Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Technical Analysis

Of

BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2001 for Greater Prudhoe Bay, Endicott, Badami and Milne Point

Submitted by

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2001 corrosion program report submitted by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the October 2001 and April 2002 Meet & Confer sessions. BPXA and ADEC mutually agreed to a performance metric guide prior to drafting the 2001 report. The results are a much improved report that better defines the service categories and basic summary statistics.

The 2001 report contain more detail and is wider in scope than the 2000 Report and covers corrosion management strategy and objectives. BPXA has done a good job in further clarifying how it uses raw corrosion data to focus its inspection and inhibition programs. However, in some cases, the facility piping population was included with the non-common carrier piping population. While the facility piping information is useful, it makes an analysis of the non-common carrier piping difficult to perform.

Internal corrosion control in oil flow lines is clearly indicated by coupons and inspections, with average corrosion rates approaching the historical minimum. Produced water flow lines had a slight increase in the corrosion rates compared to 2000. A specific corrosion inhibitor test program was implemented for the produced water system and will continue in 2002. There were two flow lines inspected using an inline inspection tool. There were 11,369 inspections, six saves and one leak for flow lines during 2001.

Internal corrosion control in oil well lines is clearly indicated by coupons and inspections, with average corrosion rates approaching the historic minimum. Coupons for produced water well lines indicate an increase in corrosion rates, but a corrosion inhibitor program specifically aimed at the produced water system is under development. Coupons for the seawater injection well lines indicate an increase in corrosion rates, almost doubling since 1999. The cause has been identified and remedial actions were taken in 2001, results will be available during 2002. There were 9,780 inspections in 2001, substantially more than previous years. There were five saves and one leak for well lines in 2001.

Presently, external corrosion is a significant risk for pipeline repairs and/or leaks for BPXA. External corrosion under insulation was reported as the cause for 28 repairs and two leaks in 2000 and 17 repairs and two leaks in 2001. The percent corroded remained consistent with the past 3-year average (~5%). Overall, the weld-pack inspection program is ~40% complete, with ~120,000 weld-packs remaining. Plans are to more than double the number of weld-pack inspections for 2002. Below grade piping baseline program is on schedule for completion in 2003 with roughly 60% completed through 2001. There were no excavations in 2001.

The ACT corrosion programs continue to evolve in 2001. Endicott is unique given the use of duplex stainless steels in the production system. The main concern here is the inter-island water pipeline (IIWL). Corrosion control for the IIWL uses a combination of maintenance pigging, biociding, and inhibition. Inspection of the IIWL indicates little corrosion activity. Milne Point is unique given the amount of buried piping associated with this field. There have been 60 excavations of buried piping over the past two years with some locations showing corrosion.

The water injection system coupons have exceeded the 2 mpy corrosion rate until 2001. This is a result of a specific inhibition program started in 2000. Northstar and Badami are relatively new fields and have limited data, which shows no corrosion.

CORROSION PROGRAM STATUS – GREATER PRUDHOE BAY

Internal Corrosion Management

Monitoring & Inspection – General

Coupon monitoring activity levels have remained relatively flat from 1995 to the present. BPXA continuously updates its program in an ongoing effort to optimize the coupon program to deliver "maximum corrosion management information". Overall, the coupon results for the current reporting period are very encouraging. BPXA states that the "The reduction by a factor of 10 (of coupon corrosion rates) over the last 10 years is a direct result of an aggressive corrosion mitigation program…" Clearly the inhibition program is making advances in corrosion mitigation.

BPXA presents the total number of inspections for GPB as ~60,000 per year since 1995. The total number of inspections actually increased in 2001 to ~61,000, reversing a 3-year trend of lower inspection numbers (Figure B.4). The 2001 total includes ~40,000 inspections which are performed on the facilities (not non-common carrier piping) and considered outside the scope of the Charter. This information is useful as it lends context to the inspection program, but one must be careful when trying to analyze the aggregate information. It is interesting to note the shift from a 50/50 split to a 66/33 split between facilities and field piping in the past two years. This change in emphasis is due to BPXA asserting corrosion control on field piping is adequately addressed. Lastly, within the field piping category the ratio of flow line (cross-country) inspections to well-line inspections has changed from a 70/30 to 55/45.

Percent inspection increases is a useful metric for quantifying the gross effort expended, but it is function of the number of re-inspected locations. According to Table B.8(c), the target is zero increases. It is not clear if the number of re-inspected locations is a statistical sample of known damaged locations, a fixed number of locations, or based on some other criteria.

Several graphs were included to demonstrate the effectiveness over time of the inhibition program using inspection increases and pipe condition for three phase oil lines (flow and well). The major effort is now on fine tuning the system to maintain or increase the current level of corrosion control for the piping.

Monitoring & Inspection – Cross Country (Flow) Pipelines

Coupon monitoring for "oil" system indicates the average corrosion rate in cross-country flowlines is at or near its historical minimum. The number of coupons at or below the 2 mpy threshold set by BPX for conformance is approaching the 100% mark.

Coupon monitoring in produced water system shows a slight increase in corrosion rate as well as pitting rate when compared to 2000, however both levels are below their respective targets.. In general, an increase in corrosion inhibitor in the 3-phase system shows some carryover benefit to the produced water system. BPXA has been testing corrosion inhibitors for this system, and two successful candidates were identified in 2001 and the program will continue in 2002.

Coupon monitoring for the seawater injection system shows no data for 2001 (Table 5.1 and 5.2). It should be noted there were only two coupons in 2000, so the lack of data is not a significant issue.

There were 11,369 inspections of flow lines during 2001, >9,000 for oil and >1,400 for water. The percent inspection increases for re-inspected water and oil flow lines increased slightly from 2000, but compared to the overall average they are lower. There were six saves (two oil, one water, three processed oil) and one leak in 2001. The three repairs for processed oil occurred are associated with a dead-leg which is scheduled to be removed in 2002.

Two produced water lines (M-69 and S-69) were inspected with an inline inspection tool (smart pig). With the exception of stating follow-up manual inspections to "proof" the tool were performed, no results are discussed.

Monitoring & Inspection – Well Lines

Coupons monitoring corrosion in oil production service show a significant reduction in corrosion rates with a step reduction in the average corrosion rate in 1997 (figure C.3). In 2001 93% of all coupons in this service category were below the 2 mpy conformance threshold. This is also a slight improvement over 2000 results. Conformance levels in the 99% range should be possible given the corrosion mitigation performance in cross-country lines.

Coupon monitoring in produced water system show a 6-year high in corrosion rate as well as an increase in pitting rate from 2000. The previously described inhibitor testing program will hopefully have a beneficial effect for this service.

Coupon monitoring in seawater injection system stands out in this report because of the increasing corrosion rate trend illustrated by Figure C.5. Pitting and weight loss rates in this service category have almost doubled since 1999. The primary factors responsible for this increase are cited as dissolved oxygen levels and microbial corrosion. BPXA is vigorously moving ahead with a program to reverse this corrosion trend in. Dissolved oxygen targets have been set to "<20 ppb", dissolved oxygen metering is being improved, vacuum tower performance is being upgraded through the use of an anti-foaming compound, a new oxygen scavenger catalyst is being tested and plant repair and maintenance schedules are being evaluated. Coupon pull frequencies have been shortened in this service category to allow for more frequent monitoring.

There were 9,780 inspections of well lines during 2001, >8,000 for oil and >1,000 for water service categories. This represents the largest number of inspections on well lines for the reported period. Given the number of leaks and number of saves for well lines is greater than that of the flow lines, the balance in emphasis appears to be a positive move. The percent inspection increases for re-inspected well lines decreased slightly, continuing the 4-year downward trend. There were five saves (4 oil and 1 water) and three leaks in 2001 attributed to internal corrosion.

Internal Corrosion Mitigation

BPXA expends considerable effort to develop and test new corrosion inhibitors. A rigorous testing procedure is outlined in the report showing, illustrating how inhibitors transition from the laboratory to field testing. Figure D.4 clearly shows pitting on coupons exposed to production in an unsuccessful corrosion inhibitor trial. Eighteen new products have been developed for use in the continuous well-head injection program since 1995. BPXA is carefully working to consolidate the number of products used field-wide.

CO_2 and solids deposition (both mechanisms can produce deep pitting) are cited as the main challenges in produced water systems where most coupon pitting is found. BPXA is moving forward in developing a corrosion mitigation plan specific to produced water, with corrosion inhibitors were tested in 1999 and 2000. Two successful candidates were identified in 2001 and BPXA states that funds were budgeted in 2002 for inhibitor injection.

Optimizing the injected volumes is critical to the economic application of inhibitor chemistry. Table D.6 and D.7 show how the average inhibitor concentration has varied over time. Inhibitor average concentration has risen from 85 ppm in 1995 to 157 ppm in 2001. BPXA is injecting nearly twice the volume it was using only 6 years ago. This increase is delivering measurable results in the systems in which it is being injected; cross-country production piping is nearing 100% corrosion rate conformance. The actual volume of chemical usage was 2.63 million gallons, which is 1.6% over the target amount of 2.59 million gallons. Based on monitoring and inspection data, corrosion inhibitor concentrations were increased (10-20% typical) in 14 pipelines.

External Corrosion Management

Above Grade Piping

BPXA exceeded their stated external inspection goals in 2001. There were twelve repairs and one leak on off-pad piping; five repairs and one leak on on-pad piping; and presumably more than 800 weld-packs refurbished at locations were corrosion was detected. The percent corroded and percent repaired results in 2001 are consistent with the 1999-2000 average percentages, and likely means there are 100+ repairs to be made on the remaining weld-packs. There were 17 repairs (12 flow lines and 5 well lines) and two leaks (1 flow line and 1 well line) in 2001. Table 1 summarizes the overall weld-pack inspection program status based on information presented for 2001.

Table 1 – GPB Above grade, non common carrier pipeline weld-pack inspection status

Service	Total Number (approx.)	Number Inspected During 2001	Number Inspected thru YE2001	% Inspected thru YE2001	Number Remaining (approx.)	2002 Forecast
X-Country/Flow Line – Off-pad		2,675	57,263			
Well Lines – On-pad		12,730	22,688			
Totals	**200,000**	**15,405**	**79,951**	**40%**	**120,049**	**35,000**

The 2000 Report states there are ~185,000 weld-packs while the 2001 Report states there are ~300,000 weld-packs. The increase can be attributed to combination of weld-packs on non-common carrier piping and facility piping. The status of piping associated with facilities is a bonus, but beyond the scope of the Charter. Furthermore, reporting only the combined population makes an assessment of non-common carrier pipeline status difficult.

BPXA has committed to accelerating its weld-pack inspection program through the addition of more resources, more than doubling the number of weld-packs (35,000 versus 13,000 avg.) to be inspected in 2002. It is unclear what percentage of the inspections is planned for non-common carrier pipelines versus facility piping.

Below Grade Piping

BPXA exceeded their stated below grade inspection goals in 2001, inspecting ~280 locations using a combination of electromagnetic pulse and guided wave technologies. BPXA is 60% complete with the inspection of a combined total of 460 cased crossings by YE2001. They are on track to complete the remainder by YE2003. Additionally all cased crossings are visually inspected to ensure they are clear of debris and if found, they are cleaned out.

There were two "moderate" and zero "severe" anomalies and no excavations performed during 2001.

Structural Concerns

There were no leaks due to structural issues in 2001. The process for identifying and repairing other structural issues was presented in the report.

CORROSION PROGRAM STATUS – ALASKA CONSOLIDATED TEAM

General

The ACT corrosion programs status continues to evolve in 2001. The level of effort applied to the satellite field corrosion programs varies between them. New piping and facilities are expected not to need as much attention as decades old, fully mature, fields, consequently BPXA has not taken its fully mature GPB corrosion program and duplicated it in these smaller fields.

Monitoring and inspection should be conducted in a proactive manner that will discover new and different corrosion mechanisms before they become a serious problem.

Endicott

Endicott "is a mature waterflood field," and the production fluid is characterized as "high temperature and high CO_2." The production system was constructed mostly of Duplex Stainless Steel (DSS), which is a corrosion resistant alloy that combines good weldability, strength, and toughness. It is highly resistant to CO_2 corrosion. Problems can occur in Duplex installations when chlorides are present or when microbial induced corrosion (MIC) takes hold. Solids deposition in stagnant internal areas and contact with stagnating brines can induce isolated pitting corrosion in this alloy. The presence of solids and microbes in the injection water may point to future challenges for the DSS piping

Coupon data indicates the production system corrosion rate remains above the 2 mpy threshold however BPXA states this is not a concern for the piping since it is fabricated mostly from DSS. Since the piping is corrosion resistant Endicott could benefit from a corrosion program targeted at solids removal and microbial control. Coupon data also indicates the water system corrosion control program is effective.

The primary corrosion concern at Endicott is the inter-island-water-line (IIWL). It is assumed that the IIWL line is carbon steel because BPXA is pigging, biociding, and inhibiting the water in the IIWL. UT Inspection results (fig. D.1) for the IIWL are good. While the number of inspection increases in the IIWL is down overall since 1998; there was a slight increase in 2001. The IIWL line was inspected using and inline inspection tool in 1995, there was no discussion of results or if another inline inspection is planned.

Table E.1 lists the cased piping external inspections performed at Endicott. Some external corrosion has been detected. The oil line inspection interval is characterized as "N/A Duplex Stainless Steel". Depending on the chloride concentrations in the ground water and ingress through weld-packs, a full baseline inspection should be made and a reasonable re-inspection interval set.

DSS is not corrosion proof, just corrosion resistant. BPX may need to reassess its surveillance philosophy in systems fabricated from DSS. BPX does not mention which DSS alloy is used in Endicott's construction. BPX provided a table (table B.1, pg 99) which lists line lengths and the number of internal and external inspections. Pitting and microbial corrosion are threats to the DSS system, some discussion of how these mechanisms progress in DSS installations and how they are controlled (pigging/biociding/solids mitigation) would be useful in the next reporting cycle.

Milne Point

Milne Point fluids are characterized by low CO_2, low operating temperature and low velocities. Corrosion under insulation and internal under-deposit corrosion mechanisms are mentioned and are consistent with the stated operating conditions. There were no leaks or repairs during 2001. Coupon data indicate very good mitigation with the single exception of the water injection system. Coupon rates in the water injection system exceeded the 2 mpy threshold until 2001. In mid-2000 corrosion inhibitor injection was begun in the water injection system and the initial results appear to be encouraging.

It is stated that Milne Point internal inspection history has been "variable" and that in 1998 a policy change was made to rectify this situation stating "a concerted effort was made towards obtaining a more consistent inspection survey". Internal under-deposit corrosion was found in the K-pad line and an inhibitor injection was begun. It is too early to determine the inhibitor effectiveness at this time. F-pad production flow line was inspected using an inline inspection tool, with the follow-up to occur in 2002.

Table E.2 shows the number of external inspections decreased from a high of 205 in 2000 to 179 in 2001. The percent inspection increases for re-inspected locations is 27% avg. for the last two years, which is well in excess of the GPB field average. Buried pipe is also an issue in the MPU since many of the gathering lines and product distribution lines are buried along the roadway. Excavations were made at 30 locations in 2001 looking for external corrosion; nineteen were new locations, eight were recurring inspections with no increases and three locations showed "slight increases". Excavations were also made at 30 locations in 2000 but results were not discussed.

Northstar

Northstar began production in late 2001 and consequently has very limited data. Fluid corrosivity is expected to moderate initially but will increase with the injection of Prudhoe Bay Gas. There are corrosion monitoring locations installed and data will be reported in the future. Presently, well production lines are treated with low concentrations of continuously injected corrosion inhibitor. No Internal and external inspection data were presented, presumably data were not collected.

Badami

Badami started in 1998 and fluid corrosivity is considered low due to the small volumes of water and low CO_2 content. There is no corrosion inhibition or corrosion monitoring (coupon) program in place. Corrosion control is monitored through the use of a small inspection program. While no external weld-packs have been inspected to date, the pipe condition is observed in conjunction with internal inspections. Internal inspections have shown no corrosion.

RECOMMENDATIONS

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

1. Total number/population of well lines, cross country lines, weld packs, below grade pipe segments would be beneficial. In addition, the number of baseline inspections and related percentages for the weld-pack and below grade piping programs would be beneficial to track overall progress during the multi-year effort. These data could be presented as a cumulative graph or in a tabular format.

2. If facility piping is to be included in future reports, an individual breakdown and presentation of the facility piping and non-common carrier piping data sets will aid future analysis of items related to the Charter.
3. In order to gain a better understanding of the operating conditions for the various pipelines, a histogram depicting the number of pipelines in each service within different %SMYS categories would be beneficial. Suggested %SMYS categories are: <10%, 10-20%, 20-30%, and >30%.
4. Provide an explanation/procedure used for selecting location for re-inspection as well as how the results are used.
5. Provide more details on the inspection techniques for large diameter (>8") cross-country water injection piping.
6. When smart pig runs were made on non-common carrier pipelines, inclusion of the results would be useful. The report indicates smart pigs were run on non-common carrier pipelines in the GPB and ACT but no results were presented. Include discussion regarding inspection intervals.
7. Pitting and microbial corrosion can be threats to the DSS system, some discussion of how these mechanisms progress in DSS installations and how they are controlled (pigging or biociding?) at Endicott would be beneficial.
8. Milne Point information regarding the results of the ongoing excavation program such as how locations are picked, leak/save data, results from previous excavations.

CONCLUSIONS

BPXA continues its thorough and aggressive corrosion control program. The 2001 Report contains more detail and is wider in scope than the 2000 Report. BPXA has consolidated/integrated the corrosion programs for GPB and will focus n optimization and continuous improvement of the program in 2002. Integration of "heritage" databases into on database (MIMIR) continues and will improve the ability to obtain and analyze data in a timely fashion,

Internal corrosion in cross-country gathering lines and oil well lines is clearly being controlled. The coupon monitoring in the seawater injection system stands out in the report because of the increasing corrosion rate trend. BPXAs planned steps to improve operations in the seawater treatment plant should reverse this negative trend for 2002. An inhibitor project aimed specifically at produced water system will continue development in 2002.

Presently, external corrosion remains a significant risk for pipeline repairs and/or leaks for BPXA. The weld-pack baseline inspection program is ~40% complete and the goal for 2002 is ~35,000 weld-pack inspection, more than double previous years effort. The below grade piping inspection program is 60% complete and on track for completion in 2003.

The corrosion programs for the ACT fields (Endicott, MPU, Badami, and Northstar) would benefit from a more consistent application of the programs developed in the GPB. Inspection and monitoring in the ACT need to be conducted in a consistent manner that will discover new and different corrosion mechanisms before they become a serious problem.

BPXA is making continual improvements to it many corrosion mitigation operations and if implemented for 2002 the next report should show reverses in the few negative corrosion trends.