11975 SENATE RESOURCES

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 on 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.

2001-CPA

Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

Phillips Alaska Inc. – 2001 Commitment to Corrosion Monitoring for Greater Kuparuk Area & Alpine

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2001 corrosion program report submitted by Phillips Alaska Incorporated (PAI) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in PAI's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the October 2001 and April 2002 Meet & Confer sessions. PAI 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.

Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition: no leaks and no saves were reported in 2001. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency; corrosion damage increases have been almost eliminated in the cross-country gathering lines through corrosion control. However, coupon pitting rates for three phase and water injection pipelines have seen relatively steady increases since 1998. While the rates are still below the target limits, PAI changed inhibitors late in 2001 in an effort to reverse this trend. In addition, the number of locations with corrosion damage increases (UT and RT) has increased compared to 2000, 35 versus 13.

Internal corrosion in well lines is an area that requires PAI's continued focus, no leaks and 24 saves (repairs) were reported in 2001. The number of saves has increased over the past three years, albeit at slower rate than the amount of pipe inspected. This suggests PAI could be approaching the "top of the curve" for internal well line corrosion control. The number of locations with corrosion damage increases (UT and RT) has also increased compared to 2000, 163 versus 115.

External corrosion at weld-packs (above and below grade) continues to pose an integrity risk. There has been an average of one leak per year over the past five years (1997-2001) due to external corrosion mechanisms. A baseline inspection of all weld-packs on off-pad, cross country pipelines was completed in 2001. Baseline inspection of on-pad weld-packs (well and cross country lines) is progressing ahead of schedule and average percent of corroded weld-packs has dropped slightly to ~2%. There were four repairs and 800+ weld-packs refurbished on above grade piping. One leak in 2001 (1HBWI) occurred on below grade piping at a weld-pack. PAI has responded by accelerating the screening inspections for below grade piping during 2001 and plans to continue at an accelerated rate in 2002. Nine below grade locations were excavated and two locations required repair; one location was sleeved and the other location was on piping that was, and has remained, out of service.

There was one failure in 2001 attributed to wind induced vibration (WIV) coupled with a potential weld anomaly. An evaluation of the design envelope is underway to ensure it is still valid. Another structural concern is well subsidence. The well subsidence mitigation plan was being implemented to control further subsidence. The corrosion group will need to continue its close coordination with those tasked with maintaining pipeline structural integrity in order to address the confluence of corrosion and structural concerns.

CORROSION PROGRAM STATUS

Internal Corrosion Management

Cross Country Pipelines – Monitoring & Inspection

Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition: no leaks and no saves were reported in 2001. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency; corrosion damage increases have been nearly eliminated in the cross-country gathering lines through corrosion control. However, corrosion pitting rates for three phase and water injection pipelines have seen relatively steady increases since 1998. While the rates are still below the target limits, if the trend continues unabated, the average pitting rate will exceed the nominal threshold of 10 mpy. In addition, the total number of locations with corrosion damage increases (UT and RT) has increased compared to 2000, 35 versus 13. PAI responded by changing inhibitors late in 2001 in an effort to reverse this trend.

PAI reports that coupon or probe corrosion rates exceeded threshold targets in 19 lines and they responded by increasing the corrosion inhibitor concentrations for all 19 lines. In addition, inspection showed nine lines with "minor" corrosion where the coupons did not exceed the target corrosion rate. The corrosion inhibitor concentrations for all nine of these lines were also increased. This helps to illustrate and reinforce the importance of both programs.

An ongoing item of concern is the difficulty of inspecting produced water injection piping with diameters larger than eight to ten inches, which is considered radio-opaque and limits the use of radiographic techniques. PAI states they are going to "evaluate the possibility of smart pigging cross-country water injection lines larger than 8" O.D." during 2002. However the report states the corrosion tends to manifest in the un-piggable, stagnant portions of the systems. It is not clear if there are segments that met both criteria (>8" and stagnant flow) and how they will be inspected.

Well Lines - Monitoring & Inspection

Internal corrosion in well lines is an area that requires PAI's continued focus; no leaks and 24 saves (17 injection and 7 production) were reported in 2001. The number of saves has increased over the past three years, albeit at slower rate than the amount of pipe inspected. This suggests PAI could be approaching the "top of the curve" for internal well line corrosion control. PAI will need to reassess its corrosion management situation when new production horizons are brought on line and fed into the existing production gathering system. Corrosion control may be lost due to the addition of new production.

Production well line coupon data indicate very low general and pitting corrosion rates. Injection well line coupon data indicates very low general corrosion rates. Pitting rates for this service are below the action limit; however they are above the historic average and have an increasing trend over the past 5 years.

The number of locations with corrosion damage increases (UT and RT) has also increased compared to 2000, 163 versus 115. 124 increases were in production service and 39 increases were in the injection service. The 2000 data is presented as an aggregate so comparisons

between service types are not possible. It is unclear if there are specific targets for repeat inspections using manual RT and UT techniques but the percent repeated for each inspection type and service type vary widely. It is also unclear if there is a target or action limit for the percent increase value.

Internal Corrosion Mitigation

PAI switched to a different corrosion inhibitor (Cortron 2000-25) during 2001, but has plans to return to the previous incumbent (Cortron RU-276) in 2002. Figure 6 depicts the field wide corrosion inhibitor usage, recommended volume, and the % difference between the recommended volume and the actual volume. PAI's compliance with its own corrosion inhibition targets has improved over time; reporting an average deviation of +0.7% for 2001, a slight over-treatment, showing an excellent level of control. Figure 6 also shows a step-like increase in inhibitor volume occurring in the third quarter of 2001.

PAI is continuing to move forward with the wellhead inhibitor injection program, but the program appears to be slipping in schedule. The 2000 Report and April 2001 slides indicated 3-5 drill sites were scheduled for startup in 2001. The November 2001 slides indicated one drill site (1G) would be constructed late 2001 to early 2002. April 2002 slides indicate construction is still planned for 1G and other sites are funded and in the design/procurement stages. As discussed previously, the well lines should benefit greatly from this program.

External Corrosion Management

Above Grade Piping

PAI exceeded their stated external inspection goals in 2001. During 2001, the baseline inspection for all off-pad weld-packs was completed and all weld-packs found with corrosion have been refurbished. Also during 2001, the baseline inspection for on-pad weld-packs was 48% complete overall and is progressing ahead of PAI's stated 2005 completion schedule.

There were three repairs on off-pad piping, two repairs on on-pad piping and more than 800 weld-packs refurbished. The percent corroded and percent repaired results for 2001 are consistent with the overall average percentages, and likely means there are 5-10 repairs to be made on the remaining ~18,000 weld-packs. Refer to Table 1 for the overall weld-pack program status of the PAI weld-pack inspection program.

In April 2001, PAI stated they were going to test "inhibitor spikes" on 25-50 weld-packs, however little information was provided as to the status of this test program.

In 2003, PAI will begin a prioritized program to re-inspect weld-packs that have not been previously refurbished (five years after the baseline inspection). This activity will likely remain necessary through the end-of-field life.

Table 1 - Above grade weld-pack inspection status

Service	Total Number (approx.)	Number Inspected During 2001	Number Inspected thru YE2001	% Inspected thru YE2001	Number Remaining	2002 Forecast
X-Country-Off-pad	67,291	292	67,291	100%	0	0
X-Country-On-pad	10,400	3,919	6,344	61%	4,056	1,780
Well LinesOn-pad	24,000	5,489	10,320	43%	13,680	4,000
Totals	**101,691**	**9,700**	**83,955**	**83%**	**17,736**	**5,780**

Note: This table represents an effort to reconcile numbers presented in the 2000 and 2001 PAI reports. There is the possibility for minor discrepancies.

Below Grade Piping

PAI exceeded their stated below grade inspection goals in 2001, inspecting 228 new locations using a combination of electromagnetic pulse and guided wave technologies. One additional screening technology, guided-ultrasonic, was evaluated and deemed "not superior" to the incumbent and will not be used at this time. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

One leak in 2001 (1HBWI) occurred on below grade piping at a weld-pack. PAI has responded by accelerating the screening inspections for below grade piping during 2001 and plans to continue at an accelerated rate in 2002. Nine below grade locations were excavated and two locations required repair; one location was sleeved and the other location is on piping that was, and has remained, out of service.

A proper accounting of the total population of below grade piping would lend context to the status of this program. Based on information presented in the 2000 and 2001 reports there appears to be a total population of ~740 below grade locations. Refer to Table 2 for an initial attempt to summarize the status of this program.

Table 2 - Below Grade Piping Baseline Inspection Status

	Total Number (approx.)	Number Inspected During 2001	Number Inspected thru YE2001	Number Remaining
Oil - Significant	385			
Non Oil - Significant	210			
Oil - Low Risk	46			
Non Oil – Low Risk	95			
Totals	**739**	**228**	**438**	**301**

Note: This table represents an effort to reconcile numbers presented in the 2000 and 2001 PAI reports. There is the possibility for minor discrepancies.

Structural Concerns

Subsidence

There were no leaks attributed to subsidence in 2001. PAI continues to prioritize and upgrade existing wellhead riser supports and flooring susceptible to subsidence. Thermal siphons are also being installed in near well-bore location to promote re-freezing and stabilization of the soil. PAI has updated its new well construction and water injection conversion requirements to include thermal siphons and riser supports on the well installations.

Wind Induced Vibration

Vibration dampeners are installed on all lines lying within a range of degrees perpendicular to the prevailing wind direction. One failure (DS2X) occurred at a weld on a pipeline orientated 1° outside of the range. Metallurgical analysis is being performed to rule out a weld defect. In response PAI is re-evaluating the design criteria to ensure the envelope is still large enough. Perhaps of greater concern is the identification of one "area" that is within the existing envelope but did not have dampeners installed. While dampeners are planned for installation during 2002, the integrity of pipelines in this "area" should be verified. Information such as age of lines/length of exposure, corrosion history, etc. could be used in a qualitative assessment to ensure there are no anomalies in the susceptible areas of the pipelines.

RECOMMENDATIONS

Recommendations for 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. 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%.
3. Provide an explanation/procedure used for selecting location for re-inspection as well as how the results are used.
4. Provide more details on the inspection of large diameter (>8") cross-country water injection piping and the results of the proposed smart-pigging evaluation.
5. In addition to the existing data presentation, consider combining the leaks and saves from the BGPP with the External Leaks and Saves data. Presently it appears the 2001 leak is included but the two repairs (saves) are not.
6. Additional information on the number and integrity of lines identified in the WIV envelope without dampeners.

CONCLUSIONS

PAI continues their vigorous corrosion control program and has met or exceeded all of the stated inspection goals during 2001. The new report format is much improved and easier to comprehend.

Cross-country pipelines inspection data indicates a clear degree of internal corrosion control however the coupon pitting rates have been increasing in recent years and the number of corrosion damage increases also increased over last year. PAI has responded by returning to a previous inhibitor formulation as well as increasing the overall inhibitor concentrations. Lastly, smart-pigging is being investigated for inspection of large diameter Mixed Water cross-country piping.

Well line internal corrosion control appears to be approaching the "top of the curve," but still requires significant effort. The number of corrosion increases and number of saves were greater than the previous year. The schedule for testing wellhead inhibitor injection has slipped; but there should be preliminary results during 2002.

External corrosion control is progressing and all of the off-pad piping baseline inspections are completed. There are still more than 17,000 on-pad weld-packs remaining, and extrapolating the results to date, means there are several areas that will require repair. After the failure (1HBWI), the below grade screening program was accelerated during 2001 and two additional repairs were required.

Improvements were made to the well construction specifications to include floors with permanent pipe supports and thermo-siphons on new wells and retrofits to existing structures. Wind-Induced-Vibration specifications are being evaluated to determine whether or not a change needs to be made in light of the failure (DS2X) in 2001.

Beyond the Mitigation, Monitoring and Inspection goals outlined for 2002, PAI will be performing testing and/or improvements in the following areas:

- Engineered surfactant treatment aimed at removing solids in hard to treat water injection distribution lines.
- Corrosion Inhibitor development/testing
- Kuparuk corrosion database improvements
- Alpine database development
- WIV and well subsidence prioritization/evaluation.

2002 - BP

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.

2002-CPA

Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

ConocoPhillips Alaska Inc. – 2002 Commitment to Corrosion Monitoring for Greater Kuparuk Area & Alpine

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2002 corrosion program report submitted by ConocoPhillips Alaska Incorporated (CPAI) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in CPAI's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the October 2002 and April 2003 Meet & Confer sessions.

Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition; no leaks and no saves were reported in 2002. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency. Corrosion damage increases have been almost eliminated in the cross-country production gathering lines. Coupon pitting rates for three phase pipelines reversed the increasing trend seen during the past 5 years, due primarily to a change in inhibiters late in 2001. The mixed water injection average coupon pitting rates are above the target levels and is mostly attributed to piping at CPF2 locations. The percentage of locations with corrosion damage increases (UT and RT) has increased significantly for water injection service compared to 2001, 22%[1] vs. 0%.

Internal corrosion in well lines is an area that requires CPAI's continued focus; 2 leaks and 17 saves (repairs) were reported in 2002. The number of saves is roughly the same as in 2000, as is the footage of inspected pipe. The percentage of locations with corrosion damage increases (UT and RT) decreased slightly compared to 2001.

A baseline inspection of all weld-packs on cross country off-pad pipelines was completed in 2001. Baseline inspection of on-pad weld-packs (well and cross country lines) is progressing ahead of schedule and average percent of corroded weld-packs is around 3%. There were six repairs (~3% of corroded weld-packs) and more than 800 weld-packs refurbished on above grade piping.

CPAI completed the screening inspections for all Priority 1, below grade piping locations during 2002. Eight below grade locations were excavated and two locations required repair; one location was sleeved and the other location was replaced/upgraded.

There were no failures in 2002 due to structural related issues. An evaluation of the wind induced vibration (WIV) design envelope was completed in 2002 and recommendations implemented. The well subsidence mitigation program continued during 2002.

[1] Manual RT – 4 increases/14 repeats; Manual UT – 1 increases/9 repeats; Total – 5 increases/23 repeats = 22%

CORROSION PROGRAM STATUS

Internal Corrosion Management

Cross Country Pipelines – Monitoring & Inspection

Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition; no leaks and no saves were reported in 2002. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency. Corrosion damage increases have been nearly eliminated in the cross-country production gathering lines. Coupon pitting rates for the three phase and water injection pipelines reversed the increasing trend seen during the past 5 years, due primarily to a change in inhibitors late in 2001

Monitoring data for cross country water injection pipelines shows the average pitting rate exceeds the target. These data are largely dominated by results from CPF2 and work is ongoing in 2003 to determine the cause. The percentage of locations with corrosion damage increases (UT and RT) has increased significantly for water injection service compared to 2001, 22% vs 0%. The increases are primarily confined to one pipeline, 2EDCWI, and are the first increases identified to date on the water injection system.

CPAI reports that coupon or probe corrosion rates exceeded threshold targets in 20 pipelines and they responded by increasing the corrosion inhibitor concentrations target for all 20 pipelines. Eleven of these pipelines were also reported in 2001 as having exceeded corrosion rate targets and the response was increasing the corrosion inhibitor concentration target. Most of these eleven pipelines show little improvement and in some cases had worse results. Refer to Table 1 for a comparison of these eleven pipelines.

Table 1 - 2000 and 2001 Three-phase CC Production pipelines with corrosion rates exceeding targets

Common Line	2001			2002		
	Coupon Grade	Probe Rate	Inspection Increase	Coupon Grade	Probe Rate	Inspection Increase
1-2Z1QGPO	A	<.5	Yes	A	<.5	Yes
1RPO	F,D	>.5	Yes	C	<.5	
2KPO	D	<.5		C	<.5	
2TAMKHPO	A	<.5	Yes	A	>.5	Yes
2TPO	D	>.5		D	<.5	
2UPO	A	<.5	Yes	A	<.5	Yes
3CPO	D	<.5		D	<.5	
3MIPO	C	<.5		D	<.5	
3RQOPO	D	>.5		C	<.5	

Common Line	2001			2002		
	Coupon Grade	Probe Rate	Inspection Increase	Coupon Grade	Probe Rate	Inspection Increase
XCL/WO at CPF2	F,C	<.5		C	<.5	
XCL/WO at CPF1	D	<.5		B	N/A	Yes

Note: Shaded cells indicate either no change or condition is worse than 2001 result

In addition, inspection showed five lines with inspection increases where the coupons did not exceed the target corrosion rate. The corrosion inhibitor concentrations for all five of these lines were also increased. This helps to illustrate and reinforce the importance of both programs.

An ongoing item of concern is the difficulty of inspecting produced water injection piping with diameters larger than eight inches, which is considered radio-opaque and limits the use of radiographic techniques. CPAI evaluated the feasibility of using inline inspection for these pipelines during 2002, and concluded that while technically feasible it is cost prohibitive. CPAI will continue to rely on "spot UT" measurements for these pipelines.

Well Lines - Monitoring & Inspection

Internal corrosion in well lines is an area that requires CPAI's continued focus; two leaks and 17 saves (8 injection and 9 production) were reported in 2002. The number of saves is roughly the same as in 2000, as is the footage of inspected pipe.

Production well line coupon data indicate very low general and pitting corrosion rates, however CPAI notes that the inspection data indicates higher rates are being experienced. Injection well line coupon data indicates very low general corrosion rates. Pitting rates for this service are below the action limit, however they are 2-3 times above the historic minimums and have been so for the past three years.

The percentage of locations with corrosion damage increases (UT and RT) decreased slightly compared to 2001. It is unclear if there are specific targets for repeat inspections using manual RT and UT techniques, but the percent repeated for each inspection type and service type vary widely. It is also unclear if there is a target or action limit for the percent increase value.

Internal Corrosion Mitigation

CPAI's compliance with its own corrosion inhibition targets has improved over time; reporting an average deviation of +0.9% for 2002; a slight over-treatment. CPAI is continuing to move forward with the wellhead inhibitor injection program; with four additional drill sites to be added during 2003. The well lines should benefit greatly from this program. CPAI continues to develop and test new inhibitor formulations with lab and field trials continuing through 2003.

Under deposit corrosion has been identified as a key corrosion mechanism and a test using a chemical surfactant product to promote wetting of oil fouled solids is being put in place at DS1E.

External Corrosion Management

Above Grade Piping

CPAI exceeded their stated external inspection goals in 2002. The baseline inspection for all off-pad weld-packs was completed in 2001 and a program for recurring inspections targeted at "medium wet" weld-packs was begun in 2002. The baseline inspection for on-pad weld-packs was 70% complete overall and is progressing in accordance with CPAI's stated 2005 completion schedule. The forecasted number of weld-pack inspections for 2003 is roughly 1/3 of 2002 and 2001 inspection levels. It is not clear if this represents a reduction in effort, an increase in physical complexity of the piping system, or a combination of both.

There were zero repairs on off-pad piping, six repairs of piping on-pad and more than 800 weld-packs refurbished. The percent corroded and percent repaired results for 2002 are consistent with the overall average percentages, and likely means there are still ~10 repairs to be made on the remaining ~10,000 weld-packs. Refer to Table 2 for the overall weld-pack baseline inspection status.

Table 2 - Above grade weld-pack baseline inspection status

Service	Total Number (approx.)	Number Inspected During 2002	Number Inspected thru YE2002	% Inspected thru YE2002	Number Remaining	2002 Forecast
X-Country-Off-pad	67,291	0	67,291	100%	0	0
X-Country-On-pad	10,400	2,658	9,568	92%	832	416
Well Lines On-pad	24,000	4,116	14,400	60%	9,600	1,632
Totals	**101,691**	**6,774**	**91,259**	**90%**	**10,432**	**2,048**

Note: This table represents an effort to reconcile numbers presented in previous CPAI reports. There is the possibility for minor discrepancies.

The number of saves is roughly the same as in 2000, as is the footage of inspected pipe (RTR). The percentage of locations with corrosion damage increases (UT and RT) decreased slightly compared to 2001.

Buffer spikes were installed at 76 weld-packs locations as part of a test. The concept is a time-release sodium phosphate salt that serves to increase the pH of the electrolyte in contact with the steel surface, helping to create a passive layer on the steel surface. Little additional information was provided as to the status of this test program.

Below Grade Piping

CPAI exceeded their stated below grade inspection goals in 2002, inspecting 130 previously un-inspected Priority 1 locations using a combination of electromagnetic pulse and guided wave technologies. One additional screening technology, torsional wave, was evaluated and deemed "not superior" to the incumbent and will not be used at this time. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

Eight below grade locations were excavated and two locations required repair; one location was sleeved and the other location was replaced. The remaining six locations were refurbished to prevent further corrosion. Refer to Table 3 for a summary status of this program. The only Priority 1 locations left to inspect are on piping that is less than 10 years old. While age is an important factor, it is unlikely to be the controlling factor for corrosion of the below grade piping. Additional significant factors include: pipeline wall thickness, pipeline operating temperature, location of crossing in relation to drainage, fluid velocities, and fluid corrosivity. It is unclear if these other factors have been considered for the remaining Priority 1 locations.

Table 3 - Below Grade Piping Baseline Inspection Status

Description	Total Number (approx.)	Number Inspected During 2002	Number Inspected thru YE2002	Number Remaining
Priority 1 Oil	375	38	331	44[2]
Priority 1 Non-Oil	243	92	226	17
Priority 2 Oil	19	0	1	18
Priority 2 Non-Oil	98	0	0	98
Priority 3 Oil	22	0	1	21
Priority 3 Non-Oil	15	0	2	13
Totals	**772**	**130**	**561**	**211**

Notes:
1) This table represents an effort to reconcile numbers presented in previous CPAI reports. There is the possibility for minor discrepancies.
2) The only un-inspected Priority 1 pipelines are less than 10 years old

Structural Concerns

Subsidence

There were no leaks attributed to subsidence in 2002. CPAI continues to prioritize and upgrade existing wellhead riser supports and flooring susceptible to subsidence. Thermal siphons are also being installed in near well-bore location to promote re-freezing and stabilization of the soil.

Wind Induced Vibration

There were no leaks attributed to WIV in 2002. An evaluation of the WIV design envelope was completed in 2002 and recommendations implemented

RECOMMENDATIONS

Recommendations for future reports are as follows.

1. In addition to the existing data presentation, consider combining the leaks and saves from the BGPP with the External Leaks and Saves data. Presently it appears the 2001 leak is included, but the two repairs (saves) are not. Refer to CPAI Figure A1.
2. Coupon corrosion rate data is the only specific data presented for Alpine. It is not clear if inspection and mitigation information is commingled or excludes Alpine. Clarification of the treatment of Alpine data in future reports would be beneficial.

CONCLUSIONS

CPAI continues their vigorous corrosion control program and has met or exceeded all of the stated inspection goals during 2002.

Cross-country pipelines inspection data indicates a clear degree of internal corrosion control and the increasing coupon corrosion trend was reversed in 2002. Corrosion control, primarily inhibitor injection, has maintained the low leak/save frequency. Corrosion damage increases have been almost eliminated in the cross-country production gathering lines. The mixed water injection average coupon pitting rates are above the target levels and is mostly attributed to piping at CPF2 locations.

Inline inspection was evaluated for large diameter mixed water cross-country piping and deemed too costly to pursue as a primary inspection method. CPAI proposes to use spot UT measurements for these pipelines; however it is unclear if this will yield an adequate degree of confidence as to the condition of these pipelines. The percentage of locations with corrosion damage increases (UT and RT) has increased significantly for water injection service compared to 2001, 22% vs. 0%.

Well line internal corrosion control appears to be approaching the "top of the curve," but still requires significant focus. There were 2 failures and 17 repairs on well lines during 2002. The percentage of corrosion increases, level of inspections and number of saves were equivalent to 2000 results. The testing of wellhead inhibitor injection began in 2002 and plans are to add four additional well sites during 2003.

The external corrosion control program is progressing and the off-pad piping recur inspection program will begin in earnest during 2003. There are still more than 10,000 on-pad weld-packs requiring baseline inspections and extrapolating the results to date, there are several areas that will require repair. All of the Priority 1 below grade piping, older than 10 years, has had a baseline inspection.

There were no failures in 2002 due to structural related issues. An evaluation of the WIV design envelope was completed in 2002 and recommendations implemented. The well subsidence mitigation program continued during 2002.

2003-BP

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 preserved 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 wate 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 hig er 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 pr ide 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.

2003-CPA

Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

ConocoPhillips Alaska Inc. – Commitment to Corrosion Monitoring Year 2003 for Greater Kuparuk Area & Alpine

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. is responsible for the technical review of the 2003 corrosion program report submitted by ConocoPhillips to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion of ConocoPhillips 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 Kuparuk Area (GKA) has a conservatively managed corrosion control program. This suggests a long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.

Monitoring, mitigation, and inspection data support the conclusion that the GKA assets are being preserved, but isolated locations of accelerated internal corrosion exist and have been found by inspections. The isolated locations of corrosion are where leaks may occur. ConocoPhillips appears to have responded to this threat by conducting wide-ranging inspections. Additional inspections are focused on known damage locations, but it does not appear presently possible to predict the onset of all new locations of accelerated corrosion.

Monitoring data, presented by ConocoPhillips, 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. Presentation of in-line inspection data would also be useful.

Inspection data supports the conclusion that seawater and mixed water systems are being adequately managed for internal corrosion and program improvements are continuously being made. A problem in the Central Processing Facility #2 (CPF2), resulting in corrosion in the mixed water system, was identified and addressed.

External corrosion of above-ground piping is largely confined to weld packs and ConocoPhillips 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 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 ConocoPhillips 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 KUPARUK AREA

Internal Corrosion Management

Production System (Well Lines and Flow Lines)

The data provided by ConocoPhillips supports the conclusion that the internal corrosion control/inspection program is well managed and effectively preserving the facilities for the future. It is notable that ConocoPhillips presents data in a transparent way and answers questions with candor. However, the data presented does not fully reflect the existence of isolated locations of accelerated corrosion that could potentially result in leaks. Although isolated locations of corrosion are repairable, they could have an environmental consequence if not detected. The ConocoPhillips approach to controlling these leaks appear to consist of a wide-sweeping and aggressive inspection program.

From a global perspective of oil and gas production, GKA has one of the most conservatively managed internal corrosion control programs. Corrosion inhibition appears to be controlling general corrosion and isolated locations of accelerated corrosion are identified by an expansive inspection program. This suggests a long-term commitment to preserving facilities for future production and sensitivity to environmental consequences.

Monitoring, mitigation, and inspection data support the conclusion that the GKA assets are being adequately maintained and preserved. Corrosion control efforts meet or exceed standard oilfield industry practice. The average corrosion rates of coupons and probes are near zero and the average pitting rate is <5 mpy. A 5 mpy corrosion rate is put into context by considering that a 0.375-inch wall thickness pipe would have over 70% of its wall thickness after 20 years. Inspection data supports the conclusion that most of the asset has low corrosion rates, but isolated locations of accelerated corrosion rates do exist. 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 inspection intervals and methods at GKA are set by a risk based program approach, identified in the 2000 report, for all pipelines. The program methodology is based on the consequence and likelihood of corrosion related failures. Isolated locations of accelerated corrosion exist and have been found by inspections. The significance of isolated areas of accelerated corrosion within GKA is not intuitively reflected in the monitoring data presented by ConocoPhillips because many of the coupons and probes are not located where accelerated corrosion occurs (an effort has been made since 1997 to improve this). 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. Additionally, presenting in-line inspection data would aid in understanding the distribution of accelerated corrosion within a pipeline system.

Seawater and Mixed 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 mixed produced/seawater injection system is mitigated by carryover inhibition from the production system and the upstream treatment of the seawater.

Significant corrosion caused by the mixed water from CPF2 was identified by inspections and by monitoring results that indicated high coupon corrosion rates. Since the outcome of a CPF2 biocide program review was to revise the treatment procedures, it is assumed that the root cause of corrosion was determined to be bacteria. It is not clear if the bacteria originated from the seawater system (which should have already been treated with biocide) or from the commingled produced water. Biocide treatments are generally most effective when applied furthest upstream.

External Corrosion Management

Above Grade Piping

ConocoPhillips plans to complete inspection and repair (as necessary) of all weld packs in 2004. 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 a 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

In 2003 ConocoPhillips inspected 82 cased crossings (chosen by risk prioritization) 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. ConocoPhillips 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.

RECOMMENDATIONS

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. Future coupons should be placed at locations that represent the highest susceptibility to corrosion.
2. Identify criteria to be used for locating future coupons.
3. Based on the inspection methodology and guidelines in the GKA corrosion inspection program, define matrix or priority indices used for selecting inspection locations that may be prone to accelerated corrosion.
4. 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).
5. Continue the commitment to external corrosion inspection and mitigation of the weld packs.

CONCLUSIONS

ConocoPhillips has presented sufficient information to demonstrate that its corrosion control program meets the spirit of the Charter Agreement. This suggests a 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. ConocoPhillips has made a notable commitment to inspect and repair (when necessary) all of the weld-packs. ConocoPhillips inspects cased crossings by using visual inspections and state-of-the-art long-range inspection tools; however, it should be recognized that long-range inspection tools may have technical issues that need to be resolved.

2004 - BP

Corrosion Monitoring of Non-Common Carrier

North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc.

Commitment to Corrosion Monitoring Year 2004

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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). Inline 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–

2004-CPA

Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

ConocoPhillips Alaska Inc. – Commitment to Corrosion Monitoring Year 2004 for Greater Kuparuk Area & Western North Slope

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2004 corrosion program report submitted by ConocoPhillips Alaska, Inc. (CPAI) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to manage corrosion in CPAI non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the 2005 Meet & Confer sessions.

The data provided by CPAI 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.

The CPAI corrosion program emphasizes the identification of locations where 1) the likelihood of previous damage is greatest, and 2) corrosion rates are likely to be highest. Highest priority is placed on locations where the likelihood of damage and high corrosion rates coincide.

The overall corrosivity of the three phase production system is relatively low, but isolated locations of accelerated corrosion are known to exist. These locations are identified primarily through an extensive inspection program and controlled by chemical corrosion inhibitors.

Although seawater and produced water injection systems are normally considered to have lower susceptibility to corrosion compared to three phase production systems, a leak occurred in 2005. Although information existed on increasing corrosion rates, the lack of previous corrosion in this system did not prompt a major increase in its risk priority. Because of the leak, the injection system priority was elevated and increased mitigation and inspection actions are being taken.

External corrosion of above-ground piping is largely confined to weld packs, and CPAI has made a notable commitment to removing this threat through inspection and repair (where necessary) of all locations.

External corrosion at cased crossings represents a corrosion threat over which CPAI has a difficult challenge. This is because of the difficulty with accessing the pipe surface. In response to this challenge, CPAI has proactively implemented state-of-the-art technologies in further development of long range inspection techniques. CPAI recognizes the current technical limitations of these tools and is working with a vendor to further enhance them.

CORROSION PROGRAM STATUS – GREATER KUPARUK AREA (GKA) & WESTERN NORTH SLOPE (WNS)

The data provided by CPAI supports the conclusion that the corrosion management program is effective and exceeds common industry practice.

The CPAI corrosion program emphasizes the identification of locations where time to failure is shortest. That is, the program seeks to find locations where 1) the likelihood of previous damage is greatest, and 2) corrosion rates are likely to be highest. Highest priority is placed on locations where the likelihood of damage and high corrosion rates coincide. The consequence of a leak in any part of its system is considered to have similar safety or environmental consequences. Risk is therefore controlled by reducing the likelihood of failure.

It is notable that CPAI continues to present data in a transparent way and answers all questions with candor. Information from written reports, presentations, and verbal questions is consistent. In addition, the CPAI corrosion control staff is highly competent and an extensive QA/QC program is in place to monitor the performance of contractors.

Internal Corrosion Management

Three Phase Production System (Well Lines and Flow Lines)

The overall corrosivity of the GKA system is relatively low, but isolated locations of accelerated corrosion are known to exist. Corrosion inhibition appears to be making general corrosion unlikely and appears to be minimizing localized corrosion. Localized corrosion, not mitigated by inhibition, is primarily identified by an expansive inspection program.

Localized corrosion appears to be associated with the presence of solids and/or deposits that create crevices under which corrosion is accelerated and/or delivery of chemical treatment is restricted. The effect of solids on corrosion is reduced by chemical action (i.e., surfactants) that is aided by production velocities sufficient to keep solids mobilized.

All inspection, monitoring, mitigation, and inspection data support the conclusion that the GKA assets are being adequately preserved. Corrosion control efforts exceed standard oilfield industry practice. The average corrosion rates of coupons and probes are near zero and the average pitting rate is low.

The corrosion inspection and monitoring program has several components:

- Real-time radiography (RTR) is performed system-wide at approximately 5-year intervals. This inspection covers long continuous lengths of pipe selected to serve at least two purposes. The first is that defects that could result in leaks are identified and repaired. The second is that locations of corrosion damage that are not near-term integrity threats are identified as known-damage-recurs (KDR's) so that a growth rate can be determined. KDR's are scheduled for ultrasonic inspection at a time sooner than the next RTR survey. KDR's are also identified by conventional factors to prioritize susceptibility to corrosion (e.g., dead-legs, high velocity flow).

- KDR's are measured ultrasonically at less than 3-year intervals (2 month minimum), and the results are used for 1) determining if the location becomes an integrity threat in need of repair, and 2) determining corrosion growth rate for feedback to mitigation. The rate of KDR inspections is approximately 5% of the system every 5 years. All lines with internal corrosion damage are monitored by KDR inspections. The number of KDR locations on each line is determined by the severity and amount of damage. Guidelines specify there should be three to ten KDR locations per damaged line unless there is a good reason for fewer or more locations.
- Corrosion monitoring consists of corrosion coupons and probes. Their purpose is primarily to identify changes in corrosivity over time. It is recognized that coupons are not typically placed in the most susceptible location and that the rates do not necessary represent what is occurring on the pipe wall. This limitation in the coupon program is compensated by the KDR program. An increase in coupon corrosion rate therefore serves as an indication of a possible problem triggering further action. It is recognized that a coupon without corrosion does not necessarily indicate the lack of corrosion in a line.

In the 2003 report, a concern was raised that data reported by CPAI did not reflect the significance of isolated corrosion. This was because 1) corrosion coupons and probes are not typically located where the corrosion is considered most likely, and 2) presenting coupon data in an averaged form does not reflect the isolated high corrosion rate coupons. This issue was resolved by further communication from CPAI regarding the use of KDR's at locations considered most susceptible to corrosion. Since CPAI does not rely on coupons to identify locations most susceptible to corrosion, the importance of the coupon corrosion rates and their distribution of corrosion rates are of lesser importance than what is found by inspections.

Seawater and Mixed Water Injection

In general, seawater and produced water injection systems have lower susceptibility to corrosion compared to three phase production systems. The gas phase containing CO_2 and H_2S has been removed, and the presence of only one phase (i.e., water) simplifies delivery of chemical treatment. Corrosion caused by bacteria or oxygen are the most likely corrosion mechanisms. Corrosion of the CPAI seawater system is mitigated by removing oxygen and injecting biocides. Corrosion of the mixed produced/sea-water injection system is mitigated by carryover inhibition from the production system (and the upstream treatment of seawater) and increased line velocities to help reduce under-deposit corrosion. Additionally, cleaning pigs and a biocide are being used to remove deposits and kill bacteria. These actions are consistent with good corrosion control practices.

In 2005, a leak occurred in the water injection system at 2H pad, which was attributed to microbiologically induced corrosion (MIC). It is noteworthy that coupon corrosion rates have been high since 2002, and pitting rates exceeded 25 mpy in 2004. In hindsight, the high coupon rates are consistent with the leak, but it should be recognized that corrosion management programs (including that of CPAI) typically prioritize locations where likelihood of previous damage and high existing corrosion rates coincide. In this case, information existed that corrosion rates had increased, but the likelihood of previous corrosion damage was considered low. On that basis, other locations within the system were given higher priority. Because of the

leak, the future risk priority of the water injection system has been raised and additional mitigation, monitoring, and inspection has been implemented.

External Corrosion Management

Above Grade Piping

CPAI is committed to removing corrosion under weld-pack insulation as an integrity threat. No leaks were caused by external corrosion in 2004. CPAI completed tangential radiography testing (TRT) on all cross country lines and well lines. Two locations of severe damage were identified and repaired. A new weld pack design is intended to prevent future water ingress and corrosion at these field-applied insulation locations. To check the performance of the new design, at least 100 of the refurbished weld packs were inspected for water ingress. No corrosion under insulation was found in any of the areas inspected.

Below Grade Piping

External corrosion at cased crossings represents a corrosion threat over which CPAI has a difficult challenge. This is because of the difficulty with accessing the pipe surface. In response to this challenge, CPAI has proactively implemented state-of-the-art technologies in further development of long range inspection techniques. CPAI recognizes the current technical limitations of these tools and is working with a vendor to further enhance them.

In 2004, all casings were visually inspected (i.e., at the ends), and identified problems were remediated (e.g., pipe insulation in contact with casing, debris). Nine casing locations were excavated, inspected refurbished and repaired (as required). Additionally, 63 cased crossings were assessed using long-range ultrasonic inspection.

CPAI reports that 764 cased crossings are located in GKA. Because the pipe cannot be accessed without excavation and removal of the casing and insulation, inspection from outside of the pipe is not considered practical. The inspection program at GKA is heavily based on radiography of above ground insulated pipe, resulting in limited capability for inline inspection. The remaining alternative is long-range ultrasonic inspection, but the resolution of this method is less than other inspection methods used at GKA.

The primary reason for inspecting casings is for external pipeline corrosion because water and debris may enter the annular space and support corrosion. Although some differences in internal corrosion susceptibility might exist at the crossings because of elevation changes, the pipe upstream and downstream of the casing is considered representative. On that basis, it is reasonable to conclude that the absence of internal corrosion surrounding the crossing indicates low likelihood of internal corrosion within the crossing.

RECOMMENDATIONS

Recommendations for areas that warrant further review or information that should be included in future reports are as follows:

1. Further clarification regarding the mechanism of under-deposit corrosion in the three-phase oil production system.
2. Continue improvements to the mixed water injection systems until corrosion rates are below established threshold limits.
3. 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).
4. Continue commitment to aggressively address corrosion under insulation at weld pack areas.
5. Provide additional information confirming that WNS corrosion management has equal or equivalent rigor to GKA programs.

CONCLUSIONS

The data provided by CPAI 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 CPAI continues to present data in a transparent way and answers all questions with candor. Information from written reports, presentations, and verbal questions are consistent. In addition, the CPAI corrosion control staff is very competent and an extensive QA/QC program is in place to monitor the performance of contractors.

The CPAI corrosion program emphasizes the identification of locations where 1) the likelihood of previous damage is greatest, and 2) corrosion rates are likely to be highest. Highest priority is placed on locations where the likelihood of damage and high corrosion rates coincide.

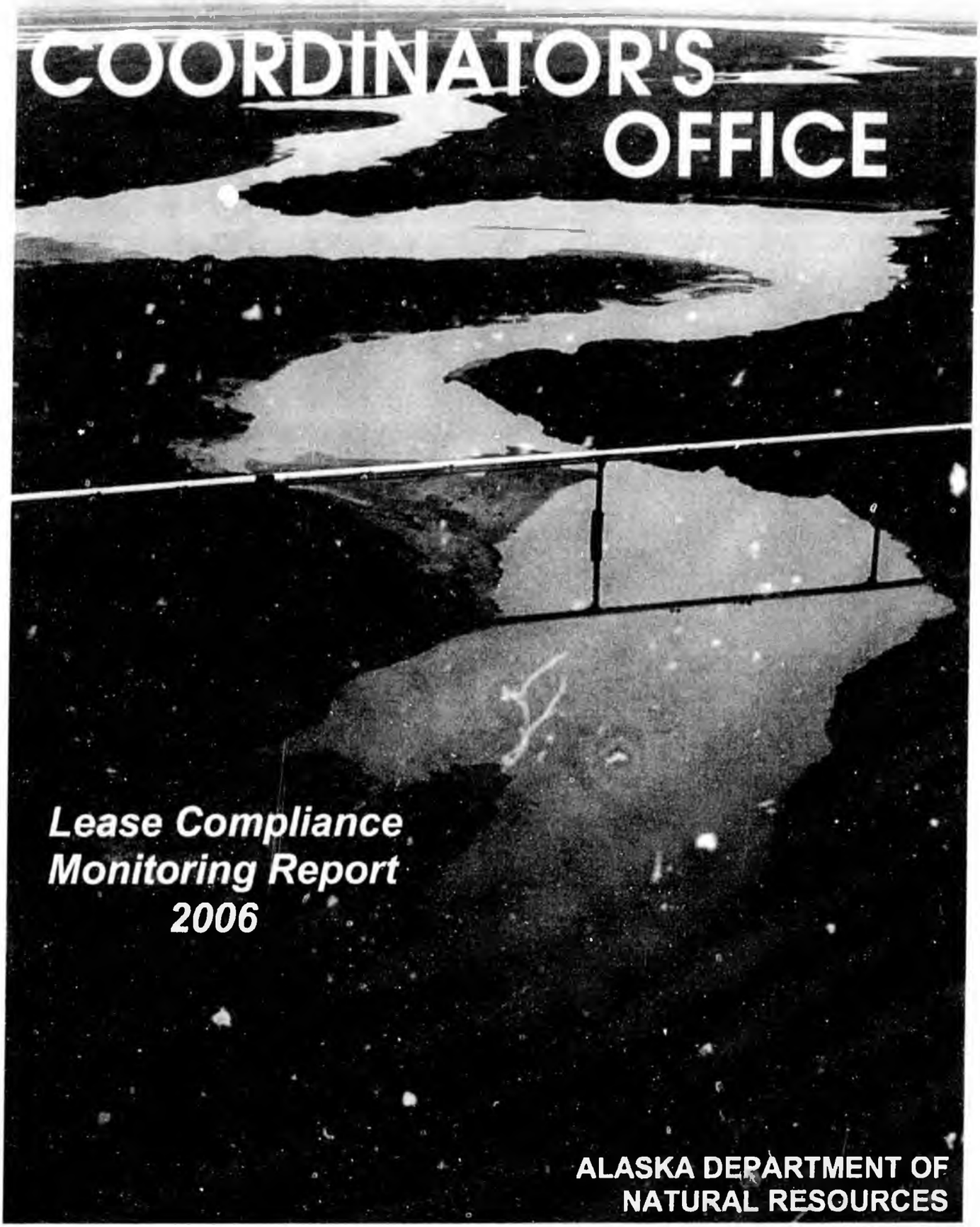
Internal corrosion of the three phase production and water injection systems are effectively managed, but a leak occurred in a water injection system considered to have low susceptibility to corrosion. CPAI has increased the risk priority of this system and has increased mitigation and inspection activity.

External corrosion of above-ground piping is largely confined to weld packs, and CPAI continues to make notable progress on removing this threat through inspection and repair (where necessary) of all locations.

External corrosion at cased crossings represents a corrosion threat over which CPAI has a difficult challenge. This is because of the difficulty with accessing the pipe surface. In response to this challenge, CPAI has proactively implemented state-of-the-art technologies in further development of long range inspection techniques. CPAI recognizes the current technical limitations of these tools and is working with a vendor to further enhance them.

PRUDHOE BAY CORROSION CRISIS, 8/18/06 (FILE 11)

STATE PIPELINE COORDINATOR'S OFFICE



Lease Compliance Monitoring Report 2006

ALASKA DEPARTMENT OF NATURAL RESOURCES

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Executive Summary

The 2006 State Pipeline Coordinator's Office Lease Compliance Monitoring Report describes the status of pipeline right-of-way leases issued by the State under Alaska Statute 38.35, the Alaska Right-of-Way Leasing Act, and one grant of right-of-way for a utility pipeline issued under Alaska Statute 38.05, the Alaska Lands Act. It is produced by the State Pipeline Coordinator's Office (SPCO), an agency within the Alaska Department of Natural Resources (ADNR) and the Joint Pipeline Office (JPO).

The State fiscal year (FY) begins on July 1 and ends on June 30. FY06 began July 1, 2005 and ended June 30, 2006. This FY06 report includes information about the prior year's construction, operations, and maintenance activities for common carrier pipelines in Southcentral and on the North Slope. Summaries of ADNR's lease administration and compliance oversight activities related to those pipelines and rights-of-way are also included.

This report is intended for use by the public, government agencies, pipeline right-of-way lessees, and others interested in these pipelines.

Note that information about the Trans-Alaska Pipeline System (TAPS) is not contained in this report, but is the focus of the Joint Pipeline Office annual report available at *http://www.jpo.doi.gov*.

Acronyms and Abbreviations

All of the acronyms and abbreviations used in this report are defined in Appendix A

Contact Information

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Anchorage, Alaska 99501
(907) 257-1300

Unless otherwise indicated, all photographs in this report were taken by the SPCO Lease Compliance Oversight Team. All maps are adapted from maps available publicly through ADNR's Alaska Mapper.

Cover Photo

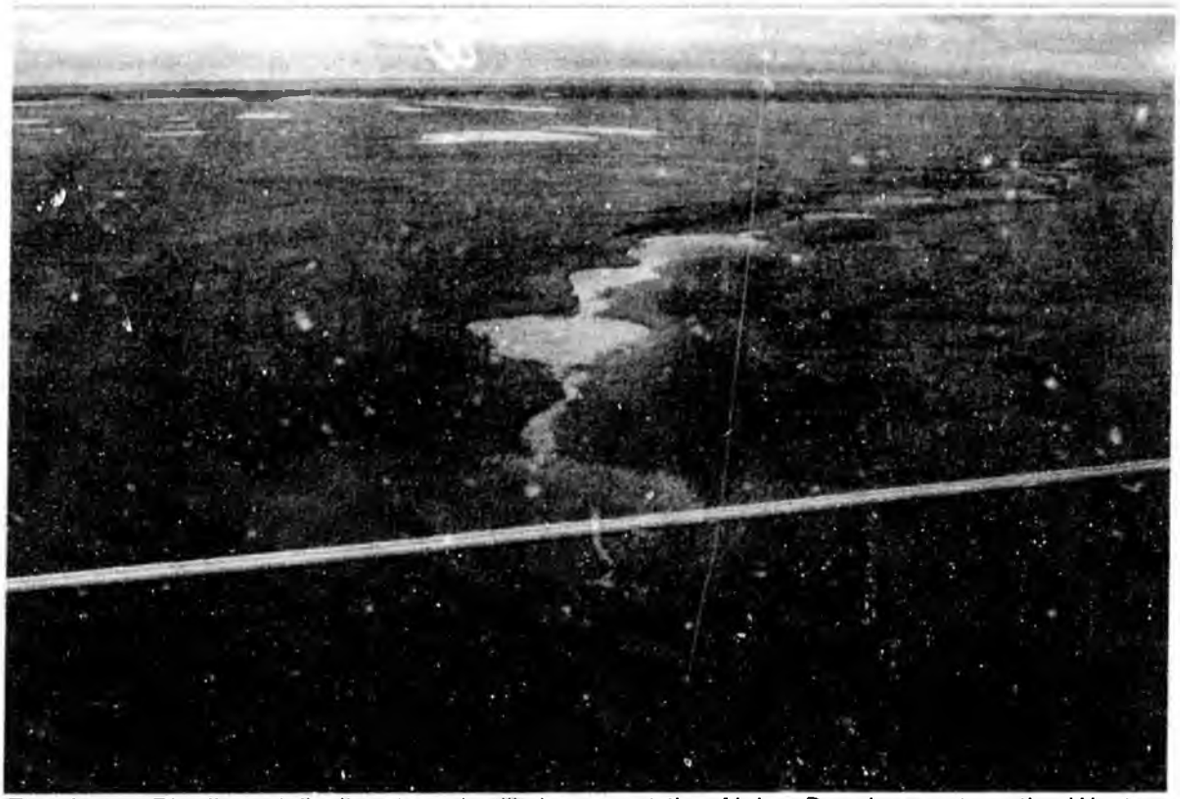
This aerial photo of an un-named stream crossing was taken during the course of a compliance oversight field surveillance of the Badami Pipelines in September 2005. The BP-operated Badami Sales Oil Pipeline connects the North Slope's easternmost development, Badami, to the Endicott Pipeline.

I. Joint Pipeline Office (JPO)

JPO Mission Statement

The Joint Pipeline Office, a consortium of State and federal agencies, regulates the Trans-Alaska Pipeline System and other Alaskan oil and gas pipelines in the best interests of the people of the nation and the State of Alaska. Safety, environmental protection, pipeline integrity, and regulatory compliance will be achieved through partnering with industry.

The Joint Pipeline Office is a consortium of State and federal agencies sharing similar regulatory or management responsibilities related to oil and gas industry pipelines in Alaska, most notably the Trans-Alaska Pipeline System. The JPO was established in 1990 to work cooperatively on large scale natural gas pipeline right-of-way (ROW) leasing and TAPS oversight.



The Alpine Pipelines (oil, diesel, and utility) connect the Alpine Development on the Western North Slope to infrastructure in the Kuparuk River Unit.

Representatives from six of the 12 agencies are co-located to coordinate pipeline compliance oversight and issue right-of-way leases and other permits needed for oil and gas industry projects. Agencies have developed cooperative agreements to share staff,

knowledge, equipment, and office space. This unique working environment eliminates duplication, is more customer-oriented, and simplifies government processes.

The US Bureau of Land Management and Alaska Department of Natural Resources are designated leads and jointly manage the JPO. Agencies retain their individual authorities while working together on common projects and issues. Agency personnel can participate in self-directed work teams and may perform oversight functions in addition to their jurisdictional responsibilities. All agencies coordinate activities, such as permitting projects, as needed. The following agencies currently participate in the JPO:

JPO-Participating State Agencies	***JPO-Participating Federal Agencies***
Dept. of Natural Resources	Bureau of Land Management
Dept. of Environmental Conservation	US Army Corps of Engineers*
Dept. of Public Safety, Division of Fire Protection	US Department of Transportation Office of Pipeline Safety*
Dept. of Labor & Workforce Development	Environmental Protection Agency
Dept. of Fish & Game*	US Coast Guard*
Dept. of Transportation & Public Facilities*	Minerals Management Service*

**No full-time representatives co-located at the JPO*

The Federal and State agencies within the JPO, except for ADNR/SPCO, currently direct their efforts on one active pipeline, TAPS. ADNR staff within the SPCO have the additional responsibility of lease administration and compliance monitoring for sixteen other active pipelines as well as pipelines in the pre-application and application stages of development.

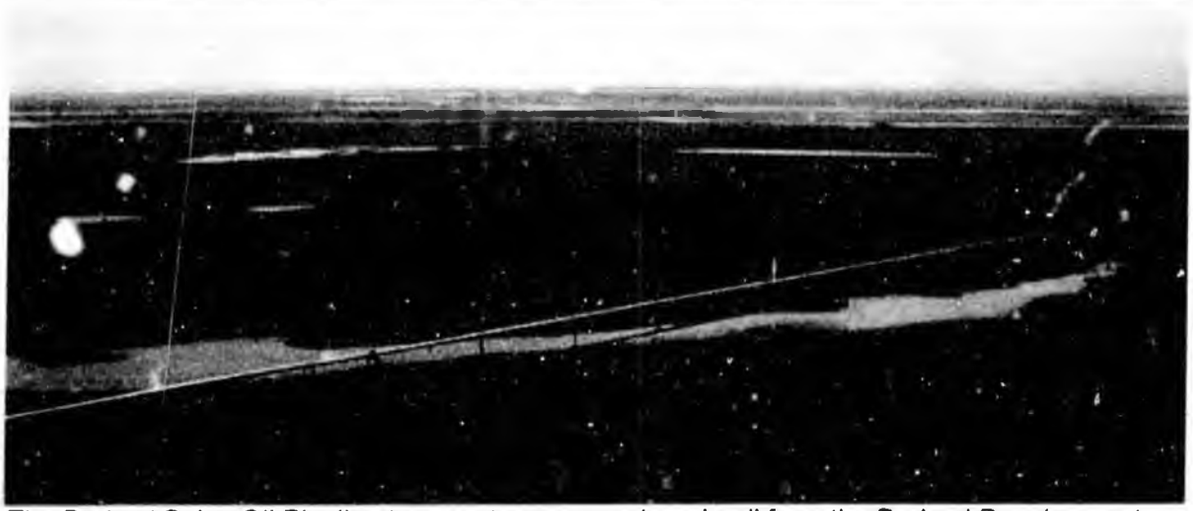
II. State Pipeline Coordinator's Office (SPCO)

Known for working with applicants early and using streamlined permitting processes, the SPCO, an office within ADNR and the lead State agency in the JPO, is responsible for administration and oversight of State pipeline ROW leases issued under Alaska Statute 38.35, the *Alaska Right-of-Way Leasing Act*. Under AS 38.35, companies proposing to operate pipelines in whole or in part on State land must apply for and be granted a ROW lease prior to construction. Key concepts in the Act include:

- The Act applies to common carrier and contract pipelines, but field gathering lines are exempted
- Lessees pay fair market value to lease State lands in the pipeline ROW
- Safeguards are included to protect the environment, public safety, and health

- Lessees reimburse the State for costs in processing and administering leases
- The State retains a continuing right of access and inspection to ensure compliance with the lease and applicable laws

Field Gathering Lines Exempt: Per AS 38.35.020(b), "The commissioner may by regulation exempt the construction or operation of field gathering lines or any reasonable classification of them from the requirement of a right-of-way lease under this chapter." Many oil and gas pipelines in Alaska are classified as field gathering lines, exempting them from AS 38.35 and SPCO oversight. 11AAC 80.055 defines field gathering lines as: "pipe and associated facilities, including separators, test equipment, pumps, treaters and tanks, used in the transfer of gas or oil from a well or other facility used in the production of gas or oil to a point where there is either a custody transfer of the gas or oil or where the gas or oil enters a common carrier pipeline, whichever first occurs." Per 11AAC 80.055, the Prudhoe Bay "Transit Lines" are classified as field gathering lines and were not authorized under 38.35. Field gathering lines are regulated in Alaska by ADEC and permitted through ADNR's Division of Oil and Gas.



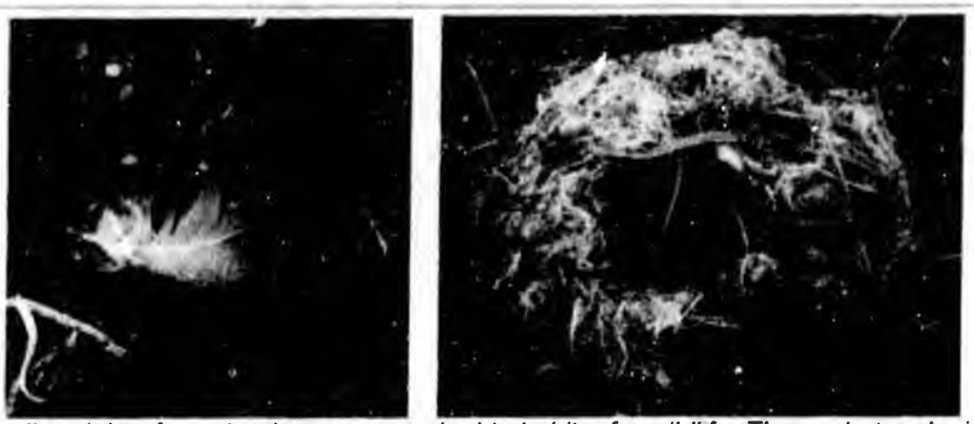
The Badami Sales Oil Pipeline transports processed crude oil from the Badami Development on the east to the Endicott Pipeline. The Badami Utility Pipeline, resting on the same supports, has been used to transport fuel gas from Endicott to Badami.

The SPCO currently administers 16 existing leases, one grant, and several proposed pipeline ROW leases within Alaska. Lease administration and compliance oversight of TAPS is accomplished cooperatively by the State and federal governments through the JPO. The remaining 16 active pipelines are administered only through the SPCO and are the subject of this report. Each State ROW lease is assigned a unique number according to the former Alaska Division of Lands (ADL) numbering system. The ADNR Land Administration System, accessible from the web at www.dnr.state.ak.us/las, is a resource where agencies, industry, and the public can obtain detailed information about ADNR case files including legal descriptions, status plats, and maps of State land in the ROW.

SPCO-administered pipeline ROW leases are listed in the table below.

Effective Right-of-Way Leases	***ADL No.***	***Status***
Alpine Oil Pipeline	415701	Operating
Alpine Diesel Pipeline	415932	Operating
Alpine Utility Pipeline (Grant)	415857	Operating
Badami Sales Oil Pipeline	415472	Operating
Badami Utility Pipeline	415965	Operating
Endicott Pipeline	410562	Operating
Kenai Kachemak Pipeline	228162	Operating
Kuparuk Pipeline	402294	Operating
Kuparuk Pipeline Extension	409027	Operating
Milne Point Pipeline	410221	Operating
Milne Point Products Pipeline	416172	Warm shutdown
Nikiski Alaska Pipeline	69354	Operating
Northstar Oil Pipeline	415700	Operating
Northstar Gas Pipeline	415975	Operating
Nuiqsut Natural Gas Pipeline	416202	Constructed; not operating
Oliktok Pipeline	411731	Operating
Trans-Alaska Pipeline System	63574	Operating

Right-of-Way Applications	***ADL No.***	***Status***
Alaska Natural Gas Transportation System	403427	Application
Dayville Road Pipeline A	229284	Application
Dayville Road Pipeline B	229285	Application
Dayville Road Pipeline C	229286	Application
Eastern North Slope Oil Pipeline	417577	Application
Eastern North Slope Gas Pipeline	417578	Application
Glennallen-Palmer Spur Line	229297	Conditional lease; no pipeline constructed
Liberty O" Pipeline	416002	Inactive application
Liberty Utility Pipeline	416003	Inactive application
Phillips Tyonek Deep Pipeline	227422	Inactive application
Point Thomson Gas Cycling Pipeline	416904	Application
Trans-Alaska Gas System	413342	Conditional lease; no pipeline constructed



State pipeline right-of-way lands serve as valuable habitat for wildlife. These photos depict a migratory bird feather (left) and a small bird nest (right) found by an SPCO surveillant within the Badami pipelines ROW during June 2006 surveillance.

The intent of the ROW Leasing Act is *"...the development, use and control of a pipeline transportation system be directed to make the maximum contribution to the development of the human resources of this State, the increase in the standard of living for all of its residents, the advancement of existing and potential sectors of its economy, the strengthening of free competition in its private enterprise system, and the careful protection of its incomparable natural environment."*

To fulfill this intent, the SPCO is charged with administering pipeline ROW leases. These duties include processing ROW applications, drafting leases for the ADNR Commissioner's approval, implementing the public review process, issuing project-specific authorizations, and monitoring compliance with lease conditions. These functions are the responsibility of the SPCO ROW Section. Administratively, two teams comprise the ROW Section, the Lease Administration Team, and the Lease Compliance Oversight Team. A description of the two teams follows.

Lease Administration

The SPCO lease administration team is currently staffed by five State ADNR employees. The team processes ROW lease applications and amendments, implements public processes, issues project-specific authorizations, administers rental and other payments, and performs other functions as necessary.

Compliance Oversight

The SPCO compliance oversight team is currently staffed by two State ADNR employees who share responsibilities for compliance oversight monitoring of the 15 active non-TAPS State pipeline ROW leases issued under AS 38.35 and one utility pipeline grant issued under AS 38.05. The team's primary function is to document compliance with lease conditions and monitor select issues as determined by the ROW

Section Chief and State Pipeline Coordinator. The compliance oversight program operates on a cyclical basis and consists of three main elements, further described in the following sections:

1) *Compliance Monitoring:* consists of field inspections called surveillances and records reviews conducted on a cyclical basis.
2) *Annual Lessees' Reports:* required by each ROW lease, the lessees submit reports annually which are reviewed by the compliance oversight team.
3) *Annual SPCO Lease Compliance Monitoring Report:* produced by the compliance oversight team, the annual report provides an opportunity for the team to review both SPCO and lessee activities for the year and can be used to focus attention on specific topics as necessary.

1) Compliance Monitoring

The purpose of SPCO compliance monitoring is to evaluate lessee compliance with active lease requirements at a frequency prescribed by the State Pipeline Coordinator. Generally, rights-of-way for constructed pipelines are inspected on a bi-annual basis. In the first year, the compliance oversight team looks at general lease compliance. In the second year, the team does more in-depth surveillance on a specific topic, such as corrosion. The work plan is scheduled so that approximately half of the leases get a general overview each year, while the other half get a more focused subject-specific surveillance. Each AS 38.35 pipeline receives some compliance monitoring each year.

To develop the work plan, the team evaluated each lease requirement and determined its functional status relative to annual surveillance efforts. For example, many lease provisions are definitions or clarifications of legal/administrative points that require no surveillance. Other provisions apply only to a certain activity phase such as construction or termination. Finally, some are invoked only after action initiated by the lessee or State Pipeline Coordinator. Those provisions are described as "conditional".

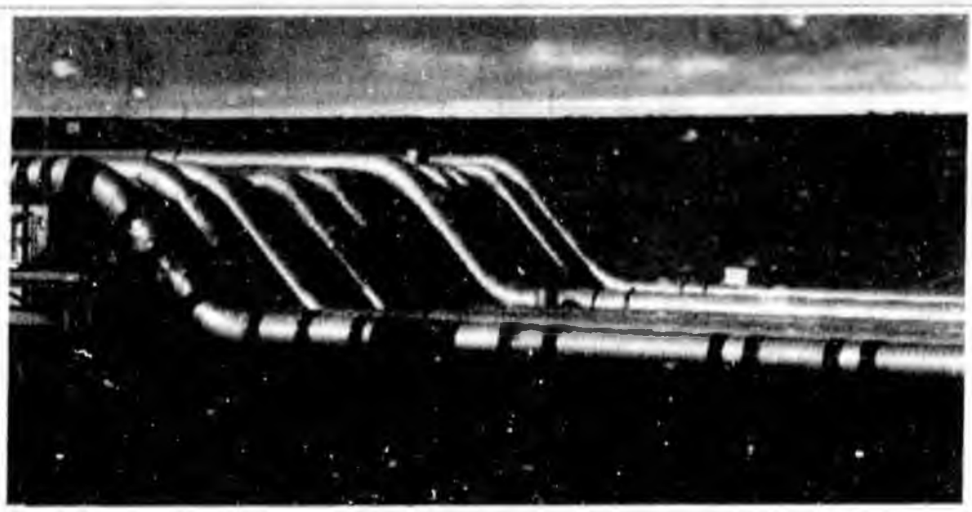
In 2003 and 2004, the SPCO conducted an internal review of the compliance monitoring program. The compliance oversight team conducted a complete surveillance regarding each checklist for each pipeline ROW, documenting compliance with every lease provision, including those that were administrative or legal in nature and those denoted as conditional, regardless of the activation status. This allowed the SPCO and lessees to fully review each lease condition and fostered a thorough discussion of the compliance oversight program. Now, the SPCO only examines those lease provisions where the need for surveillance is continuous, or conditional (if activated).

A matrix of all the requirements for each lease and the respective SPCO surveillance determination and frequency was developed. Matrices for each of the SPCO jurisdictional pipelines are documented in the case files. Each matrix summarizes three decision criteria:

1. What activity phase (construction, operation, maintenance, termination or any combination of the four) does each requirement apply to;

2. Is surveillance required (if not, why) and;

3. *If surveillance is required, what is the necessary frequency?*



Though many pipelines criss-cross Alaska's North Slope, most are not common carrier pipelines and do not lease a State ROW under AS 38.35. Instead, they are permitted through ADNR's Division of Oil and Gas under AS 38.05. Here the Endicott Pipeline and other pipelines are depicted crossing the Sagavanirktok River on a bridge near Deadhorse. The Endicott Pipeline is the one farthest back with the small white sign.

For the sixteen jurisdictional pipelines addressed in this SPCO report, the lease compliance oversight team is working with lessees, through their quality assurance programs, to ensure lease requirements are met. Lessees are responsible for conducting pipeline operations in accordance with applicable laws and the terms and stipulations of each ROW lease. Lessees document compliance through quality assurance (QA) and surveillance & monitoring programs, which are approved by the State Pipeline Coordinator. Though individual lease requirements vary, all SPCO-administered ROW leases require the lessee to develop a QA program or plan that provides evidence of compliance with lease stipulations and applicable laws. For example, the Alpine Oil Pipeline lease defines a QA Program as "all those documented, planned, and systematic actions necessary to provide evidence that the Lessee is satisfying lease commitments and requirements for integrity of the Pipeline System, health, safety, and the environment."

An important element of maintaining compliance with lease conditions and stipulations is routine inspection of the pipeline and ROW. Lessee surveillance & monitoring programs are developed to ensure measures are in place to prevent, detect, and abate conditions which could threaten pipeline integrity, the environment, or public health and safety. Revisions to QA and surveillance & monitoring programs are reviewed by SPCO staff and must be approved by the State Pipeline Coordinator prior to implementation.

In addition to oversight of lessees' QA and surveillance & monitoring activities, the compliance oversight team conducts field surveillance of pipelines and rights-of-way,

meets with lessees to learn more about their programs, and reviews records provided by lessees. The products of a compliance oversight field visit or records review are 1) Surveillance reports and 2) Surveillance field notes.

1) Surveillance Reports – After completion of a field visit, known as a surveillance, the surveillant writes up a "checklist" with a unique number which lists the lease or grant section, covenant, or stipulation that was reviewed. To complete the checklist, the surveillant provides observations to support a determination of *satisfactory* or *unsatisfactory* for the lessee's performance under that lease provision. Unsatisfactory conditions can be *minor* or *significant*. There is also an option for a surveillant to describe an unsatisfactory condition as *corrected on the spot*. Often supporting documents are attached to surveillance reports. Usually when a surveillant makes an unsatisfactory determination, the lessee is given a deadline to correct the condition or to complete required follow-up. Once signed by the surveillant and supervisor, the surveillance checklist becomes a surveillance report with a unique number. Copies are sent to the lessee's Registered Agent, entered in the JPO Document Tracking System, and the original is filed in the lease case file.

2) Surveillance Field Notes - One set of surveillance field notes for each trip may be written by the surveillant(s) and attached to a surveillance report. Each set of field notes is also filed with that lease's Quality Program. Field notes are usually detailed and contain digital photographs of field conditions to support information contained in surveillance reports. For any given field visit, there will be one set of field notes but may be one to dozens of surveillance reports which correspond to the field notes. Field notes can also apply to more than one pipeline inspected on a single field trip, while surveillance reports apply to only one ROW case file.

Because each ROW lease contains different sections and stipulations, surveillance checklists are not always directly comparable across leases. The number of surveillance reports produced is not always indicative of the scope of compliance monitoring for that pipeline. Sometimes field surveillance is focused on a specific topic, generating only a handful of detailed reports. Other surveillance trips are more general in nature and may generate dozens of surveillance reports with less detail. The SPCO annual report and surveillance field notes provide qualitative compliance monitoring information to complement quantitative data from surveillance reports. For details about this year's compliance oversight program, see Section IV of this introduction.

2) Annual Lessees' Reports

Annual comprehensive reports submitted by pipeline ROW lessees are a critical element of the compliance oversight program. The annual report is supposed to document the lessee's compliance with lease requirements. The reports are intended to provide detailed information about the lessee's pipeline activities for the previous year. In some annual reports, lessees have produced their own detailed ROW Agreement compliance matrix to show how they are achieving compliance. Information provided in the annual report can help the compliance oversight team identify future surveillance priorities.

Each ROW lease has a provision requiring a comprehensive report on pipeline activities. In addition to lease-specific requirements for annual reporting, the State Pipeline Coordinator has required that each lessee provide an annual comprehensive report on pipeline activities that includes, at a minimum:

1. The results of the lessee's surveillance & monitoring program during the preceding year, including annual and cumulative changes in facilities and operations, the effects of the changes, and proposed actions to be taken as a result of the noted changes:

- *Provide a summary of the scope of all surveillances, audits, self-assessments or other internal evaluations performed by the lessee.*
- *Summarize findings, action items and other observations identified as a result of all surveillances, audits, self-assessments or other internal evaluations performed by the lessee.*
- *Describe corrective and preventative actions planned or implemented as a result of surveillances, audits, self-assessments or other internal evaluations performed by the lessee.*
- *To the extent known, list by quarter, those surveillances, audits, self-assessments or other internal evaluations planned for next year.*

2. The state of, changes to, and results from the last year of the lessee's risk management program, Quality Assurance Program, and internal and external safety programs.

3. Lessee's performance under the right-of-way lease, including stipulations.

4. Information on construction, operations, maintenance, and termination activities necessary to provide a complete and accurate representation of the lessee's activities and the state of the pipeline system.

5. A summary of all events, incidents and issues which had the potential to or actually did adversely impact pipeline system integrity, the environment, or worker or public safety and a summary of the lessee's response.

6. A summary of all oil and hazardous substance discharges including date, substance, quantity, location, cause, and cleanup actions undertaken. Minor discharges below agreed upon thresholds may be grouped into monthly total amounts, provided the number of separate incidents is reported.

7. Any additional information requested by the State Pipeline Coordinator.

Lessees are required to submit their annual report for the previous year by January 31st. The compliance oversight team reviews each lessee's report in detail and provides feedback. If a lessee's report does not meet the minimum requirements, the team will require additional information from the lessee as necessary. For information about the 2005 lessee reports, see Section IV, This Year's Compliance Oversight Activities.

3) Annual SPCO Lease Compliance Monitoring Report

The purpose of the Annual SPCO Lease Compliance Monitoring Report, produced by the compliance oversight team, is to summarize annual lessee and SPCO activities

related to each pipeline ROW lease for the preceding Fiscal Year (July 1 through June 30). The reports generally provide some background information, a summary and analysis of the lessee's annual report, a summary of the current year's oversight program, and a look forward to upcoming issues related to each ROW lease. For information about this year's report, see Section IV, This Year's Compliance Oversight Activities.

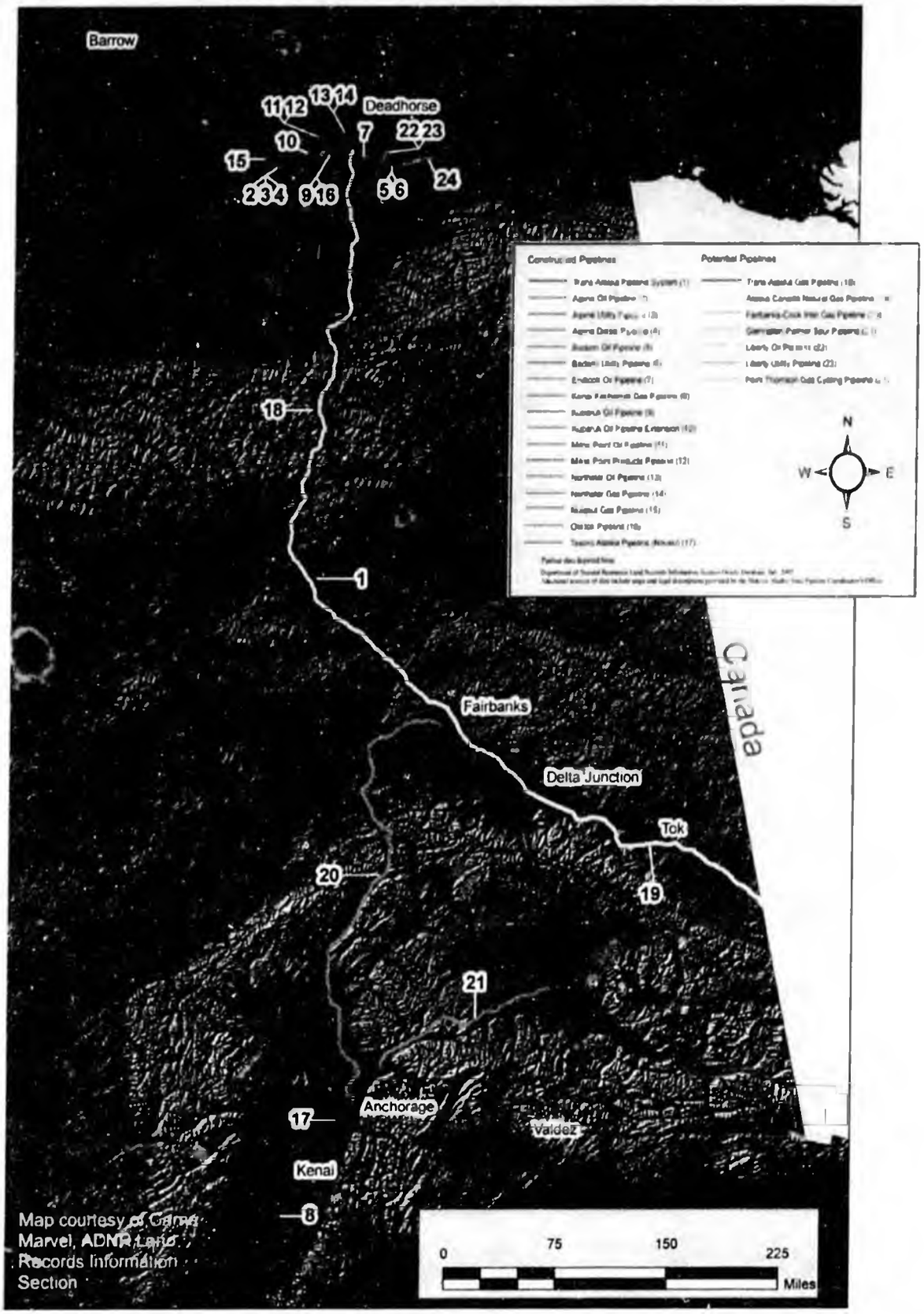
III. Pipelines Subject to Compliance Monitoring

Currently, there are fifteen non-TAPS AS 38.35 pipeline ROW leases and one AS 38.05 ROW grant subject to compliance monitoring through the SPCO. (This number does not include the Trans-Alaska Pipeline System, which is monitored through the JPO and reported on in the JPO Annual Report.) Fourteen of these pipelines are operational, the Milne Point Products Pipeline is in warm shutdown status, and the Nuiqsut Natural Gas Pipeline is constructed but not yet operational.

The following table summarizes information about the sixteen jurisdictional pipelines that are the subject of this report.

Location	*ADL*	*Name (product)*	*Length in Miles**	*ROW Lessee*
North Slope	415701	Alpine Oil	34	ConocoPhillips Company
North Slope	415932	Alpine Diesel	34	ConocoPhillips Company
North Slope	415857	Alpine Utility (Grant)	34	ConocoPhillips Company
North Slope	415472	Badami Sales Oil	25	BP Transportation (Alaska)
North Slope	415965	Badami Utility	31	BP Transportation (Alaska)
North Slope	410562	Endicott (Oil)	26	Endicott Pipeline Company
Southcentral	228162	Kenai Kachemak (Gas)	50	Kenai Kachemak LLC
North Slope	402294	Kuparuk (Oil)	28	Kuparuk Transportation Company
North Slope	409027	Kuparuk Extension (Oil)	9	Kuparuk Transportation Company
North Slope	410221	Milne Point (Oil)	10	Milne Point Pipeline LLC
North Slope	416172	Milne Point Products	10	Milne Point Pipeline LLC
Southcentral	69354	Nikiski Alaska (Refined oil products)	70	Tesoro Alaska Pipeline Company
North Slope	415700	Northstar Oil	17	BP Transportation (Alaska)
North Slope	415975	Northstar Gas	16	BP Transportation (Alaska)
North Slope	416202	Nuiqsut Natural Gas	14	North Slope Borough
North Slope	411731	Oliktok (Natural Gas Liquids)	28	Oliktok Pipeline Company

**The length values given in this table are the approximate length of the pipeline system. The length of pipeline on State-leased ROW lands may be shorter. For detailed information about State lands in a ROW, go to the chapter for that pipeline.*



Map courtesy of Carma Marvel, ADNR Land Records Information Section

IV. This Year's Compliance Oversight Activities

1) Compliance Monitoring

Between January 1, 2005 and June 30, 2006, the SPCO conducted field surveillance for 13 pipeline ROW leases and one utility pipeline grant to get an overview of those pipeline systems and monitor lease compliance in general. Additionally, some surveillance was conducted on special topics such as corrosion, construction practices, a facility re-start, and in-line inspection (ILI) operations. The following table summarizes surveillance field trips for FY06 and the latter half of FY05.

When	ADLs	Pipelines	Surveillance Topics	Surveillant(s)
June 2005	415701 415932 415857	Alpine Oil Pipeline Alpine Diesel Pipeline Alpine Utility Pipeline	General overview; surveillance of State for reduction in ROW width (release of interests)	Novinska Swanson
June 2005	69354	Nikiski Alaska Pipeline (Tesoro)	Turnagain Arm pipe replacement	Perez
June 2005	228162	Kenai Kachemak Gas Pipeline	Anomaly dig	Novinska Swanson
July 2005	228162	Kenai Kachemak Gas Pipeline	Corrosion; revegetation of Happy Valley Extension	Novinska Swanson
August 2005	69354	Nikiski Alaska Pipeline (Tesoro)	General overview	Novinska
September 2005	415472 415965 410562	Badami Sales Oil Pipeline Badami Utility Pipeline Endicott Pipeline	General overview; re-start of Badami pipelines and facilities	Novinska
November 2005	402294 409027 411731	Kuparuk (Oil) Pipeline Kuparuk Extension Pipeline Oliktok Pipeline	General overview; corrosion	Novinska
March 2006	410221 416172	Milne Point (Oil) Pipeline Milne Point Products Pipeline	General overview; follow-up on valve closure incident	Constantine
April 2006	228162	Kenai Kachemak Gas Pipeline	ROW brush clearing activities: Kasilof Extension	Novinska Constantine
May 2006	228162	Kenai Kachemak Gas Pipeline	HDD pilot boring: Kasilof Extension	Novinska
June 2006	415472 415965	Badami Sales Oil Pipeline Badami Utility Pipeline	Observation of monitoring activities at the Sag River weir	Constantine
June 2006	415472 410562 410221 415975	Badami Sales Oil Pipeline Endicott Pipeline Milne Point Oil Pipeline Northstar Oil Pipeline	Surveillance & monitoring program for early detection and abatement of corrosion	Novinska
June 2006	228162	Kenai Kachemak Gas Pipeline	Welding; HDD pipe pull	Novinska
June 2006	69354	Nikiski Alaska Pipeline (Tesoro)	General overview; stream crossings	Novinska Constantine