309.30.50.3

# Corrosion Monitoring of Non-Common Carrier North Slope Pipelines

## Technical Analysis

## Of

## Phillips Alaska Inc. – 2000 Commitment to Corrosion Monitoring for Greater Kuparuk Area & Alpine

Submitted by

COFFMAN
ENGINEERS
800 F Street
Anchorage, Alaska 99501
907/276-6664
907/276-5042 Fax
www.coffman.com

January 2002

ADEC Contract Number – 18-6000-02

# Table of Contents

# EXECUTIVE SUMMARY

Coffman Engineers, Inc. has been charged with reviewing the 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 April 2000 Meet & Confer session. The goal of this review is to examine the corrosion program report, gain a qualitative understanding of PAI's corrosion control program, and identify initial recommendations for improvement to the content and extent of topics covered.

PAI has demonstrated a clear commitment to corrosion control, and has developed a robust monitoring and inspection capability. Internal corrosion in cross-country lines indicates a clear degree of corrosion inhibition: no leaks and only one save in the last three years were reported. Chemical inhibition has reduced the leak/save frequency; corrosion damage increases have been almost eliminated in the cross-country gathering lines through corrosion inhibitor injection.

While results are currently good, PAI will have to remain vigilant, as coupon pitting corrosion rates in the three-phase cross-country gathering lines and produced water injection lines have recently increased. Increased coupon pitting rates may be signaling potential risks to the future pipeline integrity.

External corrosion at weld-packs (above and below grade) also poses an integrity risk. There has been an average of one leak per year over the past four years (1997-2000) and at least one leak this year due to external corrosion mechanisms. The level of risk requires a consistent inspection effort, and while PAI has maintained this effort, the efficiency (number of weld-packs inspected) has decreased due to piping configuration for on-pad piping. The level of inspection resources for external corrosion of on-pad piping should be re-evaluated to ensure it is commensurate with the corrosion risk.

There was one failure in 2000 attributed to well subsidence, which currently is the only other structural concern for PAI. A mitigation plan has been developed and is 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.

The PAI report and presentation materials were an initial step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan. PAI and ADEC have committed to better define reporting metrics and definitions for future reports.

# COMMITMENT TO CORROSION MONITORING

The Charter agreement between the State of Alaska, BPXA and PAI required the development of a "performance management program for the regular review" of the corrosion monitoring and related practices for the non-common carrier North Slope pipelines. As a result of 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 warranting 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 STRATEGIES

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

### Internal Corrosion Strategy

The Produced fluid gathering lines have been seeing increased corrosivity over the past several years due to increasing water production, reservoir souring (Hydrogen Sulfide ($H_2S$)), and solids deposition (pgs. 4,5). Most of the field piping follows a trunk-and-lateral design that increases in nominal diameter as it approaches the production facility. Drill site production joins a trunk line through smaller diameter lateral pipelines; therefore several drill-sites contribute to the corrosion environment in downstream piping. Corrosion inhibitor injection is the primary mitigation method employed in the GKU. Maintenance pigging for the removal of solids is not available in the majority of the production gathering system. A telescoping trunk-and-lateral piping design further complicates efforts to retrofit pigging equipment.

### *Monitoring*

Corrosion Coupons and Probes are the primary means of monitoring the corrosivity of the environment inside the pipeline. Slides 8 and 9 reports more than 1,100 physical locations are monitored. Coupon and probe data are used to optimize inhibition concentration and to set inspection intervals.

### *Inspection*

Radiographic and ultrasonic methods are the primary Non-Destructive Testing (NDT) techniques used to locate corrosion damage and track changes over time (pg. 14). Smart pigging, or inline inspection, as a means of corrosion inspection is not available for three phase production-gathering lines, and it is unclear if it is available for the produced water and seawater cross-country pipelines.

### *Mitigation*

Chemical inhibition is PAI's primary means of corrosion mitigation in the production gathering system (slide 6, pg. 16). Since corrosion mitigation through chemical inhibitor injection is the primary corrosion mitigation tool, it is crucial that PAI have the most efficient chemistry available. PAI does not protect on-pad well lines with inhibitor. The stated strategy is to "... conduct surveillance with appropriate NDT..." This strategy is changing or undergoing a trial variation as plans for installing wellhead inhibitor injection on three drill-sites are proceeding forward at this time. The project plan calls for installation of wellhead inhibition on 3-5 drill-sites per year "...until the appropriate level of drill site inhibition has been provided for the drill-sites." PAI's inability to pig solids from the production gathering system places a strong reliance on chemical inhibition and proactive inspection.

## External Corrosion Strategy

External corrosion under wet insulation is a concern for all North Slope producers. The vast majority of pipelines is above ground and thermally insulated. Snow and water can penetrate 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.

### *Monitoring*

Presently, there are no monitoring techniques used for this corrosion mechanism. This places greater emphasis on the inspection program.

### *Inspection*

Inspection methods for corrosion under insulation are radiographic and visual. Tangential radiography (TRT), C-arm fluoroscopy 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. Beginning in 2003, PAI will begin a program to re-inspect weld-packs that have not been previously refurbished, which is a significant commitment to future inspection levels. In addition, weld-packs that have been refurbished need to be sampled to verify the method is an adequate long-term solution. The weld-pack refurbishment was not characterized as a cure for corrosion-under-insulation, and this mechanism can be expected to be active throughout the rest of the field life.

*Mitigation*

Refurbishment requires the exclusion of oxygen saturated water from contact with the external pipe wall. Draining the weld-pack, refurbishing the seals to eliminate water ingress, coating the pipe, and replacing the saturated insulation is the primary refurbishment method. A more in-depth review of the measures taken in the past by PAI would be necessary before any sort of recommendation could be formulated.

# CORROSION PROGRAM STATUS

## Risk

The Kuparuk Corrosion Strategy (pg. 5) reports one of the specific program strategies is to "Develop specific risk based corrosion mitigation, monitoring, and inspection programs based upon the corrosion mechanism for a given system." The report further states "The risk assessment methodology used to develop the Strategy was based upon a subjective assessment of the consequence of a single failure of the particular type asset," and the last paragraph on page 5 states "The risk assessment conducted did not include consideration of the frequency of the risk occurring: however the likelihood of a failure was taken into account…" This calls into question the way in which the consequences of corrosion are weighed. For example, higher than normal system corrosivity in the injection well lines places more than a single flow-line at risk: the probable consequence of higher than normal pitting rates throughout a produced water injection system is multiple injection flow-line failures. PAI has identified the corrosion mechanism but it is not clear how the risk assessment methodology accounts for the probability (or frequency) of an occurrence. The risk-based methodology outlined would benefit by quantifying the frequency of a potential corrosion event. Using the consequence of a single flow-line failure to allocate assets in a situation where multiple failures are likely, underestimates the potential consequences of a given corrosion control strategy.

## Internal Corrosion Management

Once a corrosion mechanism is postulated and identified, the overall corrosion picture can be analyzed with the goal of predicting where corrosion might occur, i.e. solids deposits drop to the bottom of the pipe in slow moving liquid streams, creating under-deposit corrosion cells that impede or block the corrosion mitigating effects of inhibitor injection. Mitigating the effect of the identified corrosion mechanism becomes more difficult because solids cannot be removed from the production gathering lines. Only produced water injection distribution lines, sea-water injection distribution lines, and the wet-oil lines from CPF-3 to CPF-1/2 are piggable in the KRU. The three-phase production gathering system is not equipped with pigging facilities. PAI does not discuss how solids deposition and flow stagnation are dealt with in three-phase production lines. Reference is made to the fact that new installations in satellite fields have pigging capability in their three-phase production gathering lines. The trunk-and-lateral piping design will allow solids generated by pigging of newer satellite production lines into older gathering systems which are not piggable unless appropriate design controls are employed.

### *Monitoring*

Slide 13 shows the results of production well flowline monitoring using coupons. The average corrosion rates are less than one mil per year (mpy or 0.001 in/yr) general corrosion and less than four mpy pitting corrosion. Slide 13 also shows an action level at 3 mpy general corrosion and 10 mpy pitting and the statement on the slide cautions that inspection shows that actual pipe wall losses are higher. Slides 17 and 18 discuss inspection results for well flowlines. Slide 18 summarizes the inspection efforts for all well lines for the past seven years but does not differentiate between injector and producer wells. Slide 17 does state that 8 injectors and 10 producers required repair in 2000. It would be helpful to be able to link the monitoring results for a particular service category (i.e. production well flowlines) to the inspection results for that particular category.

Coupon pitting rates are higher, down stream in the gathering lines, than upstream in the well flowlines. One possible explanation for this result is the coupon locations at the well head and the cross-country lines are not exposed to a similar environment. The well head coupons are located generally in small diameter, vertical riser pipe while the larger diameter cross-country lines have coupon locations at the six o'clock position in horizontal pipe runs.

A coupon in a vertical position on a relatively small diameter line sees a much different pipeline environment even though it is exposed to the same fluids as solids have no place to accumulate and liquid/gas velocities can be much higher. In horizontal six o'clock positions, the coupon access fitting length can be adjusted and when it is sufficiently short the lower end of the coupon is recessed into the access fitting. This type of coupon/access fitting set-up creates a small stagnant environment at the base of the coupon where solids and microbes have the opportunity to work on the coupon. Accurate evaluation of coupon results requires understanding the coupon location and the internal hydraulic environment surrounding the coupon in question. It is not clear how PAI values these results and what steps are necessary to mitigate the increased coupon pitting rates. .

### *Inspection*

Successful corrosion control for the cross-country injection pipelines is credited to mechanical pigging efforts and corrosion inhibitor carry-over in these pipelines. While inhibitor carryover can be a benefit, it is hard to quantify. Residual concentration levels are difficult to monitor and therefore, not reported. Inspection results for this service category cannot be related to the monitoring results because slide 12 and slide 20 use different service category definitions.

Slide 20 (Inspection: internal corrosion in cross-country lines) indicates a clear degree of corrosion inhibition: no leaks and only one save in the last three years reported. Chemical inhibition has reduced the leak/save frequency; corrosion damage increases have been almost eliminated in the cross-country gathering lines through corrosion inhibitor injection. The concern in these systems is the increase in pitting corrosion noted by coupons for the last three years. No explanation of the increase in pitting seen on slide 10 is reported. In addition, the cross-country injection piping average coupon rates have exceeded the 10 mpy pitting rate action level in 12 of the last 16 years (slide 12). The inspection strategy has, appropriately, driven increases in the number of inspections as the risk of a corrosion event increased. Slide 20 clearly shows the inhibition strategy can be an effective corrosion mitigation tool. An average bulk fluid inhibitor concentration of 100 ppm (pg. 16) is reported.

Slide 18 (Inspection: internal well line) shows an increase in the number of "saves" occurring in well line piping as well as a steady increase in RT footage inspected. Eight injectors and ten producers required repair in 2000. The corrosion mechanisms vary from producer to injector and many of the well lines see service as producers or injectors. No chemical inhibition occurs at this stage in the gathering system. Any decrease in the leak frequency is due to inspection efforts catching a defect before it de-rates the line pressure or causes a leak. PAI is managing corrosion damage in this untreated piping through inspection. Previously, only minor efforts were being made to inhibit well lines, but this is changing; well-head injection is being evaluated. The inspection program seems to have reacted to early input (monitoring and inspection data) and increased the number of inspections on this category of asset.

An additional concern is the difficulty of inspecting produced water injection piping with diameters larger than ten inches. Larger diameter (>10"), water packed piping is radio-opaque and makes it impossible to pick out defects on the pipe wall. An explanation of the ability to detect defects in larger diameter, water packed pipelines should be provided.

### *Mitigation*

As stated earlier, chemical inhibition is the primary means of fighting corrosion in their cross-country gathering lines. However, there are other service categories that do not appear to be protected by chemical inhibition (i.e. well flow lines). PAI operates a vigorous program of inhibitor development (slide 15), which has significant vendor; academic, and corporate research components. A testing protocol is employed and the results are statistically validated. A corrosion inhibitor feedback system is used to determine when, where, and how much corrosion inhibitor is used (see slide 9). An average bulk fluid inhibitor concentration of 100 ppm (pg. 16) is reported.

Inhibitor injection concentration compliance may be an issue. While the target inhibitor concentration ranges within 90-105% range of the recommended concentration, the report does not state the degree of compliance actually attained. The pitting rate in slide 10 depicts an increasing coupon pitting rate that could be signaling the onset of increased pipe wall damage.

Residual inhibitor carry-over is credited with some level of mitigation in the PW injection system. Obtaining residual inhibitor concentration in the produced water system is a difficult task; however there may be other methods available such as a correlation between upstream concentration and downstream coupon corrosion rates. Slide 12 and 14 show that the PW injection distribution system coupon corrosion rates do not demonstrate the same level of corrosion control as the three-phase gathering lines upstream of the CPF (see slide 10).

Wellhead chemical inhibitor injection should lower the leak/save numbers as is seen in the treated cross-country gathering line rates on slide 20. Going to wellhead injection will increase the number of injection locations and allow for a degree of redundancy that PAI does not currently benefit from.

Internal coupon pitting corrosion rates in the three-phase cross-country gathering lines and produced water injection lines have increased. Increased coupon pitting rates may be signaling an increasing risk to the future pipeline integrity; however current inspection data shows no problems. Coupon monitoring for three-phase common lines and produced water injection flowlines is showing an increasing corrosivity trend for the last three years (slides 10 and 14). The coupon pitting rates in the injection flowlines are at their highest level for the period beginning in 1985.

Slide 12 reports the monitoring results for the produced water cross-country distribution lines; current corrosion levels are in excess of both historic minimums and overall average. Slide 12 shows pitting rates varying from less than 5 mpy to approximately 35 mpy in an apparently random fashion. The corrosivity is not under the same degree of control as that seen in lines that are directly treated with corrosion inhibitor (slide 10 for example). In addition, the slide states the corrosion activity is localized in stagnant, un-piggable section. Coupon corrosion rates in the cross-country common lines have responded favorably in the past to changes in corrosion inhibitor chemistry and concentration. Direct injection of corrosion inhibitor into the produced water injection system may be necessary to gain the same degree of control as that seen in the cross-country gathering system pipelines.

## External Corrosion Management

There are more than 101,000 weld-pack locations; ~67,000 on off-pad, cross-country pipelines and ~34,000 on on-pad pipelines. Since these pipelines are not smart-piggable, all of these locations must be manually examined with visual and radiographic techniques. PAI began the examination of all off-pad weld-packs in 1997-98, and reports being "99+ % complete" (pg. 24). To date, 75% of all the weld-packs have been inspected and 3,963 (~6%) weld-packs have required refurbishment.

Damaged weld-packs are refurbished, but the report does not detail how effective the method is against the recurrence of corrosion under insulation. Beginning in 2003, PAI will begin a program to re-inspect weld-packs that have not been previously refurbished (five years after the initial inspection). This activity will likely remain necessary through the end-of-field life.

During 1997-1999, roughly 70,000 weld-packs were TRT'd, while the plan for 2001 called for inspection of roughly 6,000 weld-packs, which represent ~25% of the remaining weld-packs. While there appears to be a reduction in this inspection program for 2000 and 2001, the level of effort remains fairly constant. The reduction in number of inspected weld-packs can be attributed to lower efficiencies for on-pad piping versus off-pad piping. This is due to the relatively complex piping configurations for on-pad piping compared to the long, straight runs of piping off-pad. Inspection of the remaining 34,400 weld-packs is proceeding on a risk-ranked basis and scheduled to be completed by YE2005.

Using the information provided, 1.9% (~1,280) had corrosion damage and 0.06% (43) weld-packs required sleeves. Applying these same percentages to the remaining population of 34,400 yields a possible 650 additional weld-packs with damage and a possible 20 weld-packs requiring sleeves.

A time-release inhibitor spike is also being tested but there are no results reported for this technique yet.

### *Below Grade Piping*

The inspection of below grade piping is affected by both of the internal and external corrosion mechanisms reported above. Since the below grade locations are cased and buried, excavation of the location is the only certain method of defect assessment at this time. Currently, two techniques (electromagnetic pulse and guided wave) are being investigated that allow a degree of defect detection without requiring excavation. PAI plans to inspect 100 locations using these techniques in 2001 in an effort to refine them. The report stated that the results of the below-grade-piping program were reported in an earlier communication, which was not evaluated by Coffman. In the future, the results of the BGPP will be combined with the annual reports.

## Structural Concerns

Subsidence - Subsidence is the only other structural concern for PAI, and one failure was reported in 2000 (2M-01) due to this concern. Piping support subsidence places additional strain on piping (which may already be weakened through corrosion). As a well is used, hot fluids and gases are circulated in and out of the ground, a thaw bulb grows around the well, the piping supports resting on or buried in the soil begin to sink into the wet ground, giving rise to what is seen in slide 30. Pipe in this condition will have higher stresses than originally planned for in the design. Incidental loads on the piping due to snow cover will also increase the stress in these areas. Placing thermal siphons behind each wellhead is an attempt to keep the permafrost intact and eliminate the subsidence of pipe supports. No results for this subsidence mitigation strategy were reported.

# RECOMMENDATIONS

Recommendations for future reports are as follows:

1. In the future it would be helpful if results reported by PAI to ADEC were presented in a format using metrics which are mutually agreed upon by PAI, BPXA and ADEC.
2. Inspection and monitoring data quality would benefit from being reported using a consistent definition of each service category. For example, when coupon monitoring results for injection wells are reported in slide 14 (injection well coupon monitoring) it would be nice to see a summary of inspection results for the same service category (i.e. injection wells). While PAI reports inspection results for well lines, both injectors and producers are lumped together, making any comparison of monitoring to inspection results problematic.
3. Provide details describing the resolution of inspection methods used to report internal corrosion in water-packed pipelines (especially in diameters in excess of 10”).

4. A summary of actual corrosion inhibitor injection concentration over time would be helpful. A highlight of any lines which are exceptions would be beneficial (i.e., is there a line which requires significantly more or less inhibitor than the others, and why?).
5. A summary quantifying the degree of inhibitor injection compliance over time would be useful.
6. A summary leak/repair history for a five year period would be useful. Include service category, internal/external corrosion, and physical pipe information (diameter, wall thickness, and years in service).
7. A discussion of details pertaining to how coupons are analyzed and ranked would be beneficial.
8. A discussion of the basis for the coupon action levels (3 mpy weight loss and 10 mpy pitting) would be beneficial.
9. A summary in the next report, identifying any significant structural concerns impacting non-common-carrier pipelines would be beneficial. If a historical look at leaks/repairs due to structural reasons were available it would place PAI's current efforts into a useful context.

# CONCLUSIONS

The PAI report and presentation demonstrates a clear, proactive, commitment to mitigate corrosion in non-common carrier pipelines, and were an initial step towards meeting the expectations outlined in the Commitment to Corrosion Monitoring plan. PAI and ADEC have committed to better define reporting metrics and definitions for future reports.

Produced fluid corrosivity is increasing and the average corrosion inhibition concentration is 100 ppm. Corrosion inhibitor injection has been proven effective so far in the three-phase gathering system and may remain effective until water-cut or pipeline hydraulic factors change. Solid sedimentation and transport coupled with microbial induced corrosion under deposits may become an issue in the three-phase gathering system, as this system is currently un-piggable. While results are currently good, PAI will have to remain vigilant, as coupon pitting corrosion rates in the three-phase cross-country gathering lines and produced water injection lines have been on the increase. Increased coupon pitting rates may be signaling potential risks to the future pipeline integrity.

The inhibitor program is mitigating corrosion damage and where damage is ongoing, inspection is used to manage the defect until it requires repair. PAI may be over-reliant on the inspection component of its mitigation strategy to prevent leaks. The inspection component has significantly increased the footage examined by radiographic methods compared previous years; this is a significant commitment in resources. The lack of pigging facilities in KRU's older, three-phase production systems is a big driver for this man-power requirement. A line that is piggable could use smart-pigs to evaluate 100% of the internal and external pipeline. PAI is installing pigging facilities in newer satellite developments.

One leak due to internal corrosion in a producing well line (1G-08) was reported for 2000. Of the approximately 6,800 RT and UT inspections for internal corrosion on well lines, 115 increases and 18 repairs were noted. This is significantly more than the inspection results for cross country piping which had ~2,000 inspections with only 13 increases and no repairs. PAI has recently undertaken steps to provide corrosion inhibitor injection on selected wellhead locations.

External corrosion under insulation will remain a risk factor in the future. The effectiveness of the weld-pack refurbishment is unknown and the re-inspection of a sample of refurbished weld-packs will allow PAI to adjust its inspection interval. As stated in the report, on-pad piping has not received the same attention as off-pad piping (the consequence of an off-pad failure was deemed greater than an on-pad failure). PAI should consider additional resources aimed at finishing the initial inspection of the weld-packs ahead of the 2005 schedule.

Below grade piping poses a leak risk. No reliable means of assessing defects in below grade pipeline segments has been validated as yet, but efforts are moving forward.

PAI reportedly has no structural issues beyond well piping support subsidence. A mitigation plan has been developed and is being implemented to control further subsidence. Pipeline sagging due to support member frost-jacking, subsidence, and snow loading of pipelines already at risk due to pipe-wall thinning are concerns that would benefit from discussion in future reports.