Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

Final Draft

Technical Analysis

Of

BP Exploration (Alaska) Inc. – Commitment to Corrosion Monitoring Year 2000 for Greater Prudhoe Bay, Endicott, Badami and Milne Point

Submitted by

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EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 2000 corrosion program report submitted by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Department of Environmental Conservation (ADEC). The report outlines the measures undertaken to mitigate corrosion in BPXA's non-common carrier North Slope pipelines. In addition, Coffman reviewed the presentation materials from the April 2000 Meet & Confer session. The goal of this review is to examine the corrosion program report, attempt to gain a qualitative understanding of BPXA's corrosion control program and identify initial recommendations for improvement to the content and extent of topics covered.

BPXA stated intent is to "to report openly, good or bad..." the results of its corrosion management programs. However, the reporting style makes it difficult to develop a qualitative understanding of the basis for their corrosion strategy. Program results have been reduced and factored; conclusions are hard to report without making inferences with regard to the underlying reasoning and strategy. The metrics chosen to report results make comparisons to industry peers difficult to quantify. No discussion of the underlying program strategy is included other than to say "Our corporate goals are no accidents, no harm to people and no damage to the environment". With these limitations in mind, the focus of this review concentrated on the Greater Prudhoe Bay (GPB) pipelines. Similar findings can be applied to the field data presented in the report.

External corrosion is the most immediate threat to pipeline integrity for BPXA. External corrosion under insulation was reported as the cause for both leaks in 2000 (table 12) and there have been two additional leaks in 2001 due to external corrosion. Repairs due to external corrosion outweigh repairs due to internal corrosion by 4:1 (table 11). Tables 1 and 2 show 13,274 inspections were made for external corrosion while 20,420, or ~50% more, inspections were done for internal corrosion. External corrosion inspection levels are not consistent with the relative risk of an internal vs. external corrosion event.

Internal corrosion rates increased in 2000 in well flow lines, drillsite gathering lines, and produced water injection lines (figure 1). The actual magnitude of the corrosion increase is not reported and subsequent damage to the pipe wall due to increased corrosivity is not quantified. Seawater distribution lines showed a small decrease in corrosion rates. Figure 1 reports the results for the internal corrosion program as an "Annualized percentage of coupons with corrosion rates <2 mpy". No differentiation between weight loss and pitting corrosion are discussed. It is also reported that some coupons were removed from its system in 2000 because "a number of coupons are installed upstream of the chemical injection location and therefore provide no meaningful data". Without knowing the baseline corrosion trend within its production system it is difficult to judge the effectiveness or value of its inhibition program.

Erosional mechanisms are well characterized and are controlled by modifying the production parameters on wells likely to produce velocities and/or solids in excess. No statistics on the extent of erosion corrosion defects was reported.

Lastly, the Work Plan required a "Summary overview of ongoing structural concerns". Structural issues beyond corrosion were not addressed in either the report or the presentation. The corrosion group will need to coordinate with those tasked with maintaining pipeline structural integrity in order to address the confluence of corrosion and structural concerns.

While the BPXA report and presentation materials where an initial attempt to meet the expectations outlined in the Commitment to Corrosion Monitoring plan, it does not provide the information necessary for detailed technical analysis. BPXA and ADEC have committed to better define reporting metrics and definitions for future reports. International standards are available as a starting place for discussion of appropriate reporting metrics.

COMMITMENT TO CORROSION MONITORING

The Charter agreement between the State of Alaska, BPXA and PAI required the development of a "performance management program for the regular review" of the corrosion monitoring and related practices for the non-common carrier North Slope pipelines. As a result of the subsequent meetings, the annual reporting requirements were defined as follows:

A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.

B. A general overview of the previous year's monitoring program.

C. Metrics which depict coupon and probe corrosion rates.

D. Metrics which characterize chemical optimization activities.

E. Metrics which depict the number and type of internal/external inspection done and, as applicable, the corrosion increases/rates and corresponding inspection intervals.

F. Metrics which characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.

G. Metrics which depict the numbers and types of corrosion and structural related spills and incidents

H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meeting described above.

ADEC contracted with Coffman Engineers, Inc to provide a technical analysis of the information presented in the annual report and determine if there any specific corrosion or pipeline structural issues which warrant further review or corrective action. In addition to the annual report, Coffman reviewed the presentation materials from the April 2001 Meet and Confer Session.

CORROSION CONTROL STRATEGY

This section outlines the strategy presented in the report and presentation. It is divided into Internal and External corrosion and describes the monitoring, inspection and mitigation components. The current program status is presented in a subsequent section.

Internal Corrosion Control

Monitoring & Inspection

BPXA uses probes and coupons to monitor internal corrosion throughout the field. Information on how the coupons are analyzed and how the data is weighted is not presented. The target, or action, limit for coupons is stated as 2 mils per year (mpy). The target, or action, limit for probes is based on location and is between 0.5 mpy and 10 mils per year.

They also employ manual and automated RT and UT inspection techniques. The report discusses the limitations of the various inspection methods. Wall losses less than 10 mils (0.010") are difficult to detect. The typical amount wall loss upon first detection is not reported. The target, or action, limit for inspection is "zero detectable corrosion," which is inferred to mean something greater than 10 mils.

The data generated from the monitoring and inspection programs is reviewed weekly and in depth reviews are made at the end of each quarter. If target values are exceeded, there is an investigation and possible mitigation.

Lastly, BPXA discusses the use of Magnetic Flux Leakage (MFL) pigging technology. MFL pigging allows an operator to inspect the entire length of pipe for both internal and external corrosion indications and would be a significant tool for determining the corrosion baseline and corrosion rates for a given pipeline or pipeline sections. There is very little discussion about the MFL pigging strategy (location, frequency, results, etc.).

Mitigation

Internal corrosion at BPXA is controlled primarily by corrosion inhibitor application and secondarily by erosional velocity controls and well start-up procedures (slide 6). There are also a host of other engineering tools, such as design, material selection, coating selection, etc.

Chemical optimization is an on-going task for BPXA. As promising new inhibitors are developed they are tested on a small scale initially, followed by a larger scale test, and if successful, used within the facilities. Several products have been developed in the past years. The target values for inhibitor concentration is 150 ppm.

External Corrosion Control

External corrosion under wet insulation is a concern for all North Slope producers. All the pipelines are above ground and the vast majority is insulated. Snow and water can be forced under the insulation where pipe segments are joined and field applied insulation was installed. These areas are known as weld-packs. When the line is warm and the water trapped under the insulation is above freezing, oxygen corrosion cells can form. Corrosion under insulation is likely to require an ongoing commitment throughout the life of the field. BPXA will have to validate an effective repair method in order to eliminate this as a fixed cost of operation.

Monitoring & Inspection

Presently, there are no monitoring techniques used for this corrosion mechanism. This places greater emphasis on the inspection program. Inspection methods for corrosion under insulation are radiographic and visual. TRT (tangential radiography), C-arm fluoroscopy and MFL smart pigging, eddy current, and digital radiography are used in conjunction with visual inspection to detect corrosion under insulation. The weld-pack locations are externally identifiable so the precise location of possible corrosion cells is easily ascertained. This mechanism can be expected to be active through-out the rest of the field life. In addition, BPXA is also using two technologies for inspecting the below grade, cased pipeline crossings; electromagnetic and guided wave inspection.

Mitigation

Draining the weld-pack, refurbishing the seals to eliminate water ingress, and replacing the saturated insulation are the primary mitigation methods. Repair requires the exclusion of oxygen saturated water from contact with the external pipe wall. External corrosion under insulation may be prevented by the redesign of the weld-pack to prevent water/oxygen ingress, application of inhibitor doped greases, or organic coatings, like tape systems and epoxies may help. In addition, weld-packs that have been repaired need to be inspected to verify the method is an adequate long term solution. A more in-depth review of the measures taken in the past by BPXA would be necessary before any sort of recommendation could be formulated.

CORROSION PROGRAM STATUS

Risk

With the exception of corrosion under insulation (pg21), the report does not discuss risk assessment protocols or risk based inspection. BPXA appears to use some form of risk based resource allocation method but the details are not reported. Judgment or experiential based protocols suffer from a lack of continuity; oil fields with production lifetimes in excess of half a century or more require a codified set of protocols otherwise the program changes when key personnel move on. BPXA may have codified its risk assessment strategy but it is not reported.

Internal Corrosion Control

Internal corrosion rates at GPB have increased in every service category except seawater in 2000 (Fig 1). It was reported that seven (7) repairs and 63 saves were recorded due to internal corrosion in 2000 (Table 11 and 12). BPXA reports its inspection results for internal corrosion as "percent of inspection increases" (see fig.4). Unfortunately only the percentage of inspections which show increases in damage is reported; not the magnitude of the wall loss.

BPXA reports a loss of corrosion control due to under-treatment with corrosion inhibitor in 2000 (pg 23). The loss of control is attributed to damaged corrosion inhibitor chemical (the active ingredients precipitated out of solution and plugged the injection tubing) and to manpower reductions incurred during the reorganization. Reportedly, these issues have been rectified and they expect to be back on-track in 2001. BPXA states damage due to these corrosion rate increases were probably limited to on pad piping because off pad piping is protected by the redundancy inherent in wellhead injection. The actual inhibitor concentration achieved in each gathering line is not reported, however the overall concentration would be lower. No attempt is made to quantify the possible extent of internal pipe wall loss due to this corrosion rate excursion. It would be beneficial to understand how the coupon and probe rates varied during this episode and whether or not inspection results saw correlative increases in pipe wall damage.

Coupon data by service class were summarized in a series of bar graphs (figure 1). The vertical axis is scaled as Annualized percentage of coupons <2 mpy. Increases in corrosivity appear as decreases in bar height. The report states that corrosion rates are increasing in the three-phase gathering system and the produced water distribution system. Figures 4 and 5 show the inspection results for internal corrosion. Increases in pipe wall damage were noted for both of the injection service categories depicted, while inspections finding increased internal damage on three-phase piping remain flat. Inspections have not detected any appreciable increase due to lower than normal inhibitor concentration in three-phase piping. The increases in the downstream produced water system could be due to the reported inhibitor under-treatment even though the three-phase piping has shown no such change.

Monitoring & Inspection

BPXA used 8,970 coupons in 2000 down from 11,574 in '97. The reduction is explained by the following:

- changes in pull frequencies in the produced water system not a reduction in locations,
- reduction in the number of coupons in the production well lines, primarily upstream of chemical injection, and
- wells that are in long term shut-in.

The number of coupon locations per service category (PW/SW/3-phase, etc.) would be beneficial for clarifying performance of the coupon monitoring program. No discussion of how coupons are analyzed is reported. Coupon grading requires a subjective, judgment-based, analysis of the coupon surface condition (pitting) as well as a weight loss measurement. There are also several Industry Standards relevant to corrosion coupon use in oil field applications.

Table 13 reports "Leaks and Saves" by year but the cause of the leaks is not reported (except for 2000) so conclusions can not be made about the historical probability of a leak due to internal vs. external causes.

Mitigation

BPXA runs an extensive program of corrosion inhibitor development. Table 6 shows the progression of corrosion inhibitor products over time. Six inhibitor formulations were used across the GPB in 2000. Why different inhibitors are used in different areas is not reported. Table 7 shows the produced water volume treated and the inhibitor concentration per year. The inhibitor concentration applied for mitigation has risen from a low of 206 ppm in 1996 to a high of 149 ppm in 2000. BPXA reports that though water volumes remain relatively flat, water-cuts have increased along with flow velocities (increased gas handling is cited) requiring an increase in inhibitor concentration over time. Continuous trials are run seeking to improve inhibitor performance and cost effectiveness.

External Corrosion Control

There are approximately 185,000 weld-packs at GPB. Slide 4 states the two corrosion related pipeline leaks it experienced in 2000 were due to external corrosion under insulation. Inspections in the year 2000 identified approximately 500 locations (out of 13,274 inspected) where damage increased due to external corrosion under insulation. Figure 3 shows that for the last four years between 4% and 8% of all the locations inspected with TRT yielded external corrosion damage. Table 8 displays the event frequency for external corrosion under insulation inspections, assigned only by pipeline operating temperature.

During 2000, BPXA repaired 28 locations due to external corrosion and only 7 locations due to internal corrosion. External corrosion will require an ongoing commitment of resources by BPXA for the life of the field. The inspection effort appears to be changing the focus from, off-pad, cross-country lines to the on-pad weld packs. In 2000, BPXA inspected 7,632 on-pad locations and 5,642 off-pad locations.

While it is difficult to be exact, it appears there have been inspections on ~70,000 weld-packs, or 38% of the total (185,000) and ~5% show pipe wall damage detected. Of the 500 locations found in 2000, there were 28 repairs, or ~5% of damaged locations. If the same percentages are applied to the remaining population there are approximately 5,700 weld-packs with pipe wall damage and almost 300 repairs to be made.

There are 1,800 below grade, cased piping segments in 350 crossings. During 2000, 200 to 300 segments were inspected and there were 0 segments either replaced or repaired. It is unclear what the total number of inspected segments overall, only 2000 inspections were reported. Extrapolating the 2000 results to the entire population, there appears to be several areas that will require repair in this category of pipe.

RECOMMENDATIONS:

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

1. Results should be reported by BPXA to ADEC in a format consistent with industry recognized standards or practices. Guidelines are available from international standards organizations and those listed below are provided as examples.

   - NACE RP0690 Standard Format for Collection and Compilation of Data for Computerized Material Corrosion Resistance Database Input
   - ASTM G15-99b Standard Terminology Relating to Corrosion and Corrosion Testing
   - ISO 8044-1999 Corrosion of Metals and Alloys: Basic Terms and Definitions

2. Inspection and monitoring data need to be reported by service category and a definition of each service category needs to be supplied. The service category definitions used by BPXA should be agreed upon and remain consistent. For instance, the corrosion data gathered for a pipeline that has been on produced water injection for 100% of its service life will have a different corrosion history than a pipeline that has seen only de-oxygenated sea water for 100% of its service life. Pipelines may see service as producers or injectors carry produced water, seawater or some mixture thereof. The rules used by BPXA to assign service categories for well inspection and monitoring programs need to be understood. The coupon database should include the well service history. The service category (production, injection, or shut-in) that predominates during the coupon exposure period should be used.

3. Results of coupon monitoring for a given service category (i.e. produced water injection wells) should be linked to the inspection results for produced water injection wells. Service category definitions used by the monitoring program need to be the same service category definitions used by the inspection program. For instance BPXA lumps all of the internal corrosion coupon results reported in slide 9 into a service category called "Well Line" yet the inspection results reported on slide 11 are divided into "3-phase Production" and "PWI/SWI Supply". This lumps wells and gathering lines in the inspection results making any correlation between monitoring results and inspections results impossible to discern.

4. BPXA should include the results of smart pig runs in its report if smart pig runs were made on non-common carrier pipelines. Table 3 reports smart pigs were run on non-common carrier pipelines in the GPB but does not report the results of these runs. The results of these inspections should be used to verify the corrosion mechanism and the extent of any corrosion networks. A histogram (i.e. frequency vs. pipe-wall penetration) of the corrosion anomalies detected from each run would be useful. When pipelines are smart-pigged more than once, the differences from run to run could be used to establish corrosion rates. Smart pigging is the only inspection technique capable of looking at the whole internal and external corrosion picture.

5. Some questions which arise after reading the report are; does BPXA pig every non-common carrier pipeline of suitable diameter? Are there plans to install/configure EOA pipelines for smart pigs? Are baseline smart-pig runs performed on newly commissioned lines? How are lines selected for smart pigging and what is the recur frequency of inspection? What were the service categories of the lines inspected and how did this inspection data compare to that gathered by other inspection techniques? Did coupon data detect a correlation with any damage discovered by pigging? Is the corrosion damage morphology consistent with the postulated corrosion mechanism?

6. Coupons should be re-installed upstream of corrosion inhibition injection locations in a statistically representative sample of production wells. BPXA removed coupons located upstream of inhibitor injection points (pg. 11) stating these locations provided "no meaningful data". The inhibited corrosion rate needs to be

measured against the uninhibited corrosion rate to determine the inhibitors efficiency.

7. Coupon access fitting locations need to be changed to reflect an improved understanding of the corrosion mechanism. BPXA reported that coupons under-reported corrosion rates or provided "no meaningful data" (page 11). These ambiguous results are consistent with an under-deposit corrosion mechanism. BPXA is missing a piece of the bigger corrosion picture and may miss significant, localized changes in the production stream baseline corrosivity.

8. BPXA should report how coupon results are analyzed. The report makes no reference to pitting corrosion rates. If pitting is not a concern or has never been implicated in a corrosion failure in the GPB then that should be stated. Pitting is a corrosion concern for typical oil field operations. The following is a sample of industry standards related to corrosion coupons:

   - ASTM G4-95 Standard Guide for Conducting Corrosion Coupon Tests in Field Applications
   - ISO 11463:1995 Corrosion of Metals and Alloys: Evaluation of Pitting Corrosion
   - ASTM G1-90 (1999)e1 Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens
   - NACE RP0775 Preparation, Installation, Analysis, and Interpretation of Coupons in Oilfield Environments
   - ASTM G46-94(1999) Standard Guide for Examination and Evaluation of Pitting Corrosion

9. Include a Historical Leak/Repair history from field start-up to the present. Leak/Repair history is a traditional means of gauging program effectiveness over time. A table that listed leaks, by cause and repairs by pipeline, would be useful for placing the results reported for 2000 into a historical context. Additional items that would be beneficial include volume of spill, identified corrective actions, and implementation of corrective actions.

10. Include a table or diagram that reports the historical inhibitor concentration for each cross-country production gathering line. BPXA reports under-treating with corrosion inhibitor due to mechanical and personnel problems (page 15). Corrosion damage is cumulative over the life of the asset and under-treatment results in increased pipe wall loss.

11. Report residual inhibitor concentrations in produced water streams. Residual inhibitor concentrations should be measured on a regular basis in the produced water fluid stream since credit is taken for the inhibition effect of the residuals. If corrosion inhibitor is injected to protect injection water distribution systems include those program details as well.

12. Maintenance pigging is a part of the corrosion mitigation effort. The pipelines which are maintenance pigged and the maintenance pigging intervals should be reported.

13. Provide a histogram of external pipe-wall defect penetration by year (frequency vs. pipe-wall penetration). The report shows 20,420 internal inspections (Table 1 and 2) and 13,274 external inspections done in 2000. The two reported leaks in 2000 were due to external causes and there are still approximately 500 locations discovered each year with increasing damage. Are the inspection resources allocated in proportion to the risk of an occurrence?

14. Develop a flow diagram detailing the decision making process or risk-based strategy used to allocate inspection, monitoring, and inhibition resources. If possible, reference a third party standard or practice (i.e. ASTM 2081-00 Standard Guide for Risk-based Corrective Action or API PUBL 581 Risk-based Inspection Base Resource Document First Edition).

15. Provide a summary in the next report of significant structural concerns impacting non-common-carrier pipelines. Provide a historical look at leaks/repairs due to structural reasons from field start-up to present.

CONCLUSIONS

The reporting style and corrosion metrics used in the subject report make it difficult to develop a qualitative understanding of the basis and underlying strategies employed by BPXA. ADEC and BPXA have committed to better define the metrics used for reporting. The BPXA report was comprehensive in scope but lacked sufficient data for a technical analysis. Industry recognized metrics are necessary to make peer to peer comparisons of program results.

External corrosion-under-insulation is the corrosion mechanism with the highest probability of producing a leak in near future. While the external corrosion program is ongoing, it may not be receiving the appropriate resources; repairs due to external corrosion exceed those due to internal corrosion by 4:1 and both leaks reported for 2000 were due to external mechanisms. Time will tell if the inspection recur frequency (table 8) for external repairs is appropriate; tracking external corrosion increases by recur interval would validate this approach.

Internal corrosion rates increased in 2000 in production gathering systems and produced water injection systems. Inhibitor concentrations necessary for corrosion control are increasing (table 7). BPXA has identified and corrected issues leading to low inhibitor concentrations that may have resulted in increased damage to piping. There have been corrosion inhibitor quality issues (pg 23) that have impacted inhibitor injection concentration compliance. Inhibitor concentrations over time need to be reported by pipeline; reporting aggregate averages does not allow for technical analysis of the program merits. Details of how BPXA analyzes coupons need to be reported. No mention of coupon pitting measurements was made. Coupons removed from locations upstream of injection locations need to be re-installed in a statistically representative number of locations.

Structural issues were not discussed and need to be included in future reports. Pipeline sagging due to support member frost-jacking, wind induced vibration, subsidence, and snow loading in pipelines already at risk due to pipe-wall thinning need to be addressed.

The corrosion program results outlined in the report submitted to ADEC demonstrate a clear commitment by BPXA to mitigate corrosion and its impact to the environment and the field assets. The adoption of mutually agreed upon metrics for reporting and additional technical detail in the next reporting cycle will eliminate many of the issues raised by this review