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

Submitted by

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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.