROSION PROGRAM STATUS

Risk

While not required by the Charter agreement, risk (risk assessment, risk based inspection, etc.) is an important tool used in corrosion control. It would beneficial if BPXA would further elaborate on how risk is utilized in future reports. For example, how BPXA evaluates the probability of a failure due to a specific corrosion mechanism and then how the consequences of the potential failure were evaluated to formulate a mitigation plan. It is clear that a form of risk based resource allocation is used by BPXA; the corrosion team has identified and responded to corrosion events and developed continuous improvements to its corrosion program when changes were deemed necessary (pg 12 and 13).

Internal Corrosion Management

Internal coupon corrosion rates at GPB have increased slightly in every service category except seawater in 2000 (Fig 1). It was reported that seven repairs and 63 saves were recorded due to internal corrosion in 2000 (Table 11 and 12). Results reported for the year 2000 show increases in the number of locations reporting ongoing pipe wall damage in all of the injection service categories (PW/SW/MI). Conversely, three-phase production well lines are relatively flat for the last two years and are at their lowest levels in the reported period (1995-2000).

BPXA reports a loss of corrosion control due to under-treatment with corrosion inhibitor in 2000 (pg 23). The loss of control is attributed to damaged corrosion inhibitor chemical (the active ingredients precipitated out of solution and plugged the injection tubing) and to manpower reductions incurred during the reorganization. These events lead to a period of corrosion inhibitor under-treatment and a subsequent increase in corrosivity. The problem was identified and these issues have been addressed, and they expect to be back on-track in 2001. BPXA believes damage due to these corrosion rate increases were probably limited to on-pad piping because off-pad piping is protected by the redundancy inherent in the wellhead corrosion inhibitor injection program. It would be beneficial to understand how the coupon and probe rates varied during this episode and whether or not inspection results saw correlative increases in pipe wall damage to the on-pad piping.

Monitoring & Inspection

BPXA used 8,970 coupons in 2000, down from 11,574 in 1997. The reduction is explained by the following:

- changes in pull frequencies in the produced water system not a reduction in locations,
- reduction in the number of coupons in the production well lines, primarily upstream of chemical injection, and
- wells that are in long term shut-in.

The number of coupon locations per service category (PW/SW/3-phase, etc.) would be beneficial for clarifying performance of the coupon monitoring program. Coupon grading usually contains a judgment-based analysis of the coupon surface condition as well as objective pit depth and weight loss measurements. A discussion detailing how coupons are evaluated by BPXA would be beneficial, as it is apparent that there are differences in the way various operators perform this function.

Table 13 reports "Leaks and Saves" by year. Saves outnumber leaks by approximately 10:1 with overall leak/save ratios running from a low of 88% to a high of 97% achieved in 2000. The change is due to inspection, BPXA found defects before they became leaks. It would be helpful, in future reports, to know the cause of the leak (internal vs. external, isolated pit or network). Some discussion of how the defect was dealt with would also be beneficial; for instance was the defect sleeved or was the pipe segment replaced.

Mitigation

BPXA runs an extensive and proactive corrosion inhibitor development program. Table 6 shows the progression of corrosion inhibitor products over time. Six inhibitor formulations were used across the GPB in 2000. Table 7 shows the produced water volume treated and the inhibitor concentration per year. The field-wide average inhibitor concentration required for mitigation (coupon corrosion rates < 2mpy) has risen from a low of 106 ppm in 1996 to a high of 149 ppm in 2000. BPXA reports that even though water volumes remain relatively flat, water-cuts have increased along with flow velocities (increased gas handling is cited) requiring an increase in inhibitor concentration over time. Continuous trials are run seeking to improve inhibitor performance and cost effectiveness.

External Corrosion Management

There are approximately 185,000 weld-packs in the GPB. Slide 4 states the two corrosion related pipeline leaks it experienced in 2000 were due to external corrosion under insulation. Inspections in the year 2000 identified approximately 500 locations (out of 13,274 inspected) where damage increased due to external corrosion under insulation. Figure 3 shows that for the last four years between 4% and 8% of all the locations inspected with TRT yielded external corrosion damage. Table 8 displays the recur frequency for external corrosion under insulation inspections, recur inspection frequencies are assigned by pipeline operating temperature. Pipeline age and wall thickness are also factors that may need to be evaluated in this context.

During 2000, BPXA repaired 28 locations due to external corrosion and only 7 locations due to internal corrosion. External corrosion will require an ongoing commitment of resources by BPXA for the life of the field. The inspection effort appears to be changing the focus from, off-pad cross-country lines to the on-pad weld packs. In 2000, BPXA inspected 7,632 on-pad weld-packs and 5,642 off-pad weld-packs for external corrosion. However, there were 20,420 (~50%

more) inspections for internal corrosion. External corrosion inspection levels do not seem to be consistent with the current relative risk of an internal vs. external corrosion event. The need for additional resources for external corrosion management should be re-examined.

While it is difficult to be exact, it appears there have been inspections on ~70,000 weld-packs, or 38% of the total (185,000) and ~5% show external pipe wall damage detected. Of the 500 locations found in 2000, there were 28 repairs, or ~5% of damaged locations. If the same percentages are applied to the remaining population there are approximately 5,700 weld-packs with potential pipe wall damage and almost 300 potential repairs to be made.

There are 1,800 below grade, cased piping segments in 350 crossings. Below grade piping is affected by both of the internal and external corrosion mechanisms reported above. Since the below grade locations are cased and buried, excavation of the location or inline inspection (not available on every pipeline) are the only certain methods of defect assessment at this time. Currently, two techniques (electromagnetic pulse and guided wave) are being investigated that allow a degree of defect detection without requiring excavation. During 2000, 200 to 300 below-grade segments were inspected and there were 3 segments either replaced or repaired. The overall total number of inspected segments to date was not reported. Extrapolating the 2000 results to the entire population, there may be several areas that could require repair.

RECOMMENDATIONS:

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. It would be beneficial if results reported by BPXA to ADEC were presented in a format using metrics that are mutually agreed upon by PAI, BPXA and ADEC.
2. Inspection and monitoring data quality would benefit from being reported using a consistent definition of each service category. For example, when coupon monitoring results for produced water injection wells are reported, it would be useful to see a summary of inspection results for the same service category (i.e. produced water injection wells). BPXA did report inspection results for well lines by service category, but it is not always apparent that the service category definition used for monitoring results is the same as that used for inspection.
3. If smart pig runs were made on non-common carrier pipelines, inclusion of the results would be useful. Table 3 indicates smart pigs were run on non-common carrier pipelines in the GPB but no results were presented.
4. A discussion of details pertaining to how coupons are analyzed and ranked would be beneficial.
5. A summary leak/repair history for a five year period would be useful. Include service category, internal/external corrosion, and physical pipe information (diameter, wall thickness, and years in service).
6. In addition to the field-wide average inhibitor concentration discussions, provide some case specific examples. For instance, if BPXA has an individual line or

gathering system that requires significantly more (or less) inhibitor than the field wide average, it would beneficial to report these exceptions.

7. If maintenance pigging is a part of the corrosion mitigation effort, then discussing the pigging intervals and program details for various service categories would be useful.

8. BPXA reports no current structural issues or concerns in the 2000 report. Other operators on the North Slope report subsidence and jacking issues in areas affected by permafrost thawing around well bores. BPXA's experience in this regard would be beneficial.

CONCLUSIONS

The BPXA report and presentation demonstrates a proactive commitment to mitigate corrosion of non-common carrier pipelines, and were a positive step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan. BPXA and ADEC have committed to better define reporting metrics and definitions for future reports.

Results show that overall pipeline internal corrosion trends have been steadily improving since 1993 and are currently reported to be at the lowest levels in 12 years. However, internal corrosion rates increased slightly in 2000 in some production gathering systems and produced water injection systems. BPXA has taken corrective steps for those systems and hopes to measure improvements in the coming year.

External corrosion is a significant risk to BPXA pipeline integrity. Both leaks reported for 2000 and 2001 were due to external corrosion. Additional resources may be required to achieve the same level of corrosion control as demonstrated for internal corrosion.

BP's Ineffective Corrosion Monitoring Program on the North Slope of Alaska

Analysis provided by *BPCONCERNS.com*
March 20, 2006

I. PURPOSE:

This analysis is the first in a series of reports and exposes which will be developed and posted by *BPCONCERNS.com* to identify and reveal publicly, errors, miscalculations, and when appropriate, allegations and evidence of intentional violations and neglect by BP and others in the oil industry.

II. THE PLAYERS:

BP, formerly known as British Petroleum, is a major multinational oil company that posted record annual profits for 2005 at $19.3 billion up 25 per cent compared with 2004. BP is the majority owner of the Trans Alaska Pipeline, as well as the majority owner and operator of the North Slope of Alaska. BP in Alaska is known as BP Alaska Exploration Inc. or "BPAX" but will be identified in this analysis as "BP". Also, for the purposes of this analysis, the state agency responsible for oversight of BP in Alaska is the Alaska Department of Environmental Conservation, Division of Spill Prevention and Response, which will be identified merely as "ADEC."

III. SUMMARY:

In late 2001, Coffman Engineers Inc. was placed under contract by ADEC to review the BP North Slope Corrosion Monitoring program and provide a report. *BPConcerns.com* recently discovered that Coffman-Engineers issued two reports to ADEC. The initial Coffman report was highly critical of BP and was reportedly suppressed by ADEC due to extreme pressure by BP to do so, and the second report, reportedly heavily edited and revised at BP's direction, is the "official" report that the Alaska state agency, ADEC acknowledges. In Section VIII we will compare details in the two reports.

IV. RECENT HISTORY:

As reported extensively in the national media over the past several weeks, the flawed BP corrosion program has allowed the largest spill ever on the North Slope to occur, spilling in excess of 267,000 gallons. Even by BP's own reluctant admission, this spill was caused by internal corrosion.

How did this massive spill occur, especially in light of the recently exposed detailed Coffman report that warned the State of Alaska in 2001 of inadequate BP corrosion monitoring and control? Why didn't ADEC act then? The study and subsequent report was to be prepared and provided to ADEC by the aforementioned independent third-party entity, Coffman Engineers[1]. Few people, outside select DEAC and BP personnel, realize there were actually two Coffman Engineers reports issued to ADEC but only one was made public. Why was the first Coffman report suppressed?

V. TWO CONFLICTING COFFMAN REPORTS:

Coffman Engineers did indeed produce an initial, well-researched, complete but succinct eleven page report, almost devoid of ambiguity, including significant but not burdensome details, footnotes, and references. For the purposes of this analysis it will be identified as the "First Coffman Report."[2] This "First Coffman Report" identified numerous deficiencies with BP's North Slope corrosion monitoring program. The second report was heavily edited and revised with direct BP influence and for the purpose of this analysis, is identified as "BP Revised Second Report." The "BP Revised Second Report" was reduced from the original eleven pages to eight pages, a number of key problems that were identified were redacted, and major expository evidence was "revised" that were identified in the earlier "First Coffman Report."

VI. BP EXPRESSED DISSATISFACTION TO ADEC:

In a previously unreleased BP document, "BP Response to Coffman Final Draft" dated November 2001, BP displays a show of power and influence over Alaska regulators, by first dismissing and degrading the results documented in the "First Coffman Report" and then pressuring ADEC to make the extreme revision of the Coffman Engineers "First Report" to make it less "negative." It has been alleged that ADEC Director Larry Dietrick complied with BP's demands without question.

BP demanded that Coffman Engineers, Inc. dilute the most damning comments, remove whole negative sections of the report, and revise the entire report, as BP noted, "The whole tone of the report [First Coffman Report] seems extremely negative ...and "[presents] very few positive references." BP went on to quietly upbraid ADEC Director Larry Dietrick for the report, "It would be more appropriate if the report was worded as a request for more information and suggested actions or options to be investigated." ADEC was extremely compliant to BP's demands and allegedly intimidated Coffman Engineers to rewrite the report with BP's changes incorporated.[3]

VII. ADEC CALLS FOR DRASTIC REVISIONS OF REPORT AT BP's REQUEST

The following conflicting findings in the two reports demonstrate the duplicity of BP and the danger of the alleged complicity of ADEC Director Mr. Dietrick with Mr. Mach. Please see excerpts from the Coffman "First Report" (blue heading) and the corresponding revised findings in the "BP Revised Report" (red heading). All comments are verbatim from the two reports unless cited otherwise.

VIII. COMPARISON OF THE TWO REPORTS

EXECUTIVE SUMMARY EXCERPT from "First Coffman Report":

BPXA [BP Exploration Alaska] stated intent to 'report openly, good or bad ...' the results of its corrosion management programs. However the reporting style makes it difficult to develop a qualitative understanding of the basis for their corrosion strategy. Program results have been reduced and factored; conclusions are hard to report without making inferences with regard to the underlying reasoning or strategy. The metrics chosen to report results make comparison to industry peers difficult to quantify. No discussion of the underlying program strategy is included other than to say, 'Our corporate goals are no accidents, no harm to people and no damage to the environment.

EXECUTIVE SUMMARY EXCERPT, from corresponding section in the "BP Revised Report":

BPXA has demonstrated a clear commitment to corrosion control. BPXA has developed a comprehensive program of monitoring and inspection.

EXECUTIVE SUMMARY EXCERPT from "First Coffman Report":

The actual magnitude of the corrosion increase is not reported and subsequent damage to the pipe wall due to increased corrosivity is not quantified.
External corrosion inspection levels are not consistent with the relative risk of an internal vs. external corrosion event.
No differentiation between weight loss and pitting corrosion are discussed.
No statistics on the extent of corrosion defects were reported.
Without knowing the baseline corrosion trend within its production system it is difficult to judge the effectiveness or value of the [corrosion] inhibition program.
Lastly, the [BP] Work Plan required a summary overview of ongoing structural concerns [pipeline structural integrity]. Structural issues beyond corrosion were not addressed in either the report or the presentation.

EXECUTIVE SUMMARY EXCERPT, from corresponding section in the "BP Revised Report":

All of the comments from the "First Report" (directly above) were struck from the "BP Revised Second Report" so there are no corresponding comments.

EXCERPT FROM BODY OF "First Coffman Report":

While the BPXA report and presentation materials were an initial attempt to meet the expectations outlined in the Commitment to Corrosion Monitoring plan, it does not provide the information necessary for detailed technical analysis. (Emphasis added)

Corresponding section in the "BP Revised Report":

The BPXA report and presentation materials were a positive step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan.

EXCERPT FROM BODY OF "First Coffman Report":

With the exception of corrosion under insulation the report does not discuss risk assessment protocols or risk based inspection.

Corresponding section in the "BP Revised Report":

It is clear that a form of risk based resource allocation is used by BPXA

EXCERPT FROM BODY OF "First Coffman Report":

BPXA reports its inspection results for internal corrosion as 'percent of inspection increases'. Unfortunately only the percentage of inspections which show increases in damage is reported; not the magnitude of the wall loss.

Corresponding section in the "BP Revised Report":

Deleted from BP Revised Report.

EXCERPT FROM BODY OF "First Coffman Report":

Reportedly, these issues [problems with corrosion inhibitor and manpower reduction] *have been rectified and they expect to be back on-track in 2001.*

Corresponding section in the "BP Revised Report":
The problem was identified and these issues have been addressed, and they expect to be back on track in 2001.[4]

EXCERPT FROM BODY OF "First Coffman Report":

BPXA should include the results of smart pig runs if smart pig runs were made (Emphasis added)

Corresponding section in the "BP Revised Report":

If smart pig runs were made then inclusion of the results would be useful[5] (Emphasis added.) This is more misleading semantics. Please see footnote 3 and 4 for further information.

EXCERPT FROM BODY OF "First Coffman Report":

Does BPXA pig every non-common carrier pipeline of suitable diameter?
Are there plans to install/reconfigure EOA pipelines for smart pigs?
Are baseline smart pig runs performed on newly commissioned lines?
How are lines selected for smart pigging and what is the recur frequency of inspection?
What were the service categories of the lines inspected and how did this inspection data compare to that gathered by other inspection techniques?

Corresponding section in the "BP Revised Report":

If maintenance pigging is a part of the corrosion mitigation effort, then discussing the pigging intervals and program details for various services would be useful.

EXCERPT FROM BODY OF "First Coffman Report":

The reporting style and corrosion metrics used in the subject report makes it difficult to develop a qualitative understanding of the basis and underlying strategies employed by BPXA. The BPXA report was comprehensive in scope but lacked sufficient data for a technical analysis.[6] (See footnote 6 for explanation of why the phrase "comprehensive in scope" was used.)

Corresponding section in the "BP Revised Report":

The BPXA report and presentation demonstrates a proactive commitment to mitigate corrosion of non-common carrier pipelines and were a positive step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan.

EXCERPT FROM BODY OF "First Coffman Report":

Structural issues were not discussed and need to be included in future reports. Pipeline sagging due to support member frost-jacking, wind induced vibration, subsidence, and snow loading in pipelines already at risk due to pipe-wall thinning need to be addressed.

Corresponding section in the "BP Revised Report":

BPXA reports no current structural issues or concerns in the 2000 report.[7] (Emphasis added)

Section IX. CONCLUSIONS:

BP obviously influenced the DAEC to dilute the original Coffman Report to improve the "tone" with "positive" comments and removal of the "negative" to portray BP's corrosion efforts in a more favorable light. Unfortunately, this also removed the very points that might have prevented the current spill and future spills. Especially troublesome is the revelation that BP and ADEC have been completely informed and aware of the potential for internal corrosion leaks since at least 2001. We should not be surprised that the recent spill occurred and we should expect more as this system ages and BP continues to reduce costs and manpower.

SECTION X. RECOMMENDATIONS:

1 An independent audit by the State of Alaska to examine the documents referenced in this *BPCONCERNS.com* analysis:

   a. All Coffman Engineers Inc. submittals to ADEC.
   b. All documents, notes, diaries, emails or other communications related to this issue held by Larry Dietrick, ADEC Director.
   c. All documents, notes, diaries, emails or other communications related to this issue held by BP personnel that communicated with Larry Dietrick, ADEC Director.

2. Self disclosure by the ADEC to the United States Environmental Protection Agency and cooperation with any and all Investigators including Federal Criminal Investigators on this issue.

-Analysis by Glen Plumlee, former BP Analyst

[1] Coffman Engineers Inc. analysis of BP Corrosion Monitoring of Non-Common Carrier North Slope Pipelines – 2000 Commitment to Corrosion Monitoring – ADEC Contract No. 18-6000-02
[2] This "First Coffman Report" can be found in ADEC historical documents, under the ADEC title of Coffman Engineers, November 2001 Final Draft, Contract No. 18-6000-02.

[3] The ADEC and BP documentation described in this analysis can be requested, and received, typically free of charge, by using the Alaska State version of the Freedom of Information Act, that is, if the originals have not been "inadvertently" destroyed or lost by the agency in question. In the near future a link and examples of past, successful freedom of information requests submitted by concerned Alaska citizens will be provided on this site free to be used as a guide as needed. We will also include U.S. Federal Freedom of Information Act request examples, information, and links.

[4] Please notice the revision of the phrase, "Reportedly have been rectified" used in the first report that was changed in the BP revised report to read, "The problem was identified and issues have been addressed." The first report implied that although reportedly the problem had been rectified it was still in question by Coffman Engineers. In the second revised BP the wording was softened and states that the "issues" (not "problems") were "addressed" (not "rectified") indicating that they may have misled regulators in earlier BP reports and presentations. Semantics of this sort are very typical in oil industry reports and white papers.

[5] The words "should" and "shall" have very precise definitions in the oil industry regulations and standards. The phrase "would be useful" indicates an afterthought and not even a recommendation. That is not what Coffman Engineers originally had in mind when they used the word "should". It was meant as a recommendation. This is well understood in oil industry documentation.

[6] Again, this is a common technique in oil industry and popularly called "cover 'em up with paper", therefore the qualifying statement by Coffman Engineers, that BP provided a "comprehensive report" but it still "lacked sufficient data." This was a generous and respectful way for the author of the report to notify BP that the ploy to turnover large amounts of documents but no real data had not influenced his findings.

[7] The use of the word "current" allows a future escape from responsibility. Using "current" is another word device used in the oil industry to provide cover if future problems do occur, e.g., total failure of a pipeline due to the snow load, wind, subsidence, etc. described in the "First Coffman Report."

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Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2001 for Greater Prudhoe Bay, Endicott, Badami and Milne Point

Submitted by

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ADEC Contract Number – 18-6000-02

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2001 corrosion program report submitted by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the October 2001 and April 2002 Meet & Confer sessions. BPXA and ADEC mutually agreed to a performance metric guide prior to drafting the 2001 report. The results are a much improved report that better defines the service categories and basic summary statistics.

The 2001 report contain more detail and is wider in scope than the 2000 Report and covers corrosion management strategy and objectives. BPXA has done a good job in further clarifying how it uses raw corrosion data to focus its inspection and inhibition programs. However, in some cases, the facility piping population was included with the non-common carrier piping population. While the facility piping information is useful, it makes an analysis of the non-common carrier piping difficult to perform.

Internal corrosion control in oil flow lines is clearly indicated by coupons and inspections, with average corrosion rates approaching the historical minimum. Produced water flow lines had a slight increase in the corrosion rates compared to 2000. A specific corrosion inhibitor test program was implemented for the produced water system and will continue in 2002. There were two flow lines inspected using an inline inspection tool. There were 11,369 inspections, six saves and one leak for flow lines during 2001.

Internal corrosion control in oil well lines is clearly indicated by coupons and inspections, with average corrosion rates approaching the historic minimum. Coupons for produced water well lines indicate an increase in corrosion rates, but a corrosion inhibitor program specifically aimed at the produced water system is under development. Coupons for the seawater injection well lines indicate an increase in corrosion rates, almost doubling since 1999. The cause has been identified and remedial actions were taken in 2001, results will be available during 2002. There were 9,780 inspections in 2001, substantially more than previous years. There were five saves and one leak for well lines in 2001.

Presently, external corrosion is a significant risk for pipeline repairs and/or leaks for BPXA. External corrosion under insulation was reported as the cause for 28 repairs and two leaks in 2000 and 17 repairs and two leaks in 2001. The percent corroded remained consistent with the past 3-year average (~5%). Overall, the weld-pack inspection program is ~40% complete, with ~120,000 weld-packs remaining. Plans are to more than double the number of weld-pack inspections for 2002. Below grade piping baseline program is on schedule for completion in 2003 with roughly 60% completed through 2001. There were no excavations in 2001.

The ACT corrosion programs continue to evolve in 2001. Endicott is unique given the use of duplex stainless steels in the production system. The main concern here is the inter-island water pipeline (IIWL). Corrosion control for the IIWL uses a combination of maintenance pigging, biociding, and inhibition. Inspection of the IIWL indicates little corrosion activity. Milne Point is unique given the amount of buried piping associated with this field. There have been 60 excavations of buried piping over the past two years with some locations showing corrosion.

The water injection system coupons have exceeded the 2 mpy corrosion rate until 2001. This is a result of a specific inhibition program started in 2000. Northstar and Badami are relatively new fields and have limited data, which shows no corrosion.

CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

Internal Corrosion Management

Monitoring & Inspection – General

Coupon monitoring activity levels have remained relatively flat from 1995 to the present. BPXA continuously updates its program in an ongoing effort to optimize the coupon program to deliver "maximum corrosion management information". Overall, the coupon results for the current reporting period are very encouraging. BPXA states that the "The reduction by a factor of 10 (of coupon corrosion rates) over the last 10 years is a direct result of an aggressive corrosion mitigation program " Clearly the inhibition program is making advances in corrosion mitigation.

BPXA presents the total number of inspections for GPB as ~60,000 per year since 1995. The total number of inspections actually increased in 2001 to ~61,000, reversing a 3-year trend of lower inspection numbers (Figure B.4). The 2001 total includes ~40,000 inspections which are performed on the facilities (not non-common carrier piping) and considered outside the scope of the Charter. This information is useful as it lends context to the inspection program, but one must be careful when trying to analyze the aggregate information. It is interesting to note the shift from a 50/50 split to a 66/33 split between facilities and field piping in the past two years. This change in emphasis is due to BPXA asserting corrosion control on field piping is adequately addressed. Lastly, within the field piping category the ratio of flow line (cross-country) inspections to well-line inspections has changed from a 70/30 to 55/45.

Percent inspection increases is a useful metric for quantifying the gross effort expended, but it is function of the number of re-inspected locations. According to Table B.8(c), the target is zero increases. It is not clear if the number of re-inspected locations is a statistical sample of known damaged locations, a fixed number of locations, or based on some other criteria.

Several graphs were included to demonstrate the effectiveness over time of the inhibition program using inspection increases and pipe condition for three phase oil lines (flow and well). The major effort is now on fine tuning the system to maintain or increase the current level of corrosion control for the piping.

Monitoring & Inspection – Cross Country (Flow) Pipelines

Coupon monitoring for "oil" system indicates the average corrosion rate in cross-country flowlines is at or near its historical minimum. The number of coupons at or below the 2 mpy threshold set by BPX for conformance is approaching the 100% mark.

Coupon monitoring in produced water system shows a slight increase in corrosion rate as well as pitting rate when compared to 2000, however both levels are below their respective targets.. In general, an increase in corrosion inhibitor in the 3-phase system shows some carryover benefit to the produced water system. BPXA has been testing corrosion inhibitors for this system, and two successful candidates were identified in 2001 and the program will continue in 2002.

Coupon monitoring for the seawater injection system shows no data for 2001 (Table 5.1 and 5.2). It should be noted there were only two coupons in 2000, so the lack of data is not a significant issue.

There were 11,369 inspections of flow lines during 2001, >9,000 for oil and >1,400 for water. The percent inspection increases for re-inspected water and oil flow lines increased slightly from 2000, but compared to the overall average they are lower. There were six saves (two oil, one water, three processed oil) and one leak in 2001. The three repairs for processed oil occurred are associated with a dead-leg which is scheduled to be removed in 2002.

Two produced water lines (M-69 and S-69) were inspected with an inline inspection tool (smart pig). With the exception of stating follow-up manual inspections to "proof" the tool were performed, no results are discussed.

Monitoring & Inspection – Well Lines

Coupons monitoring corrosion in oil production service show a significant reduction in corrosion rates with a step reduction in the average corrosion rate in 1997 (figure C.3). In 2001 93% of all coupons in this service category were below the 2 mpy conformance threshold. This is also a slight improvement over 2000 results. Conformance levels in the 99% range should be possible given the corrosion mitigation performance in cross-country lines.

Coupon monitoring in produced water system show a 6-year high in corrosion rate as well as an increase in pitting rate from 2000. The previously described inhibitor testing program will hopefully have a beneficial effect for this service.

Coupon monitoring in seawater injection system stands out in this report because of the increasing corrosion rate trend illustrated by Figure C.5. Pitting and weight loss rates in this service category have almost doubled since 1999. The primary factors responsible for this increase are cited as dissolved oxygen levels and microbial corrosion. BPXA is vigorously moving ahead with a program to reverse this corrosion trend in. Dissolved oxygen targets have been set to "<20 ppb", dissolved oxygen metering is being improved, vacuum tower performance is being upgraded through the use of an anti-foaming compound, a new oxygen scavenger catalyst is being tested and plant repair and maintenance schedules are being evaluated. Coupon pull frequencies have been shortened in this service category to allow for more frequent monitoring.

There were 9,780 inspections of well lines during 2001, >8,000 for oil and >1,000 for water service categories. This represents the largest number of inspections on well lines for the reported period. Given the number of leaks and number of saves for well lines is greater than that of the flow lines, the balance in emphasis appears to be a positive move. The percent inspection increases for re-inspected well lines decreased slightly, continuing the 4-year downward trend. There were five saves (4 oil and 1 water) and three leaks in 2001 attributed to internal corrosion.

Internal Corrosion Mitigation

BPXA expends considerable effort to develop and test new corrosion inhibitors. A rigorous testing procedure is outlined in the report showing, illustrating how inhibitors transition from the laboratory to field testing. Figure D.4 clearly shows pitting on coupons exposed to production in an unsuccessful corrosion inhibitor trial. Eighteen new products have been developed for use in the continuous well-head injection program since 1995. BPXA is carefully working to consolidate the number of products used field-wide.

CO_2 and solids deposition (both mechanisms can produce deep pitting) are cited as the main challenges in produced water systems where most coupon pitting is found. BPXA is moving forward in developing a corrosion mitigation plan specific to produced water, with corrosion inhibitors were tested in 1999 and 2000. Two successful candidates were identified in 2001 and BPXA states that funds were budgeted in 2002 for inhibitor injection.

Optimizing the injected volumes is critical to the economic application of inhibitor chemistry. Table D.6 and D.7 show how the average inhibitor concentration has varied over time. Inhibitor average concentration has risen from 85 ppm in 1995 to 157 ppm in 2001. BPXA is injecting nearly twice the volume it was using only 6 years ago. This increase is delivering measurable results in the systems in which it is being injected; cross-country production piping is nearing 100% corrosion rate conformance. The actual volume of chemical usage was 2.63 million gallons, which is 1.6% over the target amount of 2.59 million gallons. Based on monitoring and inspection data, corrosion inhibitor concentrations were increased (10-20% typical) in 14 pipelines.

External Corrosion Management

Above Grade Piping

BPXA exceeded their stated external inspection goals in 2001. There were twelve repairs and one leak on off-pad piping; five repairs and one leak on on-pad piping; and presumably more than 800 weld-packs refurbished at locations were corrosion was detected. The percent corroded and percent repaired results in 2001 are consistent with the 1999-2000 average percentages, and likely means there are 100+ repairs to be made on the remaining weld-packs. There were 17 repairs (12 flow lines and 5 well lines) and two leaks (1 flow line and 1 well line) in 2001. Table 1 summarizes the overall weld-pack inspection program status based on information presented for 2001.

Table 1 – GPB Above grade, non common carrier pipeline weld-pack inspection status

Service	Total Number (approx.)	Number Inspected During 2001	Number Inspected thru YE2001	% Inspected thru YE2001	Number Remaining (approx.)	2002 Forecast
X-Country/Flow Line – Off-pad		2,675	57,263			
Well Lines – On-pad		12,730	22,688			
Totals	**200,000**	**15,405**	**79,951**	**40%**	**120,049**	**35,000**

The 2000 Report states there are ~185,000 weld-packs while the 2001 Report states there are ~300,000 weld-packs. The increase can be attributed to combination of weld-packs on non-common carrier piping and facility piping. The status of piping associated with facilities is a bonus, but beyond the scope of the Charter. Furthermore, reporting only the combined population makes an assessment of non-common carrier pipeline status difficult.

BPXA has committed to accelerating its weld-pack inspection program through the addition of more resources, more than doubling the number of weld-packs (35,000 versus 13,000 avg.) to be inspected in 2002. It is unclear what percentage of the inspections is planned for non-common carrier pipelines versus facility piping.

Below Grade Piping

BPXA exceeded their stated below grade inspection goals in 2001, inspecting ~280 locations using a combination of electromagnetic pulse and guided wave technologies. BPXA is 60% complete with the inspection of a combined total of 460 cased crossings by YE2001. They are on track to complete the remainder by YE2003. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

There were two "moderate" and zero "severe" anomalies and no excavations performed during 2001.

Structural Concerns

There were no leaks due to structural issues in 2001. The process for identifying and repairing other structural issues was presented in the report.

CORROSION PROGRAM STATUS – ALASKA CONSOLIDATED TEAM

General

The ACT corrosion programs status continues to evolve in 2001. The level of effort applied to the satellite field corrosion programs varies between them. New piping and facilities are expected not to need as much attention as decades old, fully mature, fields, consequently BPXA has not taken its fully mature GPB corrosion program and duplicated it in these smaller fields.

Monitoring and inspection should be conducted in a proactive manner that will discover new and different corrosion mechanisms before they become a serious problem.

Endicott

Endicott "is a mature waterflood field," and the production fluid is characterized as "high temperature and high CO_2." The production system was constructed mostly of Duplex Stainless Steel (DSS), which is a corrosion resistant alloy that combines good weldability, strength, and toughness. It is highly resistant to CO_2 corrosion. Problems can occur in Duplex installations when chlorides are present or when microbial induced corrosion (MIC) takes hold. Solids deposition in stagnant internal areas and contact with stagnating brines can induce isolated pitting corrosion in this alloy. The presence of solids and microbes in the injection water may point to future challenges for the DSS piping

Coupon data indicates the production system corrosion rate remains above the 2 mpy threshold however BPXA states this is not a concern for the piping since it is fabricated mostly from DSS. Since the piping is corrosion resistant Endicott could benefit from a corrosion program targeted at solids removal and microbial control. Coupon data also indicates the water system corrosion control program is effective.

The primary corrosion concern at Endicott is the inter-island-water-line (IIWL). It is assumed that the IIWL line is carbon steel because BPXA is pigging, biociding, and inhibiting the water in the IIWL. UT Inspection results (fig. D.1) for the IIWL are good. While the number of inspection increases in the IIWL is down overall since 1998; there was a slight increase in 2001. The IIWL line was inspected using and inline inspection tool in 1995, there was no discussion of results or if another inline inspection is planned.

Table E.1 lists the cased piping external inspections performed at Endicott. Some external corrosion has been detected. The oil line inspection interval is characterized as "N/A Duplex Stainless Steel". Depending on the chloride concentrations in the ground water and ingress through weld-packs, a full baseline inspection should be made and a reasonable re-inspection interval set.

DSS is not corrosion proof, just corrosion resistant. BPX may need to reassess its surveillance philosophy in systems fabricated from DSS. BPX does not mention which DSS alloy is used in Endicott's construction. BPX provided a table (table B.1, pg 99) which lists line lengths and the number of internal and external inspections. Pitting and microbial corrosion are threats to the DSS system, some discussion of how these mechanisms progress in DSS installations and how they are controlled (pigging/biociding/solids mitigation) would be useful in the next reporting cycle.

Milne Point

Milne Point fluids are characterized by low CO_2, low operating temperature and low velocities. Corrosion under insulation and internal under-deposit corrosion mechanisms are mentioned and are consistent with the stated operating conditions. There were no leaks or repairs during 2001. Coupon data indicate very good mitigation with the single exception of the water injection system. Coupon rates in the water injection system exceeded the 2 mpy threshold until 2001. In mid-2000 corrosion inhibitor injection was begun in the water injection system and the initial results appear to be encouraging.

It is stated that Milne Point internal inspection history has been "variable" and that in 1998 a policy change was made to rectify this situation stating "a concerted effort was made towards obtaining a more consistent inspection survey". Internal under-deposit corrosion was found in the K-pad line and an inhibitor injection was begun. It is too early to determine the inhibitor effectiveness at this time. F-pad production flow line was inspected using an inline inspection tool, with the follow-up to occur in 2002.

Table E.2 shows the number of external inspections decreased from a high of 205 in 2000 to 179 in 2001. The percent inspection increases for re-inspected locations is 27% avg. for the last two years, which is well in excess of the GPB field average. Buried pipe is also an issue in the MPU since many of the gathering lines and product distribution lines are buried along the roadway. Excavations were made at 30 locations in 2001 looking for external corrosion; nineteen were new locations, eight were recurring inspections with no increases and three locations showed "slight increases". Excavations were also made at 30 locations in 2000 but results were not discussed.

Northstar

Northstar began production in late 2001 and consequently has very limited data. Fluid corrosivity is expected to moderate initially but will increase with the injection of Prudhoe Bay Gas. There are corrosion monitoring locations installed and data will be reported in the future. Presently, well production lines are treated with low concentrations of continuously injected corrosion inhibitor. No Internal and external inspection data were presented, presumably data were not collected.

Badami

Badami started in 1998 and fluid corrosivity is considered low due to the small volumes of water and low CO_2 content. There is no corrosion inhibition or corrosion monitoring (coupon) program in place. Corrosion control is monitored through the use of a small inspection program. While no external weld-packs have been inspected to date, the pipe condition is observed in conjunction with internal inspections. Internal inspections have shown no corrosion.

RECOMMENDATIONS

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. Total number/population of well lines, cross country lines, weld packs, below grade pipe segments would be beneficial. In addition, the number of baseline inspections and related percentages for the weld-pack and below grade piping programs would be beneficial to track overall progress during the multi-year effort. These data could be presented as a cumulative graph or in a tabular format.

2. If facility piping is to be included in future reports, an individual breakdown and presentation of the facility piping and non-common carrier piping data sets will aid future analysis of items related to the Charter.
3. In order to gain a better understanding of the operating conditions for the various pipelines, a histogram depicting the number of pipelines in each service within different %SMYS categories would be beneficial. Suggested %SMYS categories are: <10%, 10-20%, 20-30%, and >30%.
4. Provide an explanation/procedure used for selecting location for re-inspection as well as how the results are used.
5. Provide more details on the inspection techniques for large diameter (>8) cross-country water injection piping.
6. When smart pig runs were made on non-common carrier pipelines, inclusion of the results would be useful. The report indicates smart pigs were run on non-common carrier pipelines in the GPB and ACT but no results were presented. Include discussion regarding inspection intervals.
7. Pitting and microbial corrosion can be threats to the DSS system, some discussion of how these mechanisms progress in DSS installations and how they are controlled (pigging or biociding?) at Endicott would be beneficial.
8. Milne Point information regarding the results of the ongoing excavation program such as how locations are picked, leak/save data, results from previous excavations.

CONCLUSIONS

BPXA continues its thorough and aggressive corrosion control program. The 2001 Report contains more detail and is wider in scope than the 2000 Report. BPXA has consolidated/integrated the corrosion programs for GPB and will focus n optimization and continuous improvement of the program in 2002. Integration of "heritage" databases into on database (MIMIR) continues and will improve the ability to obtain and analyze data in a timely fashion,

Internal corrosion in cross-country gathering lines and oil well lines is clearly being controlled. The coupon monitoring in the seawater injection system stands out in the report because of the increasing corrosion rate trend. BPXAs planned steps to improve operations in the seawater treatment plant should reverse this negative trend for 2002. An inhibitor project aimed specifically at produced water system will continue development in 2002.

Presently, external corrosion remains a significant risk for pipeline repairs and/or leaks for BPXA. The weld-pack baseline inspection program is ~40% complete and the goal for 2002 is ~35,000 weld-pack inspection, more than double previous years effort. The below grade piping inspection program is 60% complete and on track for completion in 2003.

The corrosion programs for the ACT fields (Endicott, MPU, Badami, and Northstar) would benefit from a more consistent application of the programs developed in the GPB. Inspection and monitoring in the ACT need to be conducted in a consistent manner that will discover new and different corrosion mechanisms before they become a serious problem.

BPXA is making continual improvements to it many corrosion mitigation operations and if implemented for 2002 the next report should show reverses in the few negative corrosion trends.

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Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2002 for Greater Prudhoe Bay, Endicott, Badami and Milne Point

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2002 corrosion program report submitted by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the October 2002 and April 2003 Meet & Confer sessions. The 2002 report contains similar detail and scope as the 2001 Report and repeats the corrosion management strategy and objectives.

BPXA made a significant improvement to their database related to multiple injection services. This change provides the ability to track well service changes, which is turn provides the ability to determine that impact on the coupon corrosion rates.

Internal corrosion control in oil flow lines is indicated by coupons and inspections, with average corrosion rates approaching the historical minimum. Produced water flow lines had a slight increase in the corrosion rates compared to 2000. There were three produced water flow lines inspected using an inline inspection tool. There were ~12,500 inspections, nine saves and no leaks in flow lines attributed to internal corrosion.

Internal corrosion control in oil well lines is clearly indicated by coupons and inspections, with average corrosion rates approaching the historic minimum. Coupons, for produced water well lines, show a decrease in corrosion rates from 2001 due to increased inhibitor carryover from the oil system and supplemental inhibitor specific to this system. Coupons for the seawater injection well lines indicate an increase in corrosion rates. The cause has been identified and remedial actions were taken in 2001, but the effects of these actions have not been fully realized due to operational issues. There were ~12,700 inspections in 2002, substantially more than previous years. In 2002, there were eleven saves and two well line leaks attributed to internal corrosion.

External corrosion continues to be a significant risk for pipeline repairs and/or leaks for BPXA, and they nearly tripled the number of weld-packs inspected to ~43,000 in 2002. External corrosion under insulation was reported as the cause for 57 repairs and two leaks in 2002. Overall, the weld-pack inspection program is ~40% complete, with ~175,000 weld-packs remaining to be inspected. The below grade piping baseline program is on schedule for completion in 2003 with roughly 80% completed through 2002. There were no below grade piping excavations in 2002.

The Alaska Consolidated Team (ACT) corrosion programs continued to evolve in 2002. Endicott is unique given the use of duplex stainless steel in the production system. The primary concern is in the inter-island water pipeline (IIWL) and carbon steel C-spools. Corrosion control for the IIWL uses a combination of maintenance pigging, biocides, and inhibition. Inspection of the IIWL indicates low levels of corrosion activity. Milne Point is unique given the amount of buried piping associated with this field. There have been multiple inspections of buried piping over the past three years with 24% (average) of the locations showing increases in corrosion in addition to new areas with corrosion. The produced water system inspection data also indicates additional work is required to bring corrosion under control. Northstar and Badami are relatively new fields and have limited data, which currently shows no corrosion.

CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

Internal Corrosion Management

Monitoring & Inspection – General

Coupon monitoring activity levels have remained relatively constant from 1995 to the present. BPXA continuously updates its program in an ongoing effort to optimize the coupon program to deliver "maximum corrosion management information". Overall, the coupon results for the current reporting period are very encouraging.

BPXA presents the average number of inspections for GPB as ~24,500 per year since 1995. The total number of inspections in 2002 was ~26,000. This level of inspection is consistent with 1998 levels and completes the reversal of a multi-year trend of lower inspection numbers (Figure B.4). The ratio of flow line (cross-country) inspections to well-line inspections was 46/54.

Percent inspection increases is a useful metric for quantifying the gross effort expended, but it is a function of the number of re-inspected locations. According to Table B.11(c), the target is zero increases. It is still not clear if the number of re-inspected locations is a statistical sample of known damaged locations, a fixed number of locations, or based on some other criteria.

BPXA made a significant improvement to their database related to multiple injection services. This change provides the ability to track well service changes, which in turn provides the ability to determine that impact on the coupon corrosion rates. Sixty percent of the injection service coupons have seen a single service during their exposure period. The remaining 40% were exposed to multiple services and BPXA reports the simple majority service category for these coupons.

Several graphs were included to demonstrate the effectiveness over time of the inhibition program using inspection increases and pipe condition for three phase oil lines (flow and well). The major effort is now on fine tuning the system to maintain or increase the current level of corrosion control for the piping.

BPXA has performed analyses showing the strong correlation between monitoring and inspection, which helps to validate that the monitoring locations are located where corrosion is expected to occur.

Monitoring & Inspection – Cross Country (Flow) Pipelines

Coupon monitoring for the "oil" system indicates the average corrosion rate in cross-country flow lines is at or near its historical minimum. The number of coupons at or below the 2 mpy threshold set by BPXA for conformance is approaching the 100% mark.

Coupon monitoring in the produced water system shows an improvement in corrosion control for this system, as compared to 2001, and is on par with historical averages. The comparison between coupons with 100% exposure and simple majority exposure to produced water show nearly identical trends, which suggests that produced water is the controlling factor for the majority exposure corrosion rates. The expansion of a produced water inhibitor program will help to maintain or increase corrosion control for this system.

Coupon monitoring for the seawater injection system shows increasing corrosion rates since 1997, with the most significant increases occurring since 2000. BPXA has acknowledged this trend multiple times and has implemented several "corrective actions" at the Seawater Treatment Plant (STP). While several mitigation measures have been implemented, BPXA is yet to see any significant benefit or reduction in corrosion rates for this system. BPXA will be focusing on this area in 2003.

There were ~12,500 inspections of flow lines during 2002, ~10,800 for oil and ~1,700 for water. The percent inspection increases for re-inspected oil flow lines increased slightly for the second year, but are still lower than the overall average. The percent inspection increases for re-inspected water flow lines more than doubled that in 2001 and is now over 10%. This increase is attributed to the increasing corrosivity in the seawater injection, which in turn was due to problems at the STP. There were nine saves (eight oil and one water) and no leaks attributed to internal corrosion in 2002.

Three produced water lines were inspected with an inline inspection (ILI) tool based on magnetic flux leakage (MFL) technology. There is a limited discussion of the results, essentially stating there were no areas that did not meet fit-for-service criteria. Also presented is the historical ILI frequency, showing a high of 25 inspections in 1992 and decreasing to 3-6 inspections since 1997. Even though ILI provides data for essentially the entire length of the pipeline, BPXA states it is "not always the most appropriate or applicable…" based on a variety of reasons.

Monitoring & Inspection – Well Lines

In 2002, 92% of all coupons in this service category were below the 2 mpy conformance threshold, which is a slight decrease from 2001 results. While coupons in oil production service show a significant reduction in corrosion rates since 1992, conformance levels in the 95-99% range should be possible given the corrosion mitigation performance in cross-country lines.

Coupon monitoring in the produced water system returned to their recent levels. These levels are expected to be maintained or improved due to the addition of an inhibitor designed for this system.

Coupon monitoring in the seawater injection system stands out for the second year because of the increasing corrosion rate trend. Weight loss rates in this service category have nearly tripled the 2001 results. These results are again attributed to problems at the STP previously discussed. The seawater injection system results will be of particular interest in 2003.

There were ~12,700 inspections of well lines during 2002, ~10,900 for oil and ~1,800 for water. This represents the largest number of inspections on well lines for the reported period. Given the number of leaks and number of saves for well lines is greater than that of the flow lines, the balance in emphasis appears to be a positive move. The percent inspection increases for re-inspected oil well lines continued a four-year downward trend. The percent inspection increases for re-inspected water well lines nearly doubled that in 2001 and is now over 10%. This increase is attributed to increasing corrosivity in the Seawater injection system, which in turn was due to problems at the STP. There were eleven saves (7 oil and 4 water) and two leaks in 2002 attributed to internal corrosion/erosion.

Internal Corrosion Mitigation

CO_2 and solids deposition (both mechanisms can produce deep pitting) are cited as the main challenges in produced water systems where most coupon pitting is found. BPXA is expanding the corrosion inhibitor program specific to produced water.

BPXA expends considerable effort to develop and test new corrosion inhibitors. A rigorous testing procedure is outlined in the report which illustrates how inhibitors transition from the laboratory to field testing. There were 12 full-scale inhibitor trials in 2002.

Optimizing the injected volumes is critical to the economic application of inhibitor chemistry. BPXA is injecting nearly twice the volume it was using only 6 years ago. This increase is delivering measurable results in the systems in which it is being injected; cross-country production piping is nearing 100% corrosion rate conformance. The actual volume of chemical usage was 2.46 million gallons, which is slightly over the target amount of 2.45 million gallons. Based on monitoring and inspection data, corrosion inhibitor concentrations were increased (5-20% typical) in 14 pipelines.

External Corrosion Management

Above Grade Piping

BPXA exceeded their stated external inspection goals in 2002 and reached a new high of ~43,000 external inspections. There were 45 repairs and one leak on flow lines; twelve repairs and one leak on well lines; and more than 800 weld-packs refurbished at locations where corrosion was detected. The percent corroded and percent repaired results in 2002 are consistent with the 1999-2001 average percentages, and likely means there are 100+ repairs to be made on the remaining weld-packs. Table 1 summarizes the overall weld-pack inspection program status based on information presented for 2002. It is still unclear if the total population presented in the report consists of only non-common carrier pipe, or if there is a mix of facility piping included[1].

Table 1 – GPB Above grade, non common carrier pipeline weld-pack inspection status

Service	Total Number (approx.)	Numb Inspected During 2002	Number Inspected thru YE2002	Inspected thru YE2002	mber Remaining (approx.)	2003 Forecast
X-Country/Flow Line – Off-pad	200,000	18,931	77,421	39%	122,579	
Well Lines – On-pad	100,000	23,797	47,190	47%	52,810	
Totals	**300,000**	**42,728**	**124,611**	**42%**	**175,389**	**35,000**

[1] This is based on conflicting information presented in earlier reports, and is addressed in our 2001 Report Recommendations.

BPXA has accelerated the weld-pack inspection program through the addition of more resources, more than tripling the number of weld-packs (~43,000 versus 13,000 avg.) inspected in 2002. The emphasis appears to be on Well lines, while the higher risk appears to be Flow lines. Flow lines have higher % Corroded, higher % Repair, and would have higher repair and cleanup costs.

Below Grade Piping

BPXA exceeded their stated below grade inspection goals in 2002, inspecting 269 locations using a combination of electromagnetic pulse and guided wave technologies. BPXA is 80% complete with the inspection of all ~1,400 cased crossings and on track to complete the remainder by YE2003. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

There were 21 "moderate" and 30 "significant" anomalies and no excavations performed during 2002. This represents a significant increase in anomalies, but they are believed to be "false-positives" due to data analysis methods. BPXA has committed to re-examine each of the "significant" anomalies in 2003. There have been no excavations on cased crossings since 2000.

Structural Concerns

There were no leaks due to structural issues in 2002. The process for identifying and repairing other structural issues was presented in the report.

CORROSION PROGRAM STATUS – ALASKA CONSOLIDATED TEAM

General

The ACT corrosion programs status continued to evolve in 2002. The level of effort applied to the satellite field corrosion programs varied between them. Monitoring and inspection should be conducted in a proactive manner that will discover new and different corrosion mechanisms before they become a serious problem.

Endicott

Coupon data indicates that the production system corrosion rate remains above the 2 mpy threshold; however BPXA states this is not a concern for the piping since it is fabricated mostly from Duplex Stainless Steel (DSS). Coupon data also indicates the water system corrosion control program is effective.

The primary corrosion concern at Endicott is the inter-island-water-line (IIWL). The percent inspection increases for flow and well lines are within historical norms; however the produced water well lines percent inspection increases have been above 10% in three of the last four years.

There were no below-grade/cased piping inspections in 2002. The oil line inspection interval is characterized as "N/A Duplex Stainless Steel". Depending on the chloride concentrations in the ground water and ingress through weld-packs, a full baseline inspection should be made and a reasonable re-inspection interval set.

There were eight repairs (6 oil and 2 water) and one leak in 2002 reported for Endicott.

Milne Point

Milne Point fluids are characterized by low CO_2, low operating temperature and low velocities. Corrosion under insulation and internal under-deposit corrosion mechanisms are mentioned and are consistent with the stated operating conditions. There were five repairs (oil lines), five sleeves (oil lines) and no leaks during 2002. Coupon data indicates good corrosion mitigation across all three systems.

Table E.2 shows the number of external inspections decreased from a high of 205 in 2000 to 70 in 2002. The percent inspection increases for external corrosion averaged 24% for the last three years, which is well in excess of the GPB field average. Buried pipe is a corrosion concern at MPU since many of the gathering lines and product distribution lines are buried along the roadway. There were 70 inspections and five excavations made in 2002. One of the five (20%) re-inspected locations showed an increase in corrosion. An additional seven inspection locations showed "minor" (<20% wall loss) external corrosion.

The number of internal inspections for flow lines has more than tripled the 1998 numbers. With the exception of the 1997 high point, the number of inspections has grown almost exponentially since 1995. The inspection trend is similar for the well lines. The produced water percent increases for internal corrosion is well above GPB levels, even allowing for when the inhibitor program was established.

Northstar

Northstar began production in late 2001 and consequently has limited data. Fluid corrosivity is expected to be initially moderate, but will likely increase with the injection of Prudhoe Bay Gas. There are corrosion monitoring locations installed and data will be reported in the future. Presently, well production lines are treated with low concentrations of continuously injected corrosion inhibitor. No internal or external inspection data was presented, presumably data was not collected.

Badami

Badami started in 1998 and the fluid corrosivity is considered low due to the small volumes of water and low CO_2 content. There is no corrosion inhibition or corrosion monitoring (coupon) program in place. Corrosion control is monitored through the use of a small inspection program. While no external weld-packs have been inspected to date, the pipe condition is observed in conjunction with internal inspections. Internal inspections have shown no corrosion.

RECOMMENDATIONS

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. Total number/population of well lines, cross country lines, weld packs, below grade pipe segments would be beneficial. In addition, the number of baseline inspections and related percentages for the weld-pack and below grade piping programs would be beneficial to track overall progress during the multi-year effort. This data could be presented as a cumulative graph or in a tabular format.
2. We recognize the desire to publish complete reports that combine the background information along with the current period results. However, it would be easier to write and review the reports if the background information and current results are presented in distinct or separate sections (background and historical information can be placed in appendices).
3. It appears the external inspection program has more emphasis on Well lines, while Flow lines appear to have higher risk. Provide information related to mitigating the highest risk pipelines for the remaining inspections.
4. Provide an explanation/procedure used for selecting locations for re-inspection as well as how the results are used.
5. Provide more details on the inspection techniques for large diameter (>8") cross-country water injection piping.
6. Additional information regarding the inline inspection (ILI) program would be of value. It is interesting that in MPU the ILI data was significantly inaccurate; 1,000 feet with significant damage versus one minor pit.

CONCLUSIONS

BPXA continues its thorough and aggressive corrosion control program. BPXA has consolidated/integrated the corrosion programs for GPB and continues to focus on optimization and continuous improvement of the program. Improvements to the database (MIMIR) continues and will improve the ability to obtain and analyze data in a timely fashion.

Internal corrosion in cross-country gathering lines and oil well lines is being controlled. The coupon monitoring in the seawater injection system stands out in the report because of the increasing corrosion rate trend. BPXA has implemented measures to improve operations in the seawater treatment plant, but operational issues have prevented the benefits from being realized. The produced water system has benefited from the inhibitor program targeted specifically at this system. Additional improvements in this program are planned in 2003.

External corrosion remains a significant risk for pipeline repairs and/or leaks for BPXA. The weld-pack baseline inspection program is ~40% complete and the goal for 2003 is ~35,000 weld-pack inspections. The below grade piping inspection program is 80% complete and on track for completion in 2003.

The corrosion programs for the ACT fields (Endicott, MPU, Badami, and Northstar) would benefit from a more consistent application of the programs developed in the GPB. MPU needs additional attention to their program. Inspection and monitoring in the new ACT fields need to be conducted in a consistent manner that will discover corrosion mechanisms before they become a serious problem.

BPXA is making continual improvements to its many corrosion mitigation operations and if implemented for 2003, the next report should show reversals in the few negative corrosion trends.

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Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2003 for Greater Prudhoe Bay, Endicott, Northstar and Milne Point

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. is responsible for the technical review of the 2003 corrosion program report submitted by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion of BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the April and August 2004 Meet & Confer sessions.

From a global perspective of oil and gas production, Greater Prudhoe Bay (GPB) and related facilities have an aggressively managed corrosion control program. This suggests an adequate long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.

Monitoring, mitigation, and inspection data support the conclusion that the GPB assets are being preserved, but isolated locations of accelerated corrosion exists and have been found by inspections. The isolated locations of corrosion are where leaks may occur (including Endicott's duplex stainless steel system). BPX has responded to this threat by implementing aggressive and thorough monitoring and mitigation programs; however, it does not appear to be presently possible to predict the onset of all new locations of accelerated corrosion.

Monitoring data, presented by BPX, is in conformance to metrics agreed to by ADEC. However, the significance of isolated areas of aggressive internal corrosion is not intuitively reflected by monitoring data because 1) extreme values cannot be readily determined, and 2) monitoring tools are generally not located where the isolated corrosion occurs. In the future, it would be beneficial for the distribution of coupon corrosion rate data be presented for an improved representation of the extreme corrosion rates.

Inspection data supports the conclusion that the seawater and produced water systems are being adequately managed for internal corrosion and program improvements are continuously being made.

External corrosion of above-ground piping is largely confined to weld packs and BPX has made a notable commitment to removing this threat through inspection and repair (where necessary) of all weld pack locations.

Long range inspection tools are used to detect external corrosion of cased pipe and buried pipe. Although this is a proactive risk based approach, it should be recognized that industry experience with these inspection methods are mixed and there may be technical issues to be resolved as is the case with many state-of-the-art technologies. It is recommended that BPX provide a comparison of inspection results versus direct examination so that the accuracy and reliability of this inspection method can be evaluated by ADEC.

CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

Internal Corrosion Management

Production System (Well Lines and Flow Lines)

The data provided by BPX supports the conclusion that the internal corrosion control/inspection program is well managed and effectively preserving the facilities for the future. However, the existence of isolated locations of accelerated corrosion could potentially result in leaks. Although isolated locations of corrosion are repairable, they could have an environmental consequence if not detected. BPX has responded to this threat by implementing aggressive and thorough monitoring, inspection and mitigation programs.

From a global perspective of oil and gas production, GPB has one of the most aggressively managed internal corrosion control programs. The level of inspection and corrosion mitigation resources directed by BPX corrosion experts is commendable. This suggests a long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.

Inspection, monitoring, and mitigation data support the conclusion that the GPB assets are being adequately maintained and preserved. Corrosion control efforts exceed standard oilfield industry practice. The average corrosion rates of coupons and probes are as low as can be practically achieved (i.e., <1 mpy). A 1 mpy corrosion rate is put into context by considering that a 0.375 inch wall thickness pipe would have 80% of its wall thickness after 75 years. Inspection data supports the conclusion that most of the asset has insignificant corrosion. However, isolated locations with high corrosion rates remain. It would be beneficial to identify in future reports (in one location, if possible) what fraction of the piping experiences accelerated corrosion rates, what the pipeline services are, what the accelerated corrosion rates are (i.e., >10 mpy) and the remedial action that was taken to reduce the corrosion rates (Note: This information is currently not required by the reporting metrics agreed to by ADEC and some of the information is currently identified in various sections of the report).

The significance of isolated areas of accelerated corrosion within GPB is not intuitively reflected in the monitoring data presented by BPX because many of the coupons and probes are not located where accelerated corrosion occurs. Rather, they are installed at locations that are convenient for installation and retrieval (as is common practice in the industry). Future coupons should be placed at locations that represent the highest susceptibility to corrosion.

The impracticality of prioritizing susceptibility to isolated aggressive corrosion is compensated by an aggressive field-wide inspection program. The effectiveness of this program is demonstrated by the high ratio of 'saves' to leaks (with 'saves' defined by detecting damage requiring repair or pressure reduction).

Seawater and Produced Water Injection

The seawater and produced water systems have relatively low corrosion rates and appear to be well managed. The presence of only one phase (i.e., water) makes corrosion management less complicated than the multiphase production system. Corrosion of the seawater system is mitigated by removing oxygen and injecting biocides. Corrosion of the produced water injection system is mitigated by oxygen removal, injecting biocides and by carryover inhibition from the production system.

Corrosion rates in the seawater systems decreased in 2003, reversing a 5-year trend. A number of actions were taken to address dissolved oxygen levels and microbiological corrosion control. Corrosion rates in the produced water systems also decreased in 2003. The upstream 3-phase corrosion inhibitor was changed and the corrosion mitigation programs were expanded specifically to address the produced water system in 2002.

External Corrosion Management

Above Grade Piping

BPXA plans to inspect and repair (as necessary) approximately 35,000 weld packs per year. This is a commendable commitment to address and remove the pipeline integrity problems associated with corrosion under insulation. Additionally, the priority for inspection is based on the consequence of failure (e.g., weld packs over tundra are higher priority than over the pad), ensuring that the highest consequence locations are repaired first. A new weld pack design is in use and is intended to prevent future water ingress and corrosion at these field-applied insulation locations.

Below Grade Piping

BPX plans to inspect cased crossings using long range inspection methods (i.e., electromagnetic pulse and guided wave technologies). Although this is a proactive risk based approach, there may be issues to be resolved with these technologies, as is the case with many state-of-the art technologies. BPX should provide data that quantifies the ability of long range inspection to detect defects that could lead to failure (i.e., compare inspection results with subsequent direct examination of the cased pipe). Where it is not practical to perform a direct exam, determining the ability to characterize defects on a pipe where a defect has been detected by long range inspection would provide added confidence to the method.

SATELLITE FIELDS

Endicott

The majority of the Endicott production system piping is constructed of Duplex Stainless Steel (DSS) that is intended to be corrosion resistant in the produced fluid environment. Minor components within the facility (i.e., C-spools) are carbon steel with corrosion managed by monitoring, inspection and repair/replacement (when necessary). Carbon steel coupons are used to monitor corrosivity, and their average rate in 2002-2003 was approximately 3 mpy. It should be noted that the coupons are not expected to reflect the rate that would be seen on the DSS (if it were to corrode) because its mechanism and rate of corrosion differs. That is, a breakdown in DSS passivity would result in localized corrosion (i.e., pitting) with a corrosion rate much higher than the rate observed by the carbon steel coupons.

The stated BPX primary corrosion concern at Endicott is the inter-island-water-line (IIWL). However, its corrosion management is similar to the produced water injection system at Prudhoe Bay and the monitoring data shows average corrosion rates near zero.

There were seven repair activities at Endicott. Five C-spools were replaced due to corrosion, one C-spool was replaced due to erosion and one stainless steel well line was sleeved due to erosion.

Milne Point

BPX has significantly improved the internal corrosion management of Milne Point production and produced water systems. These improvements include increases in corrosion inhibition, maintenance pigging, and inspection. Monitoring data shows reduction of average corrosion rates to insignificant levels (i.e., <1 mpy).

Milne Point has buried pipe containing produced fluids that require excavation for external inspection. Because of this, BPX is considering the use of long range inspection methods (i.e., guided wave ultrasonics). As previously stated, there may be issues to be resolved regarding these technologies.

There were 7 repair activities at Milne Point. Six of the repairs were on the K-pad production flow line. Additional areas have been identified for sleeve repair.

Northstar

The threat of corrosion at Northstar is considered low. Production began in late 2001 and fluids have low corrosivity. The production lines are inhibited and corrosion coupons indicate adequate effectiveness. Inspection activities have also increased.

Badami

Badami is shut-in, so damage as a result of corrosion should not result in leaks (i.e., there is no environmental consequence). From an asset preservation standpoint, external corrosion can occur on buried and/or insulated piping, and internal corrosion can occur where lines have been insufficiently dried or treated (e.g., for bacteria).

RECOMMENDATIONS

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. Continue the commitment to external corrosion inspection and mitigation on the weld packs. Identify the number of weld packs remaining to be inspected and the forecasted completion date.
2. Future coupons should be placed at locations that represent the highest susceptibility to corrosion.
3. Identify criteria to be used for locating future coupons.
4. Based on the inspection methodology and guidelines in the GPB corrosion inspection program, define matrix or priority indices used for selecting inspection locations that may be prone to accelerated corrosion.
5. Provide data that quantifies the ability of long range inspection to detect defects that could lead to failure (i.e., compare inspection results with subsequent direct examination of the cased pipe).

CONCLUSIONS

BPXA has presented sufficient information to demonstrate that its corrosion control program meets the spirit of the Charter Agreement. This suggests a proactive long-term commitment to preserving facilities for future production and sensitivity to environmental consequences. Recommendations and observations contained in this document should be viewed as opportunities for incremental improvement.

Although the vast majority of internal pipeline corrosion is being mitigated, isolated areas of accelerated corrosion have been detected through comprehensive inspections and by way of leaks that have occurred on isolated occasions. Priority should be given to those locations that represent the highest susceptibility to corrosion for future inspections.

Two significant external corrosion threats are below-ground cased crossings and weld packs on above-ground pipe. BPXA has made a notable commitment to inspect and repair (when necessary) weld-packs. BPXA also intends to inspect cased crossings with long-range inspection tools; however, it should be recognized that long-range inspection tools may have technical issues that need to be resolved.

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Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc.

Commitment to Corrosion Monitoring Year 2004

Submitted by

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ADEC Contract Number – 18-6000-02

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. is responsible for the technical review of the 2004 corrosion program report submitted by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion of BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the 2005 Meet & Confer sessions in Anchorage and Prudhoe Bay, Alaska.

The data provided by BPXA supports the conclusion that the corrosion management program is effective and exceeds common industry practice. Sufficient information has been presented to demonstrate that the corrosion control program meets the intent of the Charter Agreement.

It is notable that BPXA presented the 2004 monitoring and inspection program in a transparent way and answered all questions with candor. Information from written reports, presentations, and verbal questions are consistent. Additionally, the BPXA corrosion control staff is highly competent and an extensive QA/QC program is in place to monitor the performance of contractors.

Inspection activities in 2004 consisted of approximately 60,000 items (combined internal and external). The majority of the system had a corrosion rate of less than 2 mils/year. Monitoring, mitigation, and inspection data support the conclusion that the GPB assets are being preserved, but isolated locations of accelerated corrosion exist and have been found by inspections. In response to the isolated locations of accelerated corrosion, BPXA has implemented aggressive and thorough risk based monitoring and mitigation programs.

The GPB multiphase produced oil system is highly corrosive, if untreated. Corrosion in the majority of the pipeline system has been reduced to a negligible level as a result of the implementation and continuation of an aggressive corrosion inhibition program. Anomalies in the system are inspected, mitigated and monitored.

A significant injection water internal corrosion mechanism that BPXA is aggressively responding to is under-deposit corrosion. Inhibition levels were increased, cleaning pigs and a surfactant (SBG) were used to remove deposits and line velocities are being evaluated. The surfactant chemically removes deposits, particularly in locations where cleaning pigs cannot be run. These actions are consistent with good corrosion control practices.

External corrosion of above-ground piping is largely confined to weld packs, and BPXA has made a commendable commitment to removing this threat through inspection and repair (where necessary).

External corrosion at cased crossings represents a corrosion threat over which BPXA has a difficult challenge. This is because of the difficulty with accessing the pipe surface. In response to this challenge, BPXA is using visual, direct, smart pig and guided-wave assessments as part of their comprehensive inspection program. BPXA has proactively implemented guided-wave technology, recognizes the current technical limitations of this technology and is working to further enhance it.

CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

The data provided by BPXA supports the conclusion that the corrosion management program is effective and exceeds common industry practice. BPXA presented the 2004 monitoring and inspection program in a transparent way and answered all questions with candor. Information from written reports, presentations, and verbal questions are consistent.

BPXA utilizes a risk based corrosion management program. The program relies on an "as low as reasonably practical" strategy. In this approach there is no "acceptable" risk. High risk items get more attention and low risk items get less attention. For the most part, consequence of failure appears to be considered similarly high for the majority of the facility. Emphasis is therefore placed on reducing the likelihood of failure. Locations with highest likelihood of failure receive the greatest attention, and other locations are reduced as low as reasonably practical.

It should be noted that the planned field life has recently been significantly extended, and future production (especially natural gas) relies on maintaining the existing infrastructure. Maintenance and repair decisions are therefore justified on the basis of facility requirements for future production in addition to safety and environmental reasons.

Internal Corrosion Management

Production System (Well Lines and Flow Lines)

The data provided by BPXA supports the conclusion that the internal corrosion control/inspection program is effectively managed. The produced oil system at GPB is both extensive in size and highly corrosive, if untreated. Without mitigation, the natural corrosion rate would likely result in pipeline failure in less than a year because corrosion rates would likely range from 100 to 300 mpy. The corrosion mitigation program has reduced this corrosion rate to a negligible level for the majority of the pipeline internal surface, and efforts to further optimize the program are based on identifying, mitigating, and repairing locations of isolated high corrosion rate and/or damage.

The dominant corrosion mechanism (CO_2) has been reduced to a negligible level for the majority of the pipeline system. The average corrosion rate of coupons and probes are as low as can be practically achieved (i.e., <1 mpy), and inspection data supports the conclusion that most of the GPB asset has adequate corrosion control.

Data illustrating the distribution of internal corrosion rates as measured by monitoring and inspection was shared during meet and confer sessions. This data represents isolated locations of increased corrosion rates and reflects awareness by BPXA of the importance for considering extreme value corrosion rates rather than simple averages that may mask their existence.

The monitoring program identifies significant changes in corrosion mitigation effectiveness, and inspection verifies the effectives of the mitigation program. In addition, inspection 1) identifies locations where corrosion rates along a pipeline segment may exceed what is measured by coupons, and 2) is used to characterize previous corrosion damage (i.e., through remaining strength calculations).

Two unforeseen events occurred in the 3-phase corrosion inhibition program which resulted in higher than normal corrosion rates. Both were related to the chemical inhibitors (incumbent and test) that were being used and tested. These events were: 1) corrosion inhibitor instability at winter temperatures which resulted in the blockage of some of the chemical delivery systems, and 2) material incompatibility with a test inhibitor and the delivery system tubing. The problems were identified, analyzed and mitigated.

Seawater and Produced Water Injection

The seawater and produced water systems have relatively low corrosion rates and appear to be well managed.

The primary corrosion mechanisms in the seawater injection systems are dissolved oxygen (DO) and microbiological induced corrosion (MIC). Corrosion of the seawater system is mitigated by removing oxygen, injecting biocides, and cleaning the system of deposits.

The 100% seawater water injection systems have low corrosion rates and the overall program performance has been consistently improving since 2002. The "majority" seawater injection systems have experienced a decline in performance in 2004, after an increase in performance from 2002 to 2003. BPXA has initiated a thorough analysis to better understand the difference in performance and should be better able to address this matter in 2005.

There are a number of corrosion mechanisms of concern in the produced water injection system. Corrosion is mitigated by oxygen removal, injecting biocides, cleaning, and by carryover inhibition from the production system.

The majority of the produced water injection system had low corrosion rates. Information shared during meet and confer sessions illustrated that BPXA recognized that the corrosion rates in the product flow (coupon) may not always be representative of the corrosion rate at the pipe wall. Various corrosion mechanisms (i.e., under-deposit corrosion) may be attributed to these variances. BPXA has enhanced its cleaning program by increasing the frequency of maintenance pigging and by use of surfactants to dislodge deposits. Inspections and aggressive cleaning programs have minimized the number and potential threat of these variances.

External Corrosion Management

Above Grade Piping

Corrosion under insulation (CUI) is primarily associated with water ingress into the pipeline thermal insulation, in particular, at the field joints (weld packs). Water becomes trapped in the insulation and corrodes the uncoated pipe underneath. CUI is problematic throughout industry and is typically managed by inspection and monitoring programs.

There are approximately 300,000 weld packs at GPB and approximately 35,000 are inspected annually for wet insulation and the presence of corrosion product buildup. Roughly half have been found to contain water, and roughly 3% of those have corrosion damage (down from a high of 17% in 1995). There were two leaks due to external corrosion.

BPXA has implemented aggressive risk based monitoring and inspection programs to minimize the consequences of CUI. The priority for inspection is based on a number of variables, one of which is the consequence of failure (e.g., weld packs over tundra are higher priority than over the pad), ensuring that the highest consequence locations are repaired first. BPXA has implemented and is evaluating a new weld pack design that is intended to prevent future water ingress and corrosion at these weld pack locations.

Below Grade Piping

External corrosion at cased crossings represents a corrosion threat over which BPXA has a difficult challenge. This is because 1) the pipe cannot be directly accessed without excavation and removal of the casing and pipeline insulation (i.e., to identify damage), and 2) mitigation of active external corrosion is not easily achieved. This issue is an industry-wide problem and BPXA is actively addressing this treat with an aggressive and continually developing inspection program.

BPXA is using visual, direct, smart pig and guided-wave assessments as part of their inspection program. While each element is an important factor in the overall inspection program, it should be noted that all inspection techniques have limitations and each element should be applied where it delivers the most value.

There are approximately 1,500 cased pipe segments (approximately 28 miles) in the BPXA system. There have been two loss of containment incidents, 9 segment replacements and 6 sleeve repairs.

Baseline visual assessments have been performed on all cased crossings. The baseline inspections primarily involved looking for submerged segments and debris that could enter the annular space and support corrosion. Direct assessments (excavations or partial excavations) have been performed on 50 crossings (19 in 2004). In-line inspection tools (ILI or smart pigs) are used at GPB where pigging facilities and the process environment allow. ILI was performed on 4 lines in 2004. Advanced long-range inspection tools (guided-wave) are an important and developing part of the cased crossing inspection program and are being used within their technological limitations. Over 100 cased pipe segments were inspected using the guided-wave technology.

SATELLITE FIELDS

Endicott

The majority of the Endicott production system piping is constructed of Duplex Stainless Steel (DSS) that is intended to be corrosion resistant in the produced fluid environment. Minor components within the facility (i.e., C-spools) are carbon steel with corrosion managed by monitoring, inspection and repair/replacement (when necessary).

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water line (IIWL). Historically, corrosion control of the water injection system relied on corrosion inhibition of the injection water, supplemented by a biocide and maintenance pigging program. Improvements were made to the mitigation program in 2004. Corrosion inhibitor concentrations were increased from 20 to 30 ppm and the biocide treatment was eliminated. The program changes appear to have reversed the increase in corrosion activity that the system was experiencing. The primary monitoring method for determining the effectiveness of this program consists of ultrasonic inspection of 25 locations. There were also 719 external corrosion inspections and slight corrosion damage was found at three locations, with no repairs required.

In the production system, the primary damage mechanism was erosion. The erosion rates are monitored through inspection and mitigated through velocity management (i.e., keeping flow rates below a threshold).

In 2004, there were four repair activities and no corrosion related spills. Three repairs were due to erosion and one was the result of external mechanical damage.

Milne Point

The primary corrosion concerns are in the water injection system and corrosion of the buried piping. BPXA has improved the internal corrosion management of Milne Point production and produced water systems. These improvements include increases in corrosion inhibition, maintenance pigging, and inspection. Monitoring data shows reduction of average corrosion rates to insignificant levels (i.e., <2 mpy).

Inspections have indicated the presence of under-deposit corrosion at Milne Point. Inhibition levels were increased, cleaning pigs were used to remove deposits and line velocities are being evaluated. These actions are consistent with good corrosion control practices.

Milne Point has buried pipe containing produced fluids that necessitate excavation for external inspection. In 2004, BPXA conducted 623 inspections in 45 excavation sites.

In 2004, there were 13 repair activities and no corrosion related spills. Seven repairs were the result of internal corrosion, five were the result of external corrosion and one was the result of a freeze burst (structural related).

Northstar

The threat of corrosion at Northstar is considered low, but may increase over time. Production began in late 2001 and fluids have low corrosivity. The production lines are inhibited and corrosion coupons indicate adequate effectiveness (i.e., <2 mpy).

Since the facility is less than 4-years old, an external inspection program has not been established. A program is scheduled to be implemented in 2006.

Badami

Badami is shut-in, so the safety and environmental risk from corrosion is negligible (i.e., there is no safety or environmental consequence). From an asset preservation standpoint, external corrosion can occur on buried and/or insulated piping (none has been documented), and internal corrosion could occur if lines were insufficiently dried or treated (e.g., for bacteria).

RECOMMENDATIONS

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. Provide additional discussions regarding the anticipated field life and the necessary changes to the corrosion monitoring and inspection program to ensure the integrity of the assets throughout the extended life of the field.
2. Provide additional discussions regarding the difference in performance between the 100% seawater and the "majority" seawater injection systems.
3. Continue the commitment to external corrosion inspection and mitigation on the weld packs. Identify the number of weld packs remaining to be inspected and the forecasted completion date.
4. Provide additional information regarding the mechanism of under-deposit corrosion and the effectiveness of the programs to control it.
5. Continue the commitment to develop and enhance long range inspection techniques used at cased crossings. Supplement this commitment with direct assessments and/or inline inspections (where possible).

CONCLUSIONS

The data provided by BPXA supports the conclusion that the corrosion management program is effective and exceeds common industry practice. Sufficient information has been presented to demonstrate that the corrosion control program meets the intent of the Charter Agreement.

It is notable that BPXA presented the 2004 monitoring and inspection program in a transparent way and answered all questions with candor. Information from written reports, presentations, and verbal questions are consistent. Additionally, the BPXA corrosion control staff is highly competent and an extensive QA/QC program is in place to monitor the performance of contractors.

BPXA utilizes a risk based corrosion management program. The program relies on an "as low as reasonably practical" strategy. In this approach there is no "acceptable" risk. High risk items gets more attention and low risk items get less attention.

The majority of the system had a corrosion rate of less than 2 mils/year. Monitoring, mitigation, and inspection data support the conclusion that the GPB assets are being preserved, but isolated locations of accelerated corrosion exists and have been found by inspections. Data shared during meet and confer sessions illustrated that BPXA recognized the existence of these extreme values and is addressing their identification, repair, and mitigation as part of its integrity management program.

The inherent integrity risk from internal corrosion in the multiphase production system is high. Corrosion in the majority of the pipeline system has been reduced to a negligible level as a result of the implementation and continuation of an aggressive corrosion inhibition program. Anomalies in the system are inspected, mitigated and monitored.

A significant injection water internal corrosion mechanism that BPXA is aggressively responding to is under-deposit corrosion. Inhibition levels were increased, cleaning pigs and a surfactant (SBG) were used to remove deposits and line velocities are being evaluated. These actions are consistent with good corrosion control practices.

Two significant external corrosion threats are below-ground cased crossings and weld packs on above-ground pipe. BPXA has made a notable commitment to inspect and repair (when necessary) weld-packs. BPXA is aggressively addressing cased crossings by using visual, direct, smart pig and guided-wave assessments as part of their comprehensive inspection program.

~End of Report~

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REPORT OF INVESTIGATION

OF

REVISIONS TO COFFMAN ENGINEERING REPORT: BP EXPLORATION (ALASKA) INC – COMMITMENT TO CORROSION MONITORING YEAR 2000 FOR GREATER PRUDHOE BAY, ENDICOTT, BADAMI AND MILNE POINT

CONFIDENTIAL: ATTORNEY-CLIENT PRIVILEGE

April 24, 2006

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CONTENTS

SECTION 1: INTRODUCTION AND EXECUTIVE SUMMARY

This report summarizes the findings from an internal investigation into allegations that BPXA employees pressured representatives of Coffman Engineering to revise the conclusions in their review of BPXA's annual corrosion monitoring report for 2000. Based on a review of contemporaneous documents and interviews with representatives of BPXA, Coffman Engineering, and the State of Alaska Department of Environmental Conservation ("ADEC"), this report concludes that there is at present no credible evidence that any improper pressure was brought to bear by BPXA on Coffman. Further, the investigation established that representatives of ADEC, the agency that hired Coffman to conduct the review of BPXA's corrosion monitoring report, participated in all of the critical discussions between BPXA and Coffman, making it essentially impossible that BPXA pressured or conspired with Coffman to issue a report that misled State regulators.

This report provides a detailed chronology of the events surrounding both the preparation of BPXA's 2000 report to the State of Alaska concerning its corrosion monitoring program and Coffman's independent review that report. The investigation determined that Coffman initially issued a draft report that was critical of BPXA's report of its corrosion monitoring program.[1] Representatives of Coffman, BPXA, and the State then met and discussed the Coffman draft and BPXA's concerns and criticisms of the draft report. Coffman then issued a revised and, shortly thereafter, a final report that incorporated some of the changes and made some of the corrections BPXA had suggested, resulting in a report that generally was more positive in its assessment of BPXA's corrosion monitoring program and its 2000 report.[2] The Coffman engineer primarily responsible for preparing and revising the report was interviewed and he provided reasonable and credible explanations for the changes he made to the Coffman report. He strongly denied any pressure. A former representative of ADEC who participated in the agency's review of the BPXA and Coffman reports, likewise disclaimed the existence of any undue pressure by BPXA employees on Coffman. The evidence supports the conclusion that changes in the Coffman report reflected both better communication and agreements to change the way BPXA would report on its corrosion

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1 As discussed below, three versions of the Coffman report were generated. The first draft was circulated on November 2, 2001 and was entitled "Final Draft Technical Analysis of BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami, and Milne Point."

2 The revised report was issued on December 20, 2001 and was entitled "12/20/01 Draft Technical Analysis of BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami, and Milne Point." The final version of the report was issued in January 2002 and was entitled "Technical Analysis of BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami, and Milne Point."

monitoring program in the future that were agreed to by all parties in a review process that was open, professional, and without pressure or coercion .

Although this report concludes that the facts currently available do not show any improper conduct by BPXA, the report cautions that some individuals who participated in the review and reporting process on 2000 were not available to be interviewed and could have additional information would warrant reassessing the conclusions reached in this report.

Redacted

SECTION 2:
SCOPE AND CONDUCT OF THE INVESTIGATION

The investigation into allegations that Coffman Engineering was pressured into revising the report of its review of BPXA's 2000 Corrosion Monitoring Report commenced on April 7, 2006, at the request of the BPXA Law Department. The investigation was conducted by outside legal counsel, Jeffrey M. Feldman of the law firm of FELDMAN ORLANSKY & SANDERS in Anchorage, Alaska.

To evaluate the allegations, a plan of investigation was developed, calling for:

- Identification and collection of relevant reports and documents exchanged between BPXA, Coffman Engineering, and the Alaska Department of Environmental Conservation ("ADEC").

- Collection and review of available notes, emails, and correspondence generated or received by BPXA concerning preparation and review of BPXA's 2000 Corrosion Monitoring Report and review of the report prepared by Coffman Engineering.

- Identification of the individuals who participated in the drafting and review processes on behalf of BPXA, Phillips, Coffman Engineering, and ADEC.

- Interviews with those individuals who were available, who were believed to have knowledge of the most relevant information bearing on the allegations, and who were willing to discuss the matter.

The investigation process did not include review of several types of information and materials that would have been valuable, but were unavailable. Examples include:

- Review of Coffman Engineering documents, including emails and notes of communications with BPXA personnel and ADEC. Coffman Engineering recently received a federal grand jury subpoena for production of documents. Coffman's legal counsel advised that he is still in the process of assessing the matter and addressing issues relating to the grand jury subpoena. He explained that until those steps are completed, and he had a better sense of Coffman's position in the ongoing federal investigation, Coffman would be unable to share information with BPXA.

  Lack of access to Coffman personnel proved to be not as significant a limitation on the investigation. The principal Coffman representative responsible for drafting the 2000 report currently is employed by BPXA and was available to be interviewed.

- Review of ADEC records and communications and interviews with ADEC representatives. Some ADEC documents might be available pursuant to a public records request, but those items could not be obtained quickly, and some ADEC records likely would be protected from disclosure under exceptions to the public records statutes. The key ADEC representative in 2001 was Susan Harvey; she now works with environmental organization. It is unknown what attitudes she and other current and past ADEC employees hold concerning the current matter. The second most critical ADEC employee that was involved in the review of BPXA's 2000 Corrosion Monitoring Report, however, Sig Colburg, currently is employed by BPXA and, therefore, was available to be interviewed in connection with this report.

- Interviews with some BPXA employees. The principal BPXA representative responsible for preparation of the BPXA 2000 report, review of the Coffman report, and for communications with ADEC and Coffman was Richard Woollam. Woollam declined to be interviewed until he has had an opportunity to confer with legal counsel. BPXA's counsel met with Woollam's counsel, briefed him on the issues that were under review, and asked him to determine whether Woollam's recollections differed in any material respect from those of the other participants who had already been interviewed by BPXA's counsel. After Woollam conferred with his attorney, his attorney then confirmed that Woollam's recollection of the events was consistent with the facts that previously had been developed during the course of the investigation and which are set forth in this report. While direct access to Woollam would have been preferred, lack of direct access was ameliorated to a significant degree by the confirmations provided by Woollam's counsel and by the written record of emails and memoranda that Woollam and others within BPXA generated, and which document the drafting and review process. As a result, it was possible to reconstruct most of Woollam's efforts and actions from the written record with a fairly high degree of reliability.

Undeniably, direct access to all of these sources of information, particularly interviews with Harvey, Woollam and Paisley, would render a more complete record. While the findings reported below are established by the information currently available, additional documents and interviews could affect some of the conclusions reached in this report.

This report is based on documents collected and interviews conducted between April 10 and April 21, 2006. The information then was organized, the relevant state and federal statutes were reviewed, and this report was prepared.

This investigation was limited to the allegation that BPXA personnel exerted undue pressure on Coffman Engineering and/or ADEC to secure revisions to Coffman's Final Draft Report, which criticized BPXA's corrosion monitoring program and its 2000 Corrosion Monitoring Report. Although the allegations involving the Coffman report arose following the GC-2 oil discharge and during a period in which other corrosion-related issues were under review, this investigation and report focus on a single issue: Did BPXA pressure Coffman and/or ADEC and, if so, were any state or federal criminal statutes violated?

SECTION 3:
STATEMENT OF FACTS, CHRONOLOGY, AND PRELIMINARY ANALYSIS

Introduction

This section of the report begins with a brief discussion of the relevant terms of the Charter Agreement entered into by BPXA and the State of Alaska. The discussion then summarizes the development of BPXA's Corrosion Monitoring Report in 2000 and the review of that report by Coffman Engineering, the consulting firm retained by the State to review and comment on the corrosion reports submitted by BPXA and Phillips.

BPXA's 2000 Corrosion Monitoring Report was submitted to the State in March 2001, and Coffman's draft report, commenting on BPXA's submission, was issued about six months later, on November 3, 2001. But the events critical to this investigation all occurred within a fairly narrow period of time: the roughly two and a half weeks from November 3 to November 21, 2001 during which representatives of BPXA, ADEC, and Coffman communicated about the Coffman draft report and reached an agreement on revisions both to the 2000 report and to the process by which future reports would be prepared by BPXA and by Coffman. The final, revised Coffman report, incorporating various changes, was issued on December 20, 2001. But the changes that were made in the report largely were agreed to by November 21, and there were few communications between the parties during the month that followed.

Charter Requirements and Corrosion Monitoring Reporting

The Charter Agreement entered into between the State of Alaska and BPXA and ARCO Alaska in 1999 required BPXA and ARCO Alaska to develop performance management programs for the regular review of corrosion monitoring practices for non-common carrier pipelines on the North Slope.[3] The producer's commitments are contained in Paragraphs II.A.6 and II.A.7 of the Charter Agreement. Provisions in Paragraph II.A.6 require that BPXA submit an annual report to ADEC on its corrosion monitoring efforts, and twice each year "Meet and Confer" with ADEC to discuss and evaluate the results of those efforts. Before the first corrosion report was submitted, the producers and ADEC met and defined the annual reporting requirements to include the following:

- Bullet items reporting the progress of the Charter Agreement corrosion related commitment
- A general overview of the previous year's monitoring program
- Metrics that depict coupon and probe corrosion rates

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3 By the time the first reports of corrosion monitoring practices required by the Charter Agreement became due, ARCO Alaska became Phillips Alaska, Inc. ("Phillips").

- Metrics that characterize chemical optimization activities
- Metrics that depict the number and type of internal/external inspections done and, as applicable, the corrosion increases/rates and corresponding inspection intervals
- Metrics that characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph
- Metrics that depict the numbers and types of corrosion and structural related spills and incidents
- A forecast of the next year's monitoring activities in terms of focus areas and inspection goals.

[000016][4] Although the parties discussed these items, including the metrics that would be utilized to measure or report various elements of the corrosion monitoring effort, it is apparent that the issues were not discussed as precisely or clearly as proved necessary. As discussed below, it later became apparent that there were different understandings about the information the corrosion reports would contain and the format by which it was presented.

In Paragraph II.A.7, the producers agreed to spend, in the aggregate, $500,000 per year for 10 years, as directed by ADEC for orphan site assessment of cleanup, arctic spill response research and design, and/or an expert or experts chosen by ADEC to provide advice regarding corrosion monitoring.

Pursuant to Paragraph V.C of the Charter Agreement, the non-monetary commitments (the annual corrosion reporting and the Meet and Confer sessions) are not enforceable at law. Rather, they constitute "corporate citizenship commitments to the Alaska community at large." The monetary commitment contained in Paragraph II.A.7 is enforceable at law until January 15, 2009. The remedies available to the State for failures by BPXA to meet its commitments under the Charter are relevant to note here. There would have been less reason and incentive for BPXA employees to exert pressure on Coffman to revise its assessment of a report BPXA was not legally bound to submit, let alone legally required to draft in a particular manner as might have been preferred by Coffman.

During 2000, representatives of ADEC, BPXA, and Phillips met to develop a draft outline or plan of what would be included in the companies' corrosion monitoring reports. The draft went through several versions, with revisions made to the list of subjects and issues that would be addressed and the format for presenting the information. Sig Colburg, an engineer serving as ADEC's representative in the process, states that the focus of the discussions was "how we would structure these reports and what would be included in them."

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4 The numbered references in this report refer to documents that were collected during the course of this investigation and that are inventoried in Appendix A to this report.

[Memorandum of Colburg Interview at 2].[5] Colburg states that both BPXA and Phillips were amenable to developing a plan for the reports that met ADEC's needs and goals, and he does not recall any disputes or problems arising during the process. [id.] Ultimately, the agreed-upon plan became the project's Work Plan, and appears as Appendix 2(a) to the BPXA 2001 Commitment to Corrosion Monitoring Report. [000518; Memorandum of Paisley Interview at 1]

BPXA's 2000 Corrosion Monitoring Report

BPXA timely submitted its first corrosion report, as required by the Charter Agreement, for calendar year 2000 in March 2001. The report was titled "Commitment to Corrosion Monitoring." [000129] The report was prepared by BPXA's Corrosion, Inspection & Chemicals Team, typically referred to as the CIC Group, and primarily was drafted by Dominic Paisley, with assistance from Kip Sprague and others. [Memorandum of Sprague Interview at 1; Memorandum of Paisley Interview at 1] Members of the CIC Group believed that they had generated a thorough and complete report that met the requirements of the Charter Agreement and standards and metrics that had been discussed in advance with ADEC and later incorporated into the Work Plan. [Memorandum of Sprague Interview at 1; Memorandum of Krenzelok Interview at 1; Memorandum of Paisley Interview at 1]

ADEC's representative, Colburg, likewise thought that the reports submitted by both BPXA and Phillips were "very good," particularly since they "were the first out of the box," by which he means the first corrosion reports produced under the Charter Agreement. [Memorandum of Colburg Interview at 2] Colburg states that both reports were thorough and reported on the major items to which the parties had agreed during the development stage. [id.] He did not regard it as significant that the two companies' reports differed some, given the differences in the companies' cultures, the differences in their fields, and the different corrosion groups that were performing the work. [id.] A copy of BPXA's 2000 Corrosion Monitoring Report is found at Appendix B to this report.

The First Meet and Confer Session

The first Meet and Confer session pursuant to the Charter Agreement was held on April 30, 2001, at the BPXA building in Anchorage. [010001] Participants included representatives of ADEC, BPXA, and Phillips. Prior to the Meet and Confer session, BPXA developed presentation materials, including a PowerPoint presentation, to summarize and illustrate some of the matters discussed in its 2000 report. [000275, 000300, 000321] The agenda for the session included presentations by BPXA and Phillips, and time for an open discussion, questions, and feedback. [010002]

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5 Colburg currently works for BPXA, having commenced work in November 2005. While his current employment status could render him vulnerable to impeachment for bias and motive, Colburg presented as a credible witness and his statements largely were corroborated by other individuals or documents.

At the Meet and Confer session, ADEC representatives mentioned their intent to contract with a corrosion expert to assist in ADEC's review of BPXA's and Phillips' corrosion data and program reports. [010008] This was not unexpected, as the use of such experts was expressly provided for in the Charter Agreement and was one of the items for which the $500,000 per year paid by BPXA and Phillips could be spent. In the weeks that followed, Sig Colburg, the ADEC engineer primarily responsible for coordinating the technical aspects of ADEC's review efforts, prepared and circulated an RFP seeking proposals for providing the independent corrosion review work.[6] [000196; Memorandum of Colburg Interview at 3] Coffman Engineering in Anchorage, Alaska, submitted a response to the RFP [000247], and ultimately, ADEC awarded the contract to Coffman.

Selection of Coffman Engineering

By July 20, 2001, BPXA learned that ADEC had entered into a contract with Coffman Engineering to provide consulting services and to review BPXA's 2000 Corrosion Report. [010011] Tim Bieri was identified as the Coffman Project Manager, and Mike Watts (an independent contractor hired by Coffman to assist on the project) was identified as the engineer responsible for reviewing the data and report. [Memorandum of Bieri Interview at 1] Woollam knew Watts as a former ARCO corrosion engineer and regarded him as someone who was "very familiar with the corrosion, mitigation, and monitoring problems on the North Slope." [010011]

Approaching the Second Meet and Confer Session

ADEC found BPXA's presentation at the first Meet and Confer session helpful, but requested additional detail on abnormal data. [010017] On October 10, 2001, with the second Meet and Confer session approaching, the CIC Group commenced efforts to prepare updated presentation materials, with the additional data and information that ADEC requested.

As those preparations continued, Woollam wrote to Susan Harvey, the lead person at ADEC for this project, to inquire about Coffman's review of BPXA's Corrosion Report. On October 24, 2001, Bieri, the Coffman engineer primarily responsible for preparing Coffman's report of its review, responded to Woollam on behalf of Harvey. [010028; Memorandum of Bieri Interview at 1] Bieri summarized some of the major issues and recommendations that he stated would be included in Coffman's review of BPXA's Corrosion Report. Among the issues that Bieri noted would be addressed were suggestions that BPXA:

(1) Better define metrics;

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6 While awaiting responses to the RFP, ADEC circulated a list of questions to BPXA based on its initial, brief review of BPXA's Corrosion Report. [010008] The questions were transmitted by ADEC to Richard Woollam on June 15, 2001. Woollam then sought assistance from Robert Krenzelok in preparing responses. [010010; Memorandum of Krenzelok Interview at 2]

(2) Include a discussion of risk and risk-based inspection;

(3) Establishing agreed upon service categories;

(4) Include pigging results;

(5) Address how coupons are analyzed;

(6) Consider whether sufficient resources had been committed to addressing external corrosion;

(7) Discuss leak history, and

(8) Discuss other structural issues.

[010028] Woollam transmitted Bieri's comments to others in the CIC Group (Felix, Krenzelok, Sprague, Merrill, and Foust) and noted that, because the Coffman report was not likely to be issued until the following week (October 31), there would be insufficient time to review the report and to provide comments to ADEC prior to the second Meet and Confer session, which was scheduled for November 5. [010030] The timing was of some concern to the CIC Group. By November, the CIC Group hoped to be in the process of preparing for the 2001 report (due following the first quarter of 2002) and have the benefit of Coffman's review of the BPXA 2000 Corrosion Monitoring Report. [Memorandum of Krenzelok Interview at 2]

By October 31, 2001, BPXA personnel completed a draft of the presentation materials for the November 5 Meet and Confer session. [010032] The content of the presentation was substantially the same as the presentation used at the previous Meet and Confer session, except that the new materials provided more detail on the "exceptions" to the corrosion program, rather than average results, as requested by ADEC. [010032]

Coffman's Final Draft Report

Two days later, on November 2, Woollam received what was referred to as the "Final Draft" of the Coffman report.[7] [010033, 000022] Woollam transmitted this to others (Foust, Blankenship, Merrill, Phillips, McCleary, Felix, Sprague, Kuzma, and Krenzelok) for review and comment.

Noting again that there was insufficient time to prepare a response to the Coffman Final Draft prior to the November 5 Meet and Confer session, Woollam advised his

7 Although the document was called a "Final Draft," it actually was the first draft circulated for review, and it was followed by others. Even though the "Final Draft" title is confusing, this report adopts Coffman's "Final Draft" terminology for the November 2 version of its report; the true final version is referred to as the "Final Report."

colleagues that the CIC Group would review the document and prepare a response prior to BPXA's next Annual Report and Meet and Confer session, scheduled for the end of the first quarter in 2002. [010033] Woollam presumably contemplated responding in that manner because he did not immediately appreciate what he soon would perceive as serious problems with the Coffman Final Draft Report. Woollam's initial thoughts on how any issues with the report would be addressed also may have been a product of the fact that the Coffman report was denominated a "Final Draft," making it unclear whether any additional drafts were contemplated. Woollam had not been told that Coffman and ADEC intended to obtain comments and to consider revising the report prior to releasing it to the public.[8] The process of distributing a draft version of the report for comment and revision was not required by the Charter Agreement; Coffman and ADEC developed this plan without discussion with BPXA or Phillips. [Memorandum of Bieri Interview at 1]

By November 3, one day after receiving the Coffman Final Draft, Woollam apparently had reviewed the report sufficiently to conclude that it contained comments and findings that were, in Woollam's view, unfairly critical of BPXA, contrary to the intent and spirit of the Charter Agreement provisions, and, in some instances, factually incorrect. Other members of the CIC Group likewise were disturbed by the tone of the Coffman report, as well as what they perceived as the technical inaccuracies. [Memorandum of Krenzelok Interview at 2] Still others thought the tone of the report suggested that Coffman had been "out to pick holes" in the BPXA report. [Memorandum of Paisley Interview at 2] Prior to receiving the Final Draft Report, there were no indications from Coffman that it had criticisms of the BPXA Corrosion Monitoring Report. Coffman representatives apparently did not ask any questions or have any contact with BPXA during the period of its review. [Memorandum of Krenzelok Interview at 2] Moreover, BPXA had received positive feedback from ADEC at the first Meet and Confer session in April, 2001, and, therefore, the report seemed out of sync with the history of communications between ADEC and BPXA. [Memorandum of Paisley Interview at 2]

In an email to Chris Phillips and Ronnie Chappell, and copied to Nancy Foust, Woollam noted that BPXA's obligations under the Charter Agreement only required BPXA to (1) file an annual report with ADEC on corrosion and (2) meet and confer twice per year with ADEC to discuss corrosion issues. His comment implied that Coffman had taken an erroneously expansive view of BPXA's obligations, as well as ADEC's authority to require broader or different reporting. Woollam went on to say that he hoped to gain a better understanding of Coffman's concerns and to secure some changes and corrections to the report at the Meet and Confer session scheduled for November 5. He indicated that he intended to confer with Susan Harvey at ADEC and determine what process was contemplated for going from a draft to a final report. He also intended to talk with Harvey

8 This is evident in a memorandum Woollam later prepared, summarizing the plan for assessing Coffman's Final Draft. The first issue listed on the memorandum is determining if "the report already is in the public domain, or likely to be, when the final document is issues (sic) and therefore BP should respond formally so that out (sic) responses are in the public domain." [000621]

about the extent to which the Coffman report had departed from the spirit and intent of the Charter Agreement provisions. [010034]

The Second Meet and Confer Session

BPXA's Meet and Confer presentation materials were finalized on November 4. [000353] In transmitting them to the CIC Group, along with the agenda for the Meet and Confer session, Woollam reiterated his intent to try to obtain a better understanding of the issues Coffman raised. [010036, 010037]

The second Meet and Confer session was held as scheduled on November 5. After this session, Woollam reported that Susan Harvey had agreed to provide BPXA an opportunity to review and comment on the Coffman draft prior to its being finalized. [010038] But the Meet and Confer session did not leave BPXA representatives with a comfortable feeling. Indeed, Sprague described the session as confrontational, particularly with respect to comments made by Watts, the former ARCO engineer with whom Coffman had contracted to assist in the review work. [Memorandum of Sprague Interview at 2] Others from BPXA did not share that impression, and it is possible that Sprague's characterization draws more from Watts' comments in the Coffman Final Draft Report (which Sprague regarded as "mean-spirited") than from Watts' comments at the Meet and Confer session. [*Id.*] But, even if so, Woollam, too, reported that they came away from the meeting "with some deep reservations about Coffman Engineers and their report. (The Coffman representatives) seemed unwilling to discuss BP/PAI's reservations or concerns. Susan Harvey seemed a little more conciliatory and has agreed to meet with BP/PAI to discuss (without Coffman)." [010085]

Reacting and Responding to the Final Draft Report

On November 6, BPXA started to collect its responses to the Coffman Final Draft, which were to be compiled into a single submission to ADEC. [010047] The first to weigh in was Dominic Paisley, who had been the principal author of BPXA's 2000 Corrosion Report. Paisley set out his comments and criticisms in a detailed email to Woollam. [010041; see also handwritten notes at 010003 and Memorandum of Paisley Interview at 2]

Also on November 6, Woollam contacted Bill Colbert in the BPXA Law Department and identified some of the issues and problems he perceived in the Coffman Final Draft. Woollam described the Coffman report as:

- Very prescriptive and inconsistent with the summary performance management process contemplated by the Charter Agreement;
- Quantitative, although Coffman was charged with developing a qualitative analysis;
- Wantonly critical; and

- Factually in error.

[010053]

Woollam sought Colbert's advice on how to respond to ADEC and Coffman regarding (1) specific problems with the report, (2) the change in direction by ADEC, and (3) the inconsistency between the approach taken by ADEC/Coffman and the requirements of the Charter Agreement.

On November 7, Nancy Foust wrote to Neil McCleary, informing him that the Coffman Final Draft was "highly negative and contains many inaccuracies." Foust advised McCleary that Woollam was conferring with Colbert about options, and that BPXA intended to "try very hard to sway Coffman and ADEC on the final version of the report." [010054]

On November 8, Colbert responded to Woollam's request for advice with a thoughtful email that analyzed the applicable provisions of the Charter Agreement and BPXA's obligations. Colbert recommended that Woollam convey his concerns and objections in a letter to ADEC, and that he try to schedule a high-level meeting between ADEC Commissioner Michelle Brown and Steve Marshall or Ross Klie at which BPXA could air its concerns about the Coffman report and learn what ADEC planned to do. Colbert specifically mentioned attempting to reach an agreement at the meeting on the objectives and key parameters of the performance management program that BPXA and ADEC would follow. [010056]

Colbert copied his response to Foust. Foust, in turn, forwarded it to Neil McCleary. In her transmittal note, Foust indicated her view that, "since the report is technically unsound, we may need to ask that you and/or Steve (Marshall) assist if our initial attempts to sway Susan Harvey (ADEC) are not successful." [010059; see also 010063]

Meanwhile, Woollam continued to receive comments and feedback from CIC Group members and he reported on November 8 that he intended to compile them into a consolidated document. [010058] Later that day, he circulated a rough draft of general comments on the Coffman Final Draft, as well as an executive summary of BPXA's comments. [010070, 000397]

The following day Woollam negotiated an extension with Susan Harvey, giving BPXA until November 30, 2001, to file its response to the Coffman Final Draft. [010072] He also reiterated his request to meet with Harvey to discuss the Coffman report and what he described as "the way forward for meeting the commitments under the Corrosion Monitoring section of the Charter Agreement." This was something Woollam first had raised at the Second Meet and Confer session on November 5. [010075]

Woollam received feedback from CIC Group members on his draft of BPXA's comments on the Coffman report, and he incorporated those comments into a revised draft. [000623] In circulating the revised draft, Woollam was mindful of trying to maintain the appropriate tone with ADEC, commenting that "We'll probably need to tone (the comments) down a little as I was getting pretty acerbic toward the end, but please review for content, did I miss any major points." [010076]

Meanwhile, Phillips was engaged in a similar effort, preparing its own comments to the Coffman Final Draft analyzing Phillips' 2000 Corrosion Monitoring report. [000001, 000629] On November 11, Woollam transmitted a copy of BPXA's draft comments on the Coffman BPXA report to Phillips [010081], and, the same day, he received a copy of Phillips' draft comments on the Coffman Phillips report. In transmitting the Phillips comments to BPXA, Maria Cherry noted that she was "still struggling though their comments....my feeling is that it is necessary to address not only the actual false statements in the Coffman report, but also all of the little misleading insinuations and slams that seem to abound in the Coffman document." [010078][9]

By November 13, Woollam had set up two meetings with ADEC for the following week. The first meeting, on November 19 with Susan Harvey, was planned to discuss "the way forward to meet Corrosion Monitoring portion of the Charter Agreement." The second, scheduled for two days later, November 21, was planned to include both Harvey and Coffman Engineers, to discuss "BP's concerns with the Final Draft of the Coffman Engineers' report." [010088, 010090]

<u>The November 19 Meeting With ADEC</u>

On November 19, Woollam received the final version of Phillips' comments on the Coffman Phillips report [010091], which he circulated to other members of the CIC Group. [010092] Phillips representatives met with Tim Bieri of Coffman on Monday, November 19. [010093]

The same day, Woollam met with Susan Harvey (but without Coffman). The meeting went well, and Woollam subsequently reported that:

- Harvey indicated she could influence the style of the Coffman report, but was reluctant to enforce changes in the recommendations, as she felt that the document was an independent third-party audit.

- The parties discussed BPXA working collaboratively with ADEC to improve integrity programs.

- BPXA made the case that the Coffman report was not an unbiased appraisal of the program or the report; Harvey acknowledged this concern but did not commit to any specific changes.

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9 Also on November 11, 2001, Woollam made inquiries within BPXA about whether Coffman had any contracts with BPXA. [010080] The reason for Woollam's inquiries is not apparent from the written record.

- Harvey recognized the lack of interaction with Coffman as a failing in the process and committed to addressing the issue.

Woollam described the meeting with Harvey as "very professional and reasonable," with Harvey appearing as "the voice of reason." She encouraged detailed discussion of the issues at the joint meeting with ADEC and Coffman that was scheduled for two days later. [010093] In hindsight, this meeting appears to have been the point at which the process began to turn. The Meet and Confer session, two weeks earlier on November 5, had not left BPXA with a good feeling. But Harvey apparently appreciated at least some of the concerns Woollam raised and, as reported by Woollam, reacted in a positive and constructive manner, setting the stage for the meeting with Coffman two days later.

The November 21 Meeting With ADEC and Coffman

On November 20, Woollam circulated to other members of the CIC Group his final version of BPXA's comments on the Coffman Final Draft. [010094, 000639] His document was titled "BP Concerns/Comments on the Final Draft Coffman Engineering Report"; it consists of five pages of bullet point comments and responses to various statements in the Coffman Final Draft. By any measure, the comments and responses are stated clearly, professionally, dispassionately, and without rancor. [000639] Woollam delivered these comments the following day to ADEC at the meeting attended by representatives of ADEC, Coffman, and BPXA. Woollam's report of the November 21 meeting suggests that it was even more productive than was the meeting with Harvey on November 19. The parties discussed BPXA's concerns and comments about the Final Draft and spent significant time reviewing the claims of technical inaccuracy in the report. [Memorandum of Foust Interview at 2]

The November 21 meeting likely is the most critical event that occurred in this matter. It was the first time that BPXA presented and discussed with Coffman the substance and details of its comments and concerns about Coffman's draft report. As detailed below, it also was the meeting at which ADEC and Coffman agreed to make various changes to the draft report. If any undue pressure had been brought to bear on the review process by BPXA, it would have to have been – or at least would have to have surfaced – at this meeting. But there is no evidence of that at all. That the meeting went as well as it did, resulting in what appears to have been a very positive and constructive response from both ADEC and Coffman, suggests that the process was not infected with the kind of pressure or overbearing presentation that has been alleged.

Bieri, the Coffman engineer principally responsible for writing and then revising the Final Draft, and who was present for the November 21 meeting, states unequivocally that BPXA did not attempt to pressure ADEC or Coffman into making changes. Bieri strongly denies the essential allegation that the Coffman report was changed as a result of any such pressure.[10] Bieri did state that the BPXA representative felt strongly about the concerns they

10 Bieri stated that he had a reasonable and professional relationship with Woollam. He denied that he ever felt attacked or threatened by Woollam, and stated that Woollam treated

expressed, and he felt "pressured" only to the extent that he expected that if changes were not made there ultimately would be "dueling reports," by which he meant the Coffman report and a BPXA rebuttal and, conceivably, a rebuttal to the rebuttal. This was not the process that was envisioned. Bieri states that the reason the draft report was circulated was to afford others an opportunity for comment and to afford Coffman an opportunity to revise the report to better capture the data and information. He says that there would have been no reason to circulate the draft had there not been a willingness to revise the report as seemed appropriate. [Memorandum of Bieri Interview at 2] From his perspective, the process went forward the way it was intended, and he agreed to changes in the tone and substance of the report only to make it more accurate and better balanced.[11] Bieri stated that he understands that, if one looked only at the first and final drafts of the report, a question could be raised about why the changes were made. But he says that if one looks at the evolving relationship between ADEC and the producers, the development of Coffman's role, and the metrics that the parties agreed would be used, it is easier to understand why the changes in the report, including the changes in tone, were made and how the process was addressed in later reports. [Memorandum of Bieri Interview at 3]

In his summaries of the November 21 meeting, Woollam reported that:

- There was a clear desire by both ADEC and Coffman to move the relationship to a more collaborative and cooperative basis from the adversarial relationship which the Final Draft had initiated.

- There was willingness on the part of Coffman and ADEC to address the BPXA concerns about style and balance, to move away from the highly negative and to represent both the good and the bad rather than just the perceived gaps.

- There was recognition of the need for an increased level of interaction between BPXA and Coffman.

- *At ADEC's request*, Coffman agreed to rewrite/reword the report to reflect the style/balance concerns, and to address some of the technical issues.

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him with respect and patience. [Memorandum of Bieri Interview at 3] Bieri's colleague at Coffman, Mike Watts, is reported to have been a more strident voice during the review process. Watts was not located or interviewed in connection with this investigation and Bieri acknowledged that it is possible that Watts has a different perspective on the process. [*Id.*]

11 Bieri currently works for BPXA (he was hired in 2004, three years after the events at issue here occurred). To that extent, his statements are subject to impeachment for bias and motive, since he conceivably has a reason not to offer statements adverse to his current employer. But Bieri presents as a very credible and convincing witness, and all of his statements are consistent with those of other participants to the process. [See, e.g., Memorandum of Foust Interview at 2, 3; Memorandum of Sprague Interview at 2]

- *At ADEC's request*, Coffman agreed to rewrite/reword the report to reflect the style/balance concerns, and to address some of the technical issues.

[010095, emphasis added] ADEC agreed to afford BPXA an opportunity to review the next version of the report before it was finalized, with an intent to issue the Final Report before the end of 2001.

Woollam concluded his report of the November 21 meeting, saying, "In summary, we appear to be in a much better place than we were two weeks ago, however we will need to wait until we see the revised report to be certain of how much attention has been paid to the concerns raised. In the meantime, Rick and I will be working with ADEC/Coffman to address any questions." [010095] "[O]ur concerns have been clearly heard and understood by both ADEC and Coffman, and that as a result the relationship with these two organizations will and has improve (sic)." [010096]

A report by Phillips on the substance of its own meeting with ADEC and Coffman "paint(ed) a similar picture from the Phillips perspective." [010095]

In addition to resolving the issue of revisions to the Coffman report, the November 21 meeting also initiated a dialog among the participants that ultimately led to a more clearly defined set of standards and metrics that would be used in future annual corrosion reports, both by BPXA and Phillips, as well as by ADEC and Coffman. Those standards and metrics ultimately became Appendix 2(b) to the BPXA Corrosion Monitoring Report for 2001 (issued in 2002) [000402, 000522], and they remain in use by the parties.

Revisions to the Coffman Report

The following day, November 22, Woollam transmitted an electronic version of BPXA's comments on the Coffman Final Draft to Bieri and Elaine Cederstrom at Coffman. Woollam was sensitive to preserving the positive atmosphere of the November 21 meeting and, in his cover email, noted that "the comments are an amalgamation of a number of different individuals' comments which I have edited and tried to remove the more 'emotional' comments – I apologize ahead of time if I haven't managed this successfully." [010097]

While Coffman personnel were reviewing the BPXA comments and revising the report, Woollam started to analyze or "post-mortem" what accounted for the problems that had been encountered in the process of generating the draft report. In a November 25 email to Neil McCleary and Nancy Foust, Woollam observed that, in his view, there were issues about both process and communication. With regard to process, Woollam stated that there was:

- "Lack of sophistication on the part of Coffman in that Tim Bieri issued a report without thinking through the reaction and consequences of the report."

- "Lack of review…at senior levels within Coffman and/or ADEC; if there had been review then issues about balance and the report being public would not have occurred."

- "Lack of communication between Coffman/ADEC and Coffman/BP...led to a considerable number of misinterpretations and misconceptions which results in recommendations and conclusions which are erroneous."

[010098] It also is likely that the fact that the process was new, and the standards, formats, and content of the annual corrosion monitoring reports all were being refined, contributed to the process that was experienced in 2001. Woollam concluded that, in future years, BPXA would have to "take a more active role in education of both ADEC and Coffman...and] more proactively facilitate and manage this process." [010098] McCleary sent a note congratulating Woollam and Foust for "an improving relationship and better quality report." [010098]

On December 20, 2001, Coffman generated a revised draft report with (from BPXA's perspective) a significantly improved tone; it incorporated many of BPXA's comments. [000013].[12] In transmitting the revised draft to BPXA for review, Bieri at Coffman noted that "We attempted to address everyone's concerns and observations and hope this version is a little more palatable." Bieri requested that BPXA provide its feedback on the revised draft and offered to discuss any questions or concerns "through the holidays." [010101]

Without question, there were significant changes in the report, particularly in the Executive Summary section. There were few, if any, substantive changes to data or technical information, but there were substantial changes in tone and emphasis. Among the statements that were included in the Final Draft but were deleted or changed in the revised version of the report circulated on December 20 were the following (page references are to the Final Draft; italicized references are to the revised draft of 12/20/01):

- "Reporting style makes it difficult to develop a qualitative understanding of the basis for their corrosion strategy." (Page 2)
- "Program results have been reduced and factored." (Page 2)
- "Conclusions are hard to report without making inferences with regard to the underlying reasoning and strategy." (Page 2)
- "The metrics chosen to report results make comparisons to industry peers difficult to quantify." (Page 2)
- "No discussion of the underlying program strategy is included other than to say "'Our corporate goals are no accidents, no harm to people, and no damage to the environment.'" (Page 2)

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12 The 12/20/01 draft was titled, "12/20/01 Draft Technical Analysis of BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami and Milne Point." [000013]

- "External corrosion is the most immediate threat to pipeline integrity for BPXA." (Page 2)

- "Internal corrosion rates increased in 2000 in well flow lines, drillsite gathering lines, and produced water injection lines." (Page 2)

- "The actual magnitude of the corrosion increase is not quantified." (Page 2)

- "No differentiation between weight loss and pitting corrosion are discussed." (Page 2)

- "Without knowing the baseline corrosion trend within its production system it is difficult to judge the effectiveness or value of its inhibition program." (Page 2)

- "No statistics on the extent of erosion corrosion defects was reported." (Page 2)

- "Information on how the coupons are analyzed and how the data is weighted is not presented." (Page 4)

  <u>Replacement language in the revised report states</u>: *"It is unclear how the coupons are analyzed and how the data are weighted." (Page 3)*

- "There is very little discussion about the MFL pigging strategy (location, frequency, results, etc.)." (Page 4)

- "BPXA will have to validate an effective repair method in order to eliminate this as a fixed cost of operation." (Page 4)

- "Presently, there are no monitoring techniques used for this corrosion mechanism." (Page 5)

- "BPXA appears to use some form of risk based resource allocation method but the details are not reported. Judgment or experiential based protocols suffer from a lack of continuity...BPXA may have codified its risk assessment strategy but it is not reported." (Page 5)

  <u>Replacement language in the revised report states</u>: *"It is clear that a form of risk based resource allocation is used by BPXA; the corrosion team has identified and responded to corrosion events and developed continuous improvements to its corrosion program when changes were deemed necessary." (Page 5)*

- "Internal corrosion rates at GPB have increased in every service category except seawater in 2000." (Page 5)

Replacement language in the revised report states: "Report results indicate internal pipeline corrosion trends for GPB West have been steadily improving since 1993 and are currently at their lowest levels in 12 years." (Page 2)

- "Unfortunately, only the percentage of inspections which show increases in damage is reported; not the magnitude of the wall loss." (Page 5)
- "No attempt is made to quantify the possible extent of internal pipe wall loss due to this corrosion rate excursion." (Page 6)
- "No discussion of how coupons are analyzed is reported." (Page 6)

Replacement language in the revised report states: "A discussion detailing how coupons are evaluated by BPA would be beneficial, as it is apparent that there are differences in the way various operators perform this function." (Page 6)

Finalizing the Coffman Report

The CIC Group reviewed the revised report. They found it more reflective of BPXA's corrosion monitoring program and better balanced than the earlier draft of the report. [Memorandum of Krenzelok Interview at 3] Woollam's directions to the group stated that "unless we find gross error and have very substantial objections and/or comments I would prefer to leave the report largely unchanged rather than enter into a second round of corrective action/requirements." [010101] The review of the revised report was completed quickly and the same day (December 21) Woollam transmitted a short email to Bieri at Coffman noting "just a couple of very minor comments" and concluding that, "apart from the comments above, the report is a balanced review and BP has no further issues or comments so please move ahead with issuing the document." He closed his note saying, "Hope you and your family have a good Christmas and New Year and I look forward to working with Coffman/ADEC early in 2002 on the next phase of the program." [010100]

Coffman received the few additional BPXA comments favorably and issued the final version of its report shortly thereafter, in January 2002. [000047][13]

ADEC apparently was satisfied with the outcome of the process. ADEC representatives received copies of all the drafts of the Coffman report and attended all the critical meetings. As a result, ADEC personnel were fully informed of the issues and concerns that were discussed, as well as the revisions that were made to the drafts and the reasons for those revisions. At no time did ADEC representatives complain or raise any

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13 The final version of the report is titled "Technical Analysis of BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami and Milne Point." [000047]

question about the revisions or express any concern that the report was being inappropriately watered down. [Memorandum of Bieri Interview at 3]

The satisfactory resolution of BPXA's concerns over Coffman's Final Draft appears to have been both appreciated by and a surprise to BPXA managers. On December 27, Nancy Foust sent a short note to Woollam expressing appreciation for the "great results." By way of reply, Woollam commented that he "really didn't think we would get this far based on the first draft and on the initial feedback from the November Meet and Confer session"; he indicated that he intended to follow up with Coffman "to keep the process moving forward and positive." [010102]

That apparently is what occurred. The process that was developed during 2001 was utilized in the following years. BPXA submitted its annual reports consistent with the standards and metrics that were worked out during the process of reviewing the 2000 reports. Likewise, the Coffman review reports for 2001,[14] 2002,[15] 2003,[16] and 2004[17] all were prepared consistent with the metrics and standards worked out by the parties in 2001 and they were finalized without problems or conflicts. [010103; Memorandum of Bieri Interview at 1; Memorandum of Sprague Interview at 2; Memorandum of Krenzelok Interview at 3] Bieri, the principal Coffman engineer assigned to the project, attributes the more difficult process encountered in the first year to the absence of common metrics, which were worked out by agreement of the parties during the course of the review and revision of the 2000 report.

Redacted

14 000056.

15 000078.

16 000088.

17 000095.

Redacted

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Redacted

CONCLUSION

The evidence reviewed during the course of this investigation does not support the allegation that employees of BPXA exerted undue or inappropriate pressure on representatives of Coffman Engineering to revise the report of their review of BPXA's 2000 Corrosion Monitoring Report.

The evidence reviewed during this investigation establishes that representatives of ADEC received and reviewed copies of the various drafts of the reports, as well as the comments and concerns submitted by BPXA, and attended all of the critical meetings at which the Coffman report was discussed. As a result, the evidence does not support a finding that ADEC was, in any respect, misled by or unaware of the revisions that were made to the Coffman report. Indeed, the evidence establishes that ADEC representatives were actively involved in the process by which those revisions were incorporated.

Finally, even if the evidence supported the allegations discussed above, it is not apparent that the actions alone, without more, would constitute an independent criminal offense under either state or federal law. But if the facts of the allegations could be proved, they could have evidentiary significance in connection with a prosecution of BPXA for negligence-based offenses (state or federal), since the facts would tend to establish (1) knowledge on the part of BPXA dating back to 2001 of deficiencies in its corrosion monitoring program and, (2) that BPXA did not act to address the deficiencies but, rather, sought to conceal them by securing revisions to a critical report.

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Alyeska pipeline SERVICE COMPANY

Top Ten List

Item	Comments	Status
1. Replace drain lines at PS03. In 2005, a survey of drain lines at all pump stations was completed; areas of pitting were discovered at PS03	*PS-3 drain line replacement completed during the July 22 and 23, 2006 pipeline shutdown.*	Completed 7/22-23/2006
2. Work with North Slope producers to determine what corrosion investigation has been performed and clarify responsibility for the line from Skid 50 to PS-01 (600' of which are buried).	*All five incoming lines' points of ownership transfer have been identified and points of demarcation have been clarified. Inspections of lines are identified in Items #3 and #4 below.*	Completed June 2006
3. Redo some of the 2005 PIT work completed on PS01 deadlegs to ensure there is no accelerated corrosion; include 29 additional sites in PS01 PIT work. Evaluate results and include recommended work in 2007 program.	*PS01 PIT work has been added to the 2006 corrosion investigation program scope. This includes a survey of 29 new locations on various incoming lines and reinspection of some deadleg locations that were surveyed in 2005.36 additional sites were inspected. Evaluation of results is ongoing.*	Completed UT investigation June 2006; expect report by Sept 2006
4. Investigate Sadlerochit incoming line to TAPS between Alyeska's point of demarcation and PS01meters	*At least one location on the buried portion of the Sadlerochit incoming line will be excavated and visually inspected in the fall of 2006. Up to two additional sites may be checked based on results of BP's upstream corrosion data analysis when that data becomes available to Alyeska.8/14 – Design package for dig work will be ready for review on Aug*	Ongoing,expect dig completion Sept/Oct 2006

Alyeska pipeline SERVICE COMPANY

Top Ten List

Item	Comments	Status
5. Review pig data at steep pipe gradients for any anomalies.	*Reviewed pig data and did not find any anomalies in these areas.*	Completed May 2006
6. Collect liquid sample at PS01 strainers (before meters) and test for corrosivity. Also UT drain line off PS01 meter strainer.	*This is incorporated into the PS01 PIT program supplemental scope being added to the 2006 corrosion investigation program.* *Two UT inspections are complete. One showed no corrosion. The other, a tee fitting, showed minor internal corrosion but due to the increased fitting thickness was still greater than nominal wall for the piping class* *Water tests attempted; no significant water found (0.2%). Will not continue sampling as it is not practical or effective.*	Completed June 2006
7. Run a corrosion pig on TAPS.	*Contract negotiations began June 14 to run an MFL pig from BJ Pipeline Inspection Services. Target date to begin the run is August 6, 2006 with all 800 miles complete by August 30* *8/14 - Pig run completed from PS01 to PS04 on Wednesday, August 9, 2006. Pig run from PS04 to Valdez delayed to further evaluate effects of reduced throughput (i.e. slack line, increased wax, battery capacity, etc.)*	Completed pig run from PS01 to PS04 on Aug. 9, 2006. PS04 to VMT scheduled for September 2, 2006

Alyeska pipeline SERVICE COMPANY

Top Ten List

Item	Comments	Status
8. During BP pigging, conduct solids observations, water sampling and testing. Assess sampled water for bacteria and corrosivity. Assess solids volume and water corrosivity at pig traps along TAPS. Adjust operations accordingly.	*Water testing methods are under discussion. A negligible volume of solids was observed to be dislodged on the Lisburne pigging project. No significant water volume was found. Ongoing as BP OTL line pigging continues.* *8/14 – Will meet with BP team this week to coordinate collection of water samples on the BP side of the line as we have not been successful with water sample collection on the Alyeska side of the line*	On going
9. Evaluate need to increase TAPS baseline corrosion inhibitor volumes. Determine additional inhibitor volume needed during BP pigging based on anticipated solids level.	*Baseline volume increases are currently being evaluated. Anticipate increase in injection cycles during BP's pigging.* *PL analysis is complete and volumes have been determined. VMT analysis is in progress. Estimate implementation by September 1.* *8/14 – Corrosion inhibitor rates have been increased at various locations on the Pipeline and at the Valdez Marine Terminal.*	Completed August 2006
10. Inspect PS01 incoming line block valve bodies and drain piping and PS01 Sadlerochit valve (BL-120). This may be an early indicator of water and/or chemical issues.	*The 2006 corrosion investigation program scope will inspect BL-120 body drain piping as well as a currently unidentified site on the incoming 36" piping in the same general location. See Item #4.* *One site was inspected on the BL-120 drain between the valve body and the 2" drain valve. No corrosion was noted.*	Completed June 2006

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Alyeska pipeline SERVICE COMPANY

P.O Box 196660 ANCHORAGE, ALASKA 99519-6660 TELEPHONE (907) 787-8700

Kevin M. Hostler
President & Chief Executive Officer

May 12, 2006

Steve Marshall, President
BP Exploration (Alaska) Inc.
900 East Benson Blvd.
Anchorage, Alaska 99508

Subject: Receipt of Material from Non-routine Pigging of Producer Lines

Dear Steve:

A team of Alyeska engineers, oil movement specialists, and others have completed an initial assessment in response to your April 25th, 2006 request to help manage the pigging materials that result from BPXA's proposed pigging activities in the EOA, WOA and Lisburne POTLs. This letter summarizes results of that assessment and describes the basis under which Alyeska would continue working on this request.

Alyeska's evaluation of the potential impacts to TAPS facilities if this material is to be received, is to ensure the activities and resultant impacts of receiving pigging material from the connecting pipelines meet the following standards:

- Any pigging activities will not adversely impact safety, environment or TAPS integrity.
- Any pigging materials from these activities will not adversely impact the safe and efficient transportation of crude oil in TAPS, nor adversely impact TAPS crude oil quality.
- Anything TAPS does relating to this type of pigging activity must be done for any connector in the future, should the situation arise again, or a similar situation on a different connection.
- TAPS must be reimbursed for its costs, paid fair market value for the use of its facilities, and be provided assurances that the risks of taking the materials are borne by BPXA.

As such, Alyeska initiated an assessment on TAPS equipment, systems, and operations from a safety, environmental, integrity, compliance and legal perspective. The assessment teams were directed to evaluate the apparent potential impacts and/or hazards to TAPS if the proposed BPXA maintenance cleaning pig material from these POTLs is routed into TAPS.

Because of the potential impacts to TAPS from these pigging materials, the first conclusion of the assessment is that if possible BPXA should handle these materials without utilizing TAPS. As a result, we request BPXA undertake a thorough engineering and cost analysis of its best options to remove the solids into a BPXA facility before they enter PS 1. As explained below, with agreement from BPXA to reimburse our costs, Alyeska will initiate a similar analysis of the best options involving TAPS, for eventual comparison with the BPXA option.

Based upon our present assessment, Alyeska can not at this point approve receipt of the pigging materials into TAPS, either to the mainline or to a tank at Pump Station 1. With regard to the first option, our assessment evaluated transporting the pigging materials through the TAPS mainline and into the Valdez Marine Terminal. The introduction into TAPS of these pigging materials is expected to pose significant adverse risks, particularly to safety, systems integrity and the environment. These risks can not be mitigated to an acceptable level, and Alyeska does not intend to consider this option further.

Based on Alyeska's assessment of the second option, to route pigging materials to a breakout tank at Pump Station 1, Alyeska is not prepared at this time to approve this option. Alyeska is willing to continue to explore and develop this option. There are several sub-options within this general concept that could be further developed. Fully developed options will be compared internally, and with the BPXA options on the basis of effectiveness in protecting the safe and efficient transportation of oil, worker and public safety, integrity, environmental protection and regulatory compliance to determine whether a TAPS option is acceptable to Alyeska, the TAPS Owners, BPXA, and government agencies.

Alyeska's assessment of a PS 1 storage tank option indicates that it is possible, but not certain, that impacts could be mitigated to an acceptable level of risk. While not attractive to Alyeska or the TAPS system, with additional analysis and consideration provided by BPXA, this option could potentially be viable, if TAPS elects to accept the operational and associated legal risks. A thorough evaluation of all the various issues, risks and mitigation measures of this option would need to be completed to allow Alyeska to make a final decision and recommendation to the TAPS Owners. Important issues that need to be resolved are whether this option could be accomplished without negatively impacting the maintenance shutdown of TAPS in July, and the strategic reconfiguration project. Also, this option has the potential to impact TAPS oil shippers. Accordingly our plan is to further evaluate this option in close coordination with BPXA, the TAPS regulators, and TAPS Owners.

While further analysis could change it, the concept currently envisioned is as follows: TAPS would temporarily lease the use of a crude oil breakout tank at PS 1 and the upstream piping to BPXA. Under this approach, Alyeska would retain a necessary amount of operational control of these assets. All pigging materials would be routed from the BPXA operated POTLs pig runs directly into the leased tank and removed as cleaning pig runs are completed. BPXA would retain custody of the pigging solids and accompanying crude oil until the solids had been removed. Ultimately, only normal quality crude oil would be delivered to the TAPS mainline. Alyeska would reserve the right to use the leased facilities for unplanned conditions as well as certain defined (e.g., TAPS shutdown) conditions and BPXA would agree to manage the contents of the tank in a manner that ensures that TAPS potential needs could be met. When BPXA has completed its use of the piping and tank for receipt and removal of pigging solids, the facilities would be returned to Alyeska in a condition equal to, or better than, when transferred to BPXA through the lease.

The findings of Alyeska's TAPS Impact Assessment and our legal analysis support this recommendation.

If BPXA would like to pursue this further Alyeska proposes that we proceed as follows:

A. Develop a funding agreement between BPXA and Alyeska to cover Alyeska assessment costs to date and costs in developing a detailed plan for the PS 1 storage tank option. This work will include, but not be limited to, preliminary design of facilities, assessment of issues, risks and potential variations on the option and preliminary review with the TAPS Owners, the JPO and regulators.

B. Work together as follows:

   1. As a prerequisite for Alyeska moving forward with its analysis, we request BPXA to evaluate and document its best alternatives available for managing the pigging materials upstream of PS1. We need this information so that we can have an informed discussion with the TAPS Owners and our regulators about the best options to handle the pigging materials. We wish to be clear on an important point: even if, after analysis, use of a PS 1 tank appears to be the best option from a cost and timing perspective, it may not be acceptable from an operational, compliance and legal perspective.
   2. If this analysis produces a plan that meets all our criteria for acceptance, Alyeska will only proceed with the plan after we have a contract whereby BPXA agrees to bear the costs incurred by Alyeska and TAPS to accommodate BPXA's request and to put TAPS in a position to accept the pigging materials, including the costs of risk mitigation, and the fair market rental value of the facilities.
   3. Our agreement with BPXA must address all elements of this arrangement, including by not limited to an indemnity agreement whereby BPXA will provide full indemnification of Alyeska and the TAPS Owners for any liabilities that may arise from the decision to accept the pigging materials (including claims based on negligence, gross negligence, willful misconduct, or

criminal acts). A demonstration of financial responsibility similar to other TAPS connectors would be required, along with other terms and conditions appropriate to this new agreement.

4. Commit to establish connection permits and agreements for the PBU and Lisburne connections. Although we will not require completion of the connection agreements before the pigging operations commence, Alyeska will require a written statement of intent to complete them by the end of 2006, recognizing that RCA approval may take longer.

C. Alyeska will provide a full briefing to its regulators, in advance, on Alyeska's proposed action and all relevant circumstances and considerations affecting it.

D. Alyeska will require a formal pigging plan from BPXA prior to receipt of GPB pigging materials into TAPS facilities.

E. Alyeska will obtain any necessary approvals of the TAPS Owners after the above action items have been completed and before any pigging materials are allowed into TAPS.

F. Alyeska will simultaneously adopt the foregoing points as a formal and non-discriminatory policy for dealing with similar requests (by BPXA and others) in the future.

If BPXA agrees to proceed on this basis, the following members of the Alyeska senior management team are designated for interaction with BPXA representatives:

Mike Joynor, Oil Movements Manager – technical and operational issues
Jordan Jacobsen, VP and General Counsel – legal and contractual issues
Rob Shoaf, Compliance Officer – regulatory issues

Alyeska is prepared to proceed with this approach upon acceptance from BPXA. Please contact me if you wish to discuss this further.

Sincerely,

K M Hostler

cc: TAPS Owners Committee

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Re-evaluation Of The
TAPS Impact Assessment of Receiving Pigging Solids From BPXA Produced Oil Transit Lines Interim Report

TO: Kevin Hostler, President and CEO
FROM: Mike Joynor, Oil Movements Manager
DATE: August 8, 2006

RE: Re-evaluation of the TAPS Impact Assessment of Receiving Pigging Solids From BPXA Produced Oil Transit Lines –Interim Report

In response to your request, please find attached the summary of the Re-evaluation of the TAPS Impacts Assessment Team's Interim Report regarding the impacts of receiving pigging solids from the proposed BPXA cleaning and inspection pigging activities of the EOA, WOA and Lisburne Produced Oil Transit Lines.

The Assessment Team re-evaluated the potential impacts to TAPS facilities and operations as a result of shutting in Greater Prudhoe Bay. The attached summary reflects the findings and recommendation of the team. This summary has been reviewed by and is acceptable to the Law Department. The summary is an accurate representation of the evaluations and assessments that were conducted.

This summary will be produced for limited distribution, and distribution is managed by way of controlled and numbered copies.

Mike Joynor
Assessment Team Lead

Based on a previous request by BP Exploration Alaska, Alyeska Pipeline Service Company performed an assessment for receiving pigging solids into TAPS from BPXA produced oil transit lines. The result of this effort was published on May 12, 2006 and is titled "TAPS Impact Assessment of Receiving Pigging Solids From BPXA Produced Oil Transit Lines Interim Report". Based on BPXA's revised estimates of pigging solids within the EOA and WOA POTL's and the recent decision to remove those lines from service, APSC has re-evaluated specific portions of the Interim Report relevant to receiving solids into PS-01 tankage. Although the considerations and findings within the Interim Report are still valid, the re-evaluation was conducted due to the revised solids estimates, and that the lower transit line throughput will reduce the oil velocities necessary to keep the solids in suspension.

The Interim Report pointed out two possible alternatives for accomplishing Option 1 "Routing Pigging Materials to PS-01 Tankage"; a) using existing station piping, b) a new and separate temporary bypass line to tankage. The results are explained below.

The evaluation determined that under the conditions of lower throughput and velocities, that the solids impacts may be worse than expressed in the Interim Report and result in high risk scenarios. The scenarios include complete plugging of PBU connection facility preventing further deliveries of crude, requiring debris removal and posing long term corrosion risks.

The increased risk is primarily attributed to the lower velocities which will not keep the solids in suspension in route to PS01 TK110. It is estimated that a minimum of 4 ft/s is required to keep solids in suspension in horizontal piping and a velocity of more than 7 ft/s may be required in vertical sections of piping.[1] Additional uncertainties include the quantity, intensity and composition of solids delivered.

[1] These numbers are estimates only. Data on particle densities and sizes of the pigging solids would be required to determine what velocities would actually be required to keep the solids in suspension – the actual velocities may be higher or lower depending on the sizes and densities.

The initial TAPS Impact Assessment assumed a minimum transit line throughput of 400,000 BPD from the PBU connection. We now are expecting much lower throughput ranging between 100 and 300 MBPD. The table below shows velocities at these various flow rates.

	Skid 50 to PS01 Meters			In Station Piping (not shown in drawing)				
	20"	34"	36"	20"	24"	36"	42"	48"
Crude Velocity (fps) at 300,000 bbl/d	8.94	3.09	2.76	8.94	6.21	2.76	2.03	1.55
Crude Velocity (fps) at 250,000 bbl/d	7.45	2.58	2.30	7.45	5.17	2.30	1.69	1.29
Crude Velocity (fps) at 200,000 bbl/d	5.96	2.06	1.84	5.96	4.14	1.84	1.35	1.03
Crude Velocity (fps) at 150,000 bbl/d	4.47	1.55	1.38	4.47	3.10	1.38	1.01	0.78
Crude Velocity (fps) at 100,000 bbl/d	2.98	1.03	0.92	2.98	2.07	0.92	0.68	0.52

Note: Pipe thickness not taken into account.

Existing Station Piping

The team evaluated the increased amount of solids which may be liberated from the initial pig runs between FS01 and Skid 50. An additional 53 yds^3 of solids settled out in this segment of piping when the FS02 to FS01 segment was pigged. These solids will be easily liberated during the FS01 to Skid 50 pigging along with some amount of solids that were already present in this segment. The team believes that there is high probability of high volumes of solids that could be liberated during the initial pig runs. Coupled with the issue of lower throughput and vertical sections of piping this presents a real concern that the solids will drop out and remain in the segment of piping from Skid 50 to PS01 Meters. There is the potential that this segment of piping could be completely plugged depending on the volume and type of solids, and the location in the piping where the solids were to drop out upstream of the PS01 meters.

The team identified a mitigative measure for handling the solids that would drop out in the station piping downstream of the metering skid. This measure would involve using the booster pumps along with installing some short jumper lines to flush the station piping to tankage. With this option, APSC can achieve high velocities through the station piping which will flush any settled solids into Tank 110. However, the team did not identify any mitigative options for the piping from Skid 50 to the PS01 meters. It was determined that the majority of the solids would settle out in this section of piping due to the low velocities and profile of the piping. Aside from the low velocities, the next major hurdle is the vertical piping and manifold going into the PS01 Metering Building.

New and Separate Temporary By-Pass Line

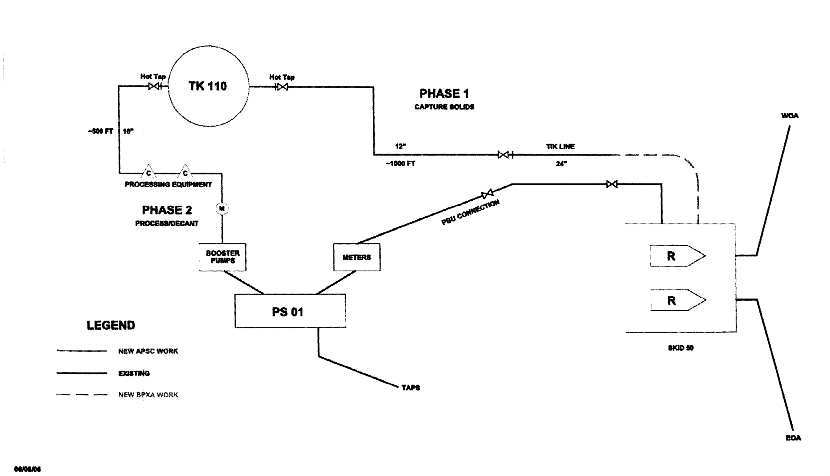
There is an option to install a new temporary bypass of TAPS facilities. This option utilizes a combination of new and existing (abandoned from the BPXA's TIK project) piping directing the pig runs from BPXA's Skid-50 facility into Tank 110 at Pump Station 1. The TIK option requires modification of Skid-50 piping and additional piping to tie into the TIK pipe, which is an abandoned segment of 24-inch pipe. This route would be completed by construction of a temporary 12-inch pipeline from the TIK endpoint to a hot tap into the 48-inch inlet piping immediately adjacent to Tank 110.

Upon capture of the pigging materials into Tank 110, processing equipment would be staged at Pump Station 1 to decant oil from an elevated draw point at a new hot tapped connection to the tank. This decant line would feed a series of centrifuges to separate and capture water and solids while allowing the injection of saleable "clean" oil back into TAPS. The water and solids would be collected and disposed of as hazardous waste.

Conclusion

The recommendation is to install a temporary station bypass utilizing the TIK line. This option eliminates the risk of introducing large quantities of solids into the line upstream of the metering skid and the possibility of plugging the PBU connection to TAPS. No feasible mitigative measure short of replacing the entire line has been identified. This would result in the only delivery connection for PBU to PS-01 taken out of service.

OVERALL TAKE-IN-KIND (TIK) PIPING SCHEMATIC



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Alyeska pipeline
SERVICE COMPANY

To:

From: Peter Murphy, ext. 8428, MS 583

Date:

- JUNE 2ND (SUNDAY)
TOUR ARCO FACILITIES
... check w/ NEXT week,
will probably see NEXT
SATURDAY

★ Something to think about ★
- ARCO corrosion wants to
PIG THEIR oil line to us. (August)
ENDURO CALIBER SMART PIG.
... DID FLOW 1 TO FLOW 2 LAST
year ... DEBRIS plugged up our screens
so didn't continue

- IDEA ... series of sized
cleaning pigs.
... send to trackage + go by
footage? ... skip strainers +
meters
... breaking new ground ...
1st pigging for ARCO.
... has B.P. done?
... potential temp changes
to accompany.

PIGGING ✓

LAST TIME - No one even told us it was coming! we were NOT ready.
4 - 70 gallon barrels of slag
last year, over 2 day period.
they were like little "dorito
chips" $CaCO_3$ (?) deposits.
★ - ... if had gotten all at once,
we would have to shut them
in.

- got most slag from line
lifts last time. Didn't get
as much from their pigging.

- If one day event, keep
our procedure all Alyeska.
if longer, ... supply
ARCO personnel to change
strainers, etc .... we would
still have to do lockout/isolate
SOP's
... last time lost 1 strainer basket
& dinged up 1 meter.
★ check last years inspection reports.

✓

Ed - don't envision same type
of problem ... 'cuz more
of a "one-time" deal than
the line lifting procedure.
- Also causes us 1½ day
tear-down / meter inspection
w/ mechanics/operators/
measurements specialists.
... may be able to time as
a "quarterly" inspection.

(Krischke / Kreischke is alternate) 659-5485 or pager 659-5191-483
mon. to mon. – George Williamson – ARCO Prudhoe 3 8-14-91 pm
(mostly B shift) ? Pigging oil sales line 1st + 2nd week of Sept.
- 34" from flow 1 to skid 50 may cause us problems.
- Ran caliper pig last year (like a cleaning pig) ... & had lots of problems w/ our filters

-

→ wants to come up w/ a plan to handle their problems.

☆ → they'll pay for extra people to change (ARCO, contract, or Alyeska)
☆ → what support do we need?
- max 3 day each for 2 lines, (1) 30" + (1) 34". ... ∴ 6 day period.

☆ → need to get together & draft up a plan of how to handle this. He'll give us copy of their cleaning ~~pig~~ plan.

. Their plan starts out w/ mild cleaning pig .... ~~w~~ want to go to one w/ brushes afterwards, but won't

☆ → 1 pg or so memo from Jimmy or whoever is familiar w/ this on what/when problem was last year ... something they could put their hands on.

8-22-91

lmr

Arco Pigging

✓ - WANT CONTRACT help ... Veco or whoever, Hazwhopper TRAINED.

mc. A - NEED to AMEND S.O.P. to Allow PARTIAL DRAW-down.

✓ - NEED 1 Alyeska person & 2 CONTRACTORS for ~~ea~~ both day & night shift.

✓ → will be 3RD & 4TH week of SEPT. .. 34" Line to us 30" from Flow 1 to Flow 2

- What ENVIRON. procedures? manifests? PAPERWORK is needed.

- go to TANKAGE in the event of A meter plug?

ARCO PIGGING.

get this info to ARCO

PER M. KOPP .. ARCO PIGGING

→ CAN'T DO ARCO TO TANKS FOR metering

- their meters ARE NOT AS ACCURATE, NOR ARE THEY PROVEN w/ provers.
- We physically CANNOT isolate their flow from B.P. unless we flow through the PROVER (MAX = 2100 BBl/hr)

- WITH ONLY 1 TANK, it needs to be Kept AS A relief TANK ... with all other producers going tightline it is likely that we would have to relieve... it would then SCREW up MEASUREMENT

★ → ARCO REALLY JUST NEEDS TO INSTALL STRAINING CAPABILITY AT SKID 50.

STRAINER BASKETS:

★ - NEED TO HAVE AMF FABRICATE SPARES FOR US.
- MANUF. WENT OUT OF BUSINESS
- NEW OWNER HAS NO plans/drawings for new basket.
- PERRY MARKLEY WAS TRACKING (x 8849) THIS + IS NOW AT AMF.

Per George ~~B~~ Baskets were manufactured due to same problem in Valdez.

★ → ARCO CAN go to Slop for AN hour OR two.

9-19-91

ARCO PIGGING NOTES:

- 30" line to Plant 1; Sept 26TH to 25TH
  (NO IMPACT ON PS-1 expected)

CALL ABOUT NEED TO LOWER NGLS TO KEEP V.P. LOW ENOUGH.

* TEMP from ARCO will be RAISED to 130°F or 140°F for 2 DAYS prior … STARTING Sept. 24TH.

- 34" line pigging: Sept 20TH to 24TH.
  … heat line 1ST?

yes. 1 DAY behind schedule.

→ DO WE HAVE ARCO CONTRACTORS COMING ON SITE ~~FRIDAY~~ SATURDAY?

CALL George Williamson; ARCO.

CONCERNS.

- BACK OFF NGL'S WHEN RAISE TEMPS (TO KEEP V.P. below 13.3)
- CONTRACTOR help … who, when, where?
- CONTACT/procedure for debris removal

→ WON'T be raising temp during 34" line pigging, only during the 30" line.

→ CONTRACTORS will be coming over this AFT. to get ORIENTATION/film etc. Haz whop trained

→ George Williamson will be contact for debris removal. CONTRACTORS will do.

→ WORK is 1 day behind schedule. Will START SAT. MORN.

- takes 3 people to do.
1 has to be Alyeska.

arco strainer cleanings — 9/1/90 → 11/22/90

- takes ≈ 45 minutes to do each one (once you get used to doing).
--- but don't follow SOP.

9-1 = D = 25-30 gals
C = 10 gals
A = 2 buckets
D = 2 buckets
9-2 = D = 2 buckets
C = 2 buckets
D = 5 buckets
A = 2 buckets
C = 2 buckets
D = 3 buckets
9-5 = D = 2 buckets
9-6 = D = 3 buckets
9-7 = C = 2 ? buckets
D = 2 ? buckets
9-13 = D = 1 Bucket
9-14 = C = 1 ? bucket
9-15 = A = 1 ? Bucket
9-25 = D = 1 ? Bucket
C = 1 ? Bucket
9-27 = C = 2 buckets.
D = FULL .... bulging out basket, replaced basket.
10-1 = C = 1 ? bucket ?
11-22 = D = 8 gal
C = 4 gal

- in addition to these are dp cell sense-line plug ups & turbine meter plug-ups.

- 1 bucket ≈ 5 gal (?)

- No meter on stand-by run.

- had to have producer slow-downs several times.
- change before ≈ 3 psi .... or you split baskets. (alarms at 2 psi)

need hoist, air impact wrenches, pads, drip tar overpack barrel (haz-waste overbarrel).

Worked on Endicott Four way
valve motor starter (Hope its fixed)
Up Dated software on ARCO and
Kuparuk IBM and um3000 Computers.

9/20/91 Daily vapor pressure analyzer maint.

Replaced motor starter and
Aux contacts for four way valve
in Endicott. (ran proofs on both
meters ok) maybe its fixed.

[illegible]/91 Daily vapor pressure analyzer maintenance
setup to inspect Kuparuk meters, then
ARCO launched a pig this Direction and
the whole analyzer skid plugged up
and we couldn't Empty the Strainers
fast enough. updated software
on LisBurne um 3000 and IBM Computers.

[illegible] Daily vapor pressure analyzer maint.
were expecting arco to launch another
pig today, so every thing is sort of
on hold.
Not as much problem with pig this Time
Pulled 53B Meter inspected Changed
Rotor and put back in service.

[illegible] Daily vapor pressure Analyzer maint.
Pulled 53 D meter, found fiberous
material on Rotor. Cleaned meter
and put back in service.
Changed check valve on
Kuparuk Sample recovery pump
Discharge.

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RECOMMENDATION

SENT TO COMPLIANCE REGISTRY
Hardcopy__ Electronically ✓
# of Copies 1 / Date 4/11/06

Date: April 11, 2006

Subject: **CPF # 5-2002-5024M**
BP Exploration (Alaska), Inc. (BPXA)

From: Chris Hoidal
Director, Western Region, PHMSA, PHP-500

To: Compliance Registry, PHP-60

Recommendation: Issue Order Directing Amendment

Justification: On June 24, 2002, PHMSA issued to BPXA a Notice of Amendment (NOA). On July 19, 2002, BP responded to the NOA and indicated their intent to implement PHMSA's recommendations, and they also requested a 120-day extension to provide the information to PHMSA. On October 31, 2002, BPXA submitted their amended procedures to PHMSA.

Notice Items 1a, 1b and 1c.:

The NOA required BPXA to amend their procedures to consider a broader range of leak size in calculating the buffer zone and stream transport. BPXA's response indicated that they considered a range of failure sizes starting from a pin-hole size to a worst-case guillotine break to determine an appropriate buffer zone for North Slope pipeline and overland discharges. BPXA's overland analysis considered pipeline characteristics including operating pressures, segment volumes, oil density and viscosity, pipeline construction and typical North Slope environmental conditions.

BPXA pipelines (Badami, Endicott, NGL, Milne Point and Northstar) directly intersect Ecological and Drinking water USA's, and according to the expanded 2003 NPMS update to reflect Census Bureau revisions, the BPXA's pipelines directly intersect an Other Populated Area (OPA). BPXA's IM program manual, Section 4.5, Table 4-1, "Direct Crossing Analysis Summary" verifies this statement.

BPXA conducted a risk assessment and has determined that the only portion of its pipeline system that can affect HCA's is the offshore portion of the Northstar pipeline, which could affect the Beaufort Sea Ecological HCA (Bowhead Whale), which is shown in Table 4-5.

BPXA's position of not using the required 2000 census information, not considering HCA's in the water transport system analysis, excluding worker population centers and Other Populated Areas, and excluding the ecological impact on the spectacled eider populationand habitat is not in agreement with the IM rule.

- BPXA cannot exclude direct intersections with a North Slope ecological HCA based on a study that determined the impact on the spectacled eider population as minimal. Detrimental effects to the habitat of the spectacled eider must be considered as well as effects to the actual population.

- Water transport analysis does not include consideation of the potential impact on HCA's (e.g., the Beaufort Sea ecological HCA). BPXA used their Oil Discharge Prevention and Contingency Plan (ODPCP) as a basis for water transport analysis. The ODPCP does not include any consideration of HCA's, so it is not possible to determine if a release into water could affect an HCA (e.g., the Beaufort Sea ecological HCA) when conditions are such that the North Slope has substantial water flow.

Conclusion: Issue an Order Directing Amendment to BPXA to modify their segment identification process to include direct or indirect impacts to Ecological, Drinking Water or Other Populated Area HCAs on the North Slope in the absence of sound technical justification. BPXA must perform their segment identification utilizing the most current information available, the 2000 Census data. To exclude any pipeline segment that directly intersects an HCA or could affect an HCA through an indirect means such as overland spread or water transport of released material, BPXA must provide a sound technical justification.

RECOMMENDATION

SENT TO COMPLIANCE REGISTRY
Hardcopy__ Electronically ✓
# of Copies 1 / Date 4/11/06

Date: April 11, 2006

Subject: **CPF 5-2004-5019M**
BP Exploration (Alaska), Inc. (BPXA)

From: for Chris Hoidal
Director, Western Region

To: Compliance Registry

Recommendation: Issue Order Directing Amendment for Item 1a.
Issue Order Directing Amendment for Items 1b, 1c, 1d, 2, 3, 4a, 4b, 4c, 5a, 5b and 6 and Acknowledge All Actions are Complete for these items.

Justification: On February 23, 2005, PHMSA issued a Notice of Amendment to BPXA. On May 15, 2005, after an extension, BPXA submitted their response. It appears that BPXA has adequately modified their procedures for all items except 1a.

Item 1a: 195.452(f)(1) and (b)(4)(ii):

PHMSA does not agree with BPXA's rationale for excluding Other Populated Areas (OPA) when identifying pipeline segments that could affect a High Consequence Area (HCA). BPXA states in their response, "it is unlikely that oil spread or migration resulting from a guillotine break would extend beyond 0.5 mile from the release point." This statement is not correct as BPXA did not consider the Town of Deadhorse OPA that was expanded in the 2003 National Pipeline Mapping System (NPMS) update that reflected the Census Bureau revisions after the 2000 census.

Further, BPXA's Integrity Management (IM) manual, Section 1.5.2.2 states, "Since DOT's NPMS is based on the 1990 Census Designated Place (CDP) [emphasis added] analysis and the 2000 CDP definition conflicts with DOT's rulemaking definition, BPXA continues to identify Other Populated Areas by the 1990 Census data." This statement is also contrary to 195.452(d)(3)(i), as OPS updated the population HCAs to reflect the 2000 census data in 2003 (Federal Register, Volume 68, Page 3092, January 22, 2003).

BPXA also contends that they could not affect Prudhoe Bay OPAs in the statements made in Section 1.5.2.2 of their IMP; however, they have not performed any studies to document the actual populations in the Prudhoe Bay area and that they are located outside of the buffer areas used by BPXA's segment identification process.

BPXA has not included work camp populations along their pipelines in the evaluation of potential impacts on populated areas. BPXA rationalizes this exclusion by stating that these workers are trained in emergency response procedures and accept the inherent risks of working in the North Slope environment and further excludes them by making the statement that these workers are not residents. PHMSA does not agree with this exclusion. The rule does not exclude any population centers located near a pipeline.

Conclusion: Issue an Order Directing Amendment to BPXA to modify their segment identification process to include work camps or any other populated areas on the North Slope in the absence of sound technical justification. BPXA must perform their segment identification utilizing the most current information available, the 2000 Census data. To exclude any pipeline segment that directly intersects an HCA or could affect an HCA through an indirect means such as overland spread or water transport of released material, BPXA must provide a sound technical justification.

22

Smith, Lisa P

From:	Foust, Nancy C
nt:	Wednesday, April 12, 2006 7:04 PM
o:	Jacobsen, Rosanne M
Subject:	FW: Charter Agreement - Corrosion Monitoring
Attachments:	RE: Coffman Report for BPXA; CEI BPXA Review.ZIP; BP 2000 Annual Corrosion Report to ADEC Final II.ZIP; ADEC April 2001 V3 Final Presentation.ZIP; Work Plan Rev 6.pdf; Charter Agreement.pdf

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From:	Foust, Nancy C
Sent:	Wednesday, November 07, 2001 9:47 PM
To:	McCleary, Neil
Cc:	Woollam, Richard C
Subject:	FW: Charter Agreement - Corrosion Monitoring

Neil --

As you may be aware if you've had an opportunity to review the draft Coffman Engineering report on our corrosion program (commissioned by ADEC as a part of the Charter Agreement), the report is highly negative and contains many inaccuracies. During our second "meet and confer" session with ADEC on Monday, the Coffman project manager came across clearly that he felt the report is not really a "draft." Richard pressed for time for us to respond and we were given until November 30 to do so.

Richard is conferring with Bill Colbert to determine what our options are as the report doesn't seem at all in the spirit of the Charter Agreement.

e are going to try very hard to sway Coffman and ADEC on the final version of the report as when it is finalized, it will ecome a public document.

I'm attaching also a note Richard sent in response to inquiries from Chris Phillips about the Coffman Engineering report.

Please let either Richard or I know if you have questions. Thanks.

Nancy

RE: Coffman Report for BPXA

-----Original Message-----

From:	Woollam, Richard C
Sent:	Tuesday, November 06, 2001 11:06 PM
To:	Colbert, William H (ANC)
Cc:	Foust, Nancy C
Subject:	Charter Agreement - Corrosion Monitoring

Bill,

Attached is a copy of a draft report from Coffman Engineering commissioned by ADEC with funds from the Charter Agreement. The report is a review of the 2000 Corrosion Monitoring Report and the first Meet and Confer session esentation, both of which are required under the terms of the Charter Agreement and submitted to ADEC earlier in)01.

Without understanding the legal standing of the Charter Agreement, it seems to me that the draft report doesn't meet with the spirit of the Charter Agreement where BP is supposed to develop a performance management program in consultation with ADEC.

There appear to be a number of issues with the draft report,

- It is very prescriptive and specific, and gets into the very detail of our business which is inconsistent with a summary performance management process
- The report is, in and of itself, inconsistent, the opening paragraph says Coffman are charged with developing a qualitative assessment of the program then promptly gets into quantitative issues
- The report is wantonly critical, almost to the extent of being critical for the sake of being critical
- The report is factually in error and technical in error

As a consequence, the direction which Coffman/ADEC appear to be taking is directly opposed to the original intent of a collaborative effort worked in consultation but, instead, is heading toward being very prescriptive.

I would appreciate your views on how we respond to ADEC/Coffman on the specific issues within the report, the apparent change of direction from ADEC, the inconsistency of the approach being adopted by ADEC/Coffman and the original Charter Agreement words, and options if this direction change is real and ADEC/Coffman move to dictate the program.

Thanks.

Richard.

CEI BPXA ₹eview.ZIP (142 KB) BP 2000 Annual Corrosion Repor... ADEC April 2001 V3 Final Prese... Work Plan Rev 6.pdf (19 KB) Charter ɡreement.pdf (43 KI

23

Sprague, Kip P

From:	Paisley, Dominic M
ent:	Thursday, November 08, 2001 8:48 AM
ſo:	Kuzma, John H; Sprague, Kip P; Crawford, Gary R; VanderWende, Ewout; Krenzelok, Robert P; Felix, Rick D (Anchorage)
Cc:	Woollam, Richard C
Subject:	FW: Coffman Report Comments
Sensitivity:	Confidential

My analysis of the report for our discussions at 10....

DP

-----Original Message-----
From: Paisley, Dominic M
Sent: Tuesday, November 06, 2001 11:10 AM
To: Woollam, Richard C
Subject: Coffman Report Comments
Importance: High
Sensitivity: Confidential

BP Confidential

Richard,

Here is my analysis of their report and conclusions from yesterday's meeting. As author of the 1st report, I would "ke to be involved in the discussions with Coffman/ADEC to resolve this, if possible. Treat the following as a wish ıst - I don't expect them to tear up the whole report but there are some elements that we should convey as totally unacceptable.

General

- The whole tone of the report is negative, for no good reason.
- As the whole process between us and ADEC is voluntary, words like 'should' should be removed from all recommendations. Words such as 'should, shall, will' are interpreted as a need for positive action in audits. They could be replaced with 'may' etc.
- I believe Coffman's game is to prove some pet theories and issue as NACE papers, for self glorification. They are already saying we should generate data we do not use (inhibitor residuals, uninhibited corrosion rates) - we should refuse absolutely to generate this data or we will end up doing a science experiment. This is the thin end of a 10-year wedge.
- Coffman want to standardize metrics so we make their job easy and so they can compare PPCO and BP - this will lead to the 'why do they do X when you do Y...' scenario. If we believe our programs are better reflected by separate metrics, we should stick to it. Keep metrics basic, relevant and closely related to what we use internally.
- We should seriously consider using this report to demonstrate to ADEC that Coffman are incompetent to be reviewing our corrosion programs. I believe ADEC want a reasonable relationship, but Coffman have soured it by their approach.
- We should retain the right to reply if the report is not significantly re-worked. We could include an analysis of Coffman's report as an appendix to the next annual report. The idea that we would publicly document their incompetence may make them back off.
- Some of the points are simple errors - once they have been pointed out to Coffman, there is no reason for them to remain. If they attempt to leave related recommendations in the report, it indicates they are being spiteful and this would support the need for our right to reply. They have made no attempts to better understand the

report.

- If I could be sure Coffman had innocent intentions as an independept 3rd party, I would propose we educate them in our business by inviting them to weekly meetings etc but I am concerned they have a hidden agenda and we should treat them cautiously until we are sure.

Title Page
'Milne' is mis-spelt

Executive Summary

- Aim of 'qualitative understanding' does not fit in with their requests. By any reasonable measure, we have met the requirements for a qualitative understanding - they said our report was 'comprehensive in scope' on pp10.
- Paragraph 2 indicates we have not reported openly. Can they substantiate this ? If not, this statement must be removed.
- '...results have been reduced and factored ...' replace with '... summarized', as is required to generate metrics.
- '...metrics chosen make ~~it~~ difficult to compare...' there is <u>no</u> industry wide set of metrics (see later) and ~~the~~ ones we chose are the ones we use internally. Unless Coffman can produce such a set of metrics, this statement must be removed
- '...no discussion of underlying programs...' is BS. We laid out our strategy of managing pipeline life to match field life at Meet & Confer I. Remove this statement.
- Relative risks of internal & external. They do not understand the difference between inherent and residual risk. Scope of internal program is entirely consistent with that risk. We have committed to accelerating the external program.
- '...baseline corrosion trend...' we manage to a corrosion rate, not inhibitor efficiency. The value of the program is demonstrated by the low corrosion, leak & repair rates not a spurious calculation of inhibitor efficiency.
- '...does not provide the info necessary for a detailed technical analysis'. There was absolutely no requirement for us to do so - we were charged with providing metrics that summarised our programs and we have done so. If ADEC have asked Coffman to do a detailed technical analysis of our data, they should have asked for data in a suitable format and we <u>may</u> have agreed. This reference must be removed.

pp 4, Mitigation

- 'Target value ... is 150 ppm'. No it isn't, but this is close to the field wide average. This is important as it comes up again later.

pp 5 Risk

- '...Judgment or experiential based protocols suffer from a lack of continuity; oil fields with production lifetimes in excess of half a century or more require a codified set of protocols...' This is a personal view of Coffman but is stated as a fact. Programs benefit from regular review/changes and our programs are always being revised. Need to re-word or remove.
- '... only the percentage of inspections which show increases in damage is reported; not the magnitude of the wall loss...' We were charged with reporting corrosion monitoring data. Magnitude of wall loss has nothing to do with management of corrosion - corrosion is a dynamic process, extent of wall loss is a fact. We report our FFS efforts via the leaks, saves and repair metrics.
- '...No attempt is made to quantify the possible extent...' should replace 'quantify' with 'report'. We <u>did</u> quantify it, we didn't report it.

pp 6 Monitoring and Inspection

- '...No discussion of how coupons are analyzed is reported...' This is a simple procedure, of which we have dozens. If they are interested, ask, but don't write us up for not reporting a procedure. We didn't report how we generate UT data either.

pp 8 External Corrosion Control

- '...External corrosion will require an ongoing commitment of resources by BPXA for the life of the field...' This is an opinion but is stated as fact. 'Will' should be replaced with 'will probably'.

Recommendations

1 Unless Coffman can demonstrate recognized industry reporting standards, this must be removed. The BP corrosion awareness campaign searched for years for a common set of metrics and failed to find one.

2 OK in principle. Some data (e.g. below grade piping) should be reported as aggregate. Need to be careful we do not agree to sub-divide every data type in to every service type.

3 Linking coupons and inspection is difficult to do on a case by case basis. I would propose that we demonstrate that the correlation between inspection & coupons exists and move on. OK re: service category.

4 OK

5 Every pipeline and well line on the Slope is of 'suitable diameter'. Stupid question - remove it. Re-word this in to a recommendation or scrub the whole lot of rambling questions.

6 We absolutely must refuse ~~to~~ do this for 3 reasons:

- We only generate corrosion monitoring data where we can control the outcome.
- Inhibitor efficiencies are a flawed concept used by some Operators during design. We manage to a corrosion rate and demonstrate the value of the inhibitor program by the corrosion monitoring & inspection programs, leaks/saves & repair rates etc.
- Coupon removal from live systems should never be undertaken lightly and only done where the value of the data justifies the risk. We will never expose our workforce to unnecessary risk.

7 Wrong. This statement relates to S-riser injection wells. We didn't say the results were 'ambiguous', but that they provide 'no meaningful data'. 'Under-deposit corrosion' is not a corrosion mechanism and is a red herring in this instance.

8 Remove. As stated, this is one of dozens of procedures relating to our programs. If ADEC/Coffman want this articular one, ask for it but do not write it up as a recommendation, inferring we withheld it.

9 Remove. Data does not exist. Charter Agreement dates from Yr 2000. All previous data was provided voluntarily as it existed in easily accessed format. There was never a commitment to go back and generate/gather data.

10 Line target concentrations are of no use to Coffman in this context - this relates to their belief that all lines receive 150 ppm. They vary by an order of magnitude and the target does not tell them if the line is under or over treated. I suggest we give them our flow chart on how we alter targets.

11 Reject/remove. There is no requirement for us to generate data purely for reporting purposes - our task is to report what we do, not what Coffman would like us to do. We see no value in this as we would not change 3 phase inhibition rates to alter PW residuals. Also, we not 'take credit' for residuals - they are a fact of life. I think this is one of his pet theories awaiting a NACE paper.

12 OK

13 Vast majority of data is only semi-quantitative (TRT). Histogram may not show much but OK.

14 Remove. Allocation of BP's resources is our responsibility based on our broad definition of risk (safety, health, environmental, business, reputation) and we should not discuss with Coffman/ADEC. We can discuss what defines a tolerable level of environmental risk - all that ADEC is interested in.

15 OK

Conclusions

- ... Poor metrics... No attempt was made to better understand the metrics (PPCO has discussions). No industry recognized metrics exist. Until they can demonstrate such metrics exist, they need to quit on this topic.
- '...Inhibitor concentrations over time need to be reported by pipeline; reporting aggregate averages does not allow for technical analysis of the program merits...' No value - simply showing pipeline targets tells them nothing about under/over treatment. This request demonstrates a clear lack of competence in understanding internal corrosion management.

- '...Details of how BPXA analyzes coupons need to be reported...' Again, indicates we withheld something. Remove.
- 'Coupons removed from locations upstream of injection locations need to be re-installed in a statistically representative number of locations...' Again, reject this as an incompetent/ill informed recommendation.

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Smith, Lisa P

From:	Foust, Nancy C
ent:	Wednesday, April 12, 2006 7:06 PM
o:	Jacobsen, Rosanne M
ubject:	FW: Response from Bill Colbert in Regards to Charter Agreement/ADEC and Coffman Eng Report

From:	*Foust, Nancy C*
Sent:	Thursday, November 08, 2001 6:11 PM
To:	McCleary, Neil
Cc:	*Colbert, William H (ANC); Woollam, Richard C*
Subject:	Response from Bill Colbert in Regards to Charter Agreement/ADEC and Coffman Eng Report

Neil --

This is a follow-up to the note I forwarded you last night. Please note Bill's recommendations. Believe that they are consistent with Richard's and my thoughts. We would really like to avoid having this "draft" report become finalized and therefore, in the public domain, with its current contents. Since the report is both inaccurate and technically unsound, we may need to ask that you and/or Steve assist if our initial attempts to sway Susan Harvey (ADEC) are not successful.

Bill -- Thanks for the assistance.

Nancy

-----Original Message-----

From:	Colbert, William H (ANC)
ent:	Thursday, November 08, 2001 2:51 PM
:	Woollam, Richard C
c:	Foust, Nancy C
ubject:	RE: Charter Agreement - Corrosion Monitoring

PRIVILEGED and CONFIDENTIAL
Attorney Work Product and/or
Attorney-Client Communication

Richard,

Based on the information you have provided, I share your concerns about the direction that Coffman/ADEC seem to be taking with respect to our agreement under the Charter to develop a performance management program for the regular review of our corrosion monitoring practices for non-common carrier pipelines on the North Slope.

These commitments are contained in subparagraphs II.A.6. and 7. of the Charter. Pursuant to paragraph V.C. of the Charter, the non-monetary commitments in these provisions are not enforceable at law; rather they constitute "corporate citizenship commitments to the Alaska community at large". The monetary commitment contained in II.A.7 to spend, in aggregate with Phillips, $500,000 per year for 10 years as directed by ADEC for additional orphan site assessment or cleanup, additional Arctic spill response R&D, and/or an expert or experts chosen by ADEC to provide advice regarding corrosion monitoring is enforceable at law until January 15, 2009.

Given the unacceptable state of affairs in our relationship with ADEC over this issue, I suggest that you do two things: (1) document and summarize your concerns and objections to the Coffman report in a letter to ADEC, and (2) schedule a high level meeting between ADEC Commissioner Brown and Steve Marshall or Ross Klie (or another appropriate ALT member) to air our concerns about the Coffman report and the direction and process being taken by ADEC on this matter. I suggest that one key objective of such a high level meeting would be to reach joint agreement on the objectives and key parameters of the performance management program we have committed to develop - an agreed "Terms of Reference" if you will for BP and ADEC to follow. I would expect that this issue could get sorted at a high level, but I may be overly optimistic.

Another approach, which to me makes sense only if the high level meeting doesn't produce results, is for me to contact the state Attorney General's office to see if I might be able to enlist their assistance in persuading ADEC that it is in their best

GC-2 010059

interest to cooperate and work with BP on this issue given that the Charter provides them no enforceable legal leverage whatsoever. ADEC may be operating under the mis-impression that they have the legal authority to unilaterally dictate what we do on this matter, which is not the case.

'ⁿ any event, as long as we continue to meet our financial funding obligations under the Charter and continue to attempt to ɔrk in good faith with ADEC to develop an acceptable performance management system (even if we fail to do so), I vould conclude that we have met our commitments under the Charter in respect to this issue.

Please let me know if you need further analysis or assistance.

-Bill
Chief Counsel
BP Legal-Anchorage
(907) 564-5405 voice
(907) 564-4031 fax
colberwh@bp.com

-----Original Message-----
From: Woollam, Richard C
Sent: Tuesday, November 06, 2001 11:06 PM
To: Colbert, William H (ANC)
Cc: Foust, Nancy C
Subject: Charter Agreement - Corrosion Monitoring

Bill,

Attached is a copy of a draft report from Coffman Engineering commissioned by ADEC with funds from the Charter Agreement. The report is a review of the 2000 Corrosion Monitoring Report and the first Meet and Confer session presentation, both of which are required under the terms of the Charter Agreement and submitted to ADEC earlier in 2001.

Without understanding the legal standing of the Charter Agreement, it seems to me that the draft report doesn't meet with the spirit of the Charter Agreement where BP is supposed to develop a performance management program in consultation with ADEC.

There appear to be a number of issues with the draft report,

- It is very prescriptive and specific, and gets into the very detail of our business which is inconsistent with a summary performance management process
- The report is, in and of itself, inconsistent, the opening paragraph says Coffman are charged with developing a qualitative assessment of the program then promptly gets into quantitative issues
- The report is wantonly critical, almost to the extent of being critical for the sake of being critical
- The report is factually in error and technical in error

As a consequence, the direction which Coffman/ADEC appear to be taking is directly opposed to the original intent of a collaborative effort worked in consultation but, instead, is heading toward being very prescriptive.

I would appreciate your views on how we respond to ADEC/Coffman on the specific issues within the report, the apparent change of direction from ADEC, the inconsistency of the approach being adopted by ADEC/Coffman and the original Charter Agreement words, and options if this direction change is real and ADEC/Coffman move to dictate the program.

Thanks.

Richard.

<< File: CEI BPXA Review.pdf (Compressed) >> << File: BP 2000 Annual Corrosion Report to ADEC Final

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Smith, Lisa P

From:	Foust, Nancy C
Sent:	Wednesday, April 12, 2006 7:11 PM
To:	Jacobsen, Rosanne M
Subject:	FW: BP/Coffman Engineers Contract

From:	Woollam, Richard C
Sent:	Sunday, November 11, 2001 2:13 PM
To:	Martin, Michelle O
Cc:	Foust, Nancy C
Subject:	BP/Coffman Engineers Contract

Michelle,

Could you please do a little bit of research for me in a hurry. I want to know if BP Explorations (Alaska) Inc has any contracts with Coffman Engineers and if so what and who is the contract CAM, if any. My understanding is that they have a general services contract but have been unable to find out any more than this.

Thanks.

Richard.

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Smith, Lisa P

From:	Foust, Nancy C
ent:	Wednesday, April 12, 2006 7:13 PM
.o:	Jacobsen, Rosanne M
Subject:	FW: Coffman Report for BPXA

From:	Phillips, Chris J
Sent:	Monday, November 12, 2001 9:47 PM
To:	Woollam, Richard C
Cc:	Foust, Nancy C
Subject:	RE: Coffman Report for BPXA

Thanks for your reply - perhaps you could bring me up to speed next week - when I'm back from vacation (in DC with Congress....).

Chris

-----Original Message-----

From:	Woollam, Richard C
Sent:	Monday, November 12, 2001 8:52 PM
To:	Phillips, Chris J
Cc:	Foust, Nancy C
Subject:	RE: Coffman Report for BPXA

Chris,

In summary, we came away from the Monday, 5th Nov., Meet and Confer session with some deep reservations about Coffman Engineers and their report. They seemed unwilling to discuss BP/PAI's reservations or concerns. Susan Harvey seemed a little more concialtory and has agreed to meet with BP/PAI to discuss (without Coffman).

I have been trying to set-up this meeting with Susan without success so far.

In the meantime we have documented our reservations and I have discussed the issues with Bill Colbert to get a legal interpretation.

Met with Ross K, Neil McC, Bill Colbert, and Nancy today to plot our way-forward, but, the plan is really going to depend on the reponse we get from Susan as to whether or not she is prepared to work with BP or not.

Either way, we'll get a 3rd party program review of the corrosion programs done which will hopefully be a little more realistic and better reflect the progress that has been made over the last few years.

Sorry for the rather lengthly e-mail, I'd have called by to discuss but it looks like you're out of the office for the next week or so - hopefully you're having a great vacation!

Richard.

-----Original Message-----

From:	Phillips, Chris J
Sent:	Monday, November 12, 2001 8:34 PM
To:	Woollam, Richard C
Subject:	RE: Coffman Report for BPXA

How did the meeting go? How can we get this back on track?

Chris

-----Original Message-----
From: Woollam, Richard C
Sent: Saturday, November 03, 2001 12:23 PM
To: Phillips, Chris J; Chappell, Ronnie W
Cc: Foust, Nancy C
Subject: RE: Coffman Report for BPXA

Chris,

Under the Charter Agreement between the State and BP, BP has two obligations,

- File an annual report with ADEC on corrosion and corrosion monitoring
- Meet and confer twice per year with ADEC on the corrosion and corrosion monitoring

In addition, there is a general provision which states that BP will pay the state $500,000 per annum for a number of potential uses, including, hiring a outside 'expert' to review the corrosion report and provide technical advice to ADEC on pipeline corrosion.

The report from Coffman Engineering is ADEC's use of a part of this $500,000 in the corrosion area. As the contract is with ADEC we have little or no influence on the output/content.

We are meeting with ADEC on Monday for the second 'Meet and Confer' session which Coffman will be attending. I am hoping to gain a better understanding, from Coffman, on their concerns and to make a few changes where Coffman are factually incorrect. I am also going to speak with Susan Harvey and determine what will be the process of going from a draft report to a final report, and therefore public, and determine if we can influence the content.

Finally, I plan to meet with Susan and discuss the direction of this section of the Chart Agreement, as the issues/concersn raised by Coffman are not in-line with the spirit/intent of the paragraph from the charter agreement and are not in-line with the spirit/intent of subsequent discussions with ADEC on implementing the charter agreement. This was inteded to be a collaborative/cooperative effort, not an adversarial arrangement which is the tome taken in the report.

Hope this makes sense.

Richard.

-----Original Message-----
From: Phillips, Chris J
Sent: Friday, November 02, 2001 6:16 PM
To: Chappell, Ronnie W; Woollam Richard (E-mail)
Subject: RE: Coffman Report for BPXA

So where is the good news? Why are we funding this study?

Chris

-----Original Message-----
From: Chappell, Ronnie W
Sent: Friday, November 02, 2001 7:30 AM
To: Phillips, Chris J
Subject: FW: Coffman Report for BPXA

Another reason to get our own report out early.

-----Original Message-----
From: Woollam, Richard C
Sent: Friday, November 02, 2001 7:21 AM
To: Chappell, Ronnie W
Subject: FW: Coffman Report for BPXA

Ronnie,

When finally published this will be a public document - we should probably prepare some reposnes given the generally critical tone of the report.

Thanks.

Richard.

-----Original Message-----
From: Woollam, Richard C
Sent: Friday, November 02, 2001 7:17 AM
To: Foust, Nancy C; Blankenship, George R; Merrill, Mark J; Phillips, Chris J; McCleary, Neil
Cc: NSU, CIC TL; Felix, Rick D (Anchorage); Sprague, Kip P; Krenzelok, Robert P; Kuzma, John H
Subject: FW: Coffman Report for BPXA

All,

Please find attached the final draft of the review report from Coffman Engineering on the 2000 Corrosion Monitoring Report to ADEC. Our next meeting with ADEC, Coffman will be attending, is on Monday, 5th November, so we will not be able to respond to the issues raised in the report given the late stage in submission.

The CIC Group will review the document in detail and prepapre a response prior to the next Annual Report and Meet and Confer Session with ADEC/Coffman which is schedule for end 1Q 2002.

Thanks.

Richard.

-----Original Message-----
From: Tim Bieri [mailto:bieri@alaska.coffman.com]
Sent: Friday, November 02, 2001 12:22 AM
To: 'Richard Woollam'
Cc: 'Harvey, Susan'; 'Cederstrom, Elaine'
Subject: Coffman Report for BPXA

Richard,

Here is a final draft of our report.

Timothy Bieri, P.E.
Coffman Engineers, Inc.
907-276-6664
907-276-5042 fax
<< File: CEI BPXA Review.pdf >>

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Woollam, Richard C

ᶠrom:	Tutaan, Elsa [Elsa_Tutaan@envircon.state.ak.us]
ɜnt:	Wednesday, November 14, 2001 9:29 AM
ſo:	'Woollam, Richard C'
Cc:	Cederstrom, Elaine
Subject:	RE: BP/ADEC Meetings Nov 19th and Nov 21st

Ricard, thanks for your response. I would like to confirm your meeting on 11/19 @ 9-10 am with Susan on BP Corrosion Report. The meeting will be in our office, second floor conf room.

The 11/21 @ 9:30-11 am is also confirmed with Tim Biere of Coffman, Susan and Elaine Cederstrom in ADEC on the BP's comments on BP Corrosion Report. The meeting will take place in our office, first floor large conference room.

Thank you,
Elsa Tutaan

-----Original Message-----
From: Woollam, Richard C [mailto:WoollaRC@BP.com]
Sent: Tuesday, November 13, 2001 5:47 PM
To: 'Elsa_Tutaan@envircon.state.ak.us'
Cc: 'Susan_Harvey@envircon.state.ak.us'; Foust, Nancy C; Felix, Rick D (Anchorage)
Subject: BP/ADEC Meetings Nov 19th and Nov 21st

lsa,

Sorry for not getting back to you this afternoon but I was in a meeting.

I will be available for the meetings as per your phone message,

Monday, 19th Nov, 9-10:00 am
BP/Susan Harvey to discuss was-forward to meet Corrosion Monitoring portion of the Charter Agreement

Wednesday, 21st Nov, 9:30-11:00
BP/Susan Harvey/Coffman Engineers - Tim Bieri to discuss BP's concerns with the Final Draft Coffman Engineers report

I shall be in the office most of tomorrow, 346-4029.

Thanks for the help.

Richard.

GC-2 010090

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Smith, Lisa P

From:	Foust, Nancy C
ent:	Wednesday, April 12, 2006 7:20 PM
o:	Jacobsen, Rosanne M
Subject:	FW: ADEC Meeting Feedback

From:	Woollam, Richard C
Sent:	Tuesday, November 20, 2001 1:34 PM
To:	Cherry&Snyder (Phillips)
Cc:	Felix, Rick D (Anchorage); Foust, Nancy C; NSU, CIC TL
Subject:	ADEC Meeting Feedback

Jeff/Maria,

Here is some feedback from BP's meeting with Susan Harvey yesterday,

- Susan indicated that she could influence the style of the report but was reluctant to enforce changes in the recommendations as she felt the document was an independent 3rd party audit. Note, there was no commitment that Susan would actually influence the style of the report in respect of the general concerns by raised by BP

- There was a general discussion about working collaboratively with ADEC to improve integrity programs and that this was the prefered choice, again however, there was no commitment from Susan that this would actually happen

- With respect to the nature of the supposed audit, BP made the case the case that it was not an unbiased appraisal of the program or the report, again, Susan acknowledged that this concern but did not commit to any specific changes

- With respect to the lack of interaction with Coffman, Susan recognized this as a failing in the process to date and did commit to get involved in this issue and for improvement in the future

In summary, it was a very professional and reasonable meeting, with Susan appearing to be the voice of reason, however, as noted above there was no comitment from Susan to change the report in any substantive way although she did encourage detailed discussions of the issues at our meeting with ADEC/Coffman on Wednesday.

How did your meeting with Tim/Coffman go on Monday?

If there are any questions, please let me know.

Thanks.

Richard.

PS Jeff - Are you feeling better yet?

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Smith, Lisa P

From: Foust, Nancy C
ent: Wednesday, April 12, 2006 6:44 PM
.o: Jacobsen, Rosanne M
Subject: FW: ADEC/Coffman Review Meeting Feedback

Rosy --

Found my old electronic files and will start forwarding any e-mail I find that may be related to our discussion this afternoon.

Nancy

From: Woollam, Richard C
Sent: Sunday, November 25, 2001 1:16 PM
To: McCleary, Neil; Foust, Nancy C
Cc: Colbert, William H (ANC); Klie, Ross R; Blankenship, George R; Felix, Rick D (Anchorage)
Subject: RE: ADEC/Coffman Review Meeting Feedback

Neil/Nancy,

It seems to me there were two basic issues, the first is about process,

- Lack of sophistication on the part of Coffman in that Tim Bieri issued a report without thinking through the reaction and consequences of the report
- Lack of review, I believe that the Final Draft was issued by Coffman/ADEC without review at senior levels within Coffman and/or ADEC, if there had been review then issues about balance and the report being public would not have occurred

The second issue appears to be about communication,

- Lack of communication between Coffman/ADEC and Coffman/BP which lead to a considerable number of misinterpretations and misconceptions which results in recommendations and conclusions which are erroneous

In summary, if we are to avoid a repeat, then I think BP is going to have to take a more active role in educating both ADEC and Coffman, and I believe BP needs to more proactively facilitate and manage this process. This is obviously more work for the CIC Group but, I don't see anyway to avoid it.

Richard.

-----Original Message-----
From: McCleary, Neil
Sent: Sunday, November 25, 2001 7:41 AM
To: Woollam, Richard C; Foust, Nancy C
Cc: Colbert, William H (ANC); Klie, Ross R; Blankenship, George R; Felix, Rick D (Anchorage); NSU, CIC TL
Subject: RE: ADEC/Coffman Review Meeting Feedback

Richard

Congratulations on an improving relationship and a better quality report.

I am interested in your view as to why the change in mood and tone.

Neil

-----Original Message-----
From: Woollam, Richard C
Sent: Wednesday, November 21, 2001 4:30 PM

To: Foust, Nancy C
Cc: Colbert, William H (ANC); Klie, Ross R; Blankenship, George R; McCleary, Neil; Felix, Rick D (Anchorage); NSU, CIC TL
Subject: ADEC/Coffman Review Meeting Feedback

BP Confidential

Nancy,

Just a quick update on the ADEC/Coffman Report. Following our meeting on Monday, Rick and I have subsequently met with Coffman, Tim Bieri and Harold Hollis, on Tuesday and then jointly today with ADEC, Susan Harvey, and Coffman, Time Bieri, to discuss our concerns with the Final Draft Report from Coffman Engineers. Based on the conversations and discussions, here is a summary of the situation,

- Clear desire from both ADEC, Susan, and Coffman, Tim, to move the relationship to a more collaborative and cooperative basis from the the adversarial relationship which the Final Draft report had initiated
- Willingness on the part of Coffman and ADEC to address our concerns about style, move from the highly negative, and to address our concerns about balance, to represent both the good and the bad rather than just the perceived gaps
- Recognition of the need for an increased level of interaction between BP and Coffman
- At the request of ADEC, Coffman are going to work to rewrite/reword the report to reflect the style/balance concerns and issues, and to address some of the technical issues
- Susan indicated that both BP and PAI would get an opportunity to review the draft of the next version before it was finalized with the intent to issue before year end

In summary, we appear to be in a much better place than we were two weeks ago, however, we will need to wait until we see the revised report to be certain of how much attention has been paid to the concerns raised. In the meantime Rick and I will be working with Coffman/ADEC to address any questions.

Attached are some comments from Maria Cherry, my counterpart in Phillips, to her management which paint a similar picture from the Phillips perspective.

If there are any additional comments or questions, please let me know.

Thanks.

Richard.

<< Message: ADEC Meeting on Consultant's Report >>

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Smith, Lisa P

From:	Foust, Nancy C
Sent:	Wednesday, April 12, 2006 7:25 PM
To:	Jacobsen, Rosanne M
Subject:	FW: Coffman revisions to BPXA review
Attachments:	CEI BPXA Review v2.pdf; Two DEC employees stripped of power.ZIP; DEC Regulator Role Change.ZIP

From: Woollam, Richard C
Sent: Friday, December 21, 2001 9:33 AM
To: NSU, CIC TL; Felix, Rick D (Anchorage); Krenzelok, Robert P; Sprague, Kip P; Crawford, Gary R; Kuzma, John H; VanderWende, Ewout
Cc: McCleary, Neil; Blankenship, George R; Foust, Nancy C; Merrill, Mark J
Subject: FW: Coffman revisions to BPXA review

All,

Please see below from Tim Bieri, a quick review suggests that many of our comments have been incorportaed into the re-write. I would like to respond back to Tim as soon as possible, so comments by the end of today would be appreciated.

Unless we find gross errors or have very substantial objections and/or comments I would prefer to leave the report largely unchanged rather than enter into a second round of corrective action/requirements.

Also, note that Jeff Mach, copied on the original e-mail, is the individual who was assigned many of Susan Harvey and Robert Watkin's responsibilities in the recent ADEC reorganization. I assume this means that Jeff Mach now has responsibility for Charter Agreement commitments, however, I will try and clarify this.

Note, I have attached the recent press coverage of the ADEC changes.

Thanks.

Richard.

-----Original Message-----
From: Bieri, Tim [mailto:bieri@alaska.coffman.com]
Sent: Friday, December 21, 2001 8:54 AM
To: Mach, Jeff; Richard Woollam
Cc: Stears, Dan; Felix, Rick D (Anchorage); Cederstrom, Elaine
Subject: Coffman revisions to BPXA review

Jeff/Richard

We attempted to address everyone's concerns and observations and hope this version is a little more palatable. We would like to issue the report soon (by YE if possible), so please provide your feedback sooner versus later. I will be available to discuss any questions or concerns through the holidays...
Regards,
Timothy Bieri, P.E.
Coffman Engineers, Inc.

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SECTION FIVE
SCOPE OF WORK

5.01
Scope of Work

The Department of Environmental Conservation, Division of Spill Prevention and Response is soliciting proposals for technical consultation services to provide ADEC with expert corrosion advise in regards to pipeline corrosion and/or other pipeline structural issues as part of the Charter for Development of the Alaskan North Slope, item II.A.6, "Commitment to Corrosion Monitoring." The professional consultant would perform the following tasks:

a) Complete a review of BP's and Phillip's, annually submitted, corrosion monitoring performance management reports, which are to be submitted to ADEC on or before March 31 of each year. Determine if the reports satisfy the requirements of item II.A.6, "Commitment to Corrosion Monitoring," of the Charter for Development of the Alaskan North Slope and its associated work plan deliverables (see Attachment).
b) Provide recommendations regarding the content and extent of topics covered within the annual reports. Determine if the topics included provide a complete and adequate view of the corrosion monitoring and corrective action activities necessary for maintaining pipeline integrity. Provide recommendations on the report format/content as required. This effort is intended as a continuous improvement process of ADEC's oversight of corrosion monitoring and performance management activities conducted by BP and Phillips for their North Slope, non-common carrier pipelines.
c) Perform a comprehensive technical analysis of the specific information presented in the reports and determine if there are any specific corrosion or pipeline structural issues, which warrant further review or corrective action. Highlight any specific areas of concern and conduct further research as required to determine if corrosion monitoring, repair or corrosion management related issues meet acceptable industry practices, code and regulatory requirements. Also determine if corrosion performance trends are at expected levels. If any parameters significantly exceed expected levels (excessive corrosion rates or frequent corrosion or structural related failures/spills), provide any findings and/or recommendations for corrective actions in this area. Rank any issues of concern as: 1) a significant pipeline integrity or environmental issue requiring immediate corrective action; 2) a pipeline integrity or environmental issue warranting corrective action within a longer time period (six months); and 3) a pipeline integrity or environmental issue warranting further study to determine if any problem exists.
d) Analyze corrosion technologies and techniques being utilized for corrosion surveys and performance assessments of the North Slope, non-common carrier pipelines. Determine if the methods and equipment employed provide for an adequate corrosion monitoring program. If not, list specific areas that should be considered for improvement.
e) Participate in the semi-annual "meet and confer" sessions with BP and Phillips as ADEC's technical consultant. Provide feedback regarding review findings from the previously submitted annual reports as well as any new information presented at these meetings.
f) Recommend an "annual bullet item(s)" that can be used as an indicator of the overall corrosion performance from the data provided. It should be a simply understood criteria which will allow for effective communication to the public of the yearly status of the "Commitment to Corrosion Monitoring" Charter item.

5.02
Deliverables

The contractor will be required to provide the following deliverables:

1. Prepare a detailed proposed schedule of project milestones for completing all tasks (a-f) described within the Scope of Work within the first week of the contract period.
2. By the tenth day after the close of the first full month and each succeeding month thereafter, the contractor shall submit a progress report to the contract manager. This report will discuss the status of each task, problems encountered, any delays, and any other items that could affect the successful completion of the contract. The contractor will maintain a project timeline throughout the course of the contract and will supply an updated version to the contract manager prior to biweekly meetings. Depending on the location of the contractor, biweekly meetings will be held in person or by teleconference.
3. Following the comprehensive technical review of BP's and Phillips' annual reports, the contractor will present to the Contract Manager a separate draft report for each owner's report (BP and Phillips) documenting his/her complete analysis and recommendations of all elements described in tasks (a-d). The Department will review the contractor's reports and will present written comments to the contractor. The contractor will incorporate the comments into the reports by either making changes where appropriate or defending his/her course of action. The contractor will finalize the reports, including the comments and response as an appendix, and will submit them to the Contract Manager in typed and electronic versions.
4. The contractor will participate, help coordinate and provide feedback as appropriate during each of the semi-annual "meet and confer" sessions with BP and Phillips per scope task "e". A written report of the meeting minutes, including a technical review and comments on the information presented, as well as any follow-up action items or recommended actions will be provided by the contractor to the Contract Manager. The contractor will also be responsible for additional correspondence with the individual owners (as per direction from the Contract Manager) on any issues warranting further follow-up action.
5. The contractor will provide a recommendation to the Contract Manager, following review of the data available described in the owner's reports, of an "annual bullet item(s)" as described under task (f) in the scope .

5.03
Work Schedule

The contract term and work schedule set out herein represent the State's best estimate of the schedule that will be followed. If a component of this schedule, such as the opening date, is delayed, the rest of the schedule will likely be shifted by the same number of days.

The length of the contract will be from the date of award, approximately ***July 23, 2001***, for approximately 342 calendar days until completion, approximately ***June 30, 2002***.

The approximate contract schedule is as follows:

- Issue ***RFP June 11, 2001.***
- Pre-Proposal Conference ***June 25, 2001.***
- Closing date ***July 2, 2001 COB.***
- Open ***RFP July 3, 2001.***
- Proposal Evaluation Committee complete evaluation by ***July 10, 2001.***
- State issues Notice of Intent to Award Contract ***July 11, 2001.***
- Protest period begins ***July 12, 2001***
- State awards contract ***July 23, 2001.***
- Contract begins ***July 26, 2001.***
- Contractor provides detailed schedule of project milestones (Deliverable 1) to Contract manager by ***August 2, 2001.***
- Contractor submits first draft report (Deliverable 3) to Contract Manager by ***September 11, 2001.***
- State reviews first draft (Deliverable 3) from ***September 11, 2001*** to ***September 18, 2001.***
- Contractor revises first draft (Deliverable 3) by ***September 25, 2001.***
- Contractor coordinates and participates in ***October 2001*** "meet and confer" session with BP and Phillips.
- Contractor provides a written report on meeting minutes and follow-up recommendations to ADEC by ***November 15, 2001***

- Any follow-up activity required from reports, meetings and outstanding deliverables are completed and submitted by the contractor to the Contract Manager by ***June 30, 2002***.

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ONE HUNDRED NINTH CONGRESS

U.S. House of Representatives
Committee on Energy and Commerce
Washington, DC 20515—6115

JOE BARTON, TEXAS
CHAIRMAN

April 25, 2006

The Honorable Norman Y. Mineta
Secretary
U.S. Department of Transportation
400 Seventh Street, S.W.
Washington, D.C. 20590

Dear ~~Secretary Mineta:~~ Norm:

On March 2, 2006, BP officials discovered a leak in one of the North Slope's main transmission lines, several miles upstream from the Pump Station 1 of the Trans Alaska Pipeline System (TAPS). The leak resulted in the loss of between 200,000 and 300,000 gallons of crude, and is now the largest spill ever on the North Slope. On March 15, after an initial investigation, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order requiring BP Exploration (Alaska) Inc. (BP), to take several actions regarding the breached pipeline, as well as numerous other lines in the greater Prudhoe Bay operating area. More specifically, additional actions are now ordered for pipelines servicing the Prudhoe Bay West Operating Area (PBWOA), Prudhoe Bay East Operating Area (PBEOA), and the Lisburne hazardous liquid pipeline facilities, all of which are operated by BP.

Earlier this month, Committee staff visited the North Slope of Alaska and several points on the Trans Alaska Pipeline System to discuss pipeline integrity and corrosion issues and specifically investigate the possible causes of this spill. This effort followed two letters recently sent to both BP and the operator of the TAPS -- Alyeska Pipeline Service Company (Alyeska) -- to gather additional information on the spill event as well as other integrity issues.

To date, the initial efforts of BP to address potential root causes of the spill and ongoing environmental restoration efforts are commendable. Similarly, the early efforts by the company to determine where additional and similar corrosion may be occurring and placing additional North Slope pipelines in jeopardy are much appreciated. Nevertheless, there remain several questions about the causes of this spill as well as the capabilities of BP to maintain the integrity of some of the pipelines in the Prudhoe Bay operating area. Moreover, there are numerous other issues about how the key pipelines in Prudhoe Bay have been managed to date and whether additional steps may be warranted to prevent future breaches. I request your help in addressing

The Honorable Norman Y. Mineta
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some of these concerns and would appreciate your Department's response to the following questions by Tuesday, May 16, 2006:

1. The March 15 Corrective Action Order issued by PHMSA, requires that BP perform a number of maintenance procedures -- including the application of scraper pigs and smart pigs -- on several key lines serving the PBEOA and the Lisburne line. This region encompasses a number of key facilities including Flow Stations 1, 2, and 3 that eventually connect through a series of lines to Skid 50. Skid 50 is the last facility operated by BP before the transmission lines connect to PS 1 of TAPS. Item (7) of the attached Department of Transportation's (DOT) Corrective Action Order requires that BP:

 > "Perform an internal inspection using calibrated smart pig on the PBEOA and Lisburne pipelines within 3 months of receipt of this Order. Take appropriate action to address all anomalies discovered, in accordance with the standard for anomaly repair in 40 C.F.R Part 195. Record differences between inline inspection data and actual "as found" data for all anomalies and integrate that data in future analyses, mapping corrosion growth, and confirming data gathered by inline inspection tool. Develop and submit for approval a plan to perform internal inspection at regular intervals, not to exceed 5 years, and schedule for the repair of anomalies identified through those inspections. Implement that plan for approval."

 It is our understanding, however, that before implementing any internal inspection "using calibrated smart pig" -- as the order requires -- these lines must be first cleaned using a scraper pig to remove any buildup of sludge or other deposits that may have collected. In discussions with both Alyeska and BP officials, staff was informed that several key lines -- which appear to fall under the Corrective Order -- may not have been cleaned with a scraper pig since 1992. Additionally, other officials told staff that deposits of sludge may contribute to corrosion, particularly if the sludge traps a layer of water or the sludge prevents corrosion inhibitors from reaching and protecting the pipeline wall.

 (a) Does DOT share the view that sludge may be a contributing factor to corrosion (and thus pipeline integrity) and if so, how specifically?

 (b) What impact would the buildup of sludge or other material have on the effectiveness of corrosion-detection coupons?

2. Alyeska officials informed staff that the entire 800-mile TAPS is regularly cleaned with scraper pig once every 14 days.

(a) Is this DOT's understanding? And if so, what benefit does such scraping have on the integrity of this line or pipelines in general?

(b) What is DOT's understanding of the frequency of smart pigging on TAPS?

3. Staff was informed that several of the key lines serving the PBEOA (specifically the main transmission lines from Flow Stations 1, 2, and 3 that ultimately connect to Skid 50) and the Lisburne line have not been cleaned with a scraper pig, nor have they been examined with a smart pig, since as long ago as 1992. Moreover, staff was informed that these lines may now collectively contain considerable sludge and other buildup. In fact, company officials interviewed by staff said that there is potential for approximately 1,000 to 2,500 cubic yards of sludge to be removed from the pipelines that flow from Skid 50 to Flow Stations 1, 2, and 3.

(a) What is DOT's understanding of the frequency in which the key lines that service the PBEOA, from Flow Stations 1, 2, and 3 to Skid 50 have been scraped with maintenance pigs. What is DOT's understanding of the frequency of smart pigging of these lines? Please also address the frequency of smart pigging and cleaning pigging for the Lisburne line.

(b) At present, what is DOT's general understanding of the condition of all lines referenced in question 3(a)? Also, is it correct that at this point many of the lines in the PBEOA are deemed "indeterminate" by DOT?

(c) Does DOT have an estimation of the amount of sludge buildup that may exist in these lines by volume measure? What is the process for removing large amounts of sludge and buildup should it exist?

(d) Why does the entire 800-mile TAPS get scraper-pigged once every 14 days, yet many of the key lines that comprise the PBEOA have not been scraper pigged for perhaps as long as 14 years? Are there reasonable explanations for not scraper pigging these lines and does this length of time represent sound maintenance practices?

4. Staff was told by one official that previous attempts were made to operate scraper pigs on the major lines of the PBEOA (from Flow Stations 1, 2, and 3 to Skid 50) and the Lisburne line, yet some of these efforts were abandoned due to the volume of sludge being produced.

(a) Has DOT determined if earlier attempts were made to clean any or all these key lines and were significant amounts of sludge found?

(b) Has DOT asked for all documentation to show the maintenance history of those lines and any discussion regarding potential earlier difficulties in cleaning them due to high sludge or buildup volume?

(c) Does DOT even know the key results of these earlier pigging efforts?

5. Both Alyeska and BP officials told staff that if the sludge in these lines is considerable, the possibility exists that any maintenance pig sent through these lines might become stuck, which in a worst case scenario could result in the shutdowns of one or more flow stations.

(a) What is DOT's estimate of a pig "sticking" possibility?

(b) On what specific lines and in what location is this possibility greatest?

(c) Does DOT believe that cleaning these lines could result in a blockage that could result in the shutdown of one or more flow stations?

(d) Should the worst case scenario occur and flow stations are shut down, what is the implications for a "cold restart," given the time period DOT estimates such cleaning efforts will need to take place (e.g., potentially cold-weather months)?

6. If considerable amounts of sludge are discovered in these lines, how will that sludge be captured and disposed of? Some officials told staff that both the metering and strainers at TAPS's PS 1 may have to be bypassed due to anticipated volume. Staff was also told that one scenario would be to collect such sludge in the breakout tanks at PS 1. Another scenario would be to have BP collect the material at Skid 50 before the material makes it way to PS 1, yet currently there are no tanks available that could hold the possible volumes of this material. What is DOT's understanding of how this material will be handled, particularly if it is so voluminous? If the material is collected in the PS 1 breakout tanks, does that raise any safety or integrity issues for Alyeska and TAPS?

7. It is my understanding that BP Exploration (Alaska), Inc., had scheduled to smart pig the line that failed (and perhaps other key lines in the PBEOA) in 2006.

Nonetheless, there are now considerable engineering issues being "worked" to deal with the sludge problem and the potential for complications associated with running cleaning and maintenance pigs through at least some of these lines. Much of this engineering effort appears to be in its early stages. Moreover, until only recently senior officials from Alyeska appeared to know very little about the potential for downstream complications resulting from potential sludge. Given that the warmer (i.e., summer) months are approaching and this period of time is viewed as the most opportune time to run maintenance pigs through these lines, one would expect that key engineering questions about this effort would already be addressed.

(a) What evidence does DOT have regarding any scheduled pigging efforts planned for any of the lines covered by the Corrective Order that were in place prior to the rupture discovered on March 2, 2006?

(b) Has DOT asked BP for such evidence?

8. Recently, it was reported in the press that another line -- this time a small 3-inch gas pipe – also failed due to corrosion. According to press accounts, the volume of gas release in this line was too small to report to regulators. Nonetheless, we believe understanding the causes of this rupture may have some relevance to the current undertaking being pursued by DOT's Corrective Order.

(a) When, if at all, was DOT informed about this second rupture?

(b) Was this a potentially dangerous event to either the environment or workers? If so, how?

(c) Has DOT determined the causes of this failure? If so, please provide them.

At a time when crude oil prices are again reaching record-high levels and the supply is oil is tight, the soundness of the pipelines that serve the greater Prudhoe Bay operating area is critical to the Nation's national security. I appreciate DOT's efforts to work with BP, Inc., to make this operation as safe as possible and I thank you for your leadership on this important matter.

Should you have any additional questions regarding this request, please contact me, or have your staff contact Mr. Christopher Knauer of the Committee on Energy and Commerce Democratic staff at (202) 226-3400.

The Honorable Norman Y. Mineta
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Sincerely,

JOHN D. DINGELL
RANKING MEMBER

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

The Honorable Kathleen Clarke, Director
Bureau of Land Management
U.S. Department of Interior

Mr. Jerry Brossia, Authorized Officer
The Joint Pipeline Office
Federal Bureau of Land Management - Alaska State Office

Mr. Kevin Hostler, President and Chief Executive Officer
Alyeska Pipeline Service Company

The Deputy Secretary of Transportation
U.S. DEPARTMENT OF TRANSPORTATION
400 Seventh Street, S.W., Room 10200
WASHINGTON, D.C. 20590

June 05, 2006

The Honorable John D. Dingell
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Congressman Dingell:

Thank you for your letter of April 25 to Secretary Norman Mineta regarding questions and issues about the management of key pipelines in Prudhoe Bay by BP Exploration (Alaska), Inc., (BP). Secretary Mineta has asked me to respond on his behalf. Your letter raises serious questions regarding the March 2 leak of approximately 200,000 gallons of crude oil on the North Slope, as well as BP's capabilities to maintain the integrity of its pipelines in the Prudhoe Bay operating area.

I share your concerns regarding the safety of the Prudhoe Bay crude oil transit lines. The U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) is working hard to ensure BP adequately addresses the safety and integrity of all of the company's pipelines. The DOT is committed to ensuring that all operators operate their lines safely.

The Pipeline and Hazardous Materials Safety Administration issued a Corrective Action Order to BP on March 15, requiring that BP take action on several measures to ensure the protection of the public, property, and environment during this critical time. The PHMSA staff has met with BP management in Denver, Washington, DC, and Alaska and has held numerous telephone conferences with BP to resolve issues such as the sludge build-up concerns you mention in your letter.

The Department's responses to your questions are provided in the enclosure to this letter. I have also provided a copy of my response and enclosure to the parties listed in your letter.

I hope this information is helpful to you. If I can provide further information or assistance, please feel free to call me.

Sincerely yours,

Maria Cino

Maria Cino

Enclosure

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

The Honorable Kathleen Clarke, Director
Bureau of Land Management
U.S. Department of Interior

Mr. Jerry Brossia, Authorized Officer
The Joint Pipeline Office
Federal Bureau of Land Management – Alaska State Office

Mr. Kevin Hostler, President and Chief Executive Officer
Alyeska Pipeline Service Company

ENCLOSURE

Responses to Questions in Congressman John D. Dingell's April 25, 2006, Letter to the Secretary

1) (a) Does the U.S. Department of Transportation share the view that sludge may be a contributing factor to corrosion (and thus, pipeline integrity) and if so, how specifically?

Answer:
Yes, the material may be a contributing factor; sludge has been known to cause corrosion due to sulfate reducing bacteria forming underneath the sludge. The bacteria can lead to the formation of localized corrosion pits. Sludge also may have a sheltering effect, preventing chemical inhibitors from reaching the corrosion source and pipe steel to be protected. As a result of these potential concerns, DOT has ordered BP Exploration (Alaska) Inc. (BP), to conduct laboratory analyses on the sludge found in the pipeline to determine its corrosive properties and integrate those findings into an internal corrosion management plan. Additionally, DOT believes periodic cleaning operations of the Prudhoe Bay West Operating Area (PBWOA), Prudhoe Bay East Operating Area (PBEOA), and Lisburne pipelines will greatly reduce the risk of internal corrosion by sweeping away water and sediment that may reduce the effectiveness of the BP-applied corrosion inhibitors. The Corrective Action Order requires BP to commence running maintenance pigs on these three pipelines and to develop and get DOT approval of a long term plan for routine cleaning of the above-mentioned pipelines.

(b) What impact would the buildup of sludge or other material have on the effectiveness of corrosion-detection coupons?

Answer:
Corrosion-detection coupons are a widely used means for monitoring corrosion rates. Materials such as scale and sludge in the BP transit oil lines should not have affected the ability of coupons to monitor general corrosion properties in the environment. The location of the coupons will, however, impact their ability to representatively measure corrosive activity. The coupons exposed to the product stream only measure the mils-per-year corrosion rate for the areas in which they are installed. The placement of the coupons used by BP was in the higher, above-ground sections of the pipeline, which are less susceptible to internal corrosion than the lower areas of the pipeline where water and sediment that are more conducive to corrosion can accumulate. Therefore, based upon current information, the location of the coupons became a factor in BP's failure to detect an excessive corrosion rate before a leak occurred.

2) Alyeska officials informed staff that the entire 800-mile Trans Alaska Pipeline System (TAPS) is regularly cleaned with scraper pig once every 14 days.

(a) Is this DOT's understanding? And if so, what benefit does such scraping have on the integrity of this line or pipelines in general?

Answer:
Yes. Alyeska conducts cleaning pig operations on the TAPS on a 2-week cycle. The scraping removes water and other impurities that may cause corrosion, waxes (paraffin) and other materials that increase friction and thereby reduce flow rates. Regular removal of paraffin build-up improves operational efficiency and also is conducive to obtaining better in-line inspection survey results.

(b) What is DOT's understanding of the frequency of smart pigging on TAPS?

Answer:
Currently Alyeska is on a 3-year cycle for smart pigs. The next pig run is scheduled for 2007, although we have recently learned that Alyeska is planning a supplemental smart pig run in 2006 to collect additional pipe corrosion data.

3) Staff was informed that several of the key lines serving the PBEOA (specifically the main transmission lines from Flow Stations 1, 2, and 3 that ultimately connect to Skid 50) and the Lisburne line have not been cleaned with a scraper pig, nor have they been examined with a smart pig, since as long ago as 1992. Moreover, staff was informed that these lines may now collectively contain considerable sludge and other buildup. In fact, company officials interviewed by staff said that there is potential for approximately 1,000 to 2,000 cubic yards of sludge to be removed from the pipelines that flow from Skid 50 to Flow Stations 1, 2, and 3.

(a) What is DOT's understanding of the frequency in which the key lines that service the PBEOA, from Flow Stations 1, 2, and 3 to Skid 50 have been scraped with maintenance pigs. What is DOT's understanding of the frequency of smart pigging of these lines? Please also address the frequency of smart pigging and cleaning pigging for the Lisburne line.

Answer:
The BP has advised DOT that it has not conducted a maintenance cleaning pig run on the PBEOA pipeline since 1990. The BP informed us that cleaning was started in 1990, but it was not completed because BP found a significant amount of sludge and other buildup was pushed into TAPS and negatively affected Alyeska operations. The last smart pig conducted on the PBEOA line was in 1990; however, debris in the line adversely affected the quality of the data.

The BP advised DOT that it has not conducted a maintenance cleaning pig on the Lisburne pipeline since 1994. It is the DOT's understanding that the Lisburne line has never been smart pigged.

(b) At present, what is DOT's general understanding of the condition of all lines referenced in question 3(a)? Also, is it correct that at this point many of the lines in the PBEOA are deemed "indeterminate" by DOT?

Answer:
The DOT cannot confirm the condition of the lines referenced in question 3(a) until it has reviewed the results of testing required by the March 15 Corrective Action Order, which brought the referenced lines under its regulation. The Corrective Action Order requires BP to perform an internal inspection using a calibrated smart pig on the PBEOA and Lisburn pipelines. Further information should be available to DOT once the initial cleaning pig runs are complete and subsequent smart pig investigations have been conducted. The DOT will continue to monitor the situation and will carefully evaluate the data once it becomes available to ensure BP takes appropriate action to completely address all anomalies discovered in accordance with the standards for anomaly repair in 49 C.F.R. Part 195. Furthermore, DOT will be reviewing and approving BP's internal inspection plans prior to implementation.

(c) Does DOT have an estimation of the amount of sludge buildup that may exist in these lines by volume measure? What is the process for removing large amounts of sludge and buildup should it exist?

Answer:
The DOT does not have an estimate of the amount of sludge that may exist in these pipelines. The BP is currently conducting gamma ray testing to try to determine the amount of solids that may be in the pipeline. The process is to conduct iterative pigging with progressively aggressive cleaning pigs to remove the sludge and other buildup.

(d) Why does the entire 800-mile TAPS get scraper-pigged once every 14 days, yet many of the key lines that comprise the PBEOA have not been scraper pigged for perhaps as long as 14 years? Are there reasonable explanations for not scraper pigging these lines and does this length of time represent sound maintenance practices?

Answer:
The TAPS line is scraper-pigged every 14 days to remove water and other impurities, enhance operational efficiency by reducing pipeline friction, and remove paraffin that may compromise smart pig surveys. The DOT has not received a reasonable explanation why BP has not scraper-pigged these lines over an approximate 14-year period. In our opinion, based on current information, this length of time does not represent sound management practices for internal corrosion control.

4) Staff was told by one official that previous attempts were made to operate the scraper pigs on the major lines of the PBEOA (from Flow Stations 1, 2, and 3 to Skid 50) and the Lisburne line, yet some of these efforts were abandoned due to the volume of sludge being produced.

(a) Has DOT determined if earlier attempts were made to clean any or all of these key lines and were significant amounts of sludge found?

Answer:
During an April 2006 information gathering meeting, BP informed DOT that a 1990 cleaning pig attempt of the PBEOA line was terminated due to high volumes of debris present in the pipeline.

(b) Has DOT asked for all documentation to show the maintenance history of those lines and any discussion regarding potential earlier difficulties in cleaning them due to high sludge or buildup volume?

Answer:
Yes.

(c) Does DOT even know the key results of these earlier pigging efforts?

Answer:
Yes. The DOT received documentation of pig history and key results from pig data available for the smart pig run in 1998 on PBWOA.

5) Both Alyeska and BP officials told staff that if the sludge in these lines is considerable, the possibility exists that any maintenance pig sent through these lines might become stuck, which in a worst case scenario could result in the shutdown of one or more flow stations.

(a) What is DOT's estimate of a pig "sticking" possibility?

Answer:
There is always a risk that a pig may get stuck in a pipeline. Although we have not attempted to quantify the degree of risk in this case, we consider it significant enough to warrant special precautions. The BP has reported it plans to use soft low density foam pigs initially because these type of pigs can more easily traverse a reduced (partially occluded) diameter pipeline. Upon successful completion of foam pig runs, BP will ramp up with larger diameter and more aggressive (i.e., brush pigs) cleaning pigs with each subsequent cleaning operation until the line is clear of debris, scale, and sludge.

(b) On what specific lines and in what location is this possibility greatest?

Answer:
The PBEOA pipeline may have the highest possibility for sticking a pig due to significant quantities of material (sludge) found in the line on previous cleaning pig attempts. The deposits and material in this line will be the greatest at low spots, including road and animal crossings.

(c) Does DOT believe that cleaning these lines could result in a blockage that could result in the shutdown of one or more flow stations?

Answer:
Yes, a blockage or pig malfunction is a possibility; however, BP's planned approach of progressively using more aggressive pigs is a common methodology that is successfully used in the industry to prevent problems with fluid bypass around the pig or blockage of the pig's flow path.

(d) Should the worst case scenario occur and flow stations are shut down, what are the implications for a "cold restart," given the time period DOT estimates such cleaning efforts will need to take place (e.g., potentially cold-weather months)?

Answer:
The shutdown of a pipeline segment due to a maintenance pig is a possibility. After the March 2 incident and subsequent repairs, BP was able to shut-in and successfully cold restart Gathering Center #2. Its feeder lines were operational 2 weeks after a bypass pipeline was installed. It should be noted that fluids were injected into the feeder lines to prevent their freezing during shutdown and cold restart.

6) If considerable amounts of sludge are discovered in these lines, how will that sludge be captured and disposed of? Some officials told staff that both the metering and strainers at TAPS's PS 1 may have to be bypassed due to anticipated volume. Staff was also told that one scenario would be to collect such sludge in the breakout tanks at PS 1. Another scenario would be to have BP collect the material at Skid 50 before the material makes its way to PS 1, yet currently there are no tanks available that could hold the possible volumes of this material. What is DOT's understanding of how this material will be handled, particularly if it is so voluminous? If the material is collected in the PS 1 breakout tanks, does that raise safety or integrity issues for Alyeska and TAPS?

Answer:
The BP and Alyeska are currently conducting risk assessments on how to handle the material collected during BP's cleaning operations. If this material is voluminous, temporary storage at either the Skid 50 site or at PS 1 may be needed to collect the material and provide for proper disposal.

Because DOT is concerned about the potential safety impact of BP's pigging activity on Alyeska's operations, we are extending the time to June 12 for BP to start cleaning pig operations to ensure an approach is developed which protects downstream equipment, including Alyeska's filters, meters, pumps and other TAPS-related safety equipment. Alyeska must assess the amount, density and content of the sludge to know how best to manage it. Under consideration is a bypass of the pumps, meters and filters. The method used must fully consider the risks in capturing and disposing of hazardous wastes by Alyeska.

7) It is my understanding that BP Exploration (Alaska), Inc., had scheduled to smart pig the line that failed (and perhaps other key lines in the PBEOA) in 2006.

Nonetheless, there are now considerable engineering issues being "worked" to deal with the sludge problem and the potential for complications associated with running cleaning and maintenance pigs through at least some of these lines. Much of this engineering effort appears to be in its early stages. Moreover, until only recently senior officials from Alyeska appeared to know very little about the potential for downstream complications resulting from the potential sludge. Given that the warmer (i.e., summer) months are approaching and this period of time is viewed as the most opportune time to run maintenance pigs through these lines, one would expect that key engineering questions about this effort would already be addressed.

(a) What evidence does DOT have regarding any scheduled pigging efforts planned for any of the lines covered by the Corrective Order that were in place prior to the rupture discovered March 2, 2006?

Answer:
The BP presented documentation in April 2006 that a maintenance and smart pig was to be conducted during 2006 on the PBWOA Crude Oil Transit Line. The BP believed the amount of solids in the PBWOA Crude Oil Transit Line was considerably smaller and therefore much easier to manage in a routine way than that of both the PBEOA and the Lisburne Pipelines.

(b) Has the DOT asked BP for such evidence?

Answer:
Yes, DOT requested this information and BP presented documentation in April 2006 showing that maintenance and smart pig runs are planned during 2006 on the PBWOA Crude Oil Transit Line.

8) Recently, it was reported in the press that another line -- this time a smaller 3-inch gas pipe -- also failed due to corrosion. According to press accounts, the volume of gas release in this line was too small to report to regulators. Nonetheless, we believe understanding the causes of this rupture may have some relevance to the current undertaking being pursued by DOT's Corrective Order.

(a) When, if at all, was the DOT informed about the second rupture?

Answer:
My staff was informed of the rupture by BP on or about April 19, 2006.

(b) Was this a potentially dangerous event to either the environment or workers? If so, how?

Answer:
Any time an abnormal operation exists, both the environment and the associated workers could be at risk. The BP informed DOT that the failure occurred outside, not in an enclosed environment, thus, there were no trapped gases that were potentially explosive. The DOT was also verbally informed by BP that the incident occurred where workers were not present.

(c) Has DOT determined the causes of this failure? If so, please provide them.

Answer:
The BP informed DOT that the April 6 pipeline failure was due to external corrosion beneath exterior pipe insulation and provided documentation supporting this determination. Because the failure occurred on an unregulated production line, DOT has not otherwise investigated this event.

ONE HUNDRED NINTH CONGRESS

U.S. House of Representatives

Committee on Energy and Commerce

Washington, DC 20515—6115

JOE BARTON, TEXAS
CHAIRMAN

April 25, 2006

ACTION
PHMSA
S10-060426-002

The Honorable Norman Y. Mineta
Secretary
U.S. Department of Transportation
400 Seventh Street, S.W.
Washington, D.C. 20590

Dear ~~Secretary Mineta~~ Norm:

On March 2, 2006, BP officials discovered a leak in one of the North Slope's main transmission lines, several miles upstream from the Pump Station 1 of the Trans Alaska Pipeline System (TAPS). The leak resulted in the loss of between 200,000 and 300,000 gallons of crude, and is now the largest spill ever on the North Slope. On March 15, after an initial investigation, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order requiring BP Exploration (Alaska) Inc. (BP), to take several actions regarding the breached pipeline, as well as numerous other lines in the greater Prudhoe Bay operating area. More specifically, additional actions are now ordered for pipelines servicing the Prudhoe Bay West Operating Area (PBWOA), Prudhoe Bay East Operating Area (PBEOA), and the Lisburne hazardous liquid pipeline facilities, all of which are operated by BP.

Earlier this month, Committee staff visited the North Slope of Alaska and several points on the Trans Alaska Pipeline System to discuss pipeline integrity and corrosion issues and specifically investigate the possible causes of this spill. This effort followed two letters recently sent to both BP and the operator of the TAPS -- Alyeska Pipeline Service Company (Alyeska) -- to gather additional information on the spill event as well as other integrity issues.

To date, the initial efforts of BP to address potential root causes of the spill and ongoing environmental restoration efforts are commendable. Similarly, the early efforts by the company to determine where additional and similar corrosion may be occurring and placing additional North Slope pipelines in jeopardy are much appreciated. Nevertheless, there remain several questions about the causes of this spill as well as the capabilities of BP to maintain the integrity of some of the pipelines in the Prudhoe Bay operating area. Moreover, there are numerous other issues about how the key pipelines in Prudhoe Bay have been managed to date and whether additional steps may be warranted to prevent future breaches. I request your help in addressing some of these concerns and would appreciate your Department's response to the following questions by Tuesday, May 16, 2006:

1. The March 15 Corrective Action Order issued by PHMSA, requires that BP perform a number of maintenance procedures -- including the application of scraper pigs and smart pigs -- on several key lines serving the PBBOA and the Lisburne line. This region encompasses a number of key facilities including Flow Stations 1, 2, and 3 that eventually connect through a series of lines to Skid 50. Skid 50 is the last facility operated by BP before the transmission lines connect to PS 1 of TAPS. Item (7) of the attached Department of Transportation's (DOT) Corrective Action Order requires that BP:

   > "Perform an internal inspection using calibrated smart pig on the PBEOA and Lisburne pipelines within 3 months of receipt of this Order. Take appropriate action to address all anomalies discovered, in accordance with the standard for anomaly repair in 40 C.F.R Part 195. Record differences between inline inspection data and actual "as found" data for all anomalies and integrate that data in future analyses, mapping corrosion growth, and confirming data gathered by inline inspection tool. Develop and submit for approval a plan to perform internal inspection at regular intervals, not to exceed 5 years, and schedule for the repair of anomalies identified through those inspections. Implement that plan for approval."

   It is our understanding, however, that before implementing any internal inspection "using calibrated smart pig" -- as the order requires -- these lines must be first cleaned using a scraper pig to remove any buildup of sludge or other deposits that may have collected. In discussions with both Alyeska and BP officials, staff was informed that several key lines -- which appear to fall under the Corrective Order -- may not have been cleaned with a scraper pig since 1992. Additionally, other officials told staff that deposits of sludge may contribute to corrosion, particularly if the sludge traps a layer of water or the sludge prevents corrosion inhibitors from reaching and protecting the pipeline wall.

   (a) Does DOT share the view that sludge may be a contributing factor to corrosion (and thus pipeline integrity) and if so, how specifically?

   (b) What impact would the buildup of sludge or other material have on the effectiveness of corrosion-detection coupons?

2. Alyeska officials informed staff that the entire 800-mile TAPS is regularly cleaned with scraper pig once every 14 days.

The Honorable Norman Y. Mineta
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(a) Is this DOT's understanding? And if so, what benefit does such scraping have on the integrity of this line or pipelines in general?

(b) What is DOT's understanding of the frequency of smart pigging on TAPS?

3. Staff was informed that several of the key lines serving the PBEOA (specifically the main transmission lines from Flow Stations 1, 2, and 3 that ultimately connect to Skid 50) and the Lisburne line have not been cleaned with a scraper pig, nor have they been examined with a smart pig, since as long ago as 1992. Moreover, staff was informed that these lines may now collectively contain considerable sludge and other buildup. In fact, company officials interviewed by staff said that there is potential for approximately 1,000 to 2,500 cubic yards of sludge to be removed from the pipelines that flow from Skid 50 to Flow Stations 1, 2, and 3.

(a) What is DOT's understanding of the frequency in which the key lines that service the PBEOA, from Flow Stations 1, 2, and 3 to Skid 50 have been scraped with maintenance pigs. What is DOT's understanding of the frequency of smart pigging of these lines? Please also address the frequency of smart pigging and cleaning pigging for the Lisburne line.

(b) At present, what is DOT's general understanding of the condition of all lines referenced in question 3(a)? Also, is it correct that at this point many of the lines in the PBEOA are deemed "indeterminate" by DOT?

(c) Does DOT have an estimation of the amount of sludge buildup that may exist in these lines by volume measure? What is the process for removing large amounts of sludge and buildup should it exist?

(d) Why does the entire 800-mile TAPS get scraper-pigged once every 14 days, yet many of the key lines that comprise the PBEOA have not been scraper pigged for perhaps as long as 14 years? Are there reasonable explanations for not scraper pigging these lines and does this length of time represent sound maintenance practices?

4. Staff was told by one official that previous attempts were made to operate scraper pigs on the major lines of the PBEOA (from Flow Stations 1, 2, and 3 to Skid 50) and the Lisburne line, yet some of these efforts were abandoned due to the volume of sludge being produced.

The Honorable Norman Y. Mineta
Page 4

(a) Has DOT determined if earlier attempts were made to clean any or all these key lines and were significant amounts of sludge found?

(b) Has DOT asked for all documentation to show the maintenance history of those lines and any discussion regarding potential earlier difficulties in cleaning them due to high sludge or buildup volume?

(c) Does DOT even know the key results of these earlier pigging efforts?

5. Both Alyeska and BP officials told staff that if the sludge in these lines is considerable, the possibility exists that any maintenance pig sent through these lines might become stuck, which in a worst case scenario could result in the shutdowns of one or more flow stations.

(a) What is DOT's estimate of a pig "sticking" possibility?

(b) On what specific lines and in what location is this possibility greatest?

(c) Does DOT believe that cleaning these lines could result in a blockage that could result in the shutdown of one or more flow stations?

(d) Should the worst case scenario occur and flow stations are shut down, what is the implications for a "cold restart," given the time period DOT estimates such cleaning efforts will need to take place (e.g., potentially cold-weather months)?

6. If considerable amounts of sludge are discovered in these lines, how will that sludge be captured and disposed of? Some officials told staff that both the metering and strainers at TAPS's PS 1 may have to be bypassed due to anticipated volume. Staff was also told that one scenario would be to collect such sludge in the breakout tanks at PS 1. Another scenario would be to have BP collect the material at Skid 50 before the material makes it way to PS 1, yet currently there are no tanks available that could hold the possible volumes of this material. What is DOT's understanding of how this material will be handled, particularly if it is so voluminous? If the material is collected in the PS 1 breakout tanks, does that raise any safety or integrity issues for Alyeska and TAPS?

7. It is my understanding that BP Exploration (Alaska), Inc., had scheduled to smart pig the line that failed (and perhaps other key lines in the PBEOA) in 2006.

Nonetheless, there are now considerable engineering issues being "worked" to deal with the sludge problem and the potential for complications associated with running cleaning and maintenance pigs through at least some of these lines. Much of this engineering effort appears to be in its early stages. Moreover, until only recently senior officials from Alyeska appeared to know very little about the potential for downstream complications resulting from potential sludge. Given that the warmer (i.e., summer) months are approaching and this period of time is viewed as the most opportune time to run maintenance pigs through these lines, one would expect that key engineering questions about this effort would already be addressed.

(a) What evidence does DOT have regarding any scheduled pigging efforts planned for any of the lines covered by the Corrective Order that were in place prior to the rupture discovered on March 2, 2006?

(b) Has DOT asked BP for such evidence?

8. Recently, it was reported in the press that another line -- this time a small 3-inch gas pipe – also failed due to corrosion. According to press accounts, the volume of gas release in this line was too small to report to regulators. Nonetheless, we believe understanding the causes of this rupture may have some relevance to the current undertaking being pursued by DOT's Corrective Order.

(a) When, if at all, was DOT informed about this second rupture?

(b) Was this a potentially dangerous event to either the environment or workers? If so, how?

(c) Has DOT determined the causes of this failure? If so, please provide them.

At a time when crude oil prices are again reaching record-high levels and the supply is oil is tight, the soundness of the pipelines that serve the greater Prudhoe Bay operating area is critical to the Nation's national security. I appreciate DOT's efforts to work with BP, Inc., to make this operation as safe as possible and I thank you for your leadership on this important matter.

Should you have any additional questions regarding this request, please contact me, or have your staff contact Mr. Christopher Knauer of the Committee on Energy and Commerce Democratic staff at (202) 226-3400.

Sincerely,

JOHN D. DINGELL
RANKING MEMBER

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

The Honorable Kathleen Clarke, Director
Bureau of Land Management
U.S. Department of Interior

Mr. Jerry Brossia, Authorized Officer
The Joint Pipeline Office
Federal Bureau of Land Management - Alaska State Office

Mr. Kevin Hostler, President and Chief Executive Officer
Alyeska Pipeline Service Company

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Congress of the United States
Washington, DC 20515

March 24, 2006

Mr. Steve Marshall
President
BP Exploration (Alaska) Inc.
900 East Benson Blvd.
Anchorage, Alaska 99508

Dear Mr. Marshall:

Thank you for meeting with our staffs last week to discuss the North Slope oil spill currently being addressed by cleanup crews. It is our understanding that at least 200,000 gallons of crude have leaked so far from a major supply line, which ultimately delivers product to the Trans Alaskan Pipeline. This is now, unfortunately, the largest spill ever to occur on the North Slope, and one of the largest in Alaskan history. We understand that the failed line is currently being operated by BP Exploration (Alaska) Inc. (BP).

We are informed that, although company officials are still examining the root causes of the spill, the existing leak detection system failed to discover the leak. We also understand that the leading explanation appears to be corrosion and that this occurred in an area where the line dips underground at what is commonly called a "caribou crossing." While it is still unclear what caused the corrosion, we do understand that BP believes its onset was quite rapid and may have developed in as little as six months. Further, we are informed – through our staff's discussion with you and your staff – that this particular line had been tested using ultrasonic methods within the past six months, and that BP believes that the last period of testing found that the thickness of the areas of the pipe's walls that were tested were found to be within tolerance.

While we applaud such testing, we still remain unclear <u>where such tests were taken and whether such tests were made on the section that ultimately failed</u>. Moreover, we are unclear whether any of the spot testing associated with ultrasonic testing can or should be seen as representative of the entire line's condition. This is particularly important as we understand that this line had not been examined with a "smart pig" since 1998 – a process in which corrosion or other anomalies can be more thoroughly detected. In fact, we are still trying to understand the frequency at which this line was pigged (either via "maintenance pig" or "smart pig") and we look forward to receiving information that details both the frequency and method(s) used to examine this line. It is our understanding that such information will be made available to us soon.

Mr. Steve Marshall
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We recently received correspondence that raised some concerns about BP inspection methods, particularly those relating to corrosion matters. We therefore have several questions that we would ask you to respond to in order for us to better understand what specifically failed and what lessons have been learned to avoid future spills. As some of our questions may pertain to the upcoming reauthorization of the Pipeline Safety Improvement Act of 2002, we ask that you respond to the attached questions by no later than Monday, April 3, 2006.

We appreciate your cooperation and assistance in these matters of energy transport, security, and safety. If you need further information regarding this request, please contact us or our staff, Mr. Christopher Knauer with the Committee on Energy and Commerce Democratic staff at (202) 226-3400, or Mr. Jeff Petrich with the Committee on Resources Democratic staff at (202) 225-6065.

Sincerely,

JOHN D. DINGELL
RANKING MEMBER
COMMITTEE ON ENERGY AND COMMERCE

GEORGE MILLER
MEMBER
COMMITTEE ON RESOURCES

Attachment

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

Mr. Brigham McCown, Acting Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation

Questions for Steve Marshall, President
BP Exploration (Alaska) Inc.

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

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

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

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

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

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

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

bp

By Fax and U.S. Mail

Steve Marshall
President, Alaska

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 564-5422

April 3, 2006

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

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

Gentlemen:

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

S. Marshall

Steve Marshall

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

ATTACHMENT 1

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

Background

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

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

Table 1: BPXA Operated Facilities

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

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

Program Objectives and the "Fit for Service" Strategy

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

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

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

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

Specific Processes and Procedures

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

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

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

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

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

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

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

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

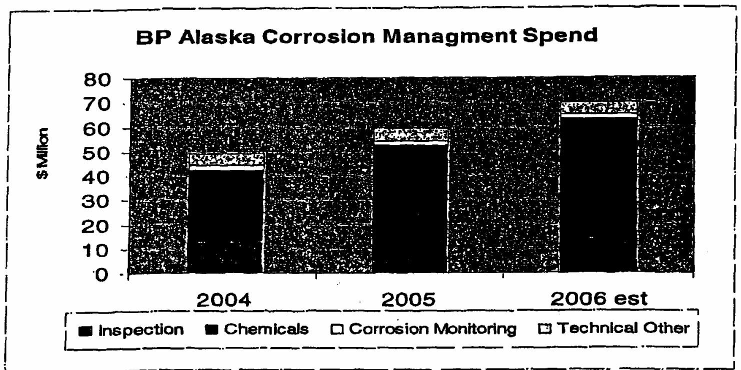
A variety of inspection techniques are used in the inspection programs described above. The techniques include **visual, ultrasonic, radiographic** and **magnetic flux** and each can be used to detect different types of damage. The basic technology in many of these techniques has also been built into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

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

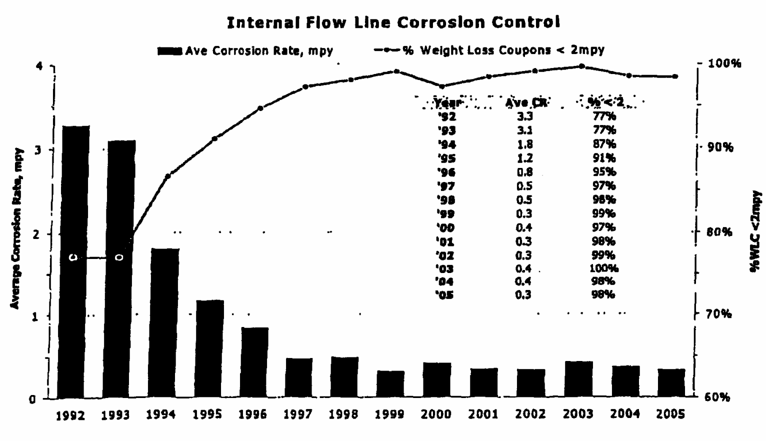
<u>Inspection Techniques</u>	<u>Corrosion Monitoring Techniques</u>
Radiography	Weight loss coupons
Tangential radiography	Electrical resistance probes
Ultrasonic	Galvanic probes
Guided wave	Linear polarization
Electro-magnetic pulse	
Magnetic flux smart-pig	

Corrosion Program Resources and Results

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



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



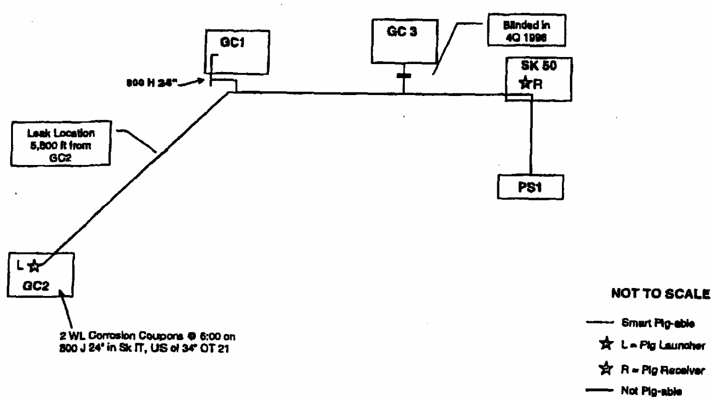
ATTACHMENT 2

Responses to Questions

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

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

WOA Pipeline Schematic for Processed Sales Oil



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

Table I

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

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

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

Table II

WOA OTL Inspection Program (August 1998 – February 2006)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The next smart pig inspection had been planned for 2006.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

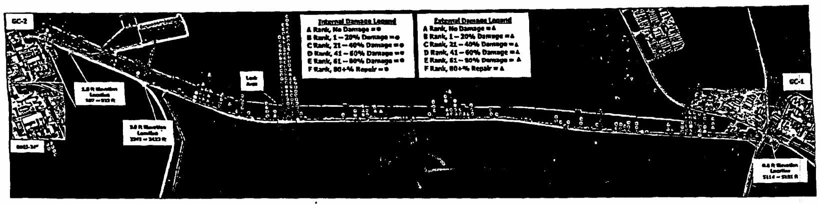
7. Please explain why the leak detection system on the OTL line failed to detect the leak and what changes will be made to leak detection systems on this and all of the BP North Slope lines.

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

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

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

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



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

Exhibit B

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

CHAIRMAN BARTON. Mr. Chairman, I want to make clear that when I mentioned Susan Harvey's name, we approached her, the committee staff approached her. She did not voluntarily come forward. It is at our request, the committee staff, that we interviewed her.

MR. WALDEN. Thank you. The Chair now recognizes the gentleman from Washington, Mr. Inslee, for 10 minutes.

MR. INSLEE. Thank you. Mr. Malone and Mr. Marshall. I want to do something that I think will be unique at this hearing and saying one good thing about British Petroleum, and that is that you have met Kyoto targets in your internal operations for reducing carbon dioxide. You have demonstrated the ability to keep our economy going while reducing carbon dioxide emissions. That is a good thing you have done. I want to note that in this hearing. But I also want to note profound disappointment in this abysmal corporate record on this particular maintenance issue, and the reason is, is that it appears from even a cursory review of this that this was not some sort of oversight. You know, people run red lights; we are all human. But this was a very willful, deliberate, clear, premeditated, if you will, decision not to do this known maintenance procedure of using smart pigs, and what leads me to that conclusion, looking at this report, a preliminary draft of the report by Coffman Engineers, this says out of Anchorage, it is entitled Corrosion Monitoring of Non-Common-Carrier North Slope Pipelines. It was received by the Department of Alaska on November 2, 2001. This was their preliminary draft, and their preliminary draft made repeated references to the efficacy of smart pigging these lines. I look at the preliminary draft before British Petroleum got their hands on it. It had lines such as, "Smart pigging is the only inspection technique capable of looking at the whole internal and external corrosion picture." That disappeared after British Petroleum talked to these engineers. No such reference in the final report. We have a line saying "Some questions which arise after reading the report are, does BP pig every non-common-carrier pipeline of suitable diameter." That line disappears from the final report. We have a line saying, "Are there plans to install/configure EOA pipelines for smart pigs?" Gone in the final report. "Are baseline smart pig runs performed on newly commissioned lines?" Gone on the final report. "How are lines selected for smart pigging and what is the recur"-- that is what it says--"frequency of inspection." It means recurrence. Gone in the final report. There are loads of language like this in this report that is gone after British Petroleum started to work on this report, and to use a bit of a British understatement, it turned an inspection report into a bit of a whitewash, and so we are here today. Now, I understand, I think, your logic that you decided just to rely on ultrasound inspections in lieu of doing smart pigging. It is a very sensitive, exquisitely effective tool but it only affects a very small part of the pipeline. When you put a sensor on the pipeline, it only gives you data for a very small section. How wide is that? When you put one of these monitors, how wide is that section?

MR. MARSHALL. It is one-foot sections.

MR. INSLEE. One-foot sections. So when you put this monitor, you are only getting data for one foot of the pipeline at a time and you go to various places and you get one-foot slices. What percentage of the pipeline did you get real data for when you do that? Just give me a ballpark. Fifty percent, 10 percent, half a percent?

MR. MARSHALL. I can't give you an honest--an exact number. I think it varies on the different lines.

MR. INSLEE. It is probably less than 5 percent, isn't it?

MR. MARSHALL. I can get you an answer. I will come back with a--

MR. INSLEE. Well, the point is to me, isn't that a fair metaphor for like a CT scan? You go to the doctor, that takes little slices of your body, and it is like giving it a CAT scan but you have just got little slices, not the whole enchilada. That is why this report specifically brought up the issue and said, "Smart pigging is the only inspection technique capable of looking at the whole internal and external corrosion picture." Now, that was in their preliminary report. Then they talked to BP and then in the final report that language disappeared. Is that accurate?

MR. MARSHALL. We have investigated, as I said. When that issue came to light, we investigated the two drafts, the draft and the final report, and we interviewed every--a number of people involved in that preparation of that report and were involved on both sides of the discussion. We haven't interviewed everybody but so far we have identified no pressure. I think that is a fair question there for Coffman to address in terms of why certain things were kept in and certain things were kept out. I don't believe BP wrote that final report. It was still a Coffman report. But so far we found no evidence of pressure on Coffman Engineering to change that report.

MR. INSLEE. Well, I am not sure I have to refer to violations of the Geneva Treaty as far as pressure. There was communication between BP and Coffman before this final report, right?

MR. MARSHALL. Absolutely. There were--

MR. INSLEE. Coffman does a lot of work in the oil and gas industry, don't they?

MR. MARSHALL. Absolutely. There were discussions between Coffman, the State Department of Environmental Conservation, BP and indeed ConocoPhillips who are working this first draft of report and I would say with any audit, it is normal and customary to sit down, discuss drafts, you know, provide additional information, you know, perhaps draw different conclusions from the data that is subsequently presented. I believe that was a large part of what was discussed between the draft and the final report.

MR. INSLEE. But it is not normal when an engineering outside consultant suggests that you consider doing the smart pigging and specifically says it is the only thing that gives you data for the pipeline--by the way, you agree with that, don't you?

MR. MARSHALL. Smart pigging gives an indication across the entire pipeline length and girth of where corrosion may be occurring which then has to be subsequently checked to precisely define what that level of corrosion is.

MR. INSLEE. I want to make sure I understand you. Smart pigging is the only thing that gives you data for the entire internal section of the pipeline that does not require you drawing assumptions that tiny little pieces of the pipeline are the same as the pieces you checked?

MR. MARSHALL. I am not a pipeline expert, Mr. Congressman. I believe that the path we are on with the east line and the west line right now of ultrasonically testing the entire length of the line will give the same kind of indications.

MR. INSLEE. But you didn't do that, did you?

MR. MARSHALL. No, we did the spot checks.

MR. INSLEE. You did spot checks, and I can tell you when Congress became somewhat experts on this, we required smart pigging essentially for the internal sections of these main lines, and obviously the TAPS system uses as well, you know, both cleaning and inspection purposes. So I just have to tell you that, haven't you concluded that your communications to this outside expert had some bearing in keeping the public from knowing that smart pigging was, A, an option to you, B, that it had been considered, and C, that you decided, you made a conscious decision not to do it?

MR. MARSHALL. I have no evidence to support those allegations, quite frankly.

MR. INSLEE. Do you have any other suggestion why this outside expert on their own desire or concern would all of a sudden whitewash this report?

MR. MARSHALL. I think it is a question maybe addressed to Coffman Engineering. I don't have any information which would eliminate that.

MR. INSLEE. Are you telling me that your investigation did not give you any reason to believe that British Petroleum asked Crowley to take this information out of the report--Coffman. Excuse me.

MR. MARSHALL. I don't have any information to support that. What I do understand is that more data was provided from the initial basis. This was the first report that was done after the charter agreement.

MR. INSLEE. I have to tell you too, one of the disappointments of my constituents is the public relations effort by the organization to I think indicate that the organization is going in an environmentally friendly manner, and we made reference to this. I saw this advertisement in Autobahn magazine just this week. It says our plans for biofuels are growing, and I think any step forward I suppose is great, but I just want to ask while I have you here, there are 170,000 pumps, gas station pumps in America. There are about 858 that have E85 available, ethanol for consumers. What can you tell us as to when British Petroleum will have 25 percent of its stations having E85 pumps available?

MR. MALONE. Congressman, if I might, I don't have that exact figure but I will get it for you. We are moving to have E85 pumps in certain of our markets right now but I don't have the number and locations with me today. If I could though, Congressman, just on your point about our values around the environment, I would say we just acquired two wind companies. We are investing some $500 million into biofuels research which we think is very important, and we also have a very aggressive program in working with alternative fuels, and I would--whether the advertising is the issue but just so you know, the core values are real.

MR. INSLEE. Let me--we would applaud any step forward so we appreciate those steps forward including, as I indicated, your CO_2 reduction. But I have to tell you, a $50 million-a-year investment in biofuels is less than chicken feed for a company that has $26 billion of profit this year. It is less than .2 percent of your net profits, not just your gross. Our Nation needs a new energy future for this country. We believe your corporation is capable, should it decide, of having a meaningful role in that, and we hope both Congress will act--it will take a new Congress but eventually we are going to act, and we hope you will be part of that, and I hope that as part of this hearing, perhaps you can go back to corporate headquarters and say maybe we need to redouble that effort as our penance for this massive abysmal failure. That would be a good result of this. I hope you will take that message back to your leader, who has done good work in this effort. Thank you.

MR. WALDEN. The chair now recognizes the gentlewoman from Wisconsin, Ms. Baldwin.

MS. BALDWIN. Thank you, Mr. Chairman. I would like to focus some questions for Mr. Marshall on the corrosion management group and I think it is also known as the CIC, the Corrosion Inspection and Chemicals Group. Are you aware of an internal audit issued in April of last year called BPXA Corrosion Management System Technical Review?

MR. MARSHALL. Could you explain the--I am sorry. Which one again?

MS. BALDWIN. Are you aware of an internal audit issued in April of last year called the BPXA Corrosion Management System Technical Review?

MR. MARSHALL. Yes, I am. I am sorry.

MS. BALDWIN. And in that report, under the section called budget processing, is the following finding, and I am just going to quote from that: "Currently, the budget is set up-front in line with flat lifting cost strategy, with corrosion management activities then developed around this budget allocation. This strategy to maintain flat lifting costs is driving behaviors counterproductive to ensuring integrity and the delivery of an effective 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 longer term and thereafter set the budget based on these activities." Mr. Marshall, this report seems to suggest that there was pressure at BP to reduce expenditures on its corrosion program. Would you agree with that?

MR. MARSHALL. I would say--I would make several comments, Congresswoman. The fact of bringing in our chief engineer to review this program I think it is an indication that while many had considered our corrosion program to be comprehensive, we were prepared to subject that to some scrutiny, to shine a spotlight on the program and find out where we could make improvements, and indeed, the perception of flat units costs was still there when the team issued that report in 2005. The same team came back in 2006 and said action had been taken. They had seen a considerable change in 12 months in their follow-up report. One of my regrets in terms of, I have thought long and hard in the last 5 to 6 months about what I could have done differently. That has occupied a big part of my time. And one of the things I regret is that I didn't do more to change the perception inside our team about spending money because the reality of what we have done or what has happened since I have been there is our lifting costs, which are a measure of spending divided by how much production, has gone from $1.89 a barrel to $5.22 a barrel. Our corrosion spend has increased by 80 percent. Our major repair spend has gone up threefold. But I recognize that still it takes a huge effort to change the perceptions of cost cutting that were a feature of the late 1990s when we experienced $9 and $10 oil and the industry took some significant belt-tightening under its way. I believe that that caused some poor practices, and certainly when I arrived in Alaska in 2001, the organization wasn't in good shape. We had a poor relationship with our workforce, we had some issues around maintenance, and one of my goals has been to change both of those. I am proud to say that the conditions today are far better than they were. They are clearly a long way short of being good enough, and I do regret that. But this is a long journey and we are going to re-establish that track record with our staff and with the public.

MS. BALDWIN. Mr. Marshall, I want to continue to explore this topic. I think you already acknowledged awareness of the investigative report from the law firm of Vinson and Elkins, October 20, 2004. They were charged with looking into allegations of workplace harassment and corrosion data falsification in the CIC, the Corrosion Inspection and Chemicals Group. So you are aware of this report, correct?

MR. MARSHALL. I am, yes.

MS. BALDWIN. Okay. What prompted Vinson and Elkins to conduct that review? Can you give us some brief history of that and what were the allegations?

MR. MARSHALL. Congresswoman, yes. I became aware of this issue in early 2003, an issue of alleged harassment in the corrosion group. That issue was raised through two channels: one, through our employee-run safety committee, and concurrently through one of our external contacts who represents one of the channels for workers to use. That was a channel that I was instrumental in setting up and that resulted in investigation by two outside counsel, Billy Guard and Paul Floudy, who went up and reviewed the situation in the corrosion group. They confirmed and established that there was an atmosphere of intimidation that was potentially suppressing safety concerns. The recommendation of that review was that the CIC manager, Mr. Woollam, should undergo coaching and counseling and change his working practice. That was their recommendation. We followed up with that. Mr. Woollam did indeed take on that training, and by some measures and follow-up was willing to kind of take that on. The following year in 2004, Billy Guard and Paul Floudy returned to the slope on a different issue and did some checking and were still concerned that there was a chilled atmosphere in the CIC team. On that basis, we said we needed to perform a more comprehensive review and that was the Vinson and Elkins review, so that was a very extensive review of everything from falsification of data, the workplace harassment, and my recollection of the Vinson and Elkins report is that while there was no apparent continuation of harassment from Mr. Woollam, the chilled atmosphere still remained. There was a legacy of chilled atmosphere and the recommendation from that team was that Mr. Woollam should be taken out of a supervisory role. I took that action one step further and believed in Mr. Woollam's best interests and in BP's best interests that Mr. Woollam should be removed to a non-supervisory role outside of Alaska, and that was what was done.

MS. BALDWIN. So bad were the allegations coming from this group that the EPAs' Region 10 Office of Suspensions and Debarment and the U.S. District Court's Anchorage Office of Probation and Pretrial Services asked BP to look into these harassment claims. Isn't that true?

MR. MARSHALL. I believe that is correct, yes.

MS. BALDWIN. And then back on the budgetary implications of this, Mr. Marshall, one of the issues mentioned in this report that seemed to cause so much strife among BP's corrosion inspectors was when the manager of the program decided to reduce the amount of staff and corrosion inspection points by 25 percent, and let me again quote from page 17 of the report. I quote: "It is not clear exactly what motivated the CIC manager to insist that the coupon crew be reduced from eight workers to six. During our interview of him, he told us there was no budget pressure as the CIC budget was increasing at the time. It appears to have been driven by a metric he developed that total coupon pulls had been reduced by 25 percent which he believed had to translate to a 25 percent reduction in crew size." Mr. Marshall, given that BP's facilities were aging and the amount of water in the field as we have heard in previous questions was increasing and the quality of oil coming from the reservoir was increasingly capable of causing corrosion, why would BP opt to cuts its coupon pulls by 25 percent, and who made this decision and why was it made?

MR. MARSHALL. The issue of the coupon crew reduction was one of the foundations of the initial review by Billy Guard and Paul Floudy. It was one that was raised in 2003. That was looked at. We took action on that and increased the crew size back to the full complement and performed the corrosion coupon pulling back to its pre-existing level, so we took action on that basis.

MS. BALDWIN. Mr. Chairman, I see that I have run out of time. I would also like to submit some further questions relating to this--

MR. WALDEN. Without objection.

MS. BALDWIN. --CIC group in follow-up. Thank you.

MR. WALDEN. The Chair now recognizes Mr. Markey for questions.

MR. MARKEY. Thank you, Mr. Chairman. Mr. Marshall, the Vinson and Elkins report depicts that a major chilling atmosphere existed in the CIC group. On page 2 of the report is the following conclusion from the Vinson and Elkins investigative team. Let me quote: "Our overall conclusion is that there is an atmosphere in the CIC group that chills reporting HSE concerns, especially among several employees of the coupon crew." Mr. Marshall, do you believe that this chilling atmosphere had any impact on the quality of this program?

MR. MARSHALL. Mr. Congressman, I can't definitively say that it did but I would say this, that we don't tolerate--I don't tolerate chilled atmospheres, harassment. We did take steps to make sure that we are doing everything we can, not only with our BP supervisors but also with our contractor supervisors.

MR. MARKEY. But did this chilling effect have any impact on the safety or quality of the program at that time?

MR. MARSHALL. I have no information to know that there was a direct correlation. Clearly the potential exists but I don't have any evidence that something was suppressed that could have resulted in an improvement.

MR. MARKEY. Well, when whistleblowers don't come forward because they are frightened obviously, they can be, and in this instance I think probably it was serious safety issues that were compromised, it appears that the manager of the CIC group, according to this report, had an extremely abrasive management style. Is that correct?

MR. MARSHALL. That is one of the conclusions, yes.

MR. MARKEY. So bad were the allegations coming from this group that EPA's Region 10 Office of Suspensions and Debarment and the U.S. District Court's Anchorage Office of Probation and Pretrial Services asked BP to look into these harassment claims. Isn't that correct?

MR. MARSHALL. That is correct, yes.

MR. MARKEY. Mr. Marshall, one allegation on page 10 of the Vinson and Elkins report's appendix notes the following allegation: "The Corrosion Inspection and Chemicals manager is brutal and screams and shouts at contractors." Here is what the Vinson and Elkins report found: "Status: We have been informed that the Corrosion Inspection and Chemicals manager had very poor communications skills but has recently been improving. This is a very common perception." Mr. Marshall, given the chilled atmosphere experienced by the employees and apparent abrasive personality of its manager, would you think that this was a favorable atmosphere to recommend that BP explore other types of corrosion detection technology such as more frequent runs of smart pigs which can be costly?

MR. MARSHALL. I am aware certainly of the conclusions of the report. I agree with the conclusions of the report in terms of the abrasive nature, the intimidation, and we have taken steps to change that. What I am not clear about is the linkage of that to the pigging runs. I have no evidence--

MR. MARKEY. Does that report not lead to the conclusion that an individual would risk losing their job if they made such recommendations and that they were not consistent with what the CIC manager wanted? Let me ask you this. What happened to the CIC manager after Vinson and Elkins did this internal report? What did you do?

MR. MARSHALL. The recommendation from both the Billy Guard review and the Vinson and Elkins review was to take action and we followed that action. Indeed, the Vinson and Elkins action was to remove Mr. Woollam from a supervisory role, which we did, and I took that one step further and said it was in Mr. Woollam's best interests and indeed BP's best interests to move him out of Alaska, which is what happened.

MR. WALDEN. Mr. Markey, just a point of interest. You might want to turn to page 6 of the Vinson Elkins report of the appendix, number 26. It would be number 26 of page 6 of the appendix. It is more along the lines of what you are raising.

MR. MARKEY. Thank you, Mr. Chairman. I appreciate it. Could I ask you, Mr. Malone, do you believe that the chilled atmosphere in the CIC group had any impact on the quality or capability of the corrosion program?

MR. MALONE. Congressman Markey, I don't have--I read the report. I don't have any direct evidence yet to be able to give you an answer on that.

MR. MARKEY. Mr. Marshall, on page 7 of the appendix of the Vinson and Elkins investigation is the following allegation: "Independent corrosion experts who are all formerly contractors working on Prudhoe Bay have resigned their positions over the last few years allegedly due to their growing worries over the potential for a serious incident on the field." Vinson and Elkins, according to their report, looked briefly into this allegation though how much is unclear, and this is what they concluded: "Status: We have been told by one person that an operator resigned because of concerns over pipe integrity. Others suggested that this is not why he resigned. We have tried to contact that individual to interview him and have thus far been unsuccessful. We are aware of no other persons who could possibly fit this description." Mr. Marshall, has BP attempted any further efforts to locate this individual?

MR. MARSHALL. I am not aware that we have. That doesn't mean to say that we have not done that. I am just not aware of it.

MR. MARKEY. Well, I would say that that was a big mistake. Mr. Marshall, has BP attempted to look further into the general allegations that independent corrosion experts felt that something was amiss in BP's corrosion management program and that this might explain the failures to truly understand the condition of your lines?

MR. MARSHALL. We take very seriously any allegations, safety concerns that are raised about our programs. It doesn't matter where they come from, whether they come through our internal channels or external channels. The only thing we need to do is be able to understand where there are specifics rather than general concerns. We have investigated hundreds, literally hundreds of allegations and issues since I have been back in Alaska in 2001. Where we have specifics, where there is specific equipment or specific lines, we can go investigate that and take the appropriate action. The only thing I find very difficult and the team finds difficult is where we have, you know, general allegations which are very difficult to address.

MR. MARKEY. Mr. Marshall, earlier this year you stated that BP was unaware of the problems that ARCO had when they had last tried to pig the eastern lines back in 1992, and that you weren't aware of the problems that Alyeska had experienced downstream as a result of ARCO's pigging of the line. Did BP do any due diligence review of the condition of ARCO's pipelines in Alaska prior to your acquisition of the company?

MR. MARSHALL. I am aware there was considerable amount of due diligence done across-

MR. MARKEY. Who did that due diligence?

MR. MARSHALL. I don't have that information.

MR. MARKEY. Did that due diligence review indicate any potential corrosion problems or solids buildup problems within ARCO's lines?

MR. MARSHALL. I am not aware of any but I am just not in possession of that information. I would be happy to go back and reconfirm that with the transfer documents.

MR. MARKEY. Now, after the ARCO merger, were any of the former ARCO employees responsible for corrosion management and control kept on by BP?

MR. MARSHALL. I don't know the answer to that question.

MR. MARKEY. Wouldn't, Mr. Marshall, those individuals have knowledge of the solids buildup problem and the difficulties that the last pig run through the eastern line had created downstream?

MR. MARSHALL. I suspect so. I don't know that for sure but I would imagine that is the case.

MR. MARKEY. So wouldn't there be someone at BP who knew about the problems that had existed before the sale was consummated?

MR. MARSHALL. I don't--I am not able to confirm that.

MR. MARKEY. You haven't found that out yet?

MR. MARSHALL. No.

MR. MARKEY. After six months?

MR. MARSHALL. We have contacted the ARCO engineer that was in charge of that pigging operation in the last few weeks and--

MR. MARKEY. You understand, Mr. Marshall, that Congressional expert is an oxymoron? We are only experts compared to other Congressmen. You have had six months to ask all of these questions which I am asking right now which directly go to the question of how much BP knew and when they knew it and you are telling me that these questions have yet to be asked in terms of what that transition period produced in terms of information for your company in terms of the corrosion inside of those pipelines, and frankly, I just don't believe it. I don't believe that in a company of your stature and expertise that no one was asking these questions at that time, and it is six months later and a Congressional committee should not be the one prompting you to go and to get the answers to those questions, and if I may, Mr. Chairman, I have one final question with your indulgence. If BP had no knowledge that pigging the eastern line would cause problems downstream for Alyeska prior to the March 2006 spill, why is it that BP chose not to pig the eastern line? Earlier you said you run about 370 pigs through your lines in Alaska but apparently these eastern and western lines weren't pigged. Why is that?

MR. MARSHALL. Mr. Congressman, the 350 to 400 pigs that we run every year are focused on those lines where we believe the probability of corrosion is to be the highest, water lines, gas lines, three-phase flow lines, typically the lines upstream of these transit lines. Clearly in retrospect, we should have pigged these lines, and going forward, we absolutely commit to a full program of very frequent maintenance pigging and smart pigging.

MR. MARKEY. Thank you, Mr. Chairman.

MR. WALDEN. Thank you. The Chair recognizes Mr. Green.

MR. GREEN. Thank you, Mr. Chairman, and I appreciate the patience of the Chair in allowing those of us on the full committee but not on the subcommittee. You know, I represent a district in Houston that has both refineries and pipelines and we live and work around them our whole lives, and I guess what bothers me is the testimony today and following the questions is that our country needs the energy, and when a company like BP that both at the refinery in Texas City and the pipeline not only the last six months of publicity but today at this hearing, and it just makes it so much harder for us to be able to deal with energy matters, even though some of our districts are so dependent on it. And whether somebody on the east or west coast wants to drill off their coasts or they want a pipeline, you know, they still want their lights turned on and they still want something in that gas station whether it is E85 or refined product, and when a company like BP does this, it sets a bad tone. You are not a third-rate company, you know, you are not a tier down. You are one of the largest in the world, and that is what is frustrating to us who know that our country has to have energy, and in Texas we have tried to provide it for 100 years, and that is the frustration I hear today, and it is frustration from the Chairman of the committee but also from those of us who have a lot of facilities. We do everything in our district from downstream to upstream. We drill and we also have chemical facilities. So that is what bothers me.

Mr. Malone, the allegations in the Texas City, and I want to talk about and in Alaska, have been made and hopefully the committee and the Federal investigators get to the bottom of it, but it just seems like there has been lower investment on maintenance and safety,which means less employment for my district because I have people that either work for the companies or they work for the contracting companies. Can you tell me about BP's plans for investment in maintenance and safety in the facilities both in Texas City and Alaska? As what you have learned in your short term there, do you see a change in the culture in BP because, you know, I see it both in the refinery side but we see it in the pipeline side.

MR. MALONE. Congressman, if I could, I just want to start with your disappointment. We are equally as disappointed, and we are in action, and in Texas City, we have done a number of items including an additional billion dollar investment into that side where we are going to look at the process safety systems, we are making the capital expenditure and the changes in management, all the actions that are necessary to assure ourselves of the safety of Texas.

MR. GREEN. Okay. Let me follow up on that. I know you have created a special committee that Secretary Baker chairs. Does that committee include people from the bargaining unit in Texas City?

MR. MALONE. It includes a union representative from the United Steelworkers.

MR. GREEN. Okay. Thank you. That is something--one of the questions that I really was concerned about because if we are going to solve the problem, it needs to be not only for folks in the front office but folks who actually do everything along the way, and I hope that that committee's recommendations will be taken seriously, because again, you set the standard whether it is Texas City, and again, I have lots of refineries along the Houston ship channel. I want to make sure, you know, that the problems are fixed because I don't want to see that happen in one of mine. I didn't want to see it happen in Texas because I actually lost a constituent, a contract worker from Bay Town, who is part of our district.

Mr. Marshall, I know that there has been some discussions on why there weren't smart pigs technologically but, you know, I remember being in Alaska in the 1980s as a State legislator, and when ARCO ran it and they talked about how the safety of these smart pigs but you are telling me that the engineering of that east and west lines when they were built were not made to handle the smart pigs to be able to tell?

MR. MARSHALL. Sorry, Mr. Congressman. Let me reestablish, that is not the impression I wish to leave with my remarks. What I was referring to earlier was I think in response to a question about whether there were alternatives in the event of issues whether we could divert the flow from one pipeline to another, and certainly what I was referring to on the west was that we had alternative bypasses that we could use. Indeed, we had actually used one of those bypasses to route oil from Gathering Center 2 to Gathering Center 1 once the OT-21 line failed. The pigging and smart pigging facilities on the east and the west were installed from day one so they do have them.

MR. GREEN. Okay. And I know you used alternatives and I guess the next question, British Petroleum is such a huge company, do you have actually part of your company that will do the smart pigging or is that something you contract?

MR. MARSHALL. We have expertise inside the company but the specifics associated with the smart pigging, we rely on a variety of contractors, well known, world known contractors to actually--

MR. GREEN. So if somebody in BP decides that I think there is enough question about this line and it seems like just what the subcommittee has brought together in 2001 the discussion went back and forth between BP on the final draft of the Coffman Engineers report, it just seems like somebody would have said maybe we ought to smart pig that line and not wait 8 to 10 years. Can someone in BP actually say yes, we need to do it, and you know, that is what bothers me that if is a cost issue, and I know oil was $10 a barrel not that long ago, I am sure it is $60 now or $70, but--and I know cost considerations but when we have different agencies saying there is a problem with the pipeline, then it would seem like the next step would be someone from the company would say okay, we have a problem, instead of negotiating the report language, ought to say maybe we ought to actually smart pig that and see what we have in that line, at least more often than every 8 years. Has that been a discussion, particularly since after the line?

MR. MARSHALL. Certainly, Mr. Congressman, since the leaks that has been a very strong discussion and certainly in retrospect, I think everybody in BP including everybody in BP Alaska says that if we could do it again, we would have pigged and smart pigged those lines.

MR. GREEN. And to set the tone for the industry though because the technology again has been around for a long time. You know, I know there are cheaper methods you can use but why would a company not on a regular basis, not every 10 years or when your technology--why would they not want to just say I am going to invest in that smart pig to make that determination?

MR. MARSHALL. Let me stress, Congressman, this is not an issue of cost. Safety and integrity spending in BP are the highest things. They don't get cut. They are the things that get through the budget so that is not something that--cost is not a consideration.

MR. GREEN. Well, why again would we see a report again negotiating the language in 2001 on a report with Alaska, the State of Alaska, but why wouldn't there have been a decision to actually smart pig those lines in 2003 or 2004 before it broke in 2006?

MR. MARSHALL. Mr. Congressman, I--

MR. GREEN. I appreciate the Mister, but you don't have to call us that. They do a lot of things to us in D.C. You know, they don't have to call us Mister.

MR. MARSHALL. Thank you.

MR. GREEN. They can't change our name.

MR. MARSHALL. The thing I am not clear about and I will look into is whether the references in the draft report, the draft of the Coffman report were referring to smart pigging the transit lines or to the flow lines, the other 1,500 miles or so of lines that we have on the North Slope. We do have a very active program of maintenance pigging, as I said earlier, 350 to 400 every year. We have inline inspections, i.e., smart pigging, on a number of our lines, whether they are regulated, and indeed many lines which aren't regulated. This is not an issue of cost. This was simply an issue of where we judged the likelihood of corrosion to be the highest, and we didn't get this one right.

MR. GREEN. Well, I know I only have a minute left, and Mr. Chairman, I would hope that whatever comes out of the investigating committee, that we may need to see legislation. But I would hope that whether it is British Petroleum or any other pipeline company would actually use the technology that has been available on a more regular basis because when it does break, it is just not near worth you sitting here today and all the problems that you are going through and also for the nature of our country because we have to have the energy, and the message that is being sent today is that if we need to do a pipeline somewhere else, and I have been involved in lots of pipelines whether it is crude or refined products different places, it is difficult. So if we can't be assured that the people running those pipelines are going to maintain them and monitor them with the technology that is available now, then it is going to be very difficult to do it, and we fight these battles in this committee all the time and on the floor and I know in the Senate so, you know, you being here today may set us back on trying to make sure that we can deal with it. And I know Mr. Inslee has got the legislation on alternatives, which is great, but for the next 20 to 30 years, hydrocarbons is what is going to keep our country running, and sure, we may be able to use ethanol, we may be able to use other things, and I support that, but I know we have to have hydrocarbons and we need more. We need obviously the North Slope, we need Anwar, we need the discovery that Chevron did, and if we can't be assured that it is going to be done safely, it is going to be very difficult in the halls of Congress, much less in the courtrooms around the country, for companies that don't do the right thing.

MR. MARSHALL. Mr. Chairman, if I could make a comment there, it wasn't a question, but I am very conscious of the impact we have had to many constituencies, to the State of Alaska, to the Nation, the disruption in oil supply. It is something that I have taken very strong personal disappointment in as has the entire Alaska team. I am also conscious of how we have let down the industry. A track record takes a long time to build, and it is very easy to lose, but I am proud to say I work for a company that will learn and will do the right thing. We are committed to investing whatever it is we need to to reestablish confidence. It may take time. We are going to work with the Department of Transportation to not only meet their standards but exceed their standards, not just bring in technology but the best technology. If we can help the industry do that better, we are committed to doing that.

MR. GREEN. Mr. Chairman, it is sad that when we have an accident like at Texas City Refinery, where the contract trailer was too close to a unit, or something in Alaska, we see the loss of both lives in Texas City but also the problems in Alaska, but I would hope that we would see legislation from it and again, a reinvigoration of not only British Petroleum but other companies to make sure that we provide that energy that our country needs.

MR. WALDEN. Thank you for your participation in the hearing today, Mr. Green. I now recognize the gentleman from Florida, Mr. Stearns, for 10 minutes.

MR. STEARNS. Thank you, Mr. Chairman. Mr. Marshall, let me just ask you, what is the status of Mr. Woollam? Has he been fired or what is his position now?

MR. MARSHALL. Mr. Woollam doesn't actually work--

MR. STEARNS. Does he still work for BP?

MR. MARSHALL. He still works for BP. He doesn't work actually in Alaska so I don't--I would call on Mr. Malone to make a comment on that.

MR. STEARNS. Mr. Malone, where does Mr. Woollam work now, and he is still an employee of BP, right?

MR. MALONE. Yes, he is. He has been put on leave.

MR. STEARNS. He was put on leave, but does he come to work every day?

MR. MALONE. No, he will not.

MR. STEARNS. And have your people done an investigation and spent some time talking to him to get his side of the story or did you just put him on leave and that is it?

MR. MALONE. The attorneys have spoken, Congressman, and they have spoken to him.

MR. STEARNS. So your attorneys have talked to his attorney?

MR. MALONE. Yes, and to him. Our attorneys have spoken to him.

MR. STEARNS. But he is still under payroll, right?

MR. MALONE. He has been put on leave but yes, he is on the payroll.

MR. STEARNS. All right. Thank you. Mr. Marshall, you just mentioned that--and I just want to make sure I understand this better. You mentioned that safety and integrity programs don't get cut in your corporation, and I guess the question is, do budgetary expenditures impact the bonus of individual managers? So the first question that I have for you is, do budgetary expenditures--if a person meets his budget, does that impact the bonus of your individual managers? Just yes or no. I would think that is pretty easy. I mean, if I have a budget and you give me a budget and I keep under budget, I guess that is positive, isn't it?

MR. MARSHALL. Costs aren't a direct linkage between reward and bonus in BP.

MR. STEARNS. Right, so the bonus is directly proportionate to the budget?

MR. MARSHALL. No. Sorry, no. I did not mean to leave that impression. It is not a direct linkage.

MR. STEARNS. There is a linkage?

MR. MARSHALL. No, there is not.

MR. STEARNS. Not? So if a person is way over budget because he or she says we need more safety and integrity in this program, we need a lot more money, that doesn't affect his--

MR. MARSHALL. Bonuses are set on the basis of a balanced scorecard, what we call a balanced scorecard of a suite of performance metrics for the business.

MR. STEARNS. Okay, and the budgetary is not one of them?

MR. MARSHALL. The budget is included in there but there is very little--

MR. STEARNS. Oh, okay. I see. Okay. I had the privilege to be here for the oversight's investigation of Enron, and during that investigation, we found that when Sharon Watkins went to her boss and talked about the problems in Enron, her boss gave the problem to Vinson and Elkins as a consulting firm and so it appears that at this point it is sort of a parallel just in that sense, that Vinson and Elkins is doing an analysis for you folks instead of you folks going out, investigating and saying we are going to make some action here, we are going to take these complaints from the EPA that came in. You sort of punted it to Vinson and Elkins. That is the same thing Enron--I am not implying anything. I am just saying, I was struck by the similarities, that you certainly punted this to Vinson and Elkins and said okay, you do analysis, we are not going to do it, you do it for us. Now, they came up--the Vinson and Elkins report contains an appendix of 72 allegations about the corrosion control program and specific safety concerns. The question for you, Mr. Marshall, is have all of these issues been addressed to your satisfaction and completely corrected, remedied, if necessary, since BP received the law firm's report?

MR. MARSHALL. There was a series of actions coming out of that report. We converted those actions into a management plan and yes, indeed, I can confirm that all those actions have been taken.

MR. STEARNS. So there is no more corrective action necessary?

MR. MARSHALL. The actions coming from the Vinson and Elkins report have all been acted on.

MR. STEARNS. On page 5 of the appendix, allegation number 19 mentions that agency inspectors are directed to inspect only good areas of the pipeline, although Vinson and Elkins found no evidence of this. Can you speak to the relationship between the Alaska Department of Environmental Conservation and BP Alaska? Can and do inspectors go wherever they want when inspecting BP's pipeline? Is it true, that what is stated is true?

MR. MARSHALL. To the best of my knowledge, I believe that is true, and not only that, I would welcome open scrutiny wherever agencies demand to go. I think that is--

MR. STEARNS. So they can go wherever they want?

MR. MARSHALL. In my opinion, I welcome that, yes.

MR. STEARNS. On page 3 of the appendix, allegation number 10 and 11 describe concerns that over the past several years there have been concerns raised about cost cutting and that corrosion control and monitoring was suffering, that serious damage was occurring to the pipelines and infrastructure. Has there been cost cutting in the corrosion program over the past seven years--several years?

MR. MARSHALL. Since I arrived in 2001, our corrosion spend has gone up 80 percent. It has increased every year and will continue to increase going forward.

MR. STEARNS. On page 4 of the appendix, allegation number 13 discusses an allegation of data scrubbing, and allegation number 17 describes concerns that corrosion field data was being manipulated. What does the report mean that no evidence was found on manipulation? In other words, the status comment doesn't explain where the investigation looked for evidence and seems to imply that data may receive a "positive spin" and isn't spin and manipulation the same thing?

MR. MARSHALL. I am not aware of anything beyond what the Vinson and Elkins report found. We take very seriously any allegations of data manipulation. It is not in a business's best interest to falsify data or for any individual to falsify data so we take that very seriously, and we found no evidence that data had been manipulated for any purpose.

MR. STEARNS. Mr. Hostler, there is a question for you. Since TAPS provides a significant percentage of Americans' energy security and evidently will for some time to come, could you tell the committee what your primary concerns are with respect to the TAPS system and what are you doing about these concerns?

MR. HOSTLER. Congressman, thank you. If you look at our risks, our primary concerns are security of the pipeline. I think everybody in this room knows the importance of this line and its security and a lot of good work is being done there. I will come back to it. We do worry about the potential for mechanical damage associated with work along the pipeline and we do worry about corrosion as we have been talking about today, both internal and external, and so we have a comprehensive integrity management program to look at all that. But the one action I would like to talk about is as a learning from the spill on March 2 and the learning from the follow-up, we have been putting a lot of effort into our corrosion program. One of the things that we have done is, we have actually initiated an intelligent pig run this year, one year prior to our next scheduled run in 2007. So we have taken the instances around the Prudhoe Bay spills and learned from that and put an action plan in place, not to discount any of the other areas that we have concerns around.

MR. STEARNS. Would you agree that regular pigging is even more important as throughput declines?

MR. HOSTLER. Yes, sir.

MR. STEARNS. As a pipeline operator, would you expect to see regular pigging of low-stress lines where the oil moves at a slower velocity?

MR. HOSTLER. In the low-stress lines, yes, sir.

MR. STEARNS. Okay. Are you aware of any crude oil pipeline that is not pigged as part of a regular corrosion maintenance program, leaving aside lines that may not be piggable due to sharp turns in the line or other structural obstacles?

MR. HOSTLER. Leaving aside those lines that have those types of problems, no, sir, I am not aware of any that are not pigged as a routine maintenance program.

MR. STEARNS. Prior to the March 2006 leak and the subsequent examination of these lines, were you aware that there might be sludge, sediment and/or scale problems with these transmission lines?

MR. HOSTLER. Prior to March 2? No, I wasn't, but I had only been in place about five months, and I don't--I cannot find any records or notice, indication within our organization that we were concerned or aware of the issues with EOA and WOA line.

MR. STEARNS. Thank you, Mr. Chairman.

MR. WALDEN. Thank you, Mr. Stearns. I think we have--everybody has had an opportunity to ask questions who are here so we will go into a second round, and I will yield myself 10 minutes.

Mr. Stears, can you briefly explain what Coffman Engineers does and who you are?

MR. STEARS. Coffman Engineers is a multi-disciplined engineering company. We have offices in Seattle, Spokane, Los Angeles and Anchorage.

MR. WALDEN. In Anchorage. Could you turn to Exhibit 10 in the binder there and could you please describe what is the Coffman report regarding Prudhoe Bay corrosion control?

MR. STEARS. It is an overview of BP's program and it gives the reader a description of what the program consists of and areas for improvement.

MR. WALDEN. And this is done for whom?

MR. STEARS. For the State of Alaska.

MR. WALDEN. And exactly what does the State of Alaska do with the Coffman reports that you submit to them in final form and how does the State utilize your analysis?

MR. STEARS. I am not positive of that. I do know they forward the results to BP but other than that, I don't know what they do with it.

MR. WALDEN. Okay. Turning to tab 9, this is BP's response to the final draft. As you are aware, BP is highly critical of the Coffman final draft, correct?

MR. STEARS. That is correct.

MR. WALDEN. And if you can now turn to tab 26, Richard Woollam's November 12, 2001, e-mail says that at the November 5 meet and confer that Coffman "seemed unwilling to discuss BP/PAI's concerns." So Mr. Stears, was Coffman surprised or frustrated by BP's response, given your view that you had satisfied the scope of the work?

MR. STEARS. This is the first time that I have actually seen this in person. I talked briefly with your staff about it. Yes, it is my understanding that BP was upset.

MR. WALDEN. Right, but was Coffman surprised or frustrated by BP's response?

MR. STEARS. My role in the program to begin with was, I was the manager of the corrosion engineering group so I just had a supervisory role, and I had to take the responses of my staff that was the direct project engineers on that.

MR. WALDEN. Were Bierry and Watts frustrated? They work for you right?

MR. STEARS. Yes. Tim Bierry did work for me. Mike Watts was a subcontractor to us, and--

MR. WALDEN. Were they frustrated?

MR. STEARS. I would say it at certain points yes, they met a level of frustration.

MR. WALDEN. And why was that?

MR. STEARS. Well, to begin with, this was the very beginning of this program, and so the roles and responsibilities, the reporting metrics, things of that nature were all being agreed upon and actually discussed both with the State and the operators at that time, and so amongst those discussions, there was quite a bit of give and take, if you will, as far as what should or should not be in the program because there were already some things that were agreed upon with the State and the operators before Coffman got involved.

MR. WALDEN. Is that what should be in your analysis or what should be in the program? I mean, the findings of your report, is that what was in disagreement here or what the scope of the report--

MR. STEARS. The scope of the report would be a better clarification of that.

MR. WALDEN. So the frustration that people who worked under you had with BP was over what should be considered?

MR. STEARS. What should be considered in the actual report as well as what should be talked about in the meet and confers.

MR. WALDEN. All right. Did Larry Dietrich or Mr. Fredriksson or any other ADEC employee ever instruct or pressure Coffman Engineers in any way to change the tone and content of the 2000 Coffman report?

MR. STEARS. No, not that I am aware of.

MR. WALDEN. Could you turn to tab 29?

MR. MARSHALL. Mr. Chairman, I apologize for the interruption. Could I be excused to go to the bathroom, please?

MR. WALDEN. Well, okay. Yes, of course. And then if--yes, absolutely. Anyway, if you turn to tab 29, this e-mail from Richard Woollam dated November 25, 2001, criticizes Coffman for a lack of sophistication and not thinking through the consequences if your final draft were really the final document. Can you respond to this criticism? Was it Coffman's job to be concerned about public reaction or consequences of the report?

MR. STEARS. No, it was our obligation to meet the contract requirements with the State of Alaska.

MR. WALDEN. Was Richard Woollam worried about the public response to the report that was as critical of BP's corrosion program as the Coffman final draft had been?

MR. STEARS. Could you please repeat that?

MR. WALDEN. Was Richard--do you know if Richard Woollam worried about the public response to the report--to a report that was as critical of BP's corrosion control program as the Coffman final draft had been? Was he worried about the final draft and the public's reaction to it?

MR. STEARS. I don't know about this one in particular. Mr. Woollam has on several occasions expressed a concern that accurate information be provided so that the public understands it.

MR. WALDEN. Could you turn to tab 28? Tab 28 criticizes Coffman for not having sufficient review of the final draft at senior levels. You were the supervisor in charge of the final draft, were you not?

MR. STEARS. I was.

MR. WALDEN. And do you have a response to this criticism?

MR. STEARS. Where are you reading from, please?

MR. WALDEN. Tab 28. Let me double check to make sure I gave you the right tab number. My apologies. We are one off, tab 29, and it is the second bullet point, lack of review I believe that the final draft was issued by Coffman ADEC without review at senior levels within Coffman and/or ADEC. There had been issues about balance and the report being public would not have occurred, and that is from Mr. Woollam.

MR. STEARS. Yes, Mr. Woollam was inaccurate in that. There were several reviews internal, first of all, between the engineers that were working on it and then I did review the draft as well as the final.

MR. WALDEN. Mr. Malone, in Mr. Marshall's absence, because the next set of questions I have is actually for Mr. Marshall, and speaking of Mr. Marshall, your timing is exquisite. I have been asking Mr. Stears about the Coffman report and some of Mr. Woollam's criticisms and concerns as expressed in e-mails and elsewhere. Mr. Marshall, at tabs 10 through 15 are documents prepared for the State of Alaska by Coffman Engineers regarding BP Alaska's corrosion control program. Can you explain the significance of these reports from BP's perspective, the Coffman reports? Do you consider them to be binding documents or helpful documents?

MR. MARSHALL. Mr. Chairman, thank you for the break.

MR. WALDEN. Yes, absolutely, and if other members need to do that, let me know.

MR. MARSHALL. These reports I would say are important documents for BP.

MR. WALDEN. Do you consider them binding documents?

MR. MARSHALL. From a legal perspective? I am not sure I understand the legality of the term to be able to say what it is.

MR. WALDEN. And I am not a lawyer so--but if you have the Coffman report that goes to the State of Alaska, do you look at that like you would, say, an internal audit and follow it precisely and say we have got to address these issues?

MR. MARSHALL. Any document which goes outside the company, we want to ensure its veracity, its accuracy. We want to provide the transparency on our operations, absolutely.

MR. WALDEN. But on these Coffman reports, do you basically consider whatever they say that you are basically bound to follow?

MR. MARSHALL. I haven't looked into the implications of Coffman, if there are specific issues there that I am not aware of, but on the basis of your question I would say that we would work to follow recommendations that Coffman came up with. We take those on board and incorporate those into our business practices.

MR. WALDEN. All right. Did you direct Richard Woollam or anyone else at BP to pressure ADEC in any way, in any way to change the tone and content of the 2000 Coffman report?

MR. MARSHALL. No, sir.

MR. WALDEN. In November of 2001, did you personally place any pressure or request of ADEC in any way to change the tone and content of the 2000 Coffman report?

MR. MARSHALL. No, sir.

MR. WALDEN. Have you ever directed any employee at BP to contact ADEC or any other State official to request the removal of an ADEC employee from oversight work on the North Slope?

MR. MARSHALL. No, sir.

MR. WALDEN. Okay. Were you aware that Susan Harvey told Richard Woollam that she was only willing to make changes to the draft of the 2000 Coffman report if BP could show factual errors?

MR. MARSHALL. No, I was not aware of that comment.

MR. WALDEN. And what would your reaction be if you knew that was her comment?

MR. MARSHALL. Sorry. Could you repeat the comment again, please?

MR. WALDEN. The comment is that Susan Harvey told Richard Woollam that she was only willing to make changes to the draft of the 2000 Coffman report if BP could show factual errors.

MR. MARSHALL. Again, not having much time to kind of consider that, my reaction would be that, that would be a very reasonable request. We have got to--I think any organization needs to make conclusions based on truth and fact. If we were unable to provide facts to shift or adjust a conclusion, that prior conclusion should still stand. If there is new information or information we hadn't provided, if it was an omission, I think that is something we would want to offer into the record--

MR. WALDEN. Absolutely.

MR. MARSHALL. --for consideration.

MR. WALDEN. All right. That wraps up my questions. Thank you, sir. Mr. Stupak.

MR. STUPAK. Thank you, Mr. Chairman. We have been talking a lot from 1992 to 2006 and the pipeline came online in June of 1977. Is that right?

MR. MARSHALL. Yes.

MR. STUPAK. Can you tell me, Mr. Malone or Mr. Marshall or anyone else at the table, if the lines were pigged at all between 1977 and 1992, during that 15-year span?

MR. MARSHALL. I am only aware of the western area line being pigged in 1990.

MR. STUPAK. Okay. Eastern was pigged in 1992, I think.

MR. MARSHALL. That is correct. What I don't have in front of me but I can find out is, were there any earlier pig runs on that--

MR. STUPAK. Yes, I would like to know that because you have a 15-year block there and we are talking about a four-year block. If you are pigging in the 15-year block when the oil is flowing a little quicker, a little stronger, I would think that it would be helpful to us because I think the only smart pigging we have, as you said, is the late 1980s on the western line. What I am hearing and the way I would guess I would paraphrase BP's testimony today was that we believe we had a good corrosion prevention program but we didn't believe we had corrosion. Is that fair? You are sitting there telling us you have this integrity in this program so are you saying therefore we didn't believe we had it? When you did pigging before, you had all kinds of problems.

MR. MARSHALL. We didn't believe we had aggressive corrosion in these lines until we started to see indications of that in the 2004-2005 time frame. The data that we had, and I do stress that it is based on the data that we had, the information that we had--

MR. STUPAK. In 2004-2005?

MR. MARSHALL. In 2004-2005 indicated an increase in corrosion on the western area line.

MR. STUPAK. Let me ask--Mr. Malone, let me ask you this question. This question came up, and I ask this question respectfully because I was just--I have been in and out of this hearing today because when constituents come from northern Michigan, even though I am stuck all day in these hearings, I still like to try to meet with them. We were talking, you know, we are at this hearing today, and a couple of them brought up the fact that on the Today show, they asked you a question about how you spend, based on the profits of BP, like one-quarter of a penny for maintenance of the lines and then I think Matt Lauer asked you if you were going to--the cost to do this replacement, I think you are doing, what, 16 miles of pipes or something like that. That has pretty tremendous cost to the company, so therefore to the average American consumer, will the cost of gas go up because of this pipeline problem or will you just take it out of profits.

MR. MALONE. Well, first of all, the way the global market works, Congressman, and particularly once the incident occurred, we didn't see a rise in the price of gas--

MR. STUPAK. That is my next question. Go ahead.

MR. MALONE. Because we were able to get supply into the west coast. We actually brought in about--

MR. STUPAK. Well, when will we start to feel the pinch here and when will the price go up then from BP's point of view? Isn't that what you are basically telling us, we haven't seen the pinch yet because other supply is adequate?

MR. MALONE. Congressman, if I can, I would like to submit that for the record because--forward a response back to you because I am not quite sure how that would work and I need to consult with--

MR. STUPAK. Because here is the question that constituents want to know: Since this has been announced, gas prices have gone down, but yet if we don't have as much oil coming in available to this country, but prices are going down, therefore they should not go up even with your added costs as prices go down, right? And that is sort of what they asked me out in the hall and I said okay, good question, I will ask.

MR. MALONE. I will get that for you, Congressman. My apologies for not--

MR. STUPAK. No, no, no problem. And by the way, Mr. Malone, at least on this side of the dais, I am sure on both sides, you had worked in the 1990s, right, in Alaska before for BP?

MR. MALONE. Yes, I did.

MR. STUPAK. And you were called over to England and no sooner got there and this happened?

MR. MALONE. I was in Alaska and I ran Alyeska also for a period of time but I had a four-year stent with BP Shipping Limited in England.

MR. STUPAK. Well, I know they indicated that in the past when we had some problems in Alaska, you were one of the people who stepped forward and got it corrected and cleaned up and we are hoping the same thing will happen here, so a lot of people up here were glad to see you take this position and we have faith that you will get this thing cleaned up as soon as possible.

Mr. Marshall, let me ask you this. Isn't it true that both the eastern and the western pipes are now low-stress lines and that they were originally designed to hold greater amounts of oil and that the flow rate of this oil was originally much higher, right? It was 800 PSI at one time and we are down to 80 PSI now?

MR. MARSHALL. Congressman, I am not in a position to say what the pressure was. The flow rate was much higher.

MR. STUPAK. Was much higher than it is now?

MR. MARSHALL. At the time, and compared to what it is right now, yes. That is correct.

MR. STUPAK. And if we can have photo number 3 up. And these are the current lines now in fact as soon as we get it up here. The red one is the one where we are working on now. This is where the March spill occurred. Again, our staff was up there over the break and took these photographs. So why were such strategic lines in the eastern and the western lines which are both low flow and thus susceptible to corrosion not replaced with smaller diameter lines earlier? Why did we have to wait for total failure to get to the point of now deciding to replace them with smaller diameter lines? I think the question earlier was 34-inch lines and now they are going to be replaced by smaller ones to get the flow going to keep the corrosion out, right?

MR. MARSHALL. And again, until we get the failure analysis of the pipe from both the OT-21's failed section which this is and the Flow

Station 2 line, it is still only a theory that velocity is a factor. It is emerging as a more likely factor than it might have been at the time of the March spill but it still only one factor. There may be others as well including microbial--

MR. STUPAK. Sure. The faster the flow, usually keeps the corrosion out, right? The water is moving and everything is moving.

MR. MARSHALL. Velocity is certainly a factor to prevent dropping out of solids or liquid but equally the effectiveness of corrosion inhibitors going through the line and the existence of bacteria and the effectiveness of bactericide to prevent the growth of bacteria are also factors.

MR. STUPAK. BP provided the committee with an internal report it issued on June 7, 2006, called the Alaska Transit Technology Review. Are you familiar with that Alaska Transit Technology Review?

MR. MARSHALL. Yes.

MR. STUPAK. Sometimes referred to as the Baxter report.

MR. MARSHALL. Yes.

MR. STUPAK. And it was done after the March 2 spill, right, and you are familiar with that one?

MR. MARSHALL. I am aware of that report, yes.

MR. STUPAK. Okay. On page 6--I realize there are no page numbers but if you go to page 6, there is a series of bullet points, and let me quote from the first bullet--

MR. MARSHALL. Excuse me, Congressman. Which tab is that?

MR. STUPAK. Hang on. Let me get it.

MR. MARSHALL. I have got it.

MR. STUPAK. You got it? Okay. I know the pages aren't numbered but on page 6 there, you will find these bullet points, and the first one says, I am quoting now, "Where sand deposits and entrained water are able to drop out from the fluid stream onto the bottom of the pipeline as a result of the low-velocity flow, this creates ideal conditions for the proliferation of sulfate-reducing bacteria (SRB) on the pipe surface. The most likely cause of the accelerated corrosion is therefore believed to be the micro-influenced corrosion (MIC) under sediment deposit onto the bottom of the pipe, and you were just talking about the MIC. So my question is then, Mr. Marshall, when did BP first suspect that such sediments were collecting in the western pipe?

MR. MARSHALL. Mr. Congressman, to the best of my knowledge, certainly from my perspective, the existence of solids in that line occurred after the March spill. Certainly the existence of solids upstream of that transit line were known before that.

MR. STUPAK. I am not necessarily talking about the solids.

MR. MARSHALL. I am sorry. I misheard the question then.

MR. STUPAK. When were you--when did BP first suspect--I mean, this is a report they provided in June--first suspect that sediments were collecting in that western line? March, after the spill, or before?

MR. MARSHALL. After the spill. Certainly from my perspective, after the spill.

MR. STUPAK. When was the water and sediment drop-out as a potential corrosion contributor first suspected by BP? Was it before or after the March spill?

MR. MARSHALL. I don't have any specific evidence of when that may have occurred at some level in our organization. I do know that we experienced planned upsets. I do know that we experienced sediment drop-out in Gathering Center 2 as a result of the startup of viscous oil production in 2004 and 2005. We did take action to remove those solids at that time.

MR. STUPAK. In 2004-2005?

MR. MARSHALL. In 2004-2005 timeframe.

MR. STUPAK. Did you try to remove the solids?

MR. MARSHALL. We basically installed sand jets into a number of our vessels. As the solids--

MR. STUPAK. How far would a jet blow the sand then?

MR. MARSHALL. It blows it into a container which we then take away and we dispose of the solids in the appropriate way, so they are actually removed from the facilities or from wherever they accumulate and are disposed of there.

MR. STUPAK. But you didn't scrape the pipe though?

MR. MARSHALL. No. The expectation was that the solids would accumulate where they are designed to accumulate inside the separators, the big vessels that exist inside Gathering Center 2, which are designed to separate the oil, gas and water, and indeed any solids from the crude oil stream.

MR. STUPAK. But in 1992 you knew that wasn't happening because on the eastern pipes that is when you had all the problems with the strainers.

MR. MARSHALL. I should stress that my understanding of what occurred in the early 1990s on the eastern side was actually calcium carbonate scale, not solids.

MR. STUPAK. But still, it would be enough to disrupt the flow of the pipe, and you said earlier in your testimony what was happening on the western you figured was happening on the eastern, so in 1992 if you figure it is happening on the eastern, why didn't you figure it was happening on the western? If it holds true for one, it holds true for the other.

MR. MARSHALL. The existence of calcium carbonate scale is something which is more of a factor on the eastern side of the field in the same way that the viscous oil is only evident on the west. The calcium carbonate scale as we have looked into it, tends to be a factor more on the east than it is on the west, certainly in terms of how it translates to the transit lines.

MR. STUPAK. Thank you.

MR. WALDEN. Thank you. We have a vote on the floor. Mr. Inslee.

MR. INSLEE. Thank you. Mr. Malone and Mr. Marshall, I asked you about this Coffman report earlier where there were very significant deletions from the report, from the preliminary draft before it went to BP, deletions about the fact that smart pigging is the only inspection technique capable of looking at the entire internal structure of the pipe. A statement, the actual magnitude of the corrosion increase is not reported. That was deleted. A statement, external corrosion inspection levels are not consistent with the relative risk. That was deleted. A statement that no differentiation between weight loss and pitting corrosion are discussed. That was deleted. No statistics on the extent of corrosion defects reported. That was deleted. You can go through this report, there are just reams of negative critical statements in the original report sent in to the State of Alaska by Coffman contractors that were then deleted after communications with British Petroleum. So the question is, how did that happen and why did that happen? It is disturbing to me that the public only found out about that after this incident, that these deletions occurred. What I want to ask you about is this disturbing e-mail that we just saw. It is an e-mail dated November 11, 2001, 9 days after the original Coffman report was submitted, so nine--

MR. WALDEN. For the record, Mr. Inslee, that is tab 25.

MR. INSLEE. Thank you. Nine days after the original was submitted, here is an e-mail from Mr. Woollam, the gentleman who took the Fifth Amendment in charge of this program, BP employee, it says, “Michelle, could you please do a little research for me in a hurry? I want to know if BP Exploration Alaska, Inc. has any contracts with Coffman Engineers, and if so, what and who is the contract CAM, if any. My understanding is that they have a general services contract but have been unable to find out any more than this. Thanks, Richard.” Now, frankly, it is hard for me to imagine another reason out of the blue this gentleman would be asking if Coffman has any other contracts with British Petroleum other than perhaps we have a way of influencing their behavior. Do you have any suggestion why this gentleman would have all of a sudden asked about Coffman contracts with BP other than perhaps finding a way to influence their behavior?

MR. MARSHALL. I have not seen this e-mail before and I really cannot comment on what Mr. Woollam's intent would be. Could I offer one alternative though, that one of the things that--if we engage with any company that is working for a third party, we need to make sure that we don't have any conflicts of interest in the dealings with them. I am not suggesting that was the case but that is certainly a possibility to avoid conflict of interest.

MR. WALDEN. Mr. Inslee, just as a point for the record, I am told by staff that actually that document is a cited document in the Feldman report.

MR. MARSHALL. I have not actually read it, so--

MR. INSLEE. Thank you. Given the attitude we have heard about this particular individual and the difficulties, your suggestion while creative I suspect probably was not the case. We will leave that to other discussion. But it is of great concern that we had this failure now about something exactly that this contractor pointed to. You have discussions with BP, there are deletions to the report and bang, you got this process now that is reduced by 8 percent, the total production of our domestic capacity. You can see why that causes us some great concern here.

I want to ask you about one suggestion I made. BP has had now what is a significant black eye. I think we would all agree with that on a failure of this responsibility and I think Mr. Malone and Mr. Marshall recognize that. The question is, what do you do as a corporation right now. I suggested sincerely that it would make sense to go back and talk to your highest decision-makers about finding a way to demonstrate your commitment to being an environmentally responsible company, and the reason this idea comes up is, Mr. Green was talking about how maybe we are, you know, decades away from having a more ethanol-based economy. I don't think it is decades. Brazil today has 40 percent of all their fuel essentially as its ethanol, it is domestically produced. This is the here and now. They drive flex fuel cars that drive either--operate either on gasoline or ethanol and they work great, and you pull up to your pump and you see which one is cheaper, the ethanol or the gasoline that day, and fully 40 percent of their fuel source is from that. This is something that we are capable of doing. But when I talk to the Brazilian leader who is responsible for developing that protocol and basically asked for his advice, what do you have to do to get there as a national. He said frankly, you have got to break the arms of the oil and gas industry because they resist putting these pumps in and they control the infrastructure. Now, there are 170,000 pumps in the United States for gasoline today and there are about 858 for E85 ethanol when almost every single station in Brazil makes that available to its consumers and they essentially broke the elbows of the oil and gas industry in Brazil to make that happen. We don't want to have to go through that. We would like British Petroleum, that controls a very significant part of the infrastructure of this country, to make a very specific corporate commitment to getting E85 pumps into their stations as fast as they can. This is very possible. The USDA has done a very sophisticated analysis and found that we could have 30 percent of our transportation needs at a minimum within 30 years from ethanol domestically produced but we need your leadership to put those pumps in to develop how we do this. Now, the Brazilian also told me, don't let those oil and gas guys tell you they can't deliver it by pipeline either because we do it down there in Brazil. So I guess the question I have for you, given your experience here, which probably hasn't been too comfortable, rightfully so, isn't it a legitimate thing for you to go back and talk to your leadership and say here is one option for us as a corporation to demonstrate moving forward after this debacle to say let us double our commitment to ethanol production in this country; let us make some specific numerical targets of how many E85 pumps we are going to have in our filling stations across this country, and you have got a lot of them in the State of Washington and I love to see them there. What do you think of that idea, going back and talking to Sir Henry Brown and say let us come up with a numerical target and let us meet it.

MR. WALDEN. Mr. Inslee, just for the record too, we are down to 3 minutes.

MR. INSLEE. All right. I am done. That is my last question.

MR. MALONE. I would say, Congressman, I felt kind of bad because when we bumped heads the last time, I think we were both bumping heads on stuff we both agreed with. I will have that discussion and I have some ideas of my own. If I could, I will come back and see you on that and I will also talk to John Browne, who has a very, very strong commitment as I do, and I will be back directly in touch with you.

MR. INSLEE. Thank you.

MR. WALDEN. Thank you, Mr. Inslee. Thank you, Mr. Malone. And just finally as we begin to dismiss this panel and recess the committee while we vote on the floor, Mr. Marshall, in light of Miss Harvey's statement to the staff that she was only willing to consider factual changes to the Coffman report, can you see how it looks a little suspicious that Ms. Harvey gets removed from the project and then the tone and overall conclusions of the final report are changed significantly? I mean, it raises some red flags for us.

MR. MARSHALL. Certainly I can understand and appreciate that. I just don't have any information to offer any further illumination to that.

MR. WALDEN. Understood. Thank you. I want to thank the panel members for being here today. I know it has been a long day already.

We have a second panel after this. We have about five votes on the House floor. We will reconvene as soon as we can get back here, but you all are free to go and we again appreciate the work you are doing and your participation in this hearing. The committee will stand in recess.

[Recess]

MR. BURGESS. The committee will reconvene and at this point I would like to call forward our second panel, Vice Admiral Thomas J. Barrett, U.S. Coast Guard, retired, Administrator for Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation; Ms. Stacey Gerard, the Chief Safety Officer, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, United States Department of Transportation; and Mr. Kurt Fredriksson, Commissioner, Alaska Department of Environment Conservation, and I want to thank you all for your forbearance. I know it has been a long afternoon while we dealt with pressing matters before the country. You are aware the committee is holding an investigative hearing and when doing so has had the practice of taking testimony under oath. Do you have any objection to testifying under oath? The Chair then advises you that under the rules of the House and the rules of the committee, you are entitled to be represented by counsel. Do you have any desire to be advised by counsel during your testimony today? In that case, if you will rise and raise your right hand, I will swear you in.

[Witnesses sworn]

MR. BURGESS. You are now under oath. You may give a 5e-minute summary of your written statements. Admiral Barrett, please, sir, you may begin your 5 minutes.

TESTIMONY OF VICE ADMIRAL THOMAS J. BARRETT, USCG (RET.), ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION; AND KURT FREDRIKSSON, COMMISSIONER, ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

VICE ADMIRAL BARRETT. Thank you, Mr. Chairman and members of the subcommittee, for the opportunity to discuss recent actions of the Pipeline and Hazardous Materials Safety Administration overseeing the safe operation of BP exploration pipelines at Prudhoe Bay, Alaska.

Our agency mission is achieving and maintaining safe, environmentally sound and reliable operation of the Nation’s pipeline transportation system. In practice, this requires understanding the condition of pipelines and ensuring that operators take actions to prevent and address any unsafe conditions.

As you know, the first responsibility for safety rests with the pipeline operator. Since the spill of approximately 5,000 barrels of crude oil from the BP-operated low-stress line at Prudhoe Bay on March 2, PHMSA has been on the job to ensure safe operations. The line where the spill occurred had not been federally regulated. In mid-March, using our statutory authority, we asserted Federal jurisdiction over the failed line and other BP unregulated low-stress lines at Prudhoe Bay, a total of 22 miles of transit line. We subsequently issued a series of orders to the operator to upgrade safety. These related to understanding conditions of the lines and ensuring the operator was taking all necessary measure to assure their safety. We ordered BP to run cleaning pigs to remove solids from the lines, run inline inspections, or smart pigs to understand the conditions of the lines from the inside out. We directed extensive ultrasound testing and an enhanced corrosion management plan. We directed external surveillance using infrared detectors to detect any leaks and also the development of plans to manage solids in a way that prevented any risk to the Trans Alaska Pipeline.

It was as a result of the pigging that we ordered that BP discovered the wall loss and leaks on a line segment in the eastern operating area that led to the production shutdown on 6 August. Our personnel have been on the job tirelessly since March overseeing and directing these actions. We brought on additional technical resources from Oak Ridge National Laboratory, and along with my western regional director, Mr. Chris Hoydell, and my chief safety operator, Ms. Gerard, I visited Anchorage and Prudhoe Bay in early July to assess the situation firsthand. I met with my field inspectors, BP and Alyeska executives, State officials including Commissioner Fredriksson, and the Joint Pipeline Office. The Acting Secretary of Transportation, Maria Cino, visited in August and I went back last week to reassess progress and compliance with our orders. While this was progressing, we also put an inspection team on the Trans Alaska Pipeline and updated our risk assessment on other lines on the North Slope to minimize risks of any ripple effects from the BP incidents.

BP is finally making progress in addressing our concerns but the operators' management of the lines in the years leading up to the March incident and their initial response to our orders was disappointing. Frankly, we do not understand why BP did not more aggressively address the corrosion problems that led to these leaks. Given the multiple risk factors for corrosion in the Prudhoe Bay environment and the low velocities on these lines, it is mystifying that BP did not run cleaning pigs regularly on these transit lines. Most pipeline operators demonstrate a higher standard of care than this regardless of whether they are federally regulated or not.

The overall safety record of the U.S. pipeline is good and getting progressively better. We are seeing a steady decline in the number of pipeline incidents that cause serious harm to people or the environment, and on August 31, the Administration proposed robust new safety requirements for low-stress pipelines in unusually sensitive environmental locations in rural areas including the BP lines at Prudhoe Bay. These rules have been in development since 2004, well in advance of these spills. Most of the lines involved are far smaller than the BP Prudhoe Bay lines. Low-stress lines in populated areas and near navigable waterways were already covered by our regulations. As this is a proposal, we are seeking public and stakeholder input about it including the scope of coverage and the requirements that should be included.

I also want to touch on our reauthorization proposal. One exception to the positive safety trends we see across the industry is damage caused by excavation on gas distribution systems. This poses serious life safety risks and the number of incidents of this type is increasing. These lines are regulated by our State partners. The Administration's pipeline safety reauthorization proposal would greatly enhance the State's ability to improve damage prevention and more effective address this risk, and I am pleased to see this priority being address by this committee.

Mr. Chairman, I want to assure you and members of the subcommittee that the Administration, the Acting Secretary and the dedicated men and women of PHMSA, by the way whose work at Prudhoe Bay I am enormously proud of, share your strong commitment to improving the safety, reliability and the public confidence in our pipeline transportation systems. We understand the importance of our mission to the citizens, communities and energy security and continued economic growth of this country.

With your permission, I will submit my written statement for the record and am pleased to answer any questions you may have. Thank you, sir.

[The prepared statement of Vice Admiral Thomas J. Barrett follows:]

PREPARED STATEMENT OF VICE ADMIRAL THOMAS J. BARRETT, ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION

September 7. 2006

I. INTRODUCTION

Chairman Barton, Ranking Member Dingell, members of the Subcommittee, thank you for the invitation to appear today. I am pleased to discuss the actions of the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) to oversee safe operations of BP Exploration pipelines on the North Slope of Alaska.

The responsibility for safety rests first with the operator. Our mission is achieving and maintaining the safe, environmentally sound and reliable operation of the nation's pipeline transportation system. This requires understanding the condition of pipelines in the U.S. and assuring that operators take action to address any unsafe condition. We manage oversight based on risk and take a "systems approach" to setting priorities. We make full use of the authority given us in the Pipeline Safety Improvement Act of 2002. Our progress with integrity management programs positioned us well to take effective action when the BP low stress transit line failed in Prudhoe Bay March 2nd. I believe quick DOT/PHMSA action was crucial to improving the performance of BP since the first incident. Only as a result of additional controls we imposed could limited operation of these key pipelines continue.

Over the past six years, PHMSA has designed and executed a risk-based systems approach to oversight of the national pipeline infrastructure. As to regulatory framework, we undertook rulemaking projects on a risk prioritized basis, acting first on those parts of the infrastructure that posed the greatest risk to people and then the environment. To begin the program, we defined high consequence areas and mapped the locations, including areas unusually sensitive to environmental damage, previously defined in regulation in 2000, in the National Pipeline Mapping System. We completed and implemented regulations which provided integrity management protections for people and the environment that could be affected by a failure from high pressure, large and small hazardous liquid pipelines and provided protections to people that could be affected by high pressure gas transmission pipelines. We began considering this rulemaking in 2003, with discussion in our advisory committees, followed by public meetings in 2004.

The BP transit pipelines that failed in Prudhoe Bay were not regulated by DOT. On August 31 we offered a proposal to bring these lines under Federal oversight. Our rulemaking proposal provides for robust integrity protections, including corrosion control with cleaning and continuous monitoring, integrity assessment, leak detection and other measures for low stress pipelines. The proposal is the last remaining element in our regulatory framework designed to protect unusually sensitive environmental areas from low pressure pipelines in rural locations. The proposal would mandate a level of care well in excess of what BP had in place in the lines that failed. The recent BP pipeline failures in Alaska are not indicative of the safety of the national pipeline infrastructure which has a steadily improving safety record. Furthermore, BP's low stress lines in Alaska are not a characteristic of other low stress pipelines in the U.S. lower 48 states. We believe that most other unregulated low stress pipelines are operated to a higher standard of care similar to that underlying our regulatory proposal, based on the record developed in connection with our rulemaking proposal.

Since the March 2 spill of 200,000 gallons of crude oil we have been working steadily to ensure BP adequately addresses the safety, integrity and reliability of all of the company's pipelines. While PHMSA was not previously regulating BP's three low pressure transit lines in Prudhoe Bay, following the spill we exercised our statutory authority to protect life and the environment. These pipelines will remain under DOT orders as long as we believe they pose a threat to life and the environment.

II. WHAT DOT HAS DONE TO RESPOND TO THE FAILURES

PHMSA has been on the job since the response began. When the accident occurred on a segment of 34" diameter above ground pipeline in the Western Operating Area referred to as OT21 on March 2, we offered our assistance on cleanup to the Unified Command conducting the response operation, under leadership of the Environmental Protection Agency (EPA). Shortly thereafter, PHMSA notified EPA, the Department of the Interior, and state agencies, as well as the Joint Pipeline Office (JPO), of our intent to exercise statutory jurisdiction over these three transit lines by issuing a Corrective Action Order (CAO) and bring them under the regulatory authority of the DOT, essentially taking the Federal oversight role in the remediation and repair of the failed line. Our order covered the Western Operating Area line, which failed in March, as well as the Eastern Operating Area and the Lisburne lines, a total of 22 miles. Our mission is and remains ascertaining the condition of these lines, understanding the failure mechanisms, and assuring that the operator takes all needed action to keep them operating safely in the future.

Our Corrective Action Order started with the fundamentals of requiring BP Exploration Alaska, Inc. (BPXA) to determine the condition of its pipelines and to repair defects. First, we ordered BPXA to run what are known as cleaning or maintenance pigs in order to remove solids in the line and to perform in-line inspections, known as smart pigging, in order to understand the pipe condition from the inside out. Second, we directed more frequent testing, and an enhanced corrosion management plan, including changing the mix of corrosion inhibitors to improve corrosion prevention. We required running cleaning pigs on a routine basis to remove water and other constituents that could contribute to internal corrosion. Third, we set standards for assuring integrity of each of BPXA's low stress pipelines in service. Fourth, we dispatched the first of many inspection teams to inspect the pipe that failed, assess the cause of failure, review operations and maintenance records, monitor operations, including testing, inspect repairs, and verify compliance with our requirements. Our inspection indicated the probable cause of the failure on March 2 to be internal corrosion. According to records provided by BPXA to the agency, the line that failed had been operating at a very low pressure, well below the 20 percent of designed yield strength that would have been the threshold for DOT regulation. BPXA's records indicate that this pipeline was designed to operate at approximately 825 psi and BPXA was operating it at about 80 psi. Most of the line is above ground on vertical and horizontal supports. The pipeline is bare steel pipe, covered with thermal insulation, surrounded with a steel jacket. The pipeline had been hydrostatically tested in 1977, and was internally inspected with a smart pig in 1990 and 1998. We found no history of previous failure. A leak detection system was installed and working but did not sound during the leak.

Until recently, BPXA has not moved as swiftly as we would have expected to comply with key requirements of our orders – namely, the requirements to clean and smart pig its low stress lines. We provided an extension in March to allow BPXA to collect more information, and a second extension in April, pushing the first deadline to June 12, 2006, more than three months after the spill. Soon after we issued the order, BPXA advised PHMSA that it would not be able to comply with the requirements to "smart pig" the lines within the specified time period, the critical step in meeting our objective of having the best possible understanding of the condition of the pipelines.

On May 23, PHMSA dispatched a more comprehensive field investigative team to evaluate all potential integrity threats to the transit lines along with BPXA programs to mitigate those threats. The team reviewed BPXA's overall program to manage the transit lines, assessed findings emerging from the monitoring plan, reviewed inspection records, observed testing procedures used on the transit lines, toured all facilities, interviewed technicians, reviewed qualifications of personnel, inspected test records, and reviewed the leak detection system. The team suggested improvements for BPXA's Interim Monitoring Strategy such as increased corrosion monitoring points to reduce the potential that vulnerable locations not be overlooked. PHMSA directed BPXA to increase the inspection frequency to provide an early warning of any unanticipated corrosion acceleration. We directed that more stringent repair thresholds be incorporated in the program and asked that communications be improved between analysts and field teams. We also required improved patrolling of the lines. Since the May field inspection, we have maintained a field oversight presence at all times to ensure the operator was taking the actions necessary to maintain safety.

Based on our analysis to date, we believe that internal corrosion, induced by microbial activity, caused the pipe to deteriorate at the point where it failed on March 2 – a low section in a caribou crossing. Typically, operators control this type of corrosion through a combination of cleaning pigs and biocide injections. The cleaning pig is usually necessary to deliver the biocide to the pipe wall and to disperse active bacteria colonies.

We do not understand why BPXA did not address these problems more aggressively much earlier. BPXA could have used cleaning pigs to clean out liquids accumulating in low spots within its low stress pipelines. Further, there is a high likelihood that cleaning pigs would have improved the effectiveness of the biocide or corrosion inhibitor by getting the chemicals to the wall of pipeline without the interference of solids and other deposits. Given the many risk factors in the North Slope environment, including use of water in the production process, the chemistry of the crude oil product itself, and the varied geologic factors in the production field, it is very puzzling that BP did not choose to run cleaning pigs. From information provided by companies who operate in less challenging environments in response to the public meetings held in conjunction with the rulemaking for low stress pipelines, we believe most operators demonstrate a higher standard of care in their operations, regardless of whether they are federally regulated or not.

On June 6, BPXA sought a further extension of the deadlines for the pigging, contending that factors beyond their control would make it impossible to complete the required pigging until the latter half of 2007. They proposed an alternative plan they claimed would provide safety equal to what could be accomplished with a smart pig until the three transit lines could be smart pigged. We denied the requested extension but issued an order making clear to BP that we were not requiring it to shut down its operations on the basis of its failure to meet the pigging deadlines. We had preliminarily reviewed the alternative test procedures and the testing data furnished by BPXA, and did not believe that a shutdown was required for safety. Our order expressly reserved all other enforcement options with respect to BP's failure to comply with the deadlines.

PHMSA engineers were very concerned about the primary reason BPXA gave for its alleged inability to complete pigging -- build up of solids, including impurities in the product stream such as waxes and other materials. Alyeska, the operator of the Trans-Alaska Pipeline (TAPS), had notified PHMSA about its concerns with adverse impact on its pipeline if these solids should be allowed to pass through from BPXA to TAPS. The Joint Pipeline Office (JPO), which coordinates TAPS issues, had concerns as well, and ensuring the continued safe operation of TAPS is a primary concern of PHMSA.

To address those concerns, PHMSA needed to understand the amount, composition and density of this "sludge" material and how it would be handled before we could allow BPXA to proceed with pigging to be sure that BPXA operations could pose no risk to the safety and reliability of the Trans-Alaska Pipeline System. Alyeska needed to be certain about its ability to handle the waste. BPXA put forward preliminary estimates of as much as 12 inches of sludge, with varying amounts in different segments of its 22 miles of transit lines. After several weeks, BP revised its estimate of the amounts of sludge in the lines downward. PHMSA still does not have a confident estimate of the amount of sludge in the line segments that have not yet been pigged. BPXA also took months to develop plans to handle the removal of sludge. Based on a conclusion that there was limited sludge in the Lisburne line, BPXA pigged that line in June.

Because of the delay in resolving this and other issues, in early July, my Chief Safety Officer, Ms. Stacey Gerard, and my Western Regional Director, Mr. Chris Hoidal, and I traveled to Prudhoe Bay and Anchorage to meet with BPXA and Alyeska executives, JPO officials and State of Alaska representatives and to see first hand what BPXA was doing to comply with our order and to overcome any engineering or other issues that would complicate or delay maintenance and smart pigging required on each of the lines. Our assessment was that BPXA was not pursuing all available options for handling the sludge and preparing for pigging. We were concerned they were exploring a single option, one at a time, rather than considering multiple options, and not working or communicating effectively. I was dismayed at the slow rate of progress and observed difficulty in problem solving, poor communications, delay in ordering needed parts and equipment, and failure to take actions necessary to ascertain fully the condition of the pipelines and to address the conditions uncovered.

For example, BPXA told us in May of the need to order valves and stopples to isolate a certain section of the failed pipeline and the need to move the pig launcher around the failed site. Two months later, during our July visit, we learned that some parts were still not ordered. It is still not clear to us that it was impossible to make plans to remove the solids and begin pigging operations by the June 12 deadline in our order.

Subsequent to this visit, on July 20, we issued an amendment (Amendment Number One) to our original order intended to address these deficiencies by mandating that BPXA develop specific plans and timetables or parallel tactics to expedite pigging operations on lines that had not yet been cleaned. We required development of preliminary engineering design and an implementation plan to install a permanent facility for handling solids resulting from cleaning pig operations plus a concurrent contingency plan for a bypass around TAPS Pump Station (PS)-1 facilities so solids could be delivered into storage. This action would assure that sediment in the product stream picked up in pigging would be safely managed in tanks to avoid contamination and maintain the safety of TAPS. We required a comprehensive engineering plan for the draining or "de-oiling" of approximately 17,000 barrels of oil contained in the idled OT21 line segment that failed in March. We also ordered the taking of wall samples and gamma ray photography post pigging to gain the best possible understanding of the real time levels of remaining solids.

By the end of July, BPXA was finally making progress to address our safety concerns and to restore reliable energy transportation service. I am pleased to report that as a result of these orders extracting product from the OT 21 segment of line was completed in late August. The PS-1 bypass – aimed at delivering solids from the WOA line through the use of a bypass line into TAPS storage tanks was successfully hydro-tested in early September and that an alternate bypass, "the Fizzy Bypass," will be completed at the end of September. All these steps are necessary to get us to our goal of understanding the condition of these pipelines and making sure the operator is doing all that is needed to operate them safely.

In our observation however, progress has also been impaired by operator error on the startup of the production line damaged by falling equipment near the Lisburne line, and failure to maintain backup compressors. Discovery of asbestos on the WOA and BP's need to provide worker protection delayed testing on the WOA. While these missteps may not appear to have a direct bearing on the low-stress line corrosion issues, failure to understand and manage change in operations always poses safety risks.

On July 22, 2006, 37 days after the deadline established in our March order, BPXA performed the smart pigging ordered by PHMSA on the 30 inch segment of the FS2-FS1 Eastern Operation Area pipeline. BP informed us of the results of the testing on August 4. The report identified 16 locations of wall loss in excess of 70 percent, including two over 80 percent, at 12 separate areas. While the failure on the Western line occurred on a low spot in a caribou crossing, the locations of severe wall loss on the Eastern line were on straight pipe.

On August 6, BPXA reported that it discovered a leak while in the process of performing direct examination of the EOA as a follow-up to the pig inspection. On the basis of this leak and the discovery of several other locations that were beginning to leak, BPXA initially reported to us its decision to shut down this and the Western line. BPXA explained that its decision was based on a complete lack of understanding of the corrosion that could cause this type of wall loss. BPXA subsequently decided to keep the Western line operating and to consider restarting the 34” segment of the Eastern line.

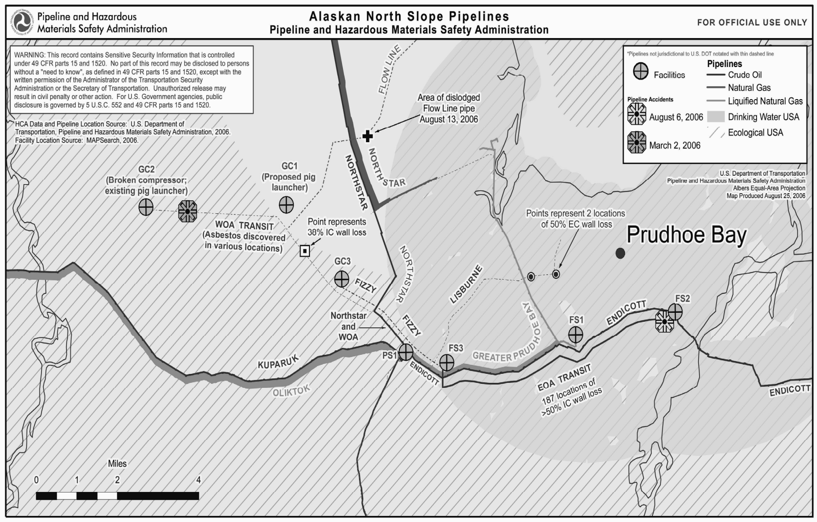
In response to this second spill on the Eastern line, PHMSA issued a second amendment to its order (Amendment Number Two) requiring additional rigorous, automated ultrasonic inspections on a continuous basis of the company’s entire North Slope pipeline network and outlining the standards BPXA would need to meet to restart its pipeline. Prior to completion of smart pigging, we need to have the best possible factual information about the condition of the pipelines. The order required the conduct of four daily ground patrols using heat-seeking infrared equipment to spot leaks along the entire length of the 22 miles of oil transit lines. The order required continuous automated ultrasonic testing on the outside of the operating portion of the Western line, including the stripping of the insulation to apply the instrument directly to the pipeline. This technology is producing promising results. The order also required the de-oiling of the failed segment of the Eastern line and specified the testing that would be needed on the Eastern line until it could be smart pigged, and as a condition of smart pigging.

In addition to imposing new requirements for BPXA, PHMSA further stepped up its presence in Alaska to respond to new threats presented by the August 6 failure. Our first concern was the impact of transit line shutdown on the Trans-Alaska Pipeline System. Reduced product flow from the BPXA transit lines could cause new safety risks to the TAPS pipeline. The hydraulics of the pipeline is set to operate at a certain threshold of product flow. It was necessary to determine whether the operation could be adjusted to a lower level flow. A reduced level of flow can cause vibrations to occur over certain high elevation passes, causing PHMSA to question whether it would be necessary to monitor strain. Long-term reduced flow rate could also cause an environment more susceptible to internal corrosion. We have determined that Alyeska can adjust the hydraulics to operate at a lower flow rate, that it is monitoring the strain caused by vibrations, and that it has an aggressive cleaning pig program to minimize internal corrosion.

Given the impact of the BPXA line shut down, we were concerned about any immediate risk that could lead to a shutdown on any of the other feeder lines to TAPS. We therefore deployed a team to update our knowledge of the risks to these other pipelines, including those at the Kuparuk, Alpine, Badami, North Star, Oliktok and Milne Point fields. We were particularly concerned about a nine-mile section of non-piggable line on Kuparuk. While we have some long-term integrity management concerns, no immediate concerns were detected.

We are working with BPXA on its plan to restart the 34” diameter section of the Eastern line (the line with extensive corrosion discovered in August) and the conditions it would need to meet to satisfy our safety concerns. Given that BPXA was not able to sufficiently explain the causes of the corrosion on the Eastern line, and the potential extent of damage to the pipe wall, PHMSA has required that BPXA demonstrate that the Eastern line is in safe condition for pigging operation. PHMSA needs to be sure that the wall condition is satisfactory to return flow to the line and pass a smart pig through it, without causing another failure. On August 29, PHMSA provided very detailed written guidance to BPXA as to how it must demonstrate the Eastern line’s integrity prior to commencing pigging operations and make appropriate arrangements for spill contingencies. PHMSA will not authorize restart until we have analyzed adequate data without undue reliance on the results of data collected on the in-service segment of the Western line.

Given recent progress with the terms of the amendments to our CAO, we are hopeful that smart pigging of the 60 percent of the 22 miles of low stress pipelines that have not been tested will be started later this fall.



PHMSA will maintain the high level of oversight needed to enforce compliance.

III. DOT'S REGULATION OF LOW STRESS LINES

The BXPA lines that failed on the North Slope were unregulated by DOT/PHMSA. On August 31, PHMSA proposed new safety requirements that would bring these lines under regulation. Our proposed rule applies to facility operators of hazardous liquid gathering and low stress pipelines in rural areas. We already regulated low stress lines in populated areas and crossing commercially navigable waterways.

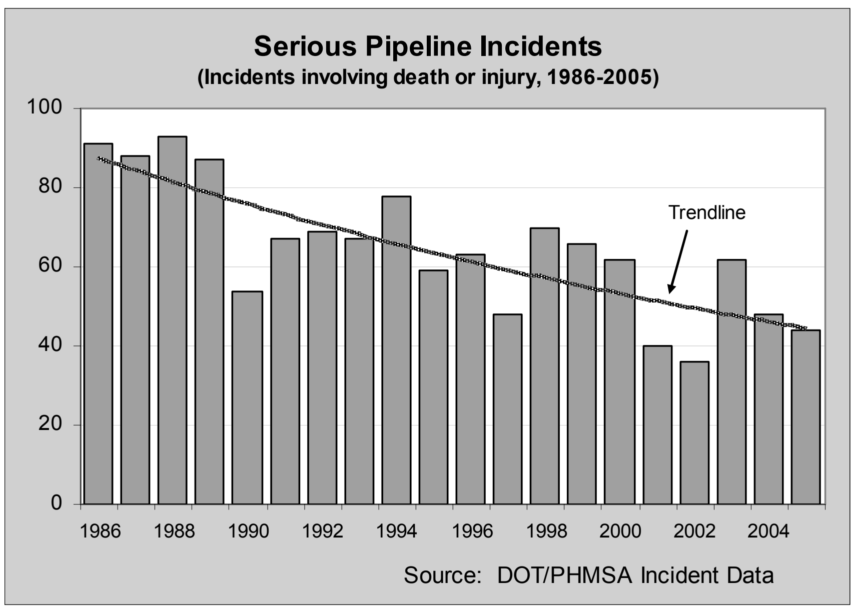
We have taken a risk-based approach – we intend to protect all lines that, in the event of a failure, could spill into an unusually sensitive area, or USA, a term we have already defined in our regulations. We have determined these to be low stress lines within a ¼ mile of a USA and of a diameter of 8 5/8 inches or more. Our assessment of which lines to regulate is based on how they can impact a USA, based on the pressure of the line and the volume of product that could be spilled. Based on data provided to us by operators of rural low-stress pipelines, spills from these types of lines have not traveled beyond a quarter of a mile from the pipelines, and three quarters of those spills have traveled no more than about 100 feet.

The proposal addresses the need to provide additional and robust integrity protection to areas where oil pipelines in rural areas could affect drinking water resources, endangered species and other ecological resource concerns. This proposed rule will enhance corrosion protection by including cleaning and continuous monitoring, integrity assessment, and leak detection. It would require operators of these lines to follow safety rules for design, construction, testing, and maximum operating pressure. In addition, the proposal would require operators to protect the lines from corrosion and excavation damage, install and maintain line markers, establish operator qualification and damage prevention programs, provide public education, and report accidents and safety-related conditions.

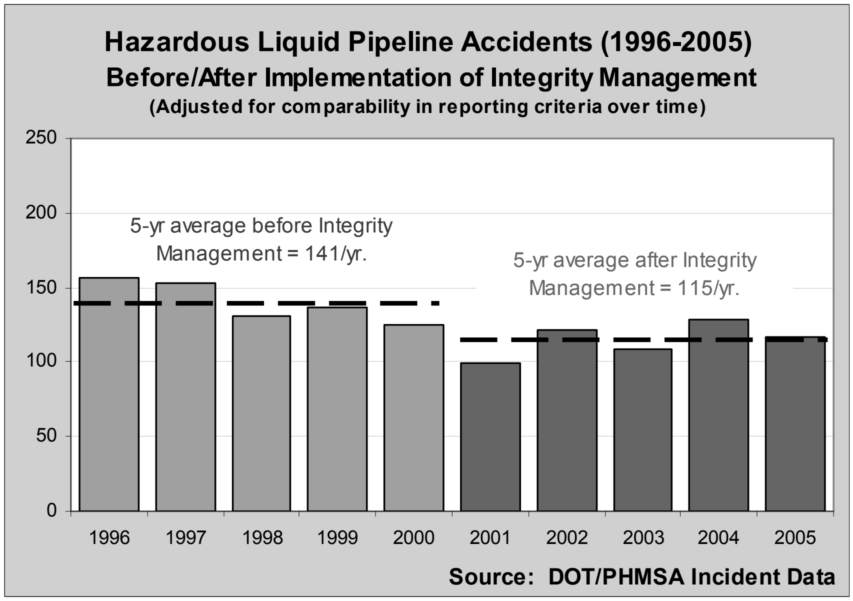
Most low stress lines in the lower 48 States of the U.S. bear little resemblance in their diameter to the low stress lines that BPXA operates on the North Slope. Most of the lines in the lower 48 States are very short in length and small in diameter. We believe that most operators of unregulated crude oil low stress lines have programs in place to regularly clean and test their pipelines. We believe the regulation we have proposed will better protect rural environmental areas. We have asked a number of questions in the notice of proposed rulemaking to get the best possible information to complete the proposal, including whether we should extend protections beyond the ¼ mile area, whether if we should require all unregulated lines to report spills, and whether implementation time frames are appropriate, and other questions. We can modify the regulatory proposal as needed based on the information that becomes available on the docket.

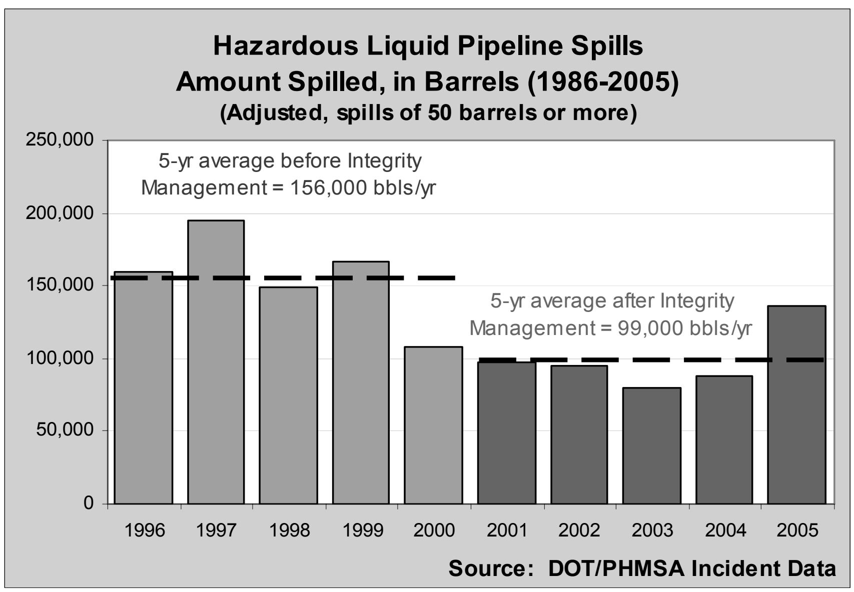
IV. THE U.S. PIPELINE INFRASTRUCTURE IS SOUND

As unfortunate as the recent Alaska incidents are, they are not a bellwether for the health of the majority of the energy pipeline infrastructure. It is in much better shape. PHMSA has designed and is implementing a strong risk-based systems approach to ensure the safety and reliability of our nation's energy pipeline infrastructure. Our regulation is having positive results. The number of serious incidents in which people or the environment are harmed is steadily declining, particularly on oil pipelines.



Our data shows the integrity management program on hazardous liquid pipelines is working. Comparing the five year periods before and after integrity management programs were implemented on hazardous liquid pipelines, spill frequency dropped 18 percent and volumes spilled dropped 35 percent.





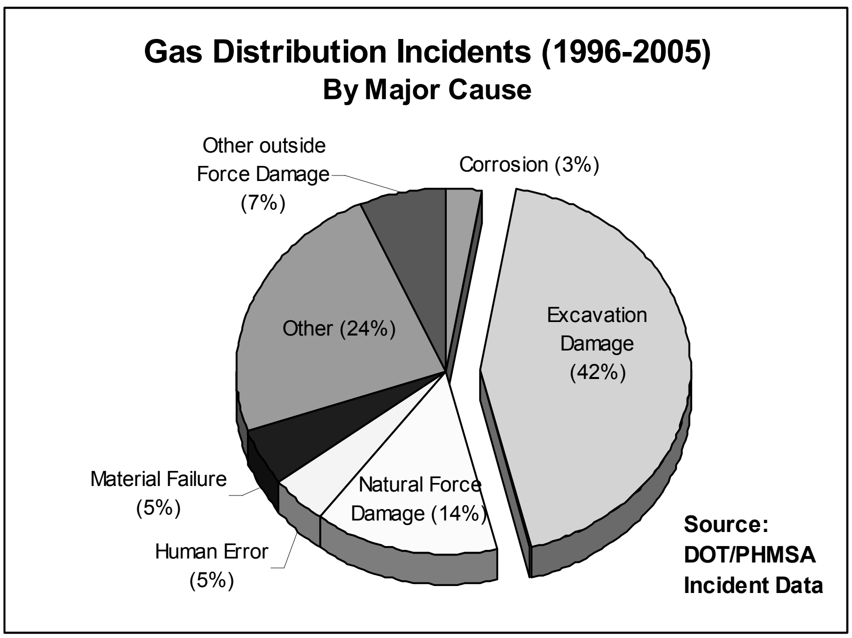
The leading causes of failure on hazardous liquid transmission pipelines are down nearly 50 percent since the integrity management programs were put in place in 2000.

Operators have a better understanding of the condition of their pipelines and the pipelines are in better condition. Safety programs are improving to sustain improved performance in the future. PHMSA closely monitors operator-specific performance and flags companies whose performance is falling for more intense oversight and inspection. We had flagged BP as one of those companies, prior to the accident in March. We have several enforcement actions in place against BPXA affiliate BP Pipelines (Alaska) Inc.

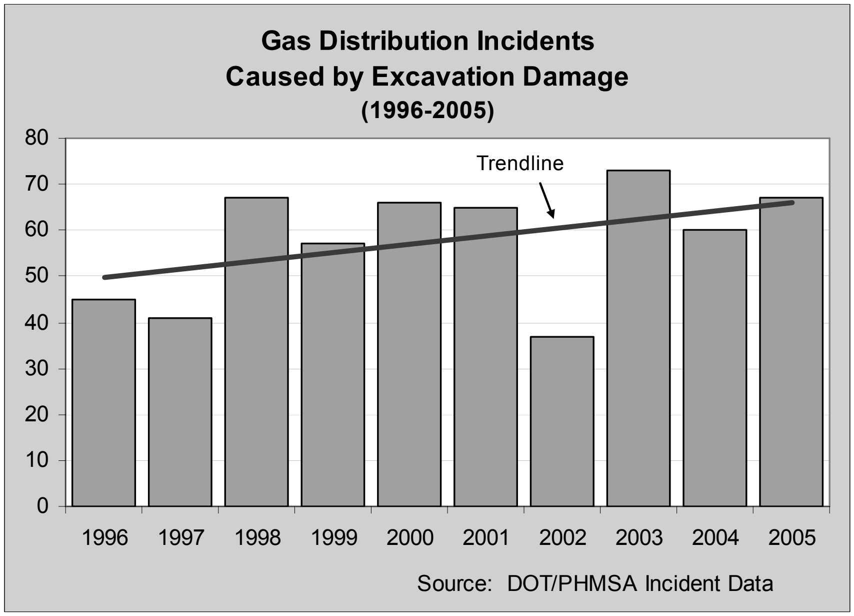
for shortcomings in its integrity management on regulated lines in Alaska. We have taken actions in recent years against BP North America for compliance issues in the lower 48 States. We intervene with operator executives to prevent accidents, usually before they happen, not just respond after the fact, and make full use of all our enforcement options, including civil penalties at the higher level authorized under the Pipeline Safety Act of 2002.

V. LET'S NOT LOSE SIGHT OF THE MOST PRESSING SAFETY PROBLEM

In the past few years, PHMSA has taken a hard look at incidents, their causes and what can be done to prevent them. One thing is clear-the leading cause of incidents (42 percent of total) in which people are hurt or killed is construction-related damage causing an immediate rupture or damage that later grows to failure. This occurs most often on the distribution systems that run through the neighborhoods where people live and work.



Unfortunately, since 1996, incidents of construction-related damages on distribution systems have clearly increased as much as 49 percent, and this in areas where people are most likely to be hurt.



This part of the pipeline system, the distribution network, is almost entirely under the jurisdiction of States, our foremost partners in pipeline safety. These incidents are almost entirely preventable. We need to help States do more, and we need new authority to make this happen.

The Secretary of Transportation recently submitted to Congress the Administration's legislative proposal to reauthorize and improve pipeline safety and protection for the environment, and also to enhance infrastructure reliability. The proposal, the "Pipeline Safety and Reliability Improvement Act of 2006" aims to build on our progress in achieving the mandates of the 2002 Act by placing more emphasis on damage prevention and enhancing state programs' oversight of pipelines.

Our progress on completing recent and past mandates and recommendations is attached.

These reauthorization concepts have been generally supported across our stakeholder community, including the Federal and State family, and we are pleased to see many of the same priorities reflected in the Committee's proposal.

VI. Conclusion

I assure the members of this Subcommittee, that the Administration, Acting Secretary Cino, and the dedicated men and women of PHMSA share your strong commitment to improving safety, reliability, and public confidence in our Nation's pipeline infrastructure.

Like you, we understand the importance of our mission to the safety of our citizens and the energy security and continued economic growth of our great Nation.

Thank you.

I would be pleased to answer any questions you may have.

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Attachments:
PHMSA Mandate Progress Chart
PHMSA Mandate Progress Graph

MR. BURGESS. Thank you. Without objection, your written statement will be submitted for the record. We will now hear from Mr. Fredriksson for 5 minutes.

MR. FREDRIKSSON. Mr. Chairman, members of the subcommittee, thank you for the opportunity to testify before the subcommittee regarding your review of BP's recent crude oil transmission pipeline failures on Alaska's North Slope. My testimony today will focus on the Alaska Department of Environment Conservation's responsibilities for oil spill prevention and response in Alaska.

To begin, I want to emphasize to the subcommittee that a thorough fact-finding investigation of BP's management of the North Slope oil field is being conducted by my department and the Alaska Department of Law. As part of the ongoing investigation, I have served subpoenas on BP and other holders of the Prudhoe Bay leases to preserve all documents related to this occurrence and pipeline corrosion going back to 1996. After the State's investigation is complete, appropriate legal action will be taken to protect Alaska's interests.

The mission of my department is to protect public health and the environment. Alaska's legislature has provided the department with a very broad and comprehensive authority to carry out this mission. As the department's commissioner, I have a duty to adopt and enforce regulations for controlling the release of pollution to Alaska's air, land and water. I take very seriously the department's duty to prevent and respond to the unauthorized release of oil and hazardous substances.

Prevention of spills is a major topic for today's hearing. However, it is important that I briefly describe the department's role in spill response. Under Alaska law, any person causing an oil spill must immediately clean up and contain the spill to the State's satisfaction. If the department determines the response to a spill is not adequate, it may undertake the cleanup itself. The response by BP and others to the Gathering Center 2 and Flow Station 2 pipeline spills has been exemplary. The spills were quickly contained, oil removed, damage to health and wildlife prevented and impact to the environment minimized. The Alaska Department of Environmental Conservation is also authorized to adopt and enforce spill prevention regulations for pipelines. Since 1992, the department has enforced regulatory leak detection requirements on crude oil transmission lines. There are currently no State corrosion control requirements for crude oil transmission lines. At this time there are also no State regulatory requirements for corrosion control or leak detection on flow lines. However, that is about to change as I will describe later in my testimony.

In the late 1990s, discussions between the State of Alaska, BP and ARCO as part of the BP-ARCO merger led to a charter agreement for development of the Alaskan North Slope that included several environmental commitments, one of which addressed pipeline corrosion. Under the provisions of the charter agreement, BP committed to report annually to my department on their current and projected corrosion monitoring, maintenance and inspection practices to assess and to remedy potential or actual corrosion and other structural concerns related to North Slope pipelines. Corrosion performance management reports have been submitted by BP annually since 2000. Each report has been independently reviewed by Coffman Engineers Incorporated, a nationally recognized independent engineering firm under contract with my department. Based on information provided by the charter agreement, the department joined with other governmental and non-governmental stakeholders in 2004 to review and update Alaska's spill prevention regulations. This review led the department to propose new corrosion control regulations for flow lines. The State placed a high priority on proposing corrosion control regulations for the flow lines because they carry a highly corrosive mixture of oil, gas and water, they have a history of leaking, and because they represent the vast majority of the pipelines on the North Slope of Alaska. Relatively speaking, the crude oil transmission pipelines were considered a much lower risk. The flow line regulations were 2 years in the making and were ready for adoption at the time of the GC-2 crude oil transmission pipeline spill which occurred in March of this year. The department immediately considered adding crude oil transmission lines to the regulatory package at the time of the GC-2 spill but decided against their inclusion because it would delay implementation of the flow line regulations. We also wanted to complete the investigation into the cause of the GC-2 pipeline failure so that our regulations would benefit from the lessons learned from that incident. Although information is still being generated and investigations such as this hearing are ongoing for the GC-2 and FS-2 incidents, it is apparent that the current corrosion management programs for crude oil transmission lines should be revised and expanded so as to be able to detect the effects of previously unrecognized corrosion mechanisms that could adversely impact the future safe operation of the infrastructure on the North Slope. A separate State regulatory proposal for crude oil transmission lines remains under consideration pending further review of the actions recently proposed by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration.

Pipeline corrosion issues are technically complex and the State's resources must be matched to the appropriate level of oversight. Following the GC-2 spill in March of this year, the Alaska Department of Environmental Conservation created an interagency Arctic Pipeline Technology Team with the Alaska Department of Natural Resources and the Alaska Oil and Gas Conservation Commission to coordinate the State's oversight of North Slope pipeline integrity. The Pipeline Technology Team is planning to hold a pipeline integrity conference in Alaska this winter to examine the latest pigging technology and best practices for corrosion management, monitoring and inspection for pipelines in Arctic climates.

To summarize, BP has accepted responsibility for correcting their pipeline failure and the governor has directed the Department of Law and my department to ensure that they are held accountable. Once discovered, the spills were contained and cleaned up with minimal environmental damage. Some of the best industry and government engineering experts are working the problems. The defective pipelines will be replaced. The State flow line regulations are expected to be in effect by the end of the calendar year, and we will be reviewing the rulemaking proposed by the Pipeline and Hazardous Materials Safety Administration to determine what additional actions the State should take.

Thank you for the opportunity to testify before the subcommittee. I would be happy to answer any questions.

[The prepared statement of Kurt Fredriksson follows:]

PREPARED STATEMENT OF KURT FREDRIKSSON, COMMISSIONER, ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Good morning. My name is Kurt Fredriksson, and I am the Commissioner of the Alaska Department of Environmental Conservation (ADEC). Thank you for the opportunity to testify before the Subcommittee regarding your review of BP's recent crude oil transmission pipeline failures on Alaska's North Slope.

Hearings like this should provide assurances to the people of the United States that Congress and the State of Alaska are diligent and vigilant in overseeing the responsible development of Alaska's important natural gas and oil resources.

My testimony today will focus on the Alaska Department of Environmental Conservation's responsibilities for oil spill prevention and response in Alaska. As requested by the Subcommittee, I will address the question of what went wrong with BP's pipeline spills, and explain what I also believe went right with these events.

To begin I want to emphasize to the Subcommittee that a thorough fact-finding investigation of BP's management of the North Slope oil field is being conducted by my department and Alaska's Department of Law. As part of the ongoing investigation, I have served subpoenas on BP and other holders of the Prudhoe Bay leases to preserve all documents related to this occurrence and pipeline corrosion going back to 1996 (enclosure 1). After the State's investigation is complete, appropriate legal action will be taken to protect Alaska's interests.

The mission of ADEC is to protect public health and the environment. Alaska's legislature has provided the Department with very broad and comprehensive authority to carry out this mission. As the department's Commissioner, I have a duty to adopt and enforce regulations for controlling the release of pollution to Alaska's air, land, and water.

I take very seriously the department's duty to prevent and respond to the unauthorized release of oil and hazardous substances.

Prevention of spills is a major topic for today's hearing, however, it's important that I briefly describe ADEC's role in spill response.

Under Alaska law any person causing an oil spill must immediately contain and cleanup the spill to the satisfaction of ADEC. If ADEC determines the response to a spill is not adequate it may undertake cleanup itself. The spiller is also strictly liable for the state's costs incurred to respond to, and oversee the cleanup.

The response by BP and others to the Gathering Center-2 and Flow Station-2 pipeline spills has been exemplary. The spills were quickly contained, oil removed, damage to health and wildlife prevented, and impact to the environment minimized.

In addition to its responsibilities for spill response, ADEC is also authorized to adopt spill prevention regulations for pipelines. Because of the complex and sometimes conflicting pipeline nomenclature in use by various state and federal agencies let me start by clarifying ADEC pipeline regulatory terminology.

There are many different types of pipelines operating on the North Slope carrying many different types of liquids and gas for many different purposes. For purposes of this testimony I will focus on aboveground pipelines on the North Slope that are subject to the state's spill prevention authorities (enclosure 2). Pipelines that carry crude oil, water and gas from the wellhead to a processing facility are called flow lines. Flow lines carry the most corrosive fluids and make up the majority of the pipelines on the North Slope. Seawater injection and produced water pipelines are included in our definition of flow lines.

Pipelines which carry crude oil from the separation facility are defined as crude oil transmission pipelines. These are single phase pipelines which carry crude oil that has been processed to remove the water and gas carried by the flow lines.

Since 1992, the department has enforced regulatory leak detection requirements on crude oil transmission lines. There are currently no state corrosion control requirements for crude oil transmission lines. At this time there are also no state regulatory requirements for corrosion control or leak detection on flow lines. However, that is about to change as I will describe later in my testimony.

The original Plan of Development for the Prudhoe Bay reservoir projected a 42% recovery of crude oil or approximately 9.6 billion barrels. Based on these estimates Prudhoe Bay was not expected to be producing oil after 1997. Fortunately, advancements in oil field recovery technology extended the life of the Prudhoe Bay field. In the late 1990's discussions between the State of Alaska, BP and ARCO as a part of the BP/ARCO merger, led to a "Charter Agreement" for development of the Alaskan North Slope that included several environmental commitments (enclosure 3).

With extended crude oil production from Prudhoe for another generation in mind, the State negotiated seven environmental commitments in the Charter Agreement with the Prudhoe Bay operators including a specific commitment concerning corrosion that specifies;

> *BP and ARCO will, in consultation with ADEC, develop a performance management program for the regular review of BP's and ARCO's corrosion monitoring and related practices for non-common carrier North Slope pipelines operated by BP or ARCO. This program will include meet and confer working sessions between BP, ARCO and ADEC, scheduled on average twice per year,*

reports by BP and ARCO of their current and projected monitoring, maintenance and inspection practices to assess and to remedy potential or actual corrosion and other structural concerns related to these lines, and ongoing consultation with ADEC regarding environmental control technologies and management practices.

Corrosion performance management reports have been submitted annually since 2000 and are independently reviewed and audited by a nationally recognized independent engineering firm. The reports are technically oriented, and intended to ensure a corrosion management program is in place for the life of the North Slope oil fields. The annual reports are available on the department's website at: www.dec.state.ak.us/spar/ipp/corrosion/index.htm.

The engineering review process and reporting metrics for the annual reports were developed during the first year of the agreement to promote the free exchange of engineering viewpoints through report drafts, meet and confer sessions, and technical meetings to clarify questions, agree on metrics for reporting, review the application of various engineering standards, and analyze a host of complex technical matters. The process allows all parties to offer their judgment and criticism and opposing viewpoints.

Based on information provided by the Charter Agreement, the department joined with other governmental and non governmental stakeholders in 2004 to review and update Alaska's spill prevention regulations. This review led the department to propose new corrosion control regulations for flow lines.

The rationale and documented basis of need for regulating flow lines is described in the summary document for the rule making (enclosure 4). In essence, state corrosion control regulations were developed for the flow lines first because they carry a highly corrosive mixture of oil, gas and water; because they have a history of leaking; and because they represent the vast majority of the pipelines on the North Slope of Alaska. Relatively speaking, the crude oil transmission pipelines were considered a much lower risk. The flow line regulations were two years in the making and were ready for adoption at the time that the GC-2 crude oil transmission pipeline spill occurred in March. The department immediately considered adding crude oil transmission lines to the regulatory package at the time of the spill but decided against their inclusion because the additional time required to re-public notice and conduct a hearing would unnecessarily delay implementation of the flow line regulations which were otherwise ready for adoption. We also wanted to complete the investigation into the cause of the GC-2 pipeline failure so that our regulations would benefit from the lessons learned from that incident. A separate state regulatory proposal for crude oil transmission lines remains under consideration pending further review of the actions recently proposed by the U.S. Department of Transportations Pipeline and Hazardous Materials Safety Administration.

Although information is still being generated and investigations are ongoing for the GC-2 and FS-2 incidents, it is apparent that the current corrosion management programs for crude oil transmission lines should be revised and expanded so as to be able to detect the effects of previously unrecognized corrosion mechanisms that could adversely impact the future safe operation of the infrastructure on the North Slope.

Pipeline corrosion issues are technically complex and the state's resources must be matched to the appropriate level of oversight. Following the GC-2 spill in March of this year, ADEC joined the Alaska Department of Natural Resources, and the Alaska Oil and Gas Conservation Commission in creating an interagency Arctic Pipeline Technology Team to coordinate the state's pipeline integrity oversight. The purpose and structure of the team is described in the Memorandum of Agreement between the three agencies (enclosure 5). Funding for the team leader, agency support costs, and technical consulting assistance is provided under the Charter Agreement. In addition, the department has directed $500,000 from the Charter Agreement be invested in a Pipeline Integrity Conference held in Alaska this winter to examine the latest technology and best practices for corrosion management, monitoring and inspection, and leak detection for pipelines in arctic climates.

To summarize, BP has accepted responsibility for correcting their pipeline failure and the Governor has directed the Department of Law and my department to ensure they are held accountable. Once discovered, the spills were contained and cleaned up with minimal environmental damage. Some of the best industry and government engineering experts are working the problems. The defective pipelines will be replaced. The state flow line regulations are expected to be in effect by the end of the calendar year and we will be reviewing the rule making proposed by the Pipeline and Hazardous Materials Safety Administration to determine what additional actions the state should take.

The good news for America is that production from Prudhoe Bay did not end in 1997 with 9.6 billion barrels. Approximately 11.3 billion barrels has now been recovered from Prudhoe Bay with expectations of pumping yet another 2 billion barrels. Extracting more oil from existing fields helps meet the nation's energy needs. Pipes can be fixed and production can be restored because Prudhoe Bay is not out of oil. Lessons will be learned from the state and federal investigations of these pipeline failures and technical review by our Arctic Pipeline Technology Team. Extended production from the Prudhoe Bay field will continue to supply the nation's energy needs with an enhanced level of safety and oversight.

MR. BURGESS. Thank you, Mr. Fredriksson. We will get to questions in just a moment. Ms. Gerard, we are willing and able to take your 5-minute testimony now--very well.

Admiral Barrett, thank you for your testimony. How would you describe the condition of BP's Prudhoe Bay transmission lines at the time the Pipeline and Hazardous Materials Safety Administration issued the corrective action order in March of 2006?

VICE ADMIRAL BARRETT. I would say they fundamentally didn't understand the condition of the lines, and if you look at our order, it was directed at accomplishing two things. It was clearly to understand the correction of the lines, ordering additional inspections to again better understand the actual conditions on those lines, and then directing appropriate safety controls, and we are still working that process forward, but I would say fundamentally, the condition of the lines is evidenced by the two leaks, one on the western side and one on the eastern side, and the basic underlying problems is, those conditions were not understood.

MR. BURGESS. Well, if I may ask, what explanation has BP given for the failure of the western operating line that resulted in the March 2006 leak?

VICE ADMIRAL BARRETT. They haven't given us a satisfactory explanation of the corrosion modeling on that line. As you know, the likely cause, although it is still being investigated, was pitting, if you will, or biologically induced or promoted corrosion in a low spot on the line, and that spot was simply not identified. The pigging--I heard some of the earlier testimony. That line was--that spot on that line was not picked up as a problem area and was not assessed using ultrasound or other means to accurately pin down that the problem existed.

MR. BURGESS. We heard earlier described ultrasound as being rather a tedious way to go about pipeline inspection. Is that correct, or can ultrasound be done in an expedient fashion?

VICE ADMIRAL BARRETT. It is an effective tool. Typically what happens, if you look at how the internal corrosion issues are assessed, is a couple of things. One is, the lines are typically swept by maintenance or cleaning pigs to keep the line clean, keep sludge from building up on the sides of the lines, allow your corrosion inhibitors to work on the side of the line, and once the sludge or the scale is cleaned, then you would want to run the cleaning, the sensor pigs down the line and get a picture, and the sensor pig will indicate where there are possible problems on the line. You might--it might show risk of wall loss to some degree, maybe 50 percent or 20 percent or 70 percent. On the eastern lines, some spots it exceeded 80 percent when they ultimately ran it. But typically then you go out with tools like the ultrasound to get a much more accurate detailed picture at the sites, the specific sites where the sensor indicates you may have a problem. So it is not really designed to run a whole line but it is very effective at getting a better picture on a particular spot, about a 12-inch site on a line.

MR. BURGESS. On the eastern side, what explanation has BP given for the problems with the eastern operating line that caused BP to shut that line down in August?

VICE ADMIRAL BARRETT. What they said basically was they their corrosion modeling completely failed. They had no explanation of what might have caused the seeps and weeps. The inline inspection was done because we ordered it on that line. Once it turned up these sites, they went out and looked at it, but fundamentally, they had no explanation as to what could have caused that, and also, the lines are different. On the western side, it is a line with many more frequent elevation changes. On the eastern side, it is much more straight pipe, so to the extent they had an explanation on the western side that said it was a low spot, maybe water collected, maybe it wasn't swept out enough, on the eastern side it is pretty much straight line and the same explanation would not apply, and what I would also add is, and I haven't seen it and perhaps you have it in your records, but I have seen this discussion about 16--when that pig run came back, about 16 spots with significant wall loss, but if you looked a little broader, you would see, I think the number I saw was about 187 spots with wall loss approaching 50 percent. This was not an isolated couple of spots. This was a number of spots where you had a substantial problem, and frankly, they had no explanation.

MR. BURGESS. What were some of the major program weaknesses that the Department of Transportation found?

VICE ADMIRAL BARRETT. Well, I think again to walk back through it, fundamentally you have to understand the condition of the line both externally and internally from a corrosion point of view, and the fundamental problem was, they were simply not running cleaning pigs, they were not running inline inspection tools. Some of the aspects of their program are perfectly fine for the limited purpose. You heard discussion about the coupons, managing--you know, they give an indication of progressive wall loss. That is perfectly acceptable but it wouldn't get at the type of pitting and biologically induced corrosion you have here. Now, the operators up there on the North Slope, the fact you may have biological corrosion as well as chemical corrosion is well known. You are injecting water into the wells, frequently seawater, so you get biological organisms in there and despite the production process, some of them can stay in your product and migrate down the line. So you have to manage against that risk, and BP did not have an effective way of doing it. And again, we are investigating and we will pin down as exactly as we can what went on with a view towards preventing this in the future, but for example, they had--they inject corrosion inhibitors. That would be a fairly common practice. As near as I could tell, they weren't measuring the effectiveness of those corrosion inhibitors down the line and they were not taking into account the fact that those inhibitors may have been held off the pipe wall by the buildup of sludge as you have heard.

So that is a long answer, but fundamentally, some answers of their program were fine. Basically it was not comprehensive and it was not comprehensive enough to address the risks, the corrosion risks on that line.

MR. BURGESS. Well, do you think some of these problems are not just limited to BP but they are more of an industry-wide problem?

VICE ADMIRAL BARRETT. No, sir, I don't. Frankly, the problems we see on these lines are not replicated elsewhere, even in Prudhoe Bay or elsewhere in the industry. The standard of care generally used--you heard Mr. Hostler from Alyeska talk earlier about the fact that they run maintenance pigs down the TAPS about every 14 days. Well, each line is different. There are different sizes. They run different products. The product coming out of the western--onto the western lines is different than the product coming out of fields on the eastern side. But typically up on the North Slope and generally in the industry, you would see maintenance pigs every couple of weeks, certainly every couple of months, but not never on lines of this type.

MR. BURGESS. Ms. Gerard, if I could ask you, is it true that BP has strongly resisted the Department of Transportation's efforts to put all 100 miles of its federally regulated lines in Alaska into the integrity management program?

MS. GERARD. That is certainly true.

MR. BURGESS. What justification did BP give for refusing to put all of its 100 miles of regulated pipelines in Alaska into the integrity management program?

MS. GERARD. By their risk assessment, they didn't think that a leak would hurt the species that live in the area that are intended to be protected by law.

MR. BURGESS. Was there a similar justification for the effect on the human population?

MS. GERARD. There was. In that case, it was the employees of the company had been trained in emergency response procedures and therefore they didn't need to have the benefit of the integrity and protection.

MR. BURGESS. Well, what then was the ultimate outcome when we had the leaks as described?

MS. GERARD. These lines that I am describing are 96 miles of the regulated high-pressure lines, not the low-stress lines, and eventually we had to order them to comply with the integrity management requirements.

MR. BURGESS. As a result of that, was it necessary to order anyone else into the integrity management program?

MS. GERARD. No. In fact, quite the opposite. We had originally estimated that about 25 percent of the high-pressure transmission miles would be determined to be necessarily protected by integrity management requirements and the actual amount the other companies besides BP put in was about 80 percent.

MR. BURGESS. Thank you. Admiral Barrett, are you satisfied with the pace of BP's repairs to Prudhoe Bay transmission pipelines in the wake of the events in March and August?

VICE ADMIRAL BARRETT. Right now, BP is progressing and doing some of the things we thought should have been done a long time ago. In general terms, their actions prior to the March spill were a disappointment. Initially after we issued our initial order, the response and actions to implement that order in my view were too slow. That is one of the reasons I went up there in July, and right now they are doing things in compliance with our order and--

MR. BURGESS. Have they made every conceivable effort to meet with the deadlines and requirements set forth in your corrective action order?

VICE ADMIRAL BARRETT. I wouldn't speculate but we have reserved all our enforcement actions or options on that. I mean, I would say going back from March through today, I would say no, they were moving slower than I thought they could have moved, and that was one of the reasons we went up and met with them.

MR. BURGESS. And we appreciate you doing so. Now, BP filed a petition with PHMSA on June 6 stating it would be unable to comply with several of the deadlines in the corrective action order for reasons "outside of its control." Do you know what some of those reasons were?

VICE ADMIRAL BARRETT. I don't want to speculate, but I don't accept that argument. If you look at what is going on up there now, for example, we have ordered them to pig the lines. The obstacle to pigging that BP--they had to manage the solids to Alyeska. That is a crucial issue. Safety of the Trans Alaska Pipeline is a major concern of mine, and what is going on up there now is, they are running bypass lines. You heard discussion of the taking bypass from skid 50 into tank 110. These actions are happening now. Why they couldn't have happened months ago eludes me frankly.

MR. BURGESS. Thank you, and I appreciate your candor. I now recognize the Chairman of the--I am sorry--the Ranking Member of the full committee, Mr. Dingell.

MR. DINGELL. Mr. Chairman, you are most gracious. Thank you.

On page 20, Admiral, of your statement, I read these words: "PHMSA closely monitors operator-specific performance and flags companies whose performance is falling for more intense oversight and inspection. We had flagged BP as one of these companies prior to the accident in March. We have several enforcement actions in place against BPXA affiliate BP Pipelines Alaska, Inc. for shortcomings in its integrity management on regulated lines in Alaska." What does that mean? What are you telling us?

VICE ADMIRAL BARRETT. Mr. Dingell, that is the same issue that Ms. Gerard alluded to a few minutes ago, that on the 100 other miles of pipeline that they have up there that are subject and have been subject to DOT regulation, the high-stress lines, getting all of those lines under the integrity management program, which we feel is essential to effective risk management and safety, frankly was resisted by BP right up until after the March spill, and so it is the type of thing that again would have caused us to question their commitment. We actually issued an order directing amendments to make them bring those lines into the full-up integrity management program, and subsequent to the spill in March and the actions we took then, they have now done so, but that went on over a 2 or 3 year period.

MR. DINGELL. Ms. Gerard, do you have any comments to add?

MS. GERARD. The key safety action that they were resisting was pigging, smart pigging.

MR. DINGELL. I wanted to get to this. Admiral, Ms. Gerard, do these matters relate to pigging, not pigging, improper pigging or anything else related to that kind of action either with regard to maintenance pigging or with regard to the kind of pigging that you do with smart pigs?

VICE ADMIRAL BARRETT. The integrity assessment program which is part of the integrity management program would require them to take those actions, the smart pig.

MR. DINGELL. Ms. Gerard?

MS. GERARD. Specifically, smart pig. We did not specify cleaning pigs in the integrity management rule.

MR. DINGELL. Okay. We will probably be sending you a letter to ask for additional information on these matters. Mr. Barrett, the current regulations governing hazardous liquid pipelines exempt certain pipelines operating at low stress from DOT regulation. That is correct, is it not?

VICE ADMIRAL BARRETT. Yes, sir, they do. That is what we have just proposed.

MR. DINGELL. In fact, the lines that failed in Alaska fell under this exemption. Isn't that true?

VICE ADMIRAL BARRETT. Yes, sir, it is.

MR. DINGELL. Can you explain to the committee why these lines were exempt from regulation? Was it a result of DOT action or something the Congress ordered the department to do?

VICE ADMIRAL BARRETT. Sir, we had been working for the 2 years previously to bring these lines under regulation. Frankly, our highest priority in the agency over the past several years was life safety, getting on high-stress liquid and gas lines that run in populated areas that threaten, you know, as you would expect, communities where people live, that threaten schools, that took on a higher priority within the agency. But clearly these low-stress lines in unusually sensitive areas were identified as an area that needed to be brought under regulation and the agency was going through the process to develop--

MR. DINGELL. Admiral, as I understand this matter, your regulations control which pipelines are under regulation and which are not. Low-pressure pipelines are under regulation or not?

VICE ADMIRAL BARRETT. Certain low-pressure pipelines that run in populated areas and that run near navigable waters are already regulated and so the lines we are talking about not regulated are those that operate in rural areas and ones in--

MR. DINGELL. Now, why were these not regulated?

VICE ADMIRAL BARRETT. Well, again, we were moving to--

MR. DINGELL. Because of the regulation. So you were moving to adopt a regulation--

VICE ADMIRAL BARRETT. Yes, sir.

MR. DINGELL. --which covered these rather than just putting them under control because you had--

VICE ADMIRAL BARRETT. Yes, sir. We had to put them under control because we--

MR. DINGELL. --to function under an existing regulation. Is that right?

VICE ADMIRAL BARRETT. That is correct, sir.

MR. DINGELL. Can you tell us when you would expect to complete that regulation?

VICE ADMIRAL BARRETT. Sir, we issued the regulation on the 31st of August as a proposed rulemaking.

MR. DINGELL. On the 31st of?

VICE ADMIRAL BARRETT. August of this year.

MR. DINGELL. Of this year?

VICE ADMIRAL BARRETT. Yes, sir. It is open for 60-day comment. We obviously are open to suggestions--it is a proposal--as to the scope of the rulemaking and the requirements that are included in it, and at the conclusion of that 60-day period, we will assess any comments or input we get and then issue a final rule.

MR. DINGELL. Now, Admiral, I wonder, does DOT currently regulate other lines in the Prudhoe Bay field?

VICE ADMIRAL BARRETT. Absolutely, yes, sir.

MR. DINGELL. Which ones?

VICE ADMIRAL BARRETT. We operate--we regulate all the high-stress lines up there operated by BP and other operators on the field, about 400 miles of lines up there actually.

MR. DINGELL. But you don't--do you regulate any other low-stress or low-pressure pipelines up there in the field?

VICE ADMIRAL BARRETT. Not until this rule is issued.

MR. DINGELL. Until the rule is issued?

VICE ADMIRAL BARRETT. Yes, sir.

MR. DINGELL. You haven't gotten around to regulating any of them, have you?

VICE ADMIRAL BARRETT. It would be the same situation as the BP low-stress lines. There are other low-stress lines up there that--

MR. DINGELL. Now, prior to the spill, was the department concerned that it didn't have any information on the two key transit lines in America's largest-producing oil field?

VICE ADMIRAL BARRETT. Yes, sir, we were, of course we would be. In fact, we had inspectors check the lines occasionally to make sure that they were being operated at low stress. In other words, if they--

MR. DINGELL. Would you give us the dates on which those inspections took place?

VICE ADMIRAL BARRETT. Sir, I would be pleased to provide that for the record.

MR. DINGELL. And if you please, would you also tell us what the inspectors reported.

VICE ADMIRAL BARRETT. Absolutely.

MR. DINGELL. So we have an understanding of that. Now, can you tell us what your concerns were?

VICE ADMIRAL BARRETT. As indicated, and I believe there was some discussion earlier, these lines in order to be considered low stress and exempt from our oversight had to operate at less than 20 percent of the maximum rated strength on the line, and so if they ran above 20 percent of the maximum rated strength, they would have come under the full oversight applied to high-stress lines. The western area line I believe was rated at about 850. It was being operated down around 80, I believe, but we would have had inspectors check to make sure that the line in fact was being operated as a low-stress as opposed to a high-stress line.

MR. DINGELL. Are you telling us that you need reporting and disclosure and maintenance authority on these lines or do you have that authority now?

VICE ADMIRAL BARRETT. We do have the authority and that is--we are using that authority to both--

MR. DINGELL. So you don't need any authority in these areas: reporting, disclosure or--

VICE ADMIRAL BARRETT. No, sir. We have the authority to issue the regulations or to do it by order as we have done with BP over the past several months.

MR. DINGELL. Now, the department though took no action on the concerns that you had with regard to this field. Is that right? You had concerns and you had concerns enough to send inspectors out to take a look at the field but you didn't take, as I gather, any regulatory action. Am I correct in assuming that you didn't respond because your own--because the absence of regulations controlling or regulating those pipelines were not on the books. Is that right?

VICE ADMIRAL BARRETT. Correct, sir. The--

MR. DINGELL. All right. Now, is it safe to say that if the DOT had concerns with these transit lines in Prudhoe Bay, the department wouldn't have been able to act on these concerns absent an accident because of the department's own regulatory exemption. Is that a fair statement?

VICE ADMIRAL BARRETT. Yes, sir. We would have required an imminent hazard, which we--which took place in March with the spill, but under our requirements, our ability to act absent a regulatory regime would have required an imminent threat to safety or health and--

MR. DINGELL. All right. Now, is it true that your current proposed rules on low-stress lines leave some 4,300 miles of low-stress lines completely unregulated without requirements to report accidents or to manage for corrosion?

VICE ADMIRAL BARRETT. That is--yes, sir, that is an estimate but the--one of the questions we asked in the rulemaking proposal was whether even absent a regulatory oversight, additional reporting requirements ought to be imposed with respect to those lines. That is one of--

MR. DINGELL. It kind of looks to me like you may have another spill coming down the road at you in some of these 4,300 miles of unregulated line because, remember, not only do you not regulate them, but you don't have reporting and you don't have disclosure and you don't have maintenance authority under your own regulations. What are you going to do about that?

VICE ADMIRAL BARRETT. A lot of these lines are overseen at the State level by States. They are for the most part much smaller than the type of lines BP is operating up here. We are talking 30- and 34-inch lines. Most of the lines that would fall outside the scope of our proposal are down below probably 16 inches at most. They are much smaller lines, carry less product.

MR. DINGELL. The line that--the two lines that you shut down were unregulated by you. Were they regulated by the State?

MR. FREDRIKSSON. Congressman Dingell, no they were not. They were regulated to the extent that we had leak detection on the--

MR. DINGELL. Well, why are you so comfortable then that these lines that you are not going to regulate in this 4,300 miles are regulated by the States?

VICE ADMIRAL BARRETT. Well, we looked at the spill history on the lines and the risk the lines posed, and again, we are capturing lines that affect or could affect unusually sensitive areas, not everywhere that the lines run, and usually the sensitive areas, we have defined them in the proposal to include areas where there are threatened or endangered species or a community water supply--

MR. DINGELL. I am curious, Admiral, which is a sensitive area and a line which traverses a sensitive area?

VICE ADMIRAL BARRETT. Again, I--

MR. DINGELL. I think--

VICE ADMIRAL BARRETT. --I want to--

MR. DINGELL. --here you might have told me and BP might have told me that none of these lines that we are addressing today where you have had the accident would have been transiting across a sensitive area.

VICE ADMIRAL BARRETT. Well, we obviously didn't agree with BP's assessment of that and we have mapped the unusually sensitive areas so they can be identified.

MR. DINGELL. Well, I think--

MR. BURGESS. The gentleman's time has expired.

MR. DINGELL. I do thank you, Mr. Chairman.

MR. BURGESS. And I apologize to the Ranking Member of the subcommittee, Mr. Stupak.

MR. STUPAK. No problem.

MR. BURGESS. I should have recognized him first. I violated protocol, but Mr. Stupak, you are now recognized.

MR. STUPAK. Admiral, you said that on the eastern pipeline there, BP said there was 16 spots of concern. You said there is more like 187.

VICE ADMIRAL BARRETT. Yes, sir. I have seen the report. There were 16 very serious spots where there was wall loss, in some cases up over 80 percent, but if you are looking at the risk profile there, we would be looking at wall losses in locations where you might have only seen it, say, down at 50 percent, might not require--it might not be as serious but it is still indicating a problem.

MR. STUPAK. Well, you said you had seen the report. Do you know the date of that report?

VICE ADMIRAL BARRETT. I can get that information and provide it for the record.

MR. STUPAK. Was it this year?

VICE ADMIRAL BARRETT. It is the result of the pigging--it is a result of the ILI, the pig run.

MR. STUPAK. That has been done after the--

VICE ADMIRAL BARRETT. And the follow-up ultrasounds based on the areas identified, but we could certainly provide that for you.

MR. STUPAK. When did Department of Transportation first learn that major solids, amounts that could not easily be pigged, were in the eastern operating area line, and so when does--when did you first learn that? Again, this year?

VICE ADMIRAL BARRETT. It would have been this year after the spill when we put inspection teams up on the lines, and we spoke also with Alyeska Pipeline. There were concerns, significant concerns, and I actually went out and looked at Alyeska and met with them to discuss that, but it would have been subsequent to the March spill

MR. STUPAK. Do you have any idea--or when do you believe that BP would have learned of this blockage?

VICE ADMIRAL BARRETT. I can't speak to when they would have learned. I can provide you exactly when they would have identified the issue to us, which would probably have been back in late March or early April.

MR. STUPAK. When should they have learned of the blockage?

VICE ADMIRAL BARRETT. Again, our assessment was they should have been regularly maintenance pigging the lines to prevent that from coming up.

MR. STUPAK. And they didn't regularly pig the lines, so you and Ms. Gerard were talking about they resisted the integrity management program over a period of 2 to 3 years?

VICE ADMIRAL BARRETT. Yes, sir.

MR. STUPAK. And when I say "they" I mean BP. Well, who would enforce the integrity management program?

VICE ADMIRAL BARRETT. We would, and we issued orders to BP to ensure that they brought that program to bear.

MR. STUPAK. So for 2 to 3 years, was it a negotiation with BP then? I mean, I just can't understand why DOT would not just say hey, look, we have been going at this for a year, let us just put forth an enforcement rule.

VICE ADMIRAL BARRETT. We did, but it is a little more complicated in the sense that they would have--once you bring them in, they would have to bring forward with that a plan to assess the condition of the lines, but, you know, I can't speak to all the decisions there, maybe Ms. Gerard can, but from my point of view, it probably took too long.

MR. STUPAK. Well, did they ever bring forth a plan to check this line then?

VICE ADMIRAL BARRETT. Eventually they did but as I--

MR. STUPAK. When was that?

VICE ADMIRAL BARRETT. It was after the March spill.

MR. STUPAK. Everything seems to be after March.

VICE ADMIRAL BARRETT. Yes. Maybe Ms. Gerard, do you have any amplifying data there? We can provide the data we have--

MR. STUPAK. Go ahead, Ms. Gerard.

MS. GERARD. Just to clarify, the initial enforcement action is called a notice of amendment, which is an enforcement tool used to make the company modify their plans. They are entitled to due process and hearings and--

MR. STUPAK. Sure.

MS. GERARD. --they brought forth information arguing with us about the fact that they couldn't possibly affect the threatened endangered species and so we went back and forth for a while until we said enough is enough, we are ordering you, directing you, used a tougher tool, order directing amendment.

MR. STUPAK. So when was that order directing amendment? Any idea?

MS. GERARD. April.

MR. STUPAK. After March. Okay. So if you have to go through this and the State, right, Mr. Fredriksson, doesn't have any enforcement on this risk management program?

MR. FREDRIKSSON. That is correct, Congressman Stupak. Our authority is over leak detection and the actual spill itself.

MR. STUPAK. Mr. Fredriksson, let me ask you this. In 2001, were you, Commissioner Michelle Brown and Larry Dietrich warned by your staff that BP's pipeline leak detection system had been out of compliance since 1997?

MR. FREDRIKSSON. No, sir.

MR. STUPAK. In 2001, did BP request a waiver from your department to avoid installing leak detection systems on the Prudhoe Bay pipelines?

MR. FREDRIKSSON. Not that I am aware of, no, sir.

MR. STUPAK. In 2001, did your department staff recommend enforcement against BP for failure to install the required leak detection system?

MR. FREDRIKSSON. I would have to check the records on that, Congressman Stupak. I do recall there was an incident that did fall within the leak detection, not moving forward on that. We took action to ensure that that moved ahead expeditiously. We took enforcement--

MR. STUPAK. Well, that was all 2001, so what did you do to make sure it moved forward expeditiously?

MR. FREDRIKSSON. It is my understanding that--I would have to check the records. I just can't speak to it in absolute terms. But I do know the leak detection system was put in place and tested and--

MR. STUPAK. Do you know when leak--

MR. FREDRIKSSON. I don't have the date, no.

MR. STUPAK. Before the spills though, right?

MR. FREDRIKSSON. Before the spills.

MR. STUPAK. And how come it didn't work if it was put in place and tested and everything? How come it didn't work?

MR. FREDRIKSSON. Congressman Stupak, the State's leak detection requirement is 1 percent of the throughout in a 24-hour period. This flow, this leak from this particular incident on GC-2 was too small to trigger an alarm with that leak detection sensitivity.

MR. STUPAK. Well, if you remember that, then let me go back and ask you the first couple questions. Were you, Commissioner Michelle Brown or Larry Dietrich warned by your staff that BP pipeline leak detection systems had been out of compliance since 1997?

MR. FREDRIKSSON. I don't have any recollection that those specific--

MR. STUPAK. But if someone told us that or reported that to this committee, you wouldn't be surprised or you couldn't dispute it, could you?

MR. FREDRIKSSON. I would be surprised to learn that the department management had been warned that BP was out of compliance for--I believe that is a 4-year period.

MR. STUPAK. Right, and did--my second question that you didn't have any knowledge of, let me ask you again. Did BP request a waiver from your department to avoid installing leak detection systems on the Prudhoe Bay pipelines?

MR. FREDRIKSSON. I can't speak definitely. I can't recall.

MR. STUPAK. Did your department receive complaints from individuals that BP was out of compliance with the integrity management system or program, I should say?

MR. FREDRIKSSON. The department has received a number of complaints over the years with respect to BP operations from a number of different sources.

MR. STUPAK. How many complaints? Would you know?

MR. FREDRIKSSON. I would not know offhand.

MR. STUPAK. Do you know how many complaints were on corrosion or concerning corrosion problems?

MR. FREDRIKSSON. I don't have the exact number, no.

MR. STUPAK. More than two?

MR. FREDRIKSSON. With respect to corrosion? I wouldn't be surprised if it was more than two and less than a half dozen.

MR. STUPAK. Between two and six then. Okay. In 2001, did your staff warn you that Prudhoe Bay pipelines lacked appropriate equipment to evacuate oil out of the line in the event of a pipeline failure and recommended that BP be required to add pumps and tanks to be able to rapidly evacuate the pipelines?

MR. FREDRIKSSON. I don't have a recollection of that, no.

MR. STUPAK. Okay. Did the Alaska Department of Environmental Conservation staff present you, Commissioner Michelle Brown and Larry Dietrich with photos of sagging pipelines, poor pipeline maintenance practice and other inspection deficiencies at BP facilities?

MR. FREDRIKSSON. I--let me speak to the sagging pipelines. I don't have any recollection on the other topics. I know I provided staff with a photograph of a sagging pipeline from a trip I took to the North Slope and asked them to follow up on it.

MR. STUPAK. And did they follow up on it?

MR. FREDRIKSSON. To my knowledge, they did.

MR. STUPAK. They did?

MR. FREDRIKSSON. I delivered the message down to the industry preparedness program to have them look into that.

MR. STUPAK. Well, wouldn't staff report back since you are the guy who is providing the photos of sagging pipelines?

MR. FREDRIKSSON. I assumed it was taken care of. I don't recall if there was a report back, to be honest.

MR. STUPAK. Well, did you, Commissioner Michelle Brown or Larry Dietrich require BP to take any action to improve the oil spill prevention measures for their pipelines as a result of your staff warnings?

MR. FREDRIKSSON. Then-Commissioner Brown, I was then deputy commissioner, Larry Dietrich was the director of spill prevention response, the actions we took with respect to corrosion were characterized best in the charter agreement. In 1999, recognizing ARCO and BP were going to merge, we identified a number of issues that we wished the oil companies to address on the North Slope, seven to be exact, one of which was with respect to corrosion.

MR. STUPAK. That was 1999 and you made seven recommendations. Did you follow up? Did the Alaska Department of Environmental Conservation follow up to see if those seven were implemented?

MR. FREDRIKSSON. Yes, we did, sir.

MR. STUPAK. And were they implemented?

MR. FREDRIKSSON. They were implemented.

MR. STUPAK. Okay. Then can you explain to me then how the Coffman Engineering November 2001 report to you stated, and I am quoting, "External corrosion is the most immediate threat to pipeline integrity for BPXA." Were there four pipeline leaks during the 2000-2001 at BP facilities due to external corrosion?

MR. FREDRIKSSON. I don't have the record. I would not be surprised that there would be.

MR. STUPAK. Well, if in 1999 they did the seven things you told them to do, how come 2 years later you have four pipeline leaks in not even a year after this agreement was agreed to?

MR. FREDRIKSSON. With respect to the corrosion program that we were investigating, we needed to learn what in fact ARCO and BP merger would do with respect to their corrosion program. We needed to understand how the ARCO corrosion management policy dovetailed with the BP corrosion monitoring policy. We needed to see--we needed to learn what steps BP now was taking to manage corrosion.

MR. STUPAK. But if you had to learn all this stuff you said in 1999, you gave them a list of things to do.

MR. FREDRIKSSON. That is correct. The agreement was signed in--

MR. STUPAK. So you learned these things before 1999, right, and these were the things you wanted done?

MR. FREDRIKSSON. Congressman Stupak, the department was concerned about corrosion before 1999. We recognized there was an aging oil field. We recognized that BP and ARCO were going to merge. Both companies had corrosion monitoring programs, inspection control programs. We wanted to learn how those--how that was going to dovetail through the merger. We required through the agreement a commitment that BP make to the State to pursue a corrosion monitoring program and to report annually to the department. It has done so. That corrosion monitoring reporting has resulted in rules that the department has now adopted for corrosion regulation on flow lines. The vast majority of the pipelines on the North Slope are flow lines. High corrosivity--

MR. STUPAK. That is fine, and I agree with all that stuff, but if no one is enforcing it, it means absolutely nothing. So--

MR. FREDRIKSSON. The regulations--

MR. STUPAK. --let me ask my last question because my time is up. What real, measurable improvements has the Alaska Department of Environmental Conservation required BP to take t0 improve oil spill prevention on their pipeline systems in the last 5 years?

MR. FREDRIKSSON. Through the charter--

MR. STUPAK. The last 5 years, yes.

MR. FREDRIKSSON. Congressman Stupak, through the charter agreement, one, we have negotiated a charter agreement. Within that charter agreement, we have a number of spill prevention and response elements, one specific to corrosion. With respect to the corrosion, the corrosion evaluation that has resulted from that charter agreement has led the department to adopt through rulemaking regulations that will soon be in effect and we fully expect to enforce those rules with respect to corrosion on flow lines.

MR. STUPAK. Sure, that is all stuff on paper. I asked for real, measurable improvements.

MR. FREDRIKSSON. I--

MR. STUPAK. There has been none, has there?

MR. FREDRIKSSON. Congressman Stupak, if you want to measure it in terms of equipment, if you want to measure it in terms of spill response, research, there has been a lot of work done over the last 5 years with respect to spill response preparedness and spill response research. There has been a tremendous amount of work done on cleanup of the

North Slope from abandoned drums. There has been a tremendous amount of work by cleanup of contaminated sites, all of which was done under the charter agreement.

MR. STUPAK. That is great, but I want to know about this pipeline, not abandoned barrels and things like that. So it sounds like the State is asleep at the switch here, or what?

MR. FREDRIKSSON. I think just the opposite. Congressman Stupak, the regulations are not adopted overnight. Those regulations that we have adopted, corrosion control, need to be done carefully, they need to be based on the best science and they need to involve the public all along including the Federal agencies that are affected in this particular issue. Spending 2 years to, one, assimilate the information we had with respect to corrosion into a regulatory package which then goes through the rulemaking process for adoption, I don't consider it to be a stand back and do nothing exercise. I am proud of the fact that we got those regulations in effect. I expect them to be enforced. I expect them to show a measurable improvement in the situation with respect to flow lines.

MR. STUPAK. I agree, and when I asked for measurable improvements, you couldn't give me any, so okay. Nothing further, Mr. Chairman.

MR. BURGESS. The gentleman's time has expired. The Chair recognizes Mr. Markey from the full committee.

MR. MARKEY. I thank the Chair very much.

MR. BURGESS. I would like to recognize you for 5 minutes but he told me I had to recognize you for 10. You are recognized.

MR. MARKEY. Meaning it is bad news for you at the table. He was trying to say that very delicately.

Admiral Barrett, the Department of Transportation has recently proposed a draft rulemaking to regulate some low-stress pipelines. How many miles of currently unrelated low-stress pipelines would be subject to regulation by your department under that proposed rule?

VICE ADMIRAL BARRETT. This rule would bring about 1,300 miles of additional lines, low-stress and gathering lines, under our oversight.

MR. MARKEY. When BP's negligence has shown us that pipelines that are regulated are far better maintained than those that are not, why has the Department of Transportation proposed to allow DOT to regulate less than 14 percent of the 5,000 miles of currently unrelated low-stress pipelines like the ones up in Prudhoe Bay?

VICE ADMIRAL BARRETT. The lines--our estimate--a lot of these lines are not currently mapped so we are using an estimate but in general, the risks posed by many of these lines--many of these lines are much smaller and don't affect unusually sensitive areas. That is areas where there is an endangered or threatened species. We already regulate lines like this that operate in populated areas or in navigable waters so simply the risk assessment and the impact--these are very small lines in many cases, a mile or two, much smaller than the BP lines for the most part. BP's are 30-, 34-inch. These lines are down at the 8-inch to 16-inch size, and frankly, the risks and the benefit equation is not as large. We look closely--

MR. MARKEY. It is not as large but why wouldn't you regulate, you know, if you know that the regulation itself serves as a deterrent to negligence?

VICE ADMIRAL BARRETT. Well, there is a cost to complying with these regulations--

MR. MARKEY. A cost to BP?

VICE ADMIRAL BARRETT. Not to BP. BP would be covered by these regulations clearly.

MR. MARKEY. It is a cost to whom?

VICE ADMIRAL BARRETT. I thought your question was, if we brought more of these lines under--

MR. MARKEY. I am sorry. The cost runs to whom?

VICE ADMIRAL BARRETT. The operator of the line, in many cases small businesses where the cost burdens would be significant.

MR. MARKEY. Okay. So you are saying that they are basically given a small-business exemption?

VICE ADMIRAL BARRETT. I am sorry, and what I would also say is this is a proposal and we are soliciting comments, and if stakeholders or the public feel that we should cover more or less lines, that the scope of the rule is too narrow, too broad or that the requirements should be more or less stringent, we are happy to take that data and input, consider it and if appropriate, adjust. It is a proposal.

MR. MARKEY. Did your department do an estimate of what the cost to big oil companies would be if you were to regulate low-stress pipelines under their control?

VICE ADMIRAL BARRETT. We do have a cost estimate in the notice and I don't recall it offhand but I would be glad to provide that.

MR. MARKEY. Is that a different cost-benefit analysis when you have a large, large company that has low-stress pipelines?

VICE ADMIRAL BARRETT. The cost benefit of the rule is looked at as a package but we are also required--

MR. MARKEY. I understand where it might be different for a small business but how about for a big oil company? When companies are making $25, $30 billion a year, it is--

VICE ADMIRAL BARRETT. Again, the large companies like BP, the type of lines we are talking about on the North Slope would be covered.

MR. MARKEY. Don't you think, Admiral, that when BP made $7.27 billion in profits during the last quarter of this year that they and other big oil companies can afford to pay to ensure that there is not a similar case of negligence, spill or shutdown elsewhere?

VICE ADMIRAL BARRETT. Well, I would come at it this way, sir, is that our obligation and our commitment is to ensure that pipelines operate safely, and if you are going to be in a business, you have to make the--the first responsibility for safety rests with the operator, and if you are going to be in this business, you have to make the investment necessary to operate your lines safely, and that is our responsibility to make sure that happens.

MR. MARKEY. Admiral, is there any requirement under these proposed regulations that companies must use internal inspection devices such as smart pigs and other pigs?

VICE ADMIRAL BARRETT. Yes, sir, but--and this is frequently--and I have heard some comment misunderstood. Even on many lines, there are segments of lines where you cannot use an inline inspection device. You may have telescoping lines, you may have bends and turns in the lines, and so we expect the company that is regulated with the integrity assessment program we have to bring forward a program that generally requires use of smart pigs but also would provide for alternatives, hydrostatic testing, radiological assessments, ultrasound assessments to get at areas where smart pigs are simply not feasible. So when you look at the rules, the language will allow for tools other than smart pigs and it is--what we do require is a complete understanding of the condition of the line.

MR. MARKEY. So it doesn't require them the use of smart pigs?

VICE ADMIRAL BARRETT. It generally would require that they have a program in place to provide--

MR. MARKEY. I understand that, but it is possible, in other words, for BP to put corrosion inhibitors into the oil using ultrasonic testing, doing these coupon pulls, all of which have been found to be woefully inadequate compared to running the pigs through the lines, and BP could have then deemed what they did to be sufficient under the proposed regulations even though it is clear that they are inadequate--

VICE ADMIRAL BARRETT. No, sir.

MR. MARKEY. --compared to running the pigs.

VICE ADMIRAL BARRETT. The programs BP had in place up there would have failed under the regulation we are proposing. We, not BP, are the ones who make the assessment of the adequacy of the program and if we feel it is inadequate--

MR. MARKEY. And why would it have failed and how would it have failed?

VICE ADMIRAL BARRETT. Because the corrosion program they had in place did not provide a comprehensive picture of the conditions of that line, specifically, the internal corrosion risks on those lines, and we would not have accepted that and our program would not accept it.

MR. MARKEY. Mr. Fredriksson, I have been told that BP is supposed to have in place a fund to ensure that at the end of its useful life, that these pipelines are safely decommissioned and dismantled without any harm to the environment obviously for the rest of eternity. Is that true?

MR. FREDRIKSSON. That is my understanding. That would fall under the State lease requirements which I am not responsible for so I can't speak definitely--

MR. MARKEY. Well, just tell me what you do know about it then. How much money is supposed to be in that program in just ballpark numbers?

MR. FREDRIKSSON. I have no idea.

MR. MARKEY. Do you know that there is supposed to be such a program?

MR. FREDRIKSSON. I understand there is a dismantling and removal provision but I have no understanding--

MR. MARKEY. Can I just--

MR. FREDRIKSSON. --or knowledge of the specifics.

MR. MARKEY. Your title is commissioner, Alaska Department of Environmental Conservation. Is that right?

MR. FREDRIKSSON. That is correct.

MR. MARKEY. And you are saying that this whole program of putting together a fund to make sure that these pipelines don't harm the environment is something that just hasn't come across your desk at all? You don't have conversations with people about it at all?

MR. FREDRIKSSON. No, that is correct. The actual removal at the end of the life is a lease arrangement and lease obligation under the Department of Natural Resources.

MR. MARKEY. It would just seem to me that the Department of Environmental Conservation has a pretty big, you know, stake at least in knowing about what is going to happen when these pipelines get dismantled but I will take you at your word. I am told that there is a multi-billion-dollar fund which is supposed to be out in place and I have also been told that BP has not funded it, that there isn't adequate money in this decommissioning fund and that instead BP is taking the profits and expatriating it and they are drilling in countries around the world but they have left this fund that is supposed to be there for the decommissioning of these pipelines relatively empty, which would seem to me to follow pretty clearly along the same lines as their lack of attention to this pipeline safety issue in general. But you are saying that is nothing you know about?

MR. FREDRIKSSON. Congressman Markey, that does not fall under the purview of DEC.

MR. MARKEY. It sounds pretty scary to me, in fact, that if this information that I have been given is accurate in terms of the long-term protection of the environment up in Alaska. I am going to pursue that, Mr. Chairman, as a line of independent questioning to the State of Alaska and to BP through you to the State and to BP.

Admiral Barrett, you say in your testimony that your department believes that most other unregulated low-stress pipelines in the lower 48 States are operated to a higher standard of care. Since you currently have regulatory oversight over those lines, what information are you basing that belief on?

VICE ADMIRAL BARRETT. Sir, in developing--as I indicated--

MR. MARKEY. I am sorry. You have no regulatory jurisdiction over it. What is the basis for you making that--

VICE ADMIRAL BARRETT. As I indicated, over the past 2 years or more than 2 years actually, we have been developing this rulemaking to bring these low-stress and gathering lines under our oversight, and in the course of public hearings and in the course of developing the record for that rulemaking, we were in fact asking about maintenance practices on the lines, what people generally were doing or not doing, and it was part of the record, and you also have the history of the regulated lines in places like the North Slope as Mr. Hostler testified.

MR. MARKEY. It sounds to me, Admiral Barrett, that you are relying upon the representations of companies, the same kind of representations that was relied upon when BP was saying that they had done the job, and I just think that at this point, Admiral, that we should discontinue that reliance upon company assertions that save them money in the short run while exposing the environment and the public to great risk in the long run, and I just think it is time for you to end that presumption that I think has been extended to the industry. Thank you, Mr. Chairman.

MR. BURGESS. I don’t think that was in the form of a question, so it probably doesn’t require a response.

Admiral Barrett, if I could be permitted one follow-up question. Isn’t it true that during the 2001 debate on high-pressure lines, it was estimated that only 22 percent of the lines were covered but 82 percent of the lines ended up being covered?

VICE ADMIRAL BARRETT. Sir, as we bring any system or piece of the pipeline system under our regulatory authority, we actually get out on the ground, inspect the situation, inspect the lines, determine, as I said, like on the low-stress lines, these are estimates. A lot of these lines are not mapped. But once this rulemaking is in place, we will get out there, check those lines, check other lines in the area, and if it seems they fit within the ambit of the rule, we will bring them under our authority. So you are exactly correct. We inspect aggressively as well as issue rules.

MR. BURGESS. So the same thing could happen here on the low-pressure lines?

VICE ADMIRAL BARRETT. Yes, sir, it could.

MR. BURGESS. Thank you very much.

MR. STUPAK. Just one follow-up question.

MR. BURGESS. Sure.

MR. STUPAK. Mr. Fredriksson, I want to go back to the year 2000. I asked a number of questions about it. And as a result, let me ask you this question. Did the Alaska Department of Environmental Conservation recommend that settlement of the enforcement action for BP's failure to install the required leak detection systems include a requirement to smart pig these lines, enhance the corrosion control programs and require non-destructive testing examination?

MR. FREDRIKSSON. Congressman Stupak, I can't answer that question. I don't know.

MR. STUPAK. Why wouldn't you know? You are the commissioner.

MR. FREDRIKSSON. I am a commissioner where we have many different settlements arranged through the Department of Law and enforcement actions. We deal with many enforcement actions. My recollection of what happened in an enforcement action in 2000 when I was not a commissioner, I don't have that information. I would be happy to look it up and get back to the subcommittee on that.

MR. STUPAK. Okay. Maybe I will submit these in writing then because I think you could go back and look up and see if there were any enforcement actions for BP during these recent years. Thanks.

MR. BURGESS. Thank you, Mr. Stupak. Do you yield back?

MR. STUPAK. Yes.

MR. BURGESS. Very well. I think that concludes our testimony. I may have one additional question for Mr. Fredriksson that I will submit as a written question but it has been a long day. Again, I appreciate everyone's forbearance on this. It is an important subject. This committee will stand in adjournment.

[Whereupon, at 4:37 p.m., the subcommittee was adjourned.]

RESPONSE FOR THE RECORD OF STEVE MARSHALL, PRESIDENT, BP EXPLORATION ALASKA, INC.

RESPONSE OF BP AMERICA INC. TO FOLLOW-UP QUESTIONS FROM HEARING OF OVERSIGHT & INVESTIGATIONS SUB-COMMITTEE SEPTEMBER 7, 2006

Questions from Congresswoman Blackburn to Steve Marshall

1. How will BP's revenues be affected because of the shutdown?

The August shutdown of the EOA reduced BPXA revenues by approximately $170 million.

2. How much are you spending to restore the Eastern Operating Area and upgrade both areas?

The Prudhoe Unit owners expect to spend around $65 million on spill response, DOT order compliance, and the building of bypasses for the Eastern Area facilities.

The full replacement of the 16 miles of East and Western transit lines with smaller diameter lines, pigging facilities plus state of the art leak detection systems will cost an estimated $200+ million.

3. How often do you "pig" your lines for internal corrosion? Inspect for external corrosion?

We conduct over 350 pig runs each year on pipelines throughout the North Slope. Our external corrosion program inspects thousands of locations each year. In 2005, we completed 34,994 external corrosion inspections.

4. What is your schedule for each of these types of inspections? Is this the normal industry standard?

The location and frequency of pigging and external corrosion inspection depends on site-specific factors. Lines are scheduled for inspection / re-inspection based on the operating conditions, results of previous inspections, and fitness for service criteria. Our program generally follows the requirements of the American Petroleum Institute's API 570 Piping Inspection Code.

5. How long does it take to perform a complete internal and external inspection of all your lines? Is this on a continual cycle?

We have a Comprehensive Inspection Program (CIP) that inspects virtually all facilities and piping on the North Slope. These inspections occur throughout the year. Individual inspection locations are selected based on previous inspection results, anticipated corrosion rates, and fitness for service criteria. Most of these locations are inspected

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every 1 to 3 years. We also have some locations on our Frequent Inspection Program (FIP) and our Corrosion Rate Monitoring (CRM) program, which involve more frequent inspections. On the whole, we inspect about 130,000 locations each year.

6. What is the normal business practice for an oil industry to have a complete inspection of its pipelines?

According to the DOT's Draft Regulatory Evaluation for hazardous liquid pipeline integrity management programs (docket RSPA 99-6355-23), an API survey concluded that large liquid pipeline operators conducted in-line inspections on 6% of their pipeline mileage each year in the period 1995 – 1999 (i.e. prior to regulatory mandates). Given that 11% of their mileage could not be pigged, this correlates to an average re-inspection interval for piggable pipes of about 15 years (some would be less frequent, others more). Note that this survey was of transmission pipeline operators (i.e. long distance, cross-country types of pipelines). The types of pipelines found in oil production operations (such as the North Slope, upstream of the Trans-Alaska Pipeline) would typically receive in-line inspection less frequently than transmission pipelines, if at all.

In the oil production industry, it is not a normal practice to conduct the type and extent of ultrasonic inspections that we perform on the North Slope. Our ultrasonic inspection program for pipelines exceeds the common industry practice for such lines.

7. When you identify corrosion problems, what measures do you take? What is the average time and cost to solve them?

Our corrosion monitoring results are maintained in a central database, which allows us to perform historical trend analyses and compare the equipment's condition versus the applicable fitness for service criteria. Our response depends on the type, location, severity, and speed of corrosion detected, and includes such things as scheduling follow-up inspections (for instance, with a more accurate inspection device), increasing corrosion inhibitor rates, reducing operating pressures or flowrates, and conducting temporary or permanent repairs or replacement.

The time and cost to resolve corrosion problems vary widely, and we do not keep data concerning average time and cost to solve them.

8. What corrosion prevention practices were in place when the West field pipelines were installed?

These pipelines were installed in the 1970s, using standard corrosion prevention practices at that time. Since then, the corrosion prevention practices have evolved into much more sophisticated and comprehensive programs, as described above.

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9. Were there any policies or procedures in place that would be triggered if severe corrosion is detected or might be detected?

We have established "fitness for service" criteria for our equipment, using commonly accepted industry practices and standards, and compare the results of our inspections to those criteria. We trigger a repair program when the equipment reaches 105% of the fitness for service criteria (i.e. we initiate repair when the equipment is still 5% above the acceptance criteria).

10. How long and at what cost does it take to replace or install one mile of pipeline?

A rule of thumb for Alaskan North Slope construction cost is $200,000 per inch-mile of pipeline.

Once pigging facilities, tie-ins, metering and leak detection are added, typical costs are in the order of $750,000 per inch-mile.

Construction schedules are very much situation dependent.

11. *How much pipeline is needed to construct a bypass line in the East fields? Can this be done immediately for a temporary fix? How long would it take a similar type of bypass to be done in the lower 48 states?*

Each bypass length and construction schedule is dependent on the configuration of the plant in question and leadtimes for pipeline availability. By illustration, the bypass lengths being constructed in the Eastern Operating area are:

	Length	diameter
FS2 to Endicott line	400ft	8"
FS1 to Lisburne line	400ft	10"
FS3 to Lisburne line	1000ft	12"

The scope of work also includes valves, fittings and metering equipment. These lines were put in place in under 3 months. There is no simple benchmark for comparing bypasses in the lower 48 states. It would be fair to say, as long as lead times are comparable, construction times are also comparable. One difference is that construction seasons in the North Slope of Alaska are limited due to climate factors.

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Questions from Congressman Burgess to Steve Marshall

1. *Did BP Exploration Alaska receive any warnings from employees that there were possible corrosion problems with these Prudhoe Bay transmission lines?*

As has previously been stated, the company is in the process of investigating matters related to the spill, including interactions with employees in prior years about corrosion in the oil transit lines. While reserving the right to supplement this response as investigation progresses, the company nevertheless notes as follows.

Corrosion and the rate of corrosion and the programs to inhibit and monitor corrosion have been the subject of employee concerns and discussion. We are continuing our review and fully expect to produce additional responsive documents In the period prior to the incidence of smart pigging of the oil transit line in the Western Operating Area in 1998, some corrosion engineers were concerned about corrosion risks in that line. Based on that expressed concern, the company performed the maintenance and smart pigging of this oil transit line in 1998.

The 1998 smart pig run found more corrosion indications than were found in the 1990 smart pig run. The maximum internal corrosion loss detected in the 1998 smart pig run was approximately 50% of the wall (corresponding to .187 inches wall remaining). These results were followed with manual ultrasonic measurements. These follow-up manual ultrasonic measurements largely confirmed the results of the 1998 smart pig. These results indicated that there had been continuing internal corrosion damage between 1990 and 1998. However, while experiencing some corrosion, OT-21 was well within the BPXA "fit for service" criterion. This fitness-for-service criterion is ANSI/ASME B31G-0.100 inch wall thickness or thickness required for 105% of the maximum allowable operating pressure. It further notes that the amount of wall loss detected by the inline inspection tool in 1998 at the particular caribou crossing where the March 2006 leak occurred was reported to be only 9%, so the pigging results did not indicate that this location was at risk.

During the late fall of 2001, BPXA was in the process of installing meters required for the leak detection system mandated by Alaska law and the Alaska Department of Environmental Conservation. As part of the implementation of this system, BPXA was evaluating locations for installing the different meters that would comprise the system. Testing of the meters at a particular location on the oil transit lines in the Eastern Operating Area was unsuccessful because of what were believed to be sediments in the line. Based on that finding and pursuant to a Compliance Order by Consent that BPXA entered into with the State of Alaska, BPXA began preparatory engineering processes to perform a maintenance pigging of the oil transit line in the Eastern Operating Area. These processes included developing an engineering plan for pigging the oil transit line, modifications to the pig receiving facilities in the Eastern

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Operating Area, and identification and implementation of all the necessary operational and engineering decisions and determinations needed to undertake this work.

BPXA ultimately located another point on the Eastern Operating Area oil transit lines where an ultrasonic meter worked, and it was able to install a turbine meter at the upstream location where sediment had apparently been detected to accurately record flow at that location. In addition, ultrasonic meters were tested and successfully installed on the oil transit lines in the Western Operating Area. As a result, the state of Alaska eliminated the requirement that the line be pigged at that time.

Beginning in 2004, the company began to detect increased rates of corrosion within the GC-2 facility. Based on those results, the company increased the number of inspections on the oil transit lines, including the OT-21 segment. Based on that testing, which showed an increasing rate of corrosion from 3 mils per year to 32 mils per year, the oil transit lines in the Western Operating Area were put on the schedule for maintenance and smart pigging in 2006.

2. *Wasn't the 2004 Vinson & Elkins Investigation, instigated by whistleblower concerns about pipeline integrity, corrosion, and safety that the Environmental Protection Agency shared with BP?*

Yes. The principal allegations that prompted the Vinson & Elkins investigation related to whether employees in the corrosion group had been retaliated against or harassed by their superiors for raising health, safety, and environmental concerns. While investigating these allegations, the Vinson & Elkins team did inquire about some issues related to corrosion on the North Slope, but the Vinson & Elkins investigation was not, and was not intended to be, a comprehensive investigation of the effectiveness of the Prudhoe Bay corrosion control program.

a. *What was the basis for this report?*

The Vinson & Elkins report was based on interviews with approximately 50 BPXA employees and contractors and the review of relevant documents. The reasoning underlying the Vinson & Elkins conclusions and recommendations is set forth in the report from that investigation.

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b. *The Vinson & Elkins Report contains dozens of allegations that concern safety and corrosion issues. Do you have any idea, over the past five years, how many times BP Alaska has been notified by employees or anonymous tips regarding concerns about corrosion in the Prudhoe Bay pipelines?*

c. *What does BP do with each of these tips or concerns?*

The following response addresses both questions b and c.

BPXA has not had a formal employee concern program, so it does not have an exact number of the allegations, concerns or tips that may have been raised about corrosion in any of the pipelines. BP encourages employees and contractors to raise concerns through the line management, and does not keep formal records of those issues that are raised and resolved through line managers. In the summer of 2001, the Operational Review Team did collect employee concerns, eight of which were about the corrosion program and/or corrosion in the pipelines. The BP America Ombudsman Program is presently in the process of reviewing all the allegations and concerns that have been raised since 2000, and upon completion of that project, we will provide additional information to the Committee. .

It is BPXA's intention to reach a determination and resolution on all concerns it receives, particularly any involving health, safety, environment, integrity or operations, which include the corrosion program. The review of the legacy concerns being conducted by the Ombudsman Office should identify what action has been taken into the concerns that have been identified since 2000. As stated above, while BPXA has not had a formal employee concerns program, it does have a number of programs that employees may use to raise concerns that they do not believe have been appropriately handled. This includes the employee-management HSE committees on both the West and East sides of the field, a 1-800 number to an independent investigator (Paul Flaherty), an HSE "hot line," and the BP Open Talk program. BP is evaluating whether to consolidate or reorganize these programs, but at the present time we believe it is important to retain any avenues that employees are familiar with to raise concerns.

d. *The Vinson & Elkins Report contains an appendix of 72 allegations about the corrosion control program and specific safety concerns. Have all of these issues been addressed to your satisfaction, and completely remedied if necessary, since BP received the law firm's report?*

BPXA, based on results of the Vinson & Elkins review, made appropriate policy changes and required the same from its contractors, as needed. BPXA continues to investigate concerns regarding the corrosion program including some of the concerns similar to those raised by the original 72 allegations.

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e. *Allegation number 29 points out that some corrosion experts – including one particular individual – resigned over concerns about pipe integrity. This seems very relevant to the topic of corrosion control. So, why wasn't this individual located and interviewed by the Vinson & Elkins investigation?*

f. *Wouldn't it be important for BP to contact this individual and determine exactly what his concerns were, and whether they were valid?*

The following response addresses both questions e and f.

Vinson & Elkins specifically asked the individual that raised this allegation to provide information so that the allegation could be investigated further. Vinson & Elkins was not provided with sufficient information to determine who the particular individual was. A number of individuals that may have had information regarding this allegation refused to speak with Vinson & Elkins.

We believed that some people had additional information which was not available to us. This problem was presented to the debarment officer, Jeanne Pascal, before the V&E report was final. Ms. Pascal directed V&E to finalize the report, observing that these individuals had the opportunity to come forward and provide information but chose not to.

g. *Allegation number 19 mentions that agency inspectors are directed to inspect only good areas of the pipeline, although Vinson & Elkins found no evidence of this. Can you speak to the relationship between the Alaska Department of Environmental Conservation and BP Alaska? Can and do inspectors go wherever they want when inspecting BP's pipeline?*

Yes. There are no limits or restrictions placed by BPXA on where inspectors for the Alaska Department of Environmental Conservation can go while they are on site.

h. *Allegation number 10 and 11 describe concerns that over the past several years there have been concerns raised about cost-cutting and that corrosion control and monitoring was suffering – that serious damage was occurring to the pipelines and infrastructure. Has there been cost cutting in the corrosion control program over the past several years?*

As stated previously, this question inquires into an area that is the subject of ongoing investigation. BPXA reserves the right to supplement this response as investigation into this and other matters progresses.

As has previously been indicated, BPXA's budget for corrosion, inspection and chemicals group has increased substantially over the past five years. The 2006 budget is

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$71 million, which is a 15% increase from 2005 and an 80% increase from 2001. These facts demonstrate that the overall budget for the corrosion program has increased over time. That being said, costs are always a consideration and are carefully reviewed annually as part of the budget process. The CIC Group, like any part of BPXA, went through the budget process and needed to justify all aspects of its program.

BPXA is still investigating whether any "cost-cutting" occurred in the corrosion control program historically that impacted safety considerations. BPXA is currently evaluating the extent to which this occurred, the programs in question, and whether any such actions had anything to do with corrosion control matters on the oil transit lines.

i. *If the corrosion control budget was increasing, why would Mr. Woollam be aggressively trying to reduce costs? Did company management direct the CIC Group to reduce costs?*

The Vinson & Elkins report could not reach a conclusion on the motivation for Mr. Woollam's decision to reduce coupon pulling staff. In his interview by the Vinson & Elkins team, Mr. Woollam stated that this reduction was done to match crew size to what he believed should have been a reduction in work that occurred because of changes to the corrosion program, which had reduced the number of coupon pulls by 25%. Mr. Woollam told the Vinson & Elkins team that this reduction was not caused by budget pressure and that the budget was in fact increasing at this time.

BPXA does, however, make every effort to manage costs well. This includes evaluating cost reduction options on a regular basis, even if these options are not selected. Moreover, the CIC Group, like other groups within BPXA, was under pressure to control costs during this time period and reducing the size of the coupon crew would have resulted in a cost savings.

BPXA is still investigating whether any cost-cutting occurred in the corrosion control program historically.

j. *It is my understanding that monitoring corrosion coupons is the key to keeping tabs on where corrosion rates are getting too high, so that action can be taken before conditions get too bad. Why then, as the Vinson & Elkins Report describes, did Mr. Woollam push so hard to reduce the corrosion coupon team by 25%? Did management direct Woollam to cut the coupon monitoring team?*

First, corrosion coupons are not the sole mechanism for assessing corrosion rates. A significant aspect of the corrosion control program is the use of ultrasonic inspection or other forms of non-destructive examination, which provide important data about corrosion rates. Second, the reduction in the size of the coupon-pulling crew did not relate to the coupons installed in the oil transit lines.

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As for the coupon program, the Vinson & Elkins report concluded that the number of coupon locations and the timing of coupon pulls had been reduced as part of an overall program to rationalize and manage the number of pulls. As that report noted, CIC managers told the Vinson & Elkins team that this is because less-frequent pulls were appropriate for certain lines, and corrosion engineers informed them that there are a number of factors affecting the decision to remove a coupon location from the pull schedule, including eliminating redundant locations on the same line, greater use and effectiveness of chemical mitigation, and greater use of other inspection techniques, such as X-rays. CIC crew members informed the Vinson & Elkins team that this makes sense from their field observations, where many coupons showed little or no corrosion when pulled. It should also be noted that there are many reasons to reduce the number of coupon pulls aside from budget concerns, as coupon-pulling is a physically challenging job performed in harsh arctic conditions, and eliminating unnecessary pulls is appropriate from a worker safety point of view. Indeed, BP Chief Engineer John Baxter recommended further evaluation of potential to reduce coupons in his 2005 report both because of the safety risk of this work and because of a belief that corrosion data might be more efficiently gathered via alternative means.

While Vinson & Elkins did not find any indication that Mr. Woollam had been directed to cut the coupon monitoring team, Mr. Woollam, like any BPXA manager, had his budget carefully reviewed as part of the budget process. Notwithstanding the increase in spending for the corrosion program, Mr. Woollam was expected to find ways to control costs.

k. *Why did Vinson & Elkins recommend that Mr. Woollam be removed from his management position on the corrosion control team? Was he removed? If so, when did you remove him and why?*

The reasoning underlying Vinson & Elkins's recommendation is stated in the report written by the Vinson & Elkins team. This report did not find that Mr. Woollam had intentionally retaliated against or harassed employees, nor did it find any information that suggested that the corrosion program was itself ineffective. Rather, the report stated that removing Mr. Woollam would be a way to address the negative atmosphere that had developed in the corrosion program organization. Moreover, it indicated that Mr. Woollam's technical skills could be appropriately used elsewhere in the BP organization. This recommendation was made in late 2004 and became effective January 1, 2005. BPXA management concluded that this was an appropriate way to address the chilled atmosphere in the CIC organization and was in the best interest of both BPXA and Mr. Woollam.

l. *On page 4 of the appendix, allegation number 13 discusses an allegation of data scrubbing, and allegation number 17 describes concerns that corrosion field data was being manipulated. What does the report mean that no evidence was found of*

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manipulation? In other words, the status comment doesn't explain where the investigation looked for evidence, and seems simply to imply that data may receive a "positive spin", isn't "spin" and manipulation the same thing?

The Vinson & Elkins report states that the team found no evidence, for example, that data was being removed from the system or altered, but notes that the investigation itself would not have been sufficient to necessarily find such evidence due to its scope. As a result, the Vinson & Elkins investigation recommended that the corrosion data system be reviewed by a technical team, which BPXA implemented. That review also found no evidence that data was being manipulated or falsified.

This report, entitled "MIMIR Application Data & Security Assessment," was provided by BPXA to Congress on September 1, 2006. It reflects an evaluation of the security posture of the MIMIR components against the industry best practices standard. The report evaluated a number of findings and conclusions in the collection reporting version data. That evaluation found no evidence to support the allegation that workers were pressured to falsify corrosion monitoring reports. That report also determined that it is not possible to remove measurements from the MIMIR system, including the so-called "worst figures." This review included an evaluation of a comprehensive event log that shows all data manipulation activities.

BPXA learned in 2002 that several employees of its inspection contractor, AII, had falsified inspection reports. As a result of this discovery, the contract was not renewed and another inspection contractor was brought in to perform this work. BPXA recognizes the importance of accurate field data and is committed to following up on any allegations. BPXA has an ongoing investigation to assure itself of, among other things, its data integrity.

RESPONSE FOR THE RECORD OF ROBERT A. MALONE, CHAIRMAN AND PRESIDENT, BP AMERICA, INC.

RESPONSE OF BP AMERICA INC. TO FOLLOW-UP QUESTIONS FROM HEARING OF OVERSIGHT & INVESTIGATIONS SUB-COMMITTEE SEPTEMBER 7, 2006

Questions from Congresswoman Blackburn to Bob Malone

1. *Is ultrasonic testing better than smart pigging to identify corrosion in oil pipelines?*

Smart Pigs, rigged with Magnetic Flux Leakage (MFL) and Ultrasonic Thickness testing (UTT) modules, are used for accurate inspections of the wall of pipelines. Smart pigs and other automated techniques are helpful in identifying locations that should be more closely monitored using one of the point inspection methods (e.g. visual; ultrasonic; radiographic).

Ultrasonic testing (UT) involves the use of a high frequency sound wave to produce a precise measurement of the thickness of a material. The technology is a well proven diagnostic tool routinely used for weld and flaw detection, as well as corrosion monitoring.

BP's North Slope pipeline monitoring and inspection program incorporates combinations of ultrasonic, radiographic, magnetic flux, guided wave and electromagnetic inspection techniques. The program did not routinely run maintenance pigs or smart pigs in the oil transit lines because North Slope pipelines are above ground, allowing for direct inspection of pipeline sections where corrosion is most likely to occur. Ultrasonic and Radiographic testing was used as a leading indicator to trigger further action. In hindsight, there was a gap in BP's program and regular use of maintenance and smart pigs will be incorporated into the monitoring and inspection program of BP's oil transit lines.

2. *Does the oil industry standard on testing for internal corrosion involve ultrasonics, pigging or both?*

The industry relies on a number of testing methodologies including ultrasonic testing and smart pigs to perform internal inspections. Smart pigs are good for identifying anomalies along the length of a pipeline. These anomalies are typically verified through the use of more precise methods like ultrasonic. BP primarily relied on the use of ultrasonic testing for its oil transit lines because these lines generally run above grade and because they shipped sales quality crude.

3. *Has BP expressed any interest in developing the oil in ANWR if the area became available for drilling? Have the recent incidents affected your future interest in development in ANWR?*

Coastal Plain exploration and development is not part of our Alaska business plan. The area is not available for exploration or development and is not the subject of active

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evaluation. Plans for growth of our Alaska business do not anticipate Coastal Plain access. We are focused, instead, on the Alaska opportunities available to the company today.

If the Congress and the President determine that energy development in ANWR is in the best interest of the United States, we will evaluate the opportunity made available by the government, assess it against the other exploration opportunities in our global portfolio, and then decide – on the basis of many factors -- whether the Coastal Plain is a place BP should explore.

We have demonstrated in Alaska and elsewhere that we can responsibly develop projects in sensitive areas. We are confident of our ability to operate in areas like the Coastal Plain of ANWR with minimal impact to the environment and in ways compatible with healthy and diverse wildlife populations.

4. *There have been some concerns about BP's safety record as this incident now joins several other accidents at BP installations. Because of these accidents, did the U.S. Chemical Safety and Hazard Investigation Board order your company to appoint an independent safety review panel? What is the current status of this panel? Is it examining BP's safety management structure and looking at all of BP's installations to determine if there are any safety concerns at any of them?*

BP established the BP US Refinery Independent Safety Review Panel ("Panel") in response to an August 2005 urgent recommendation from the U.S. Chemical Safety and Hazard Investigation Board (CSB). The CSB's recommendation followed from its investigation of a series of operational incidents at BP's Texas City refinery, including the March 2005 Isom unit explosion which tragically claimed the lives of 15 workers and injured many others. The CSB does not have authority to issue and enforce "orders" but it can issue safety related recommendations. BP voluntarily accepted CSB's recommendation and established the Panel, headed by former Secretary of State James A. Baker, to conduct a thorough and independent review of BP's process safety management systems and safety culture at its five US refineries. The Panel was formally chartered in late October 2005, and commenced its work in November 2005. As the CSB has acknowledged, in addition to Secretary Baker, the 10 member Panel is a diverse and distinguished group including six members with documented expertise in process safety or management of high risk enterprises.

The scope of the Panel's review is defined by its charter and extends to BP's entire US refining organization. The terms of the charter direct the Panel to examine and recommend any needed improvements to BP's safety management systems and safety culture. The Panel has been at work for nearly one year and has visited each of BP's five US refineries and conducted public meetings in each of those refinery's local host

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communities. Among other lines of inquiry, the Panel has: i) interviewed hundreds of refinery management personnel, hourly employees and contractors, ii) conducted an extensive survey of workforce attitudes toward safety and safety culture, iii) reviewed thousands of documents concerning BP's safety and integrity management programs, and iv) conducted detailed process safety reviews at each refinery. BP has given the Panel its full cooperation and has facilitated the Panel's access to BP's refining organization and senior management. BP expects to receive the Panel's final report with its findings and recommendations in late November 2006. BP will publish the Panel's final report and share these findings with the public so that all of industry will have the benefit of the Panel's extensive review.

While we await the Panel's report, BP has already instituted a number of significant measures since March 23, 2005 based on our own internal investigations and other learnings including those generated through our input to the Panel process. These actions have broadly been directed at the immediate incident findings, implementing ongoing improvements in operations systems and processes as well as importantly beginning to address the immediate cultural issues to emerge from the incident.

BP looks forward to receiving the Panel's report and will carefully consider its findings and recommendations. As a learning organization that is committed to continuous improvement of our operations and systems, we expect to carefully consider the application of the Panel's recommendations for improving our long term safety and integrity management programs across the company.

BP's response will be a measured one so that the full benefit of the findings will realized and sustained. We will map the findings against the actions we have already taken and those built into ongoing plans. Necessary adjustments will be identified and carefully integrated by the appropriate managers within our operational organizations. We are committed to applying relevant lessons learned across our system, and to sharing them openly with other interested parties external to BP, as part of our drive to improve safety continuously in all of our operations.

RESPONSE FOR THE RECORD OF KURT FREDRIKSSON, COMMISSIONER, ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
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October 17, 2006

The Honorable Michael Burgess
Committee on Energy and Commerce
U.S. House of Representatives
Washington DC 20515-6115

Dear Mr. Burgess:

The October 4, 2006, letter from Ed Whitfield, Chairman, Subcommittee on Oversight and Investigations for the Committee on Energy and Commerce includes several questions regarding certain actions taken by the Alaska Department of Environmental Conservation (ADEC) related to BP Exploration (BP) North Slope operations. My response to each question follows.

Question 1. Exactly what does the state of Alaska do with the Coffman Reports that you submit to them in final form? How does the state utilize the analyses and recommendations? Can you force BP to undertake the recommended actions within the reports?

The "Coffman Reports" referred to in the question are specific work product deliverables produced by Coffman Engineers, Inc. under a contractual scope of work with ADEC (enclosure 1). The final Coffman reports are retained as part of ADEC's administrative record and the recommendations are provided to the North Slope operators.

ADEC also uses the Coffman analysis of the annual corrosion monitoring reports from the North Slope operators to guide its oversight of pipeline corrosion issues. For example, information provided pursuant to the Charter Agreement led us to join with other governmental and non-governmental stakeholders in 2004 to review and update Alaska's spill prevention regulations. This review led to ADEC's recently adopted corrosion control regulations for flow lines.

ADEC can not force BP to comply with an action recommended in the final Coffman Report. The corrosion management program is a condition of the Charter Agreement and not a legally enforceable regulatory requirement.

Question 1a. In Tab 28; there is an email dated November 20, 2001 in which Richard Woollam notes that Susan Harvey explained to him that she was reluctant to enforce changes in that report. Did you share Susan Harvey's view that the document was not unlike an independent third party audit?

I was not aware of the email from Mr. Woollam at the time it was sent, nor at the September 7, 2006 hearing before the Subcommittee on Oversight and Investigations. The nature of the reports, however, is established as a matter of our contract with Coffman Engineers and its scope of work (enclosure 1). Management of the contract including state review of contractor drafts is carried out at the program level.

Question 1b. Did you or Larry Dietrick or any other ADEC employee ever instruct or pressure Coffman Engineers in any way to change the tone and content of the 2000 Coffman Report?

I gave no direction to Coffman Engineers to change the 2000 Coffman report, nor were any issues, disputes or appeals of the Coffman report brought to my attention for review or resolution. I have been told by Larry Dietrick that he gave no instructions to Coffman Engineers to change the 2000 report. I also have no knowledge or records of any other department staff ever instructing Coffman Engineers to change the 2000 Coffman Report. Coffman Engineers testified at the September 7, 2006 hearing before the Subcommittee on Oversight and Investigations that they were not instructed by any ADEC employee to change the report.

Question 2. In 2001, Did ADEC staff recommend that settlement of the enforcement action (for BP's failure to install the required leak detection systems) include a requirement to smart pig these pipelines, enhance the corrosion control programs, and require non-destructive testing (NDT) examination?

Department program staff accepted a proposal from BP for the testing, refinement and installation of leak detection on March 23, 2001 (enclosure 2). In an October 1, 2001 letter, BP notified ADEC that it would not meet the scheduled milestones (enclosure 3). A Compliance Order by Consent (COBC), No. 02-138-10, between the ADEC and BP was signed in May 2002 to resolve and settle the issue of compliance with Alaska's leak detection requirements for crude oil transmission pipelines.

As I testified at the September 7, 2006 hearing before the Subcommittee on Oversight and Investigations, ADEC does not have any regulatory requirements for corrosion control, smart pigs, or non-destructive testing of crude oil transmission pipelines for corrosion. I am not aware of any records indicating that staff recommended including corrosion control provisions in the COBC or actions taken to enforce BP's compliance with Alaska's leak detection requirements.

Question 3. During the period 2000 to the present, has anyone from BP, either directly or indirectly, contact you, Larry Dietrick, Michele Brown, or the governor's office to complain about any investigations or enforcement actions that ADEC staff was carrying out with respect to BP operations on the north slope?

I have no recollection or record of receiving a complaint from anyone affiliated with BP about any ADEC North Slope investigation or enforcement action. I have been told by Larry Dietrick that he has not received a complaint from BP regarding North Slope investigation or enforcement actions.

During the period of 2000 to December 2002, Michele Brown served as ADEC's Commissioner in Governor Knowles' administration. I have no recollection or record of Commissioner Brown of Governor Knowles' office receiving a complaint from anyone affiliated with BP about any ADEC North Slope investigation or enforcement action.

Question 4. Are you aware of any instances where an individual or entity outside of the department has requested or pressured ADEC to terminate, reassign, or demote ADEC staff.

No. I have no recollection or record of any instances where an individual or entity outside of the department has requested or pressured ADEC to terminate, reassign or demote ADEC staff.

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

Kurt Fredriksson
Commissioner

cc: 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 Joe Barton, Chairman, Committee on Energy and Commerce
John Katz, Director of State/Federal Relations and Special Counsel,
Office of the Governor

Enclosure 1

SECTION FIVE
SCOPE OF WORK

5.01
Scope of Work

The Department of Environmental Conservation, Division of Spill Prevention and Response is soliciting proposals for technical consultation services to provide ADEC with expert corrosion advise in regards to pipeline corrosion and/or other pipeline structural issues as part of the Charter for Development of the Alaskan North Slope, item II.A.6, "Commitment to Corrosion Monitoring." The professional consultant would perform the following tasks:

a) Complete a review of BP's and Phillip's, annually submitted, corrosion monitoring performance management reports, which are to be submitted to ADEC on or before March 31 of each year. Determine if the reports satisfy the requirements of item II.A.6, "Commitment to Corrosion Monitoring," of the Charter for Development of the Alaskan North Slope and its associated work plan deliverables (see Attachment).
b) Provide recommendations regarding the content and extent of topics covered within the annual reports. Determine if the topics included provide a complete and adequate view of the corrosion monitoring and corrective action activities necessary for maintaining pipeline integrity. Provide recommendations on the report format/content as required. This effort is intended as a continuous improvement process of ADEC's oversight of corrosion monitoring and performance management activities conducted by BP and Phillips for their North Slope, non-common carrier pipelines.
c) Perform a comprehensive technical analysis of the specific information presented in the reports and determine if there are any specific corrosion or pipeline structural issues, which warrant further review or corrective action. Highlight any specific areas of concern and conduct further research as required to determine if corrosion monitoring, repair or corrosion management related issues meet acceptable industry practices, code and regulatory requirements. Also determine if corrosion performance trends are at expected levels. If any parameters significantly exceed expected levels (excessive corrosion rates or frequent corrosion or structural related failures/spills), provide any findings and/or recommendations for corrective actions in this area. Rank any issues of concern as: 1) a significant pipeline integrity or environmental issue requiring immediate corrective action; 2) a pipeline integrity or environmental issue warranting corrective action within a longer time period (six months); and 3) a pipeline integrity or environmental issue warranting further study to determine if any problem exists.
d) Analyze corrosion technologies and techniques being utilized for corrosion surveys and performance assessments of the North Slope, non-common carrier pipelines. Determine if the methods and equipment employed provide for an adequate corrosion monitoring program. If not, list specific areas that should be considered for improvement.
e) Participate in the semi-annual "meet and confer" sessions with BP and Phillips as ADEC's technical consultant. Provide feedback regarding review findings from the previously submitted annual reports as well as any new information presented at these meetings.
f) Recommend an "annual bullet item(s)" that can be used as an indicator of the overall corrosion performance from the data provided. It should be a simply understood criteria which will allow for effective communication to the public of the yearly status of the "Commitment to Corrosion Monitoring" Charter item.

5.02
Deliverables

The contractor will be required to provide the following deliverables:

1. Prepare a detailed proposed schedule of project milestones for completing all tasks (a-f) described within the Scope of Work within the first week of the contract period.
2. By the tenth day after the close of the first full month and each succeeding month thereafter, the contractor shall submit a progress report to the contract manager. This report will discuss the status of each task, problems encountered, any delays, and any other items that could affect the successful completion of the contract. The contractor will maintain a project timeline throughout the course of the contract and will supply an updated version to the contract manager prior to biweekly meetings. Depending on the location of the contractor, biweekly meetings will be held in person or by teleconference.
3. Following the comprehensive technical review of BP's and Phillips' annual reports, the contractor will present to the Contract Manager a separate draft report for each owner's report (BP and Phillips) documenting his/her complete analysis and recommendations of all elements described in tasks (a-d). The Department will review the contractor's reports and will present written comments to the contractor. The contractor will incorporate the comments into the reports by either making changes where appropriate or defending his/her course of action. The contractor will finalize the reports, including the comments and response as an appendix, and will submit them to the Contract Manager in typed and electronic versions.
4. The contractor will participate, help coordinate and provide feedback as appropriate during each of the semi-annual "meet and confer" sessions with BP and Phillips per scope task "e". A written report of the meeting minutes, including a technical review and comments on the information presented, as well as any follow-up action items or recommended actions will be provided by the contractor to the Contract Manager. The contractor will also be responsible for additional correspondence with the individual owners (as per direction from the Contract Manager) on any issues warranting further follow-up action.
5. The contractor will provide a recommendation to the Contract Manager, following review of the data available described in the owner's reports, of an "annual bullet item(s)" as described under task (f) in the scope .

5.03
Work Schedule

The contract term and work schedule set out herein represent the State's best estimate of the schedule that will be followed. If a component of this schedule, such as the opening date, is delayed, the rest of the schedule will likely be shifted by the same number of days.

The length of the contract will be from the date of award, approximately ***July 23, 2001***, for approximately 342 calendar days until completion, approximately ***June 30, 2002.***

The approximate contract schedule is as follows:

- Issue ***RFP June 11, 2001.***
- Pre-Proposal Conference ***June 25, 2001.***
- Closing date ***July 2, 2001 COB.***
- Open ***RFP July 3, 2001.***
- Proposal Evaluation Committee complete evaluation by ***July 10, 2001.***
- State issues Notice of Intent to Award Contract ***July 11, 2001.***
- Protest period begins ***July 12, 2001***
- State awards contract ***July 23, 2001.***
- Contract begins ***July 26, 2001.***
- Contractor provides detailed schedule of project milestones (Deliverable 1) to Contract manager by ***August 2, 2001.***
- Contractor submits first draft report (Deliverable 3) to Contract Manager by ***September 11, 2001.***
- State reviews first draft (Deliverable 3) from ***September 11, 2001*** to ***September 18, 2001.***
- Contractor revises first draft (Deliverable 3) by ***September 25, 2001.***
- Contractor coordinates and participates in ***October 2001*** "meet and confer" session with BP and Phillips.
- Contractor provides a written report on meeting minutes and follow-up recommendations to ADEC by ***November 15, 2001***

- Any follow-up activity required from reports, meetings and outstanding deliverables are completed and submitted by the contractor to the Contract Manager by ***June 30, 2002.***

CHARTER FOR DEVELOPMENT
of the Alaskan North Slope

This **Charter for Development of the Alaskan North Slope** is entered between the State of Alaska, BP and ARCO on December 2, 1999.

BP and ARCO historically have been major participants in the development of oil resources on the North Slope of Alaska. ARCO discovered the giant Prudhoe Bay oil field in 1968. BP participated in the discovery of Kuparuk the following year. Both were leaders in building the Trans Alaska Pipeline System. Today, they are two of the largest interest owners and operators on the North Slope.

The environment for finding, developing and producing oil and gas is challenging and complex, in Alaska and the world. The giant Prudhoe Bay and Kuparuk fields are in decline. World energy markets continue to experience price volatility, competition for capital and opportunities, and financial and technical challenges to discover, develop and produce new fields. These challenges have led to large-scale industry consolidation in recent years.

Earlier this year, BP and ARCO proposed to merge. The merger and its potential impact on Alaska have been analyzed and discussed by the Governor, his Cabinet-level review team, the Legislature and the public in private, in hearings and in the media since the announcement.

There is potential both for benefit and risk to Alaska in the merger as initially proposed. In BP and ARCO's view, Alaska would benefit from the combination's financial strength and expertise, and the increased efficiencies and synergies of the combination would help make Alaska more attractive in a global oil marketplace. But Alaska would, in the State's view, lose a measure of competition, diversity and balance in the exploration, development and production of North Slope resources, and Alaska would lose the varied contributions of a leading corporate citizen.

The State of Alaska is committed to maintaining and enhancing competition, diversity and balance in the exploration, development and production of North Slope resources, sustaining and growing both oil and gas production, and ensuring that the State's natural resources are developed in an environmentally and socially sensitive and responsible manner. The State has determined therefore that its support for the merger must be conditioned upon BP and ARCO making substantial marketplace and community commitments to Alaska.

Therefore, in order to provide for greater competition, diversity, corporate responsibility, renewal and growth in the exploration, development and production of Alaskan North Slope oil and gas, the State, BP and ARCO agree to this Charter and its terms as set forth below.

I. BP and ARCO's Commitments Regarding Competition, Diversity and Growth.

A. Sale of Current Production. After the merger is completed, BP and ARCO will sell the following properties in the following manner:

1. Sale of Production. BP and ARCO will sell interests in North Slope properties producing in aggregate share not less than 175,000 barrels of gross working interest production per day to one or more purchasers. For purposes of this paragraph I.A., quantity will be measured by 1999 average daily production, except the Colville River Unit will be deemed to produce a total of 80,000 barrels of production per day.

2. Sale of Interests including Kuparuk. As part of the sale required by subparagraph 1, BP and ARCO will enter into a contract of sale with a single qualified company ("Buyer A") for at least 125,000 barrels of gross working interest production per day, including at least 50.01% of the Kuparuk River Unit total interest, and will take all reasonable available steps to enable that company to become the operator of that unit. In no event will BP or ARCO continue as operator of that unit after sale of the working interest production. For purposes of this subparagraph 2, "qualified company" means a company which is currently a joint interest owner in the Kuparuk River Unit, or a company primarily in the energy business with assets of not less than $8 billion.

3. Sale of Interest in Alpine. As part of the sale required by subparagraph 1, BP and ARCO will enter into a contract of sale with a single qualified company ("Buyer B") for at least 40% of the total Colville River Unit interest and will take all reasonable available steps to enable that company to become the operator of that unit. In no event will BP or ARCO continue as operator of that unit after sale of the interest. For purposes of this subparagraph 3, "qualified company" means a company which is currently a joint interest owner in the Colville River Unit, or a company primarily in the energy business with assets of not less than $3 billion.

4. Sale of Share of Pipelines. BP and ARCO will enter into a contract of sale with Buyer A and Buyer B for a commensurate interest in TAPS and intermediate pipelines as provided in paragraph H.

B. Sale of NPRA Lease Interests. BP and ARCO will sell not less than 220,000 net acres of their aggregate NPRA holdings to one or more purchasers. BP and ARCO will enter a contract of sale with either Buyer A or Buyer B for not less than 100,000 net NPRA acres, including at least 50.01% of BP and ARCO's combined interests in one of the sections of the NPRA designated on Exhibit A to this Charter, and will take all reasonable available steps to enable that company to become the exploration operator in that section.

C. Sale or Relinquishment of State Leases. BP and ARCO will sell or relinquish at least 400,000 net acres of undeveloped state leases, including sufficient interests in onshore/non-unitized state leases to reduce their aggregate holdings in such leases to not more than 500,000 net acres. BP and ARCO will manage the sale of this acreage to result in two exploration operatorships other than BP or ARCO in material and significant geologic play fairways on the North Slope (lease groupings which the parties agree meet this requirement are listed in Exhibit B to this Charter). As part of this sale or relinquishment of State acreage, BP and ARCO will enter contracts of sale with Buyer A and Buyer B in the combined amount of not less than 250,000 net acres of undeveloped state leases, including a minimum of 75,000 net acres for each buyer. BP and ARCO agree to meet and confer with representatives of the Alaska Department of Natural Resources, beginning within 10 days after the merger is completed and continuing for the period reasonably necessary to review the number, status, prospectivity and possible transfer options for all such holdings, as well as intended marketing or relinquishment plans.

D. Terms of Sales. Contracts for the full aggregate amount of the interests sold under paragraphs I.A. and I.B. will be signed within 6 months after the merger is completed and those transactions will be closed not later than 12 months after the merger is completed. Transfers under paragraph I.C. will be made within the period prescribed by law. All transfers of whole or partial interests in the properties and pipelines referenced in paragraphs I.A.-I.C. will be absolute, in good faith and with no minimum price. BP and ARCO agree that they will not reacquire interests transferred under paragraphs I.A.-I.C. by any means without advance approval of the State. Except as specifically provided in paragraphs I.A-I.C. and otherwise in this Charter, the sales contemplated in paragraphs I.A.-I.C. may be to various parties and include interests from various units and leases as determined by BP and ARCO. BP and ARCO may retain an interest in the units and leases it sells under paragraphs I.A.-I.C., subject to the requirement that any interest retained in exploration leases be subject to non-consent provisions permitting investment by other interest owners without BP or ARCO's consent. Any transfer under paragraphs I.A-I.C. will be subject to all necessary state and federal regulatory approvals and other requirements. BP and ARCO will use their best efforts to secure such approvals.

E. Data Availability. After the merger is completed, BP and ARCO will make their proprietary North Slope seismic and well data publicly available for purchase by any person where they have the legal right to do so. Where they do not currently have the legal right to do so, they will diligently and in good faith seek permission from the other joint interest owners to make the data available. Unless otherwise approved by the State, BP and ARCO will make the data available by contracting with a third party company, acting as marketing agent for BP and ARCO, that will market the data at prices it independently determines; except that, with respect to data generated before 1975, BP and ARCO will make the data publicly available without charge in such reasonable manner as it may determine. BP and ARCO will ensure that the data is publicly available as soon as is reasonably practicable but in all events not longer than 3 months after the merger is completed. BP and ARCO will provide the State with (1) a list of which of their North Slope seismic and well data can be made available on their own and which requires the consent of parties other than BP or ARCO, and (2) a list or lists showing all of BP and ARCO's North Slope seismic and well data from 1958 on indicating the acquisition area, the size of the acquisition area, the ownership status (sole, joint, group shoot, trade, purchase or license), when the data was acquired, the survey type, and the operator and the contractor. For data acquired after 1984, these lists will be provided as soon as is reasonably practicable but in all events before December 31, 1999. For data acquired before 1985, these lists will be provided as soon as is reasonably practicable but in all events within 3 months after the merger is completed. This paragraph applies to data generated prior to and through the date this Charter is first signed by the parties.

F. Facilities Access.

1. In the State's view, the Commissioner of Natural Resources possesses the statutory, regulatory and contractual authority to require working interest owners to provide others access to production and other facilities, on terms that are non-discriminatory, just and reasonable. The Commissioner may require access whenever necessary to maximize the economic and physical recovery of the State's oil or gas resources, maximize competition among parties seeking to explore and develop the resources, minimize the adverse effects of exploration, development, production and transportation activity, or otherwise to protect the best interests of the State. Binding arbitration between BP or ARCO and others under subparagraph 2 does not affect the Commissioner's authority to resolve questions of facility access.

2. BP and ARCO currently take no position on the State's view. BP and ARCO nevertheless commit that, after the merger is completed, neither BP nor ARCO will unreasonably withhold their voting support as facilities owners for allowing nearby satellites to have access to existing unit facilities on reasonable commercial terms. BP and ARCO agree that if a nearby satellite owner reasonably and diligently negotiates to unsuccessful impasse with facilities owners that include BP or ARCO, and after 90 day advance notice to BP and ARCO, BP and ARCO agree to subject themselves to binding arbitration governed by the rules of the American Arbitration Association on the question of reasonable commercial terms for that access.

G. Purchases From Qualified Producers. After the merger is completed, BP and ARCO agree to offer to purchase any qualified producer's ANS leasehold production on the terms reflected in the form purchase contract which is Exhibit C to this Charter. BP and ARCO may limit the total purchased under all such contracts to 30,000 barrels per day. For purposes of this paragraph I.G., "qualified producer" means a person or entity with assets of less than $1 billion (all parents, subsidiaries, affiliates and controlling parties inclusive) which produces not more than 10,000 barrels of gross working interest ANS liquid hydrocarbons per day at the time of proposed contract entry. In the event that any purchase contract under this paragraph I.G. is in effect and no RIK sales are made in a month, the State agrees to calculate the average value it received for RIV in that month for use as an alternative reference marker, and to update that average monthly to reflect retroactive revisions. The parties agree that the price at which the crude oil is purchased, and the pricing formula components of Exhibit C, will not be precedent in any royalty or severance tax proceeding or matter between them.

H. Divestiture of TAPS and Feeder Lines.

1. In order to satisfy the State's concern that the purchasers of the production interests sold under paragraph I.A. of this Charter (the "Transferee(s)") be similarly situated to BP and ARCO by ownership in TAPS, within the time frame established for paragraph I.A. transfers, BP or ARCO will enter into a contract with each Transferee to sell a share of BP or ARCO's interest in TAPS sufficient to carry the production sold to that Transferee. For purposes of this paragraph I.H., production quantity will be measured in the same manner as under paragraph I.A. and TAPS capacity will be measured in accordance with the Amended and Restated Capacity Settlement Agreement in the fixed amount of 1380 mbd.

2. After all contracts contemplated in subparagraph 1 have been entered, and during the remaining term of this Charter, BP or ARCO will offer to sell additional interests in TAPS to any person requesting to purchase a share in TAPS, up to a total aggregate amount under this paragraph I.H. of 22.295% of total TAPS ownership. The additional transfers contemplated by this subparagraph 2 will be in minimum increments of 2% of total TAPS ownership, valued at not more than the ad valorem tax value as of the time of the offer, less 5%. The parties agree that the price at which the TAPS interest is sold will not be precedent in any property tax proceeding regarding the value of TAPS.

3. Within the time frame established for paragraph I.A. transfers, BP and ARCO will enter into a contract with each Transferee to sell to that Transferee a separate share of BP and ARCO's aggregate interest in the Oliktok pipeline and in each of the intermediate crude oil common carrier pipelines serving the specific units in which the production interests to be transferred to that Transferee are located (the "relevant intermediate pipelines"). The ownership interest in each relevant intermediate pipeline to be sold to each Transferee will be equal to the percentage which the production sold under paragraph I.A. to that Transferee flowing through that pipeline bears to the overall throughput of that pipeline. The relevant production and throughput levels will be measured in the same manner as under paragraph I.A. The percentage of the Oliktok pipeline to be sold will be equal to the percentage share of the KRU sold pursuant to subparagraph I.A.2.

4. Any transfer under this paragraph I.H. will be subject to all necessary state and federal regulatory approvals and any preference rights and required approvals of the other TAPS and relevant intermediate pipeline owners. BP and ARCO will use their best efforts to secure such approvals. BP and ARCO will vote their entire interest in TAPS and the relevant intermediate pipelines in support of any such transfer. In the event any other TAPS or relevant intermediate pipeline owner exercises its preference rights with respect to the sale of a pipeline interest pursuant to subparagraphs 1, 2 or 3 hereof, the sale to that other owner will be considered a sale satisfying the obligations of that subparagraph. BP and ARCO agree that they will not reacquire interests transferred under this paragraph I.H. by any means without advance approval of the State.

I. Offer to Sell Excess Jones Act Ships. If BP's and ARCO's combined long-term ANS Jones Act fleet requirements are such that one or more ships becomes surplus of those requirements, BP or ARCO (as the case may be), will offer to sell the surplus ship or ships to other ANS producers on reasonable commercial terms. If BP or ARCO does not own the ship or ships, it will not object to arrangements by another ANS producer to acquire the ship or ships from the owner. Further, in the event that the purchaser of the ship or ships seeks ship operation services from the Alaska Tanker Company, Inc., BP will not object. Nothing in this paragraph requires BP or ARCO to assume any liability of another ANS producer concerning any of these transactions.

J. Natural Gas.

1. During the period after the merger is completed through December 31, 2003, BP and Arco shall negotiate in good faith to make available to third parties at a commercially reasonable fair market price or transportation charge that is mutually agreeable to BP and Arco, the third party and the State, Alaska North Slope natural gas in sufficient quantities to support a qualified treatment and transmission project to domestic and/or international markets. A qualified treatment and transmission project must have the demonstrated ability to:

a. obtain project construction financing;
b. provide reasonable financial security with respect to a long term 100% take or pay arrangement if the project requires a long term gas sales commitment from the producer(s) (including, if commercially reasonable, an assignment or other back-to-back pass-through of the purchaser's take-or-pay commitment from a creditworthy ultimate purchaser); and
c. obtain necessary approvals from other field interest owners.

2. BP and ARCO shall make reasonable efforts to assist in obtaining the approvals specified in

subparagraph 1.c.

3. The delivery point for gas committed to the project will be the residue gas discharge point of the Low Temperature Separators at the Prudhoe Bay Central Gas Facility, or such other point as agreed by the parties.

4. During this period, BP and ARCO will give fair consideration to all reasonable approaches, projects and plans proposed by the State, joint interest owners and others, including LNG projects developed or proposed by the newly established port authority, the gas sponsor group, Yukon Pacific Corporation and any others, pipelines to the lower 48 including those currently proposed, gas-to-liquids projects, and any other reasonable approach, project or plan for the commercialization of North Slope gas. In giving fair consideration to these various approaches, projects and plans, BP and ARCO will consider, among other things, (a) achieving the highest total project wellhead value for the State and for the sellers over the life of the project(s) and (b) other potential benefits to Alaska such as bringing gas infrastructure for the delivery of North Slope gas to communities in Alaska. BP and ARCO will meet and confer with project sponsors on reasonable request. Not less than every six months during this period, BP and ARCO will provide the Commissioner of Natural Resources with a report that identifies the name of the contact person for each project sponsor which contacted BP and ARCO during the prior 6 month period and the general nature and current status of the sponsor's project, subject to confidentiality requirements of the sponsor.

5. The obligation to negotiate with third parties does not preclude BP and ARCO from proceeding with their own project or projects to commercialize Alaska North Slope gas.

6. The obligations imposed by this section terminate before December 31, 2003 if BP and ARCO enter into a contract or contracts before that date committing Alaska North Slope gas to a qualified treatment and transmission project or projects for volumes that in the aggregate would constitute BP and ARCO's share of a Major Gas Sale under Article 26, Section 26.002 of the Prudhoe Bay Unit Operating Agreement or if the Board of Directors of BP and ARCO sanction the construction of such a project or projects before that date.

7. The parties agree that the terms of paragraph I.J. of this Charter shall be enforceable exclusively by arbitration between the State and BP and ARCO under the rules of the American Arbitration Association.

II. BP and ARCO's Environmental and Community Commitments.

A. North Slope Environmental Commitments. After the merger is completed, BP and ARCO will take the following steps to improve and protect the environment on the North Slope.

1. Cleanup of Abandoned Sites. BP and ARCO will take a leadership role in the assessment and environmental clean up of the North Slope "orphan sites" identified in Exhibit D1 (as currently written and as modified in accordance with the terms of this paragraph II.A.1.), and will spend $10,000,000 (or such greater amount as may be created by ADEC funding requests under paragraph II.A.7.) in performance of this commitment. In carrying out this role, BP and ARCO will consult with the Alaska Department of Environmental Conservation (ADEC) concerning site goals, standards and methods and will substantially complete the assessment and cleanup to the standards approved by ADEC under applicable law within six years after the merger is completed. In addition, BP and ARCO will work cooperatively with ADEC to develop a joint database of North Slope contaminated and solid waste "orphan sites" which includes the nature and location of the sites, the responsible parties and the relative priority for cleanup of each site based upon preliminary evaluation of the risk of harm to human health and the environment posed by the site. BP and ARCO will meet and confer with ADEC from time to time thereafter to arrange for priority re-ordering and substitutions and additions to Exhibit D1 as requested by ADEC, subject to the availability of funding in the spending amount identified above and to the further requirements that there is no known viable responsible party for any substitute or additional site and the site has been wholly vacated. The parties recognize that the available funding in the amount identified above may not be sufficient to assess and cleanup in full all sites identified in Exhibit D1 now or as it may be amended, and nothing in this subparagraph II.A.1. shall preclude the State from pursuing other parties for reimbursement or from seeking other funding sources for additional assessment or cleanup on any orphan site.

2. Cleanup of Abandoned Empty Barrels. BP and ARCO will require contractors conducting seismic or exploration work for them to collect and deliver abandoned empty barrels to BP or ARCO operations for handling, to inventory and map locations of empty barrels and barrels containing product, and to report any visible signs of ground contamination associated with the barrels. BP and ARCO will periodically report to ADEC regarding this effort and provide ADEC with the inventory lists, maps and reports which are developed.

3. Cleanup of Existing BP and ARCO Sites. BP and ARCO will assess and clean to the standards approved by ADEC under applicable law the contaminated sites listed on Exhibit D2. BP and ARCO will work cooperatively with ADEC and the land manager to develop cleanup plans and schedules to complete required assessment and cleanup activities at these sites. Assessment and cleanup activities at sites which are currently accessible will be substantially completed by year-end 2005 for the sites listed as "high" priority sites in Exhibit D2 and by year-end 2007 for the remainder. Sites which due to operational restrictions cannot be fully cleaned until facility or equipment abandonment will be identified by BP, ARCO and ADEC for completion according to a mutually agreed schedule. Nothing in this paragraph is intended to eliminate or supercede any other obligations BP or ARCO may have to assess, cleanup or restore these or any other sites.

4. Closure of Inactive Reserve Pits. BP and ARCO will comply with the requirements of 18 AAC 60.440 with respect to their inactive reserve pit sites and will close the inactive reserve pits subject to the Order dated May 3, 1993 in Natural Resources Defense Council Inc. v. ARCO Alaska, Inc., No. A88-287 CIV (D. Alaska) as amended within the designated time period established by the court in that matter, and will close other ARCO and BP inactive reserve pits listed on Exhibit D3A by the end of 2007 (except that in the event of currently unprojected operational delay affecting any BP site, that site may be completed on a separate mutually agreed schedule). BP and ARCO will close the ARCO and BP inactive reserve pits listed on Exhibit D3B according to a mutually agreed schedule that ends a reasonable period after work on the D3A sites has been completed.

5. Commitment to North Slope Spill Response. BP and ARCO will support, at their proportionate share, an independent professional North Slope spill response organization, such as Alaska Clean Seas or a substantially equivalent organization, and will encourage the fullest possible participation in this organization by all North Slope producers. BP and ARCO will support and vote in favor of funding to the North Slope oil spill response organization for an Arctic spill response research and development program (jointly agreed to by the spill response organization, BP, ARCO and ADEC) at an average annual level of not less than $200,000 during the 10 year period following completion of the merger.

6. Commitment to Corrosion Monitoring. BP and ARCO will, in consultation with ADEC, develop a performance management program for the regular review of BP's and ARCO's corrosion monitoring and related practices for non-common carrier North Slope pipelines operated by BP or ARCO. This program will include meet and confer working sessions between BP, ARCO and ADEC, scheduled on average twice per year, reports by BP and ARCO of their current and projected monitoring, maintenance and inspection practices to assess and to remedy potential or actual corrosion and other structural concerns related to these lines, and ongoing consultation with ADEC regarding environmental control technologies and management practices.

7. Additional Expenditure Commitment. BP and ARCO will pay or spend up to an aggregate total of $500,000 each year during the 10 year period following completion of the merger for any combination of the following as requested annually in writing by the ADEC Commissioner:

additional orphan site assessment or cleanup in excess of cap established in subparagraph 1; additional Arctic spill response research and development in excess of amount established in subparagraph 5; and/or an expert or experts chosen by ADEC to provide expert advice to ADEC regarding pipeline corrosion and/or other pipeline structural issues.

8. Payment of Unspent Funds. In the event that BP and ARCO fail to spend (or support and vote in favor of spending in the case of arctic spill response research and development) in the full amounts provided for under paragraphs II.A.1. ($10,000,000), II.A.5. ($2,000,000) or II.A.7. ($5,000,000) when and as required in those paragraphs, then BP and ARCO will pay any unspent or unsupported balance as directed by the ADEC Commissioner.

B. Marine Environmental Commitments.

1. Renewed Commitment to OPA 90. BP and ARCO renew their commitment that neither of them will seek to be relieved of the vessel retirement or replacement requirements of the federal Oil Pollution Act of 1990 ("OPA 90"), nor will either of them lobby for a reduction in its current requirements, nor will they take any other action to extend the retirement dates of the non-double-hulled tankers in their combined fleet beyond the currently scheduled retirement dates. In the event that any trade association or other group of which BP or ARCO is a member takes a different or contrary position, BP and ARCO will, upon notification and request by ADEC, issue a statement clarifying that BP and ARCO do not join in that different or contrary position, and reaffirming the position stated in the first sentence of this paragraph.

2. Replacement Vessels. In furtherance of their continuing commitment to meet or exceed the OPA 90 standards and timetable, BP and ARCO will complete the purchase and delivery of the three ARCO Millennium class tankers on current order to replace single hulled tankers now used in the combined ANS fleet, and will order and purchase additional tankers to meet their combined ANS fleet requirements on average one year earlier than required by OPA 90, with the expected result that the combined ANS fleet (including both owned and chartered vessels) will be entirely double-hulled by mid-year 2007. These additional purchased tankers will each have safety related attributes substantially equivalent to or better than Millennium or Cape class tankers, including new build double-hulls (wholly new construction), main power plant redundancy, twin propellers, twin rudders, twin independent sets of steering gear, and proven electronics (including navigation, course tracking, collision alarms, engine room monitoring, cargo and ballast monitoring, and fire and safety systems). In addition, BP and ARCO will continue to support a ship escort response vessel system for Prince William Sound at current or better levels of effectiveness.

3. Marine Operations. After the merger is completed, BP and ARCO will continue to encourage and support the company operating ANS tankers for them in using a performance management program for the regular review of its practices related to its management and operations including a safe environment, training and qualifications, and vessel operation, maintenance and management procedures. The parties expect this program will include meet and confer working sessions between the operating company and ADEC, scheduled on average once per year, reports at those working sessions by the operating company of their current and anticipated management and operations practices, ongoing consultation between the operating company and ADEC regarding ANS trade tanker management and operations practices, and the involvement of BP and ARCO in those sessions and consultations on a monitoring basis. In addition, BP and ARCO will encourage the operating company to allow the opportunity for ADEC to observe, and to be provided a copy of the written results of, management and vessel audits performed as part of a certification or re-certification process for the International Maritime Organization's International Safety Management Code or for the International Standards Organization.

C. Continued Commitment to Alaska Hire.

1. Alaska Hire Program. BP and ARCO agree that, after the merger is completed, they will continue with and extend their commitment to the people of Alaska to utilize a voluntary program to employ residents of Alaska and to use Alaska businesses. It is expected by the parties that this program will include the attributes that:

a. BP and ARCO will comply with all valid federal, State and local hiring laws in hiring Alaska residents and contractors and will not discriminate against Alaska residents or contractors, and within the constraints of law will employ Alaska residents and contractors to the extent they are available and qualified;
b. When recruiting for new hires, BP and ARCO will advertise for available positions locally and use Alaska job service organizations to notify the Alaskan public;
c. BP and ARCO will use best efforts to contract with Alaska firms and fabricate modules in Alaska whenever feasible (in determining feasibility, BP and ARCO will consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of BP and ARCO's operational standards); and
d. BP and ARCO will, to the extent permitted by law, encourage its contractors to employ, and train when necessary, residents of Alaska.

2. Reporting. BP and ARCO agree to submit to the Director, Division of Oil and Gas, for transmission to the Department of Labor, an annual report that details the specific measures that they and their contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes their efforts to use Alaska businesses for work in connection with their leases and associated activities. BP and ARCO will also furnish the Department of Labor a quarterly report regarding their employment of Alaska residents. The report will include statistical data concerning the number of resident personnel hired within the previous year.

3. Construction. The program and reporting described in this paragraph are intended to be fully consistent with the 1996 amendments to paragraphs 41 (1980 leases) and 31 (1983 lease) of the Northstar Unit leases between the State and BP.

4. Alaska Native Recruitment, Training and Hire. BP and ARCO further acknowledge their continuing support for the recruiting, training and hiring of Alaska Natives and the parties' common understanding of the desirability of providing Alaska's first citizens opportunities to participate in the economic benefits of oil and gas development, most of which takes place in rural Alaska.

D. Community Charitable Commitment. Within three months after the merger is completed, BP and ARCO will establish a charitable entity dedicated to funding organizations and causes within Alaska. The entity will provide 30% of its giving to the University of Alaska Foundation and the remainder to general community needs. Funding decisions by the entity will be made by BP and ARCO, with the advice of a board of community advisors. BP and ARCO will provide ongoing funding to this entity in an amount that is equal to .2% of BP's and ARCO's combined aggregate net Alaska liquids production after royalty times the price for WTI. Specific entity funding levels will be calculated annually, on the same date each year, referencing the liquids production and the average NYMEX WTI prompt month settlement price for the 12 months immediately preceding the calculation.

E. Annual Report. Once every year beginning in March 2001, and continuing thereafter for the term of this Charter, BP and ARCO will provide the State and the public with a written report describing BP and ARCO's performance of the commitments in this Section II during the prior calendar year. Public distribution will be accomplished by posting the report on a company internet site and such other reasonable means of public distribution as BP and ARCO may choose. The report provided for under subparagraph II.C.2. will satisfy this paragraph II.E. as well with respect to its subject matter so long as that report is also publicly distributed, and timing differences will be disregarded so long as the II.C.2 report is provided and distributed according to the schedule applying to subparagraph II.C.2.

III. Alaska's Commitments.

The State of Alaska finds that this Charter adequately addresses the concerns raised by the State during its merger review, that this Charter will provide for greater competition, diversity, corporate responsibility, renewal and growth in the exploration, development and production of Alaskan North Slope oil and gas and is by virtue of these significant benefits in the best interest of Alaska and its people. The State accordingly agrees that, in exchange for BP's and ARCO's fulfillment of their obligations under this Charter, it will not seek to enjoin the merger or seek additional orders or judgments under AS 45.50.580 related to a claim that the merger is unlawful under AS 45.50.568.

IV. BP Amoco, p.l.c.'s Commitments.

BP Amoco, p.l.c. acknowledges that, after the merger is completed, it will be the ultimate parent company of the BP and ARCO corporate entities owning the Alaska assets which are the subject of this Charter and which accordingly are the primary parties with the State of Alaska herein. In order to provide further assurance to the State that the commitments made in this Charter by these primary parties are fulfilled in all respects, BP Amoco, p.l.c. guarantees that (1) these BP and ARCO corporate entities, or such other BP/ARCO Group companies to which the obligations under this Charter are assigned or otherwise transferred, will remain fully capable during the term of this Charter to fulfill all commitments made by them herein and (2) if for any reason a commitment made by them in this Charter goes unfulfilled past the time performance is due, BP Amoco, p.l.c. will cause that performance to be otherwise fulfilled.

V. General Provisions.

A. Definitions. As used in this Charter: "State" and "State of Alaska" means the State of Alaska, through its Governor, Attorney General and Commissioners of Natural Resources and Revenue; "BP" means BP Exploration (Alaska) Inc.; "ARCO" means ARCO Alaska, Inc.; "merger" means the proposed merger between BP and ARCO's parent companies; the merger is "completed" on the earliest of the date of closing, the effective date of the merger, or the first day after ARCO parent stock is exchanged for BP parent stock; "sell" and "transfer" mean divest; "gross working interest production" means BP and ARCO's share of actual liquid hydrocarbon production, including any State royalty share; "well data" includes, in digital and analog format, any mud log, lithology log, wireline well logs, conventional core and sidewall core descriptions, repeat formation tester, log curve, directional survey, velocity survey, vertical seismic profile, geologic markers, test result, test summary, porosity and permeability data, biostratigraphic data, palynology and paleontology data, geochemical data, vitrinite reflectance data, petrographic data, and completion reports, regarding onshore or offshore exploration acreage west of the Canning River onshore and west of and including the Kuvlum prospect offshore; "seismic data" includes all seismic and ancillary data required to interpret or reprocess a seismic survey including digital files in standard exchange formats containing survey and location data, original field records, final stack and migrated processed data, final stacking and migration velocities, and a report describing the acquisition and processing of the data, regarding onshore or offshore acreage west of the Canning River onshore and west of and including the Kuvlum prospect offshore; "fair market" as used in paragraph I.J.1. will be determined with reference to the well-head netbacks pertinent to the available market(s) reasonably accessed by North Slope gas.

B. Enforcement. This Charter is governed by Alaska law. The parties agree that, except as provided in paragraphs I.J.7. and V.C., it may be enforced as a contract by (a) the Attorney General (for Alaska) and (b) its authorized representatives (for BP and ARCO) in any state or federal court in Alaska, the commitments made in this Charter may be specifically enforced, a trustee may be appointed by the court in such an action to effectuate any property transfers not accomplished as committed, and the court may also order any other appropriate remedy consistent with law. If BP, ARCO and the Federal Trade Commission enter into a consent decree or other agreement related to the merger, the terms of that decree or agreement that relate directly to or affect Alaskan assets or activities within or touching Alaskan waters may be incorporated by the State into this Charter by reference, and are enforceable by the State as though fully set forth herein. BP and ARCO acknowledge that they are subject to the personal jurisdiction of any state or federal court within the State of Alaska for the purposes of enforcing the terms of this Charter. BP Amoco, p.l.c. consents to the jurisdiction of any state or federal court within the State of Alaska for the purposes of enforcing its commitments under section IV of this

Charter. No action alleging a failure of performance under this Charter may be commenced more than four years after the alleged failure, and no action alleging a failure of performance under this Charter may be commenced in any event after January 15, 2009, except that an action as provided in the final sentence of paragraph V.C. may be commenced through January 15, 2011.

C. Enforcement of Section II. Commitments. In the event that BP and ARCO fail to perform their commitments under subparagraph II.A.8. or paragraph II.E., the State may bring an action to enforce those provisions. The other provisions of Section II of this Charter are corporate citizenship commitments to the Alaskan community at large. The parties do not intend for these other commitments of Section II to be enforced by lawsuits, and no right of action is created with respect to them.

D. Construction. This Charter may be amended only in writing by the principals to this agreement or their successors. This Charter will be binding on the parties and their respective successors and assigns, and is not intended to confer any rights or remedies upon any other persons (as used herein, "assigns" includes a transferee of substantially all of the assets of BP or ARCO but does not otherwise include a transferee of property, under this Charter or otherwise). Except as otherwise provided in this Charter, nothing herein shall be construed to impose a duty or obligation on BP or ARCO to make any additional agreements with or concessions to any other governmental or regulatory body. Where an act required of BP or ARCO under this Charter is subject to regulatory approval or action, the time limits stated in this Charter will be deemed extended as may be necessary to accommodate the time involved in securing those regulatory approvals if BP and ARCO have acted with reasonable diligence in obtaining those approvals.

E. Reporting, Notice and Access to Records.

1. BP and ARCO will submit an initial compliance report at the time they execute this Charter and will submit additional compliance reports beginning thirty (30) days from the date when this Charter is entered, and every thirty (30) days thereafter until the divestitures required under Section I have been completed or a trustee is appointed. Such reports will be in writing and each such report shall include, for each person who during the preceding thirty (30) days made an offer, expressed an interest or desire to acquire, entered into negotiations to acquire, or made an inquiry about acquiring any ownership interest in all or any portion of the divestiture assets, the name, address, and telephone number of that person and a detailed description of each contact with that person during that period. BP and ARCO will maintain full records of all efforts made to divest the assets under Section I.

2. BP and ARCO will notify the State of any proposed divestiture within two (2) business days following execution of a letter of intent or agreement for sale of the assets under Section I. The notice shall set forth the details of the proposed transaction and list the name, address, and telephone number of each person not previously identified who offered or expressed an interest in or desire to acquire any ownership interest in the divestiture assets. Within ten (10) days after receipt of the notice, the State may request additional information concerning the proposed divestiture, the proposed Purchaser, and any other potential Purchaser. BP Amoco and ARCO will furnish the additional information within ten (10) days of the receipt of the request. Within twenty (20) days after receipt of the notice or within ten (10) days after receipt of the additional information, whichever is later, the State will notify BP and ARCO in writing if it objects to the proposed divestiture. If the State fails to object within the period specified, or if the State provides notice that it does not object, then the divestiture may be consummated. If the State objects, the proposed divestiture may not be accomplished unless ordered by a court of competent jurisdiction.

3. For the purpose of determining or securing compliance with this Charter, and subject to any legally recognized privilege and reasonable notice, the State will be permitted access during office hours to inspect and copy all books, ledgers, accounts, correspondence, memoranda, and other records and documents in the possession or under the control of BP or ARCO relevant to BP or ARCO's compliance with this Charter. Subject to the reasonable convenience of BP and ARCO, and without restraint or interference from them, the State may interview their directors, officers, employees, and agents regarding any such matters. No information or documents

obtained by the State under this paragraph shall be divulged by any representative of the State to any person other than a duly authorized representative of the Attorney General, except in the course of legal proceedings to which the State is a party, or for the purpose of securing compliance with this Charter, or as otherwise required by law.

F. Effectiveness. This Charter shall be effective as of the date it is entered as written above. This Charter shall remain fully effective thereafter, except in the event that the merger agreement between BP and ARCO's parent companies is terminated, then any party may terminate this Charter by written notice to all other parties, in which event this Charter shall become null and void and of no effect, as if it were never entered.

G. Attorneys Fees. Within 30 days of the effective date of this Charter, BP and ARCO will pay the State $1,512,198 as reimbursement for its attorney's fees and costs reasonably incurred in connection with the merger through the date of this Charter. In addition, BP and ARCO will make supplemental payments to reimburse the State for reasonable attorney's fees and costs incurred by the State related to Charter implementation and compliance between the date of this Charter and 12 months after the merger is completed. These supplemental payments will be made within 30 days after the State submits a reasonably supported written request to BP and ARCO for reimbursement.

H. Warranty of Authority. Each of the persons signing below on behalf of a corporate party represents and warrants that he has the authority to execute this Charter on behalf of the party for which he signs. Each of the persons signing below on behalf of the State represents and warrants that he holds the office shown and is authorized to exercise the powers of that office on behalf of the party for which he signs. In addition, BP and ARCO specifically warrant and represent that they are fully authorized and able to make, and to ensure the performance of, the commitments made herein and that, with respect to any Alaska assets currently owned by affiliates, they have taken or will take such steps as are necessary to ensure that the commitments they make herein are accomplished.

I. Other Obligations Not Reduced. Nothing in this Charter is intended to reduce, eliminate or supersede any other obligations BP or ARCO may have under any State or federal law or regulation.

Signatures:

STATE OF ALASKA

by________________________
Tony Knowles, Governor

by________________________
Bruce Botelho, Attorney General

by________________________
John Shively, Commissioner of Natural Resources

by________________________
Wilson Condon, Commissioner of Revenue

BP EXPLORATION (ALASKA) INC.

by________________________
Richard Campbell, President

ARCO ALASKA, INC.

by________________________
Kevin Meyers, President

BP AMOCO, p.l.c.

by________________________
John Browne, CEO

by________________________
Rodney Chase, Deputy CEO

Exhibits click here **Charter Addendum (03/15/00)** click here
Back to BP-ARCO

10/11/2006 17:34 FAX 2787022 ENVIRONMENTAL Enclosure 2 002

STATE OF ALASKA

TONY KNOWLES, GOVERNOR
555 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 Section

FILE COPY

March 23, 2001

File No.: 305.50

Janet Platt
Business Assurance Manager, Environment
BP Exploration (Alaska), Inc.
P.O. Box 196612
Anchorage, Alaska 99519-6612

Dear Ms. Platt:

Re: BP Exploration (Alaska), Inc. (BPXA) Pipeline Leak Detection for the Greater Prudhoe Bay, Eastern Operating Area (EOA) and Western Operating Area (WOA)

This letter is the Alaska Department of Environmental Conservation (Department) response to BPXA's January 31, 2001 letter providing information on the Greater Prudhoe Bay leak detection plan and schedule for deliverables.

Based upon our review, the Department finds the schedule and milestones acceptable for the testing, refinement and installation of leak detection, as outlined in your proposal.

This plan demonstrates a strong commitment to substantially resolve this difficult issue before the end of the year. The Department commends BPXA's current efforts in researching ways to provide sensitive leak detection for the EOA and WOA pipelines. We are fully mindful of the difficulty this task represents when dealing with a retrofit situation for existing pipeline and facility configurations.

However, the Department has the following concerns regarding the deliverables outlined in your proposal. The following issues must be addressed by BPXA in order to obtain the Department's concurrence.

1. The letter refers to the EOA and WOA pipelines as the Prudhoe Bay pipeline network, a single pipeline system. While your January 31, 2001 letter acknowledges the Department's interpretation that each pipeline must be treated as an individual segment for the purposes of meeting the 1% threshold volume, your proposal still is based on the combined flows of EOA and WOA pipelines at Pump Station 1 for determining system sensitivity. BPXA's leak detection proposal and testing plan must be revised to achieve, at a minimum, the 1% standard for each EOA and WOA pipeline segment based upon its individual daily throughput.

Ms. Janet Platt 2 March 23, 2001
BP Exploration (Alaska)

2. The proposal establishes a target leak detection threshold of 1% for the pipelines daily throughput volume. The Department's regulations established the 1% of daily throughput volume as a minimum detection threshold. However, the technologies used for pipeline leak detection are also subject to the applicable requirements of the Department's Best Available Technology (BAT) requirements. The BPXA proposal must focus on achieving the best possible leak detection threshold based on available technologies that can be feasibly installed on the pipeline systems.

3. Your proposal is not clear as to whether or not BPXA intends to test each leak detection system using fluid draw-off for each segment. It is the Department's position that substantiating results can only be achieved by testing the system's capability to sense an actual fluid release from the pipeline. BPXA must revise or clarify the proposal to reflect that tests will be developed and conducted to determine the sensitivity of the leak detection system to sense a leak on each pipeline segment via methods that physically replicate leak conditions.

4. BPXA proposes to test ultrasonic meters for possible installation on the Prudhoe Bay pipeline system. The Department recommends that functional testing of an ultrasonic meter should occur on the Lisburne crude oil pipeline. BP has proposed that a test be scheduled to occur by April 30, 2001. This would permit testing of ultrasonic metering at the same time the turbine meters are tested, and allow comparison of data derived from the two types of meters. As proposed, BPXA's plan could result in the installation of meters without adequate testing prior to the decision to rely upon this technology.

5. Your January 31, 2001 letter states: "(t)he EFA (Ed Farmer & Associates) leak detection system requires a stable flow rate and minimal pressure transients. Large swings are inherent with North Slope facilities, due to inadequate surge capacity immediately upstream of shipping pumps." Similarly, this fact has been acknowledged in recent communications regarding the Endicott/Badami pipelines, and it was further stated that BPXA is investigating installation of a surge tank at Endicott as a remedy for this condition. As surge capacity is a significant factor in improving dynamic stability in the pipelines and likely to result in improved leak detection sensitivity, the Department requires the potential addition of surge capacity be fully examined as part of the BAT analysis and included in the testing program.

Again, we appreciate your efforts to bring this issue to a successful outcome. If you have any questions, please contact Ted Moore at 269-7569 or me at 269-7680.

Sincerely,

Robert Watkins
Section Manager

D:\bmartinez\Watkins\Leak Detection doc

cc: Susan Harvey, ADEC, Anchorage
Ted Moore, ADEC, Anchorage
Nick Glover, BPXA, Alaska
Bill Johnson, BPXA
Neil McCleary, BPXA
Bill Blosser, BPXA
James Taylor, USDOT
Carl Lautenberger, USEPA

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

October 1, 2001

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% l[illegible] 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.

NOTE

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 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**

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**

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.

   <<<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.

   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.

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 PS-2 and GC-2 segments are less than the manufacturers minimum for accurate metering. This type meter may not be BAT for that location.

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

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. <u>Timeline: December 31, 2001</u>

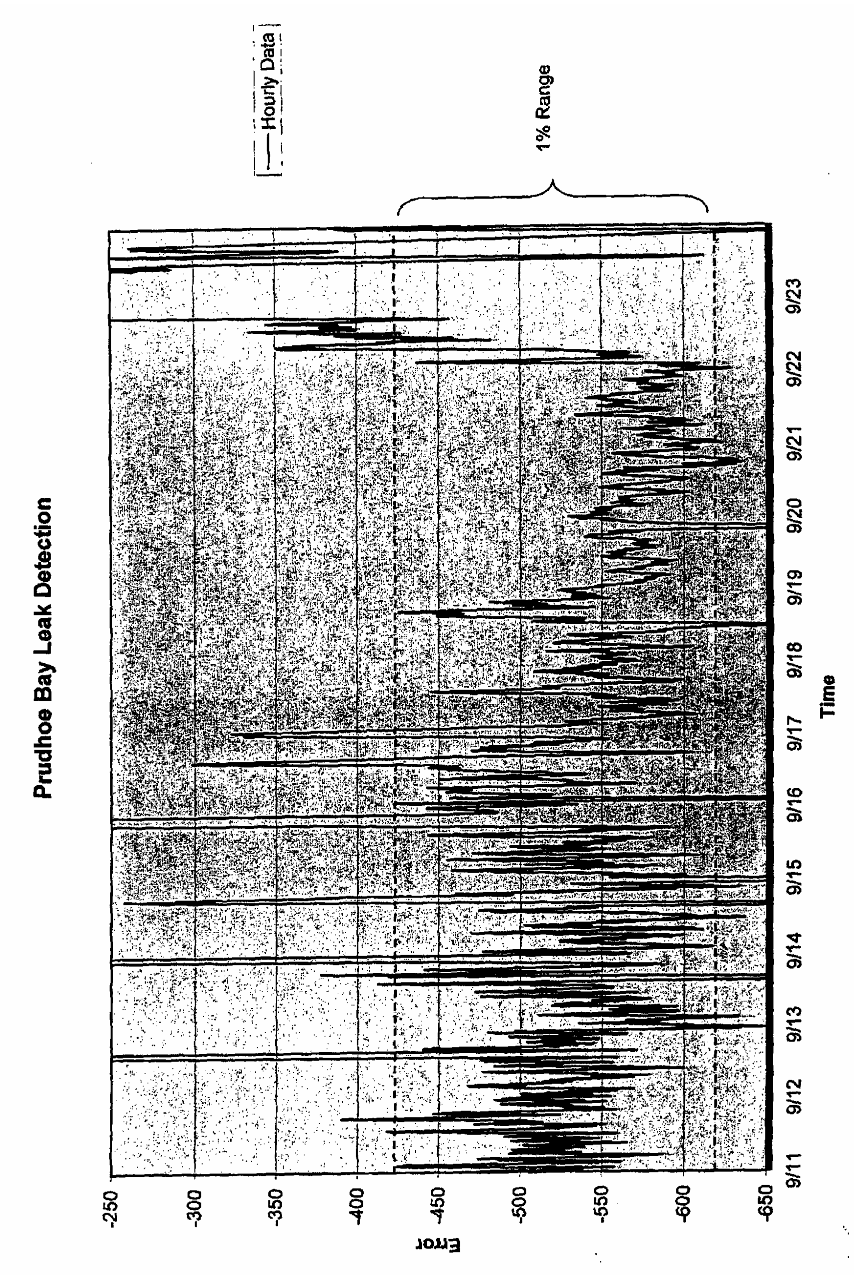
10. Retrofit Pipeline Segments - Install new meters and meter housing, integrate data acquisition with EFA leak detection system, ensure adequate power is available. Original Timeline: October 31, 2001.

    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. <u>Timeline: December 31, 2001</u>

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


Prudhoe Bay Leak Detection
Hourly Data
1% Range
Error
-250
-300
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-400
-450
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Time
9/11
9/12
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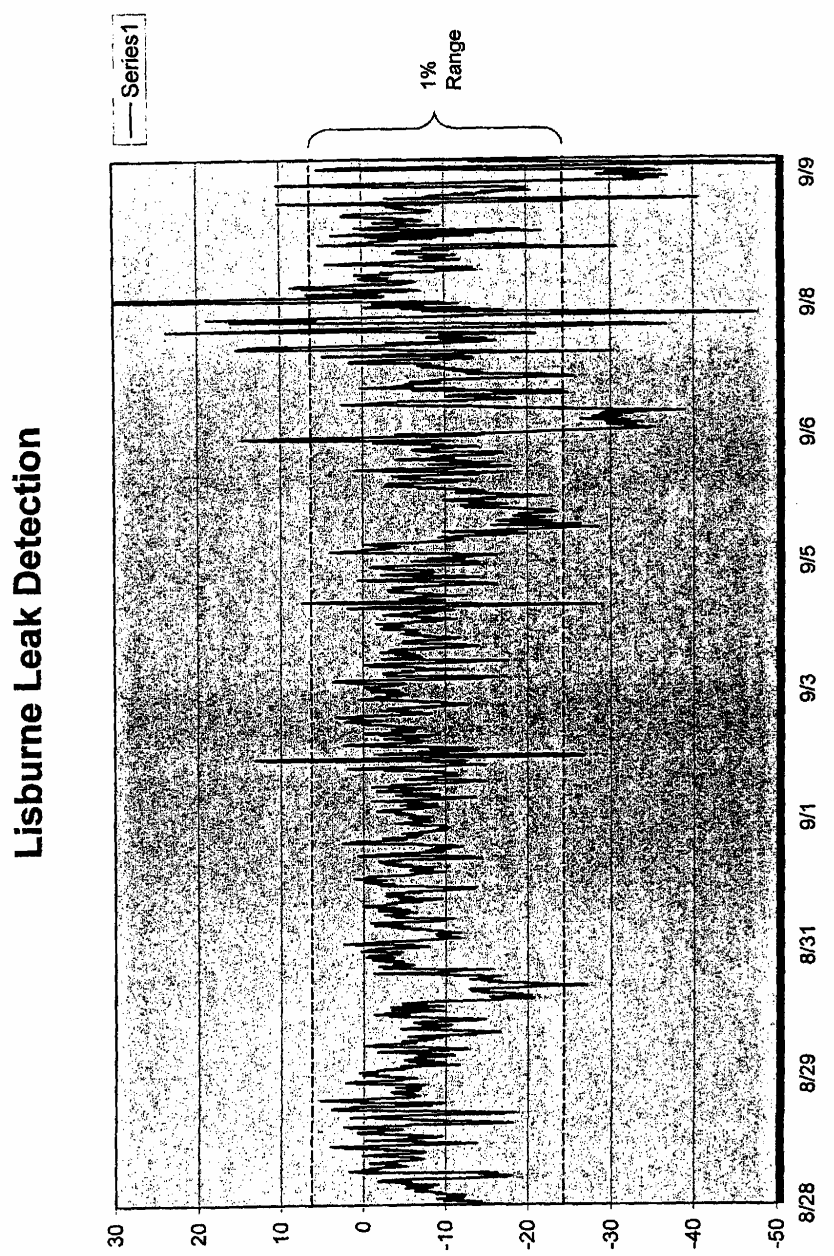
GPB 2712


Lisburne Leak Detection
Series1
1% Range
30
20
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8/29
8/31
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9/9

GPB 2713

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

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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.

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