Greater Kuparuk Area (GKA) Western North Slope (WNS) Corrosion Programs Overview

March 31, 2006

Commitment to Corrosion Monitoring
6th Annual Report to the Alaska Department of Environmental Conservation

Prepared by
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1.0 OVERVIEW

There are over $4 Billion in capital assets in the Greater Kuparuk Area (GKA). The internal corrosion potential in Kuparuk lines continues to rise as water production and H_2S levels increase. Additionally, an external corrosion potential exists where moisture penetrates and is trapped in insulation. Effective management of corrosion at Kuparuk is critical to maintain environmental and facility integrity, to reduce field operating costs, and to extend the life of the field infrastructure to meet future needs.

Alpine is ConocoPhillips Alaska's newest development and the largest onshore oil field discovered in North America in the past decade. Alpine has a nominal processing capacity of 125,000 BOPD. The Alpine development produces from a pad area of 97 acres, and has two Drill Sites; two additional satellite drill sites are being built. The corrosion management system used at Kuparuk is being applied to the Alpine field.

The purpose of this 6th Annual Report is to communicate the details of the individual programs that implement the ConocoPhillips Alaska Corrosion Strategy. In addition to the requirements of the North Slope Charter Agreement between ConocoPhillips Alaska, Inc., BP Exploration (Alaska), and the Alaska Department of Environmental Conservation, previous reporting requirements pertaining to the Below Grade Piping Program will be incorporated into this and future North Slope Charter Corrosion Reports.

A glossary of terms used in this report is included as Appendix A.

2.0 SIGNIFICANT ENHANCEMENT TO CORROSION PROGRAMS

Linear array continues to be a valuable tool for evaluation of corrosion damage in large diameter cross-country water injection lines.

The field-wide pigging program was enhanced by standardizing on the use of brush/disk pigs, monitoring of total suspended solids, and monitoring of biocide application with residual measurements.

The number of below-grade piping circuits excavated was roughly tripled from 2004 to 2005 because of a revised risk assessment of the below-grade piping circuits.

Rope Access Technology (RAT) was added to the Corrosion inspection capabilities to allow the examination of difficult-to-reach areas in piping that would otherwise require extensive scaffolding.

The amount of tangential radiographic (TRT) inspection coverage was increased at weld packs where “medium” water is found at the 6 o’clock (bottom-of-pipe) position to include a minimum of an additional 12 o’clock inspection; a 360-degree inspection is performed where possible.

3.0 Program Status Summary - Kuparuk

3.1 Year 2005 Overview

3.1.a Kuparuk Monitoring & Mitigation

In 2005 we had several significant accomplishments:

- Tested two new corrosion inhibitor formulations and placed one new corrosion inhibitor in a larger scale test.
- Enhanced the maintenance pigging program for the water injection system at CPF-2 using multiple pig runs, improved biocide treatments, and total suspended solids monitoring.
- Deferred commingling of waters at CPF3 based on lessons learned from the 2K WI spill.
- Moved data reporting for the coupon monitoring system from an MS Access based reporting system to an Oracle based reporting and tracking system for ease in future analysis.
- Enhanced the pump performance at selected drill sites to increase consistency of chemical inhibition.

Average general and pitting coupon corrosion rate data for Year 2005 are presented in Tables 1 and 2.

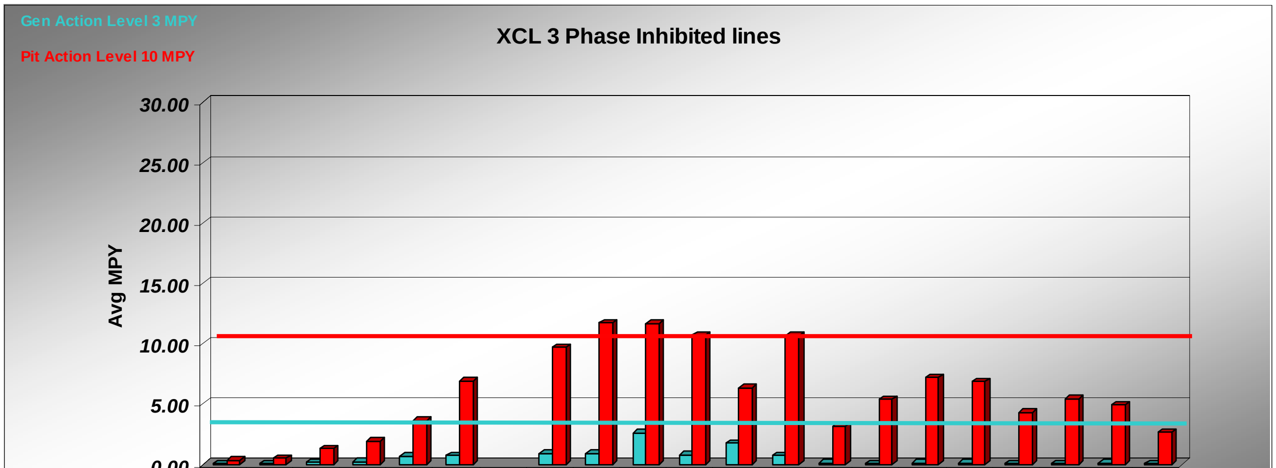
Table 1. Average general corrosion rates for corrosion coupons by service category.

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average General Corrosion Rate, mpy (target=<3)	Number of Lines with Conformant General Corrosion Rates	Percent of Lines with Conformant General Corrosion Rates
Three-phase Production Cross-Country Lines	55	0.05	55	100
Seawater Cross-Country Lines	2	7.3	1	50
Mixed Water Injection Cross-Country Lines	24	0.5	24	100
Production Well Flow Lines	501	0.2	495	99
Water Injection Well Flow Lines	388	0.8	358	92

Table 2. Average pitting corrosion rates for corrosion coupons by service category.

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Percent of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Cross-Country Lines	55	2.6	52	95
Seawater Cross-Country Lines	2	7.4	2	100
Mixed Water Injection Cross-Country Lines	24	19.5	15	63
Production Well Flow Lines	501	2.9	478	95
Water Injection Well Flow Lines	388	14.6	243	63

Note: See graph and associated discussion on Figures 1 through 5 of this report.



	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Gen	0.01	0.06	0.16	0.23	0.65	0.74		0.90	0.89	2.59	0.76	1.76	0.74	0.07	0.05	0.12	0.11	0.05	0.03	0.08	0.05
Pit	0.31	0.48	1.29	1.89	3.63	6.91		9.68	11.70	11.67	10.67	6.30	10.62	3.18	5.34	7.21	6.82	4.31	5.45	4.89	2.64

Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 1 suggest that general corrosion is under control. The data presented in Tables 1 and 2 and in Figure 1 include corrosion coupon data from the wet oil lines starting at CPF3 and going to CPF1 and CPF2.

Recurring CRM inspections also support the conclusion that corrosion is under control in the three-phase production cross-country lines. In 2005, 419 corrosion-rate monitoring (CRM) inspections were conducted, with one minor increase found. Other internal inspection data supporting the CRM data are discussed in section 3.1.c, below.

Where corrosion rates exceeded targets, corrosion inhibitor concentrations were increased and/or the amount of inspection was increased. In 2005, coupon, probe or inspection-based corrosion rates exceeded targets or revealed increased damage on eight lines. In 2005, inspection results indicated minor corrosion had occurred in four of these eight lines. A complete listing of the lines with coupon/probe corrosion rates that exceeded targets and/or where inspection indicated increased damage is given in Table 3.

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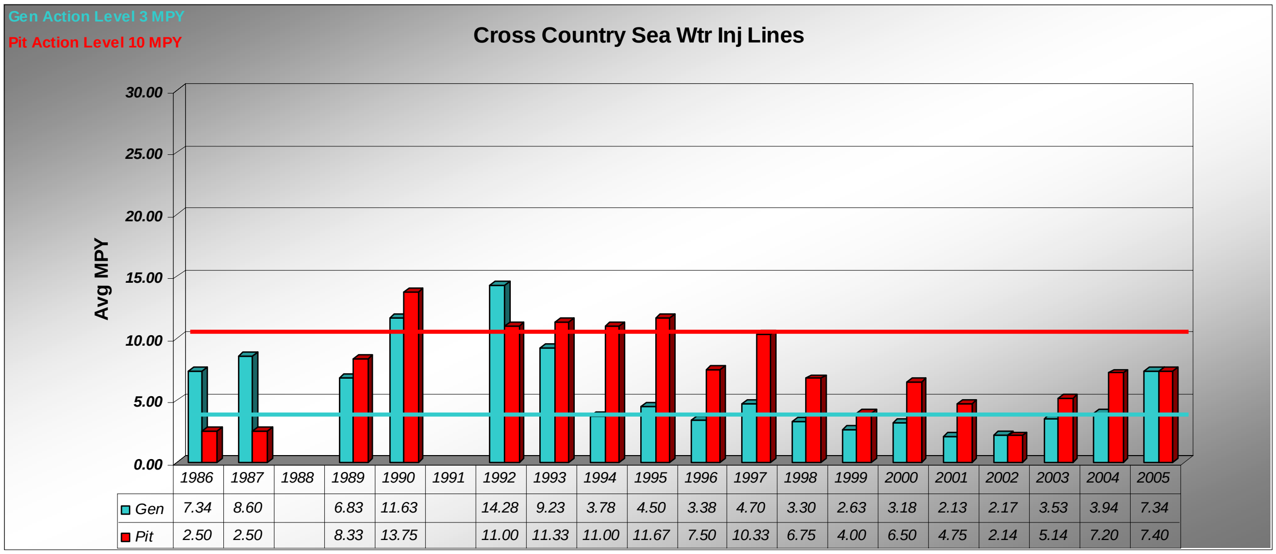
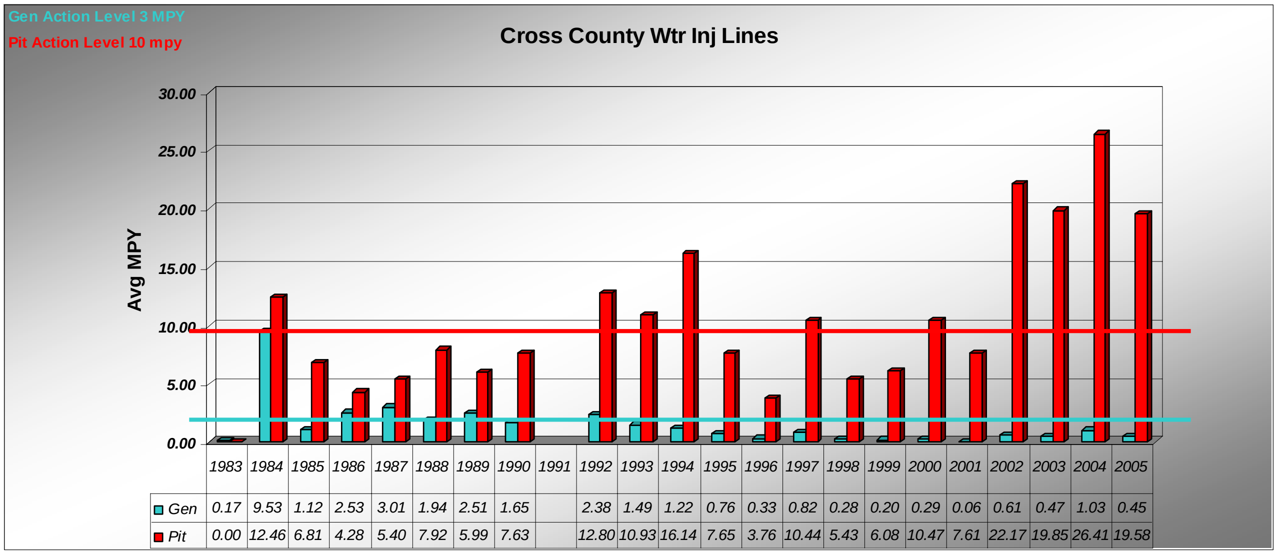


	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Gen	7.34	8.60		6.83	11.63		14.28	9.23	3.78	4.50	3.38	4.70	3.30	2.63	3.18	2.13	2.17	3.53	3.94	7.34
Pit	2.50	2.50		8.33	13.75		11.00	11.33	11.00	11.67	7.50	10.33	6.75	4.00	6.50	4.75	2.14	5.14	7.20	7.40

Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Sea Water Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 2 above, show the average corrosion rates for the sea water cross-country line coupons. Higher coupon corrosion rates were caused by higher dissolved oxygen concentrations seen during 2005 break-up and oxygen scavenger was added to decrease the dissolved oxygen concentration; these coupons are located near the exit of the sea water treatment plant (STP) and are not believed to be indicative of corrosion in the sea water injection system. Increased coupon corrosion rates detected are currently under review, with biocide concentration and pigging frequency increased in early 2006. Smart pigging of the 30-inch sea water line from the STP to the CW Skid is planned for 2006.



	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Gen	0.17	9.53	1.12	2.53	3.01	1.94	2.51	1.65		2.38	1.49	1.22	0.76	0.33	0.82	0.28	0.20	0.29	0.06	0.61	0.47	1.03	0.45
Pit	0.00	12.46	6.81	4.28	5.40	7.92	5.99	7.63		12.80	10.93	16.14	7.65	3.76	10.44	5.43	6.08	10.47	7.61	22.17	19.85	26.41	19.58

Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Water Injection Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 3 show that average general corrosion rates are below the threshold, but that pitting rates for the field are above the threshold. Seawater and produced water commingling was suspended at CPF2 in August 2005 and coupons replaced then; coupons were retrieved from CPF2 in late November with pitting rates reduced markedly from previous pulls. Coupon results are used to prioritize inspection efforts. During 2005 additional equipment was installed and procedures were implemented to provide enhanced biocide treatments at CPF2. Cleaning pigs were upgraded to include brushes in addition to the disks and the pigging procedures changed to included multiple (three) pig runs per monthly cleaning cycle.

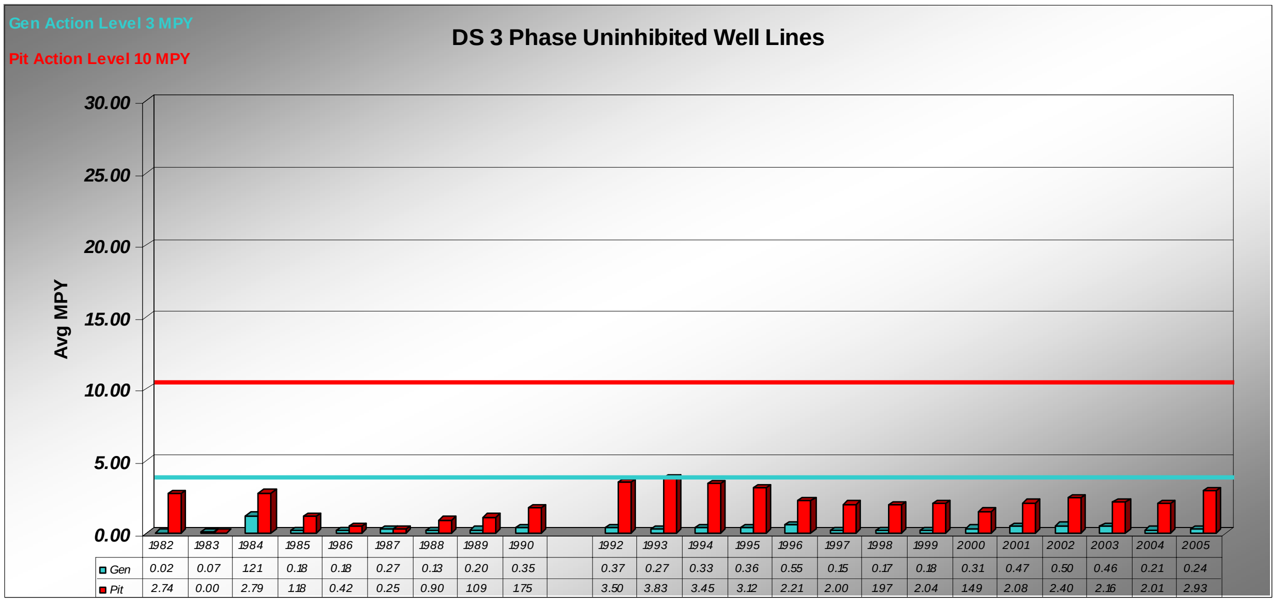


Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Well Flow Lines: While the monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figures 4 and 5 suggest that corrosion rates are below targets, inspection data indicate that higher corrosion rates have been experienced historically. The well line inspection data are discussed in section 3.1.b below, and are a good example of why monitoring data alone cannot be relied upon to characterize corrosion in a given system. For three-phase production, coupons monitor free flowing fluid and have not shown the predominant, under-deposit corrosion mechanism.

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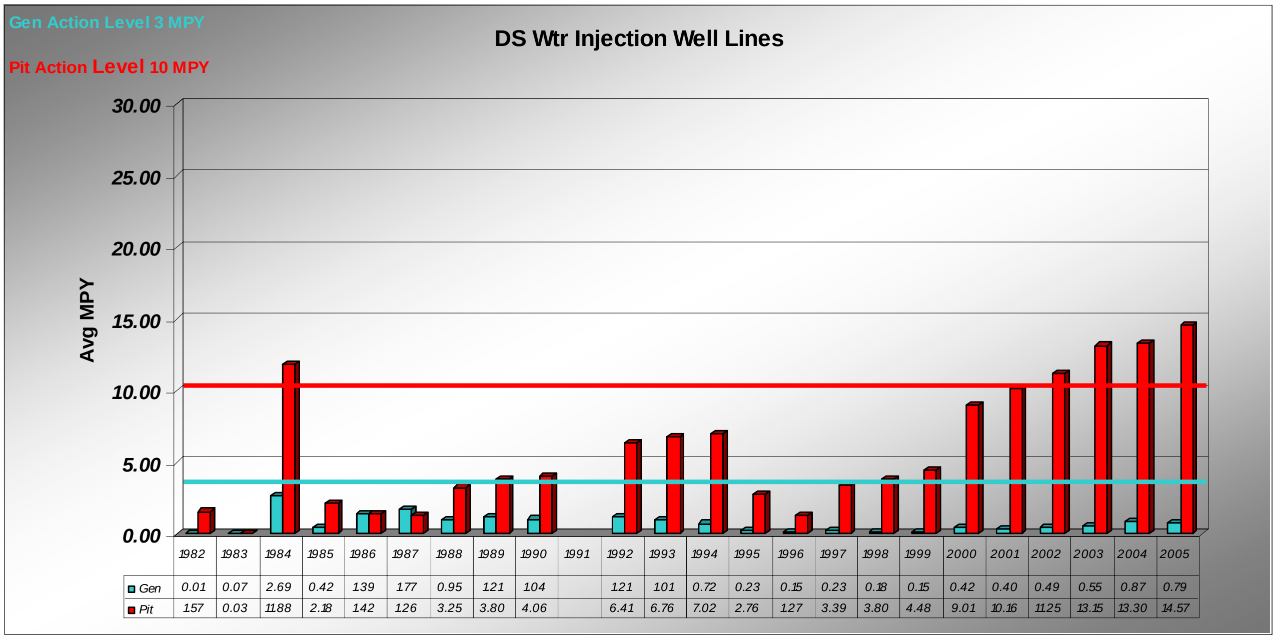

Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

Water Injection Well Flow Lines: As discussed in section 3.1.b below, the well line inspection data on water injectors show that there are a significant number of corrosion related repairs. The water feeding this system is treated at the facilities with biocide and is discussed under Figure 3 - Water Injection Cross-Country Line Coupons. We believe that the increasing trend of coupon corrosion rates in the water injection well lines is caused by additional solids accumulating in the well lines because of low flow rates and improved pigging upstream of the well lines.

Mitigation:

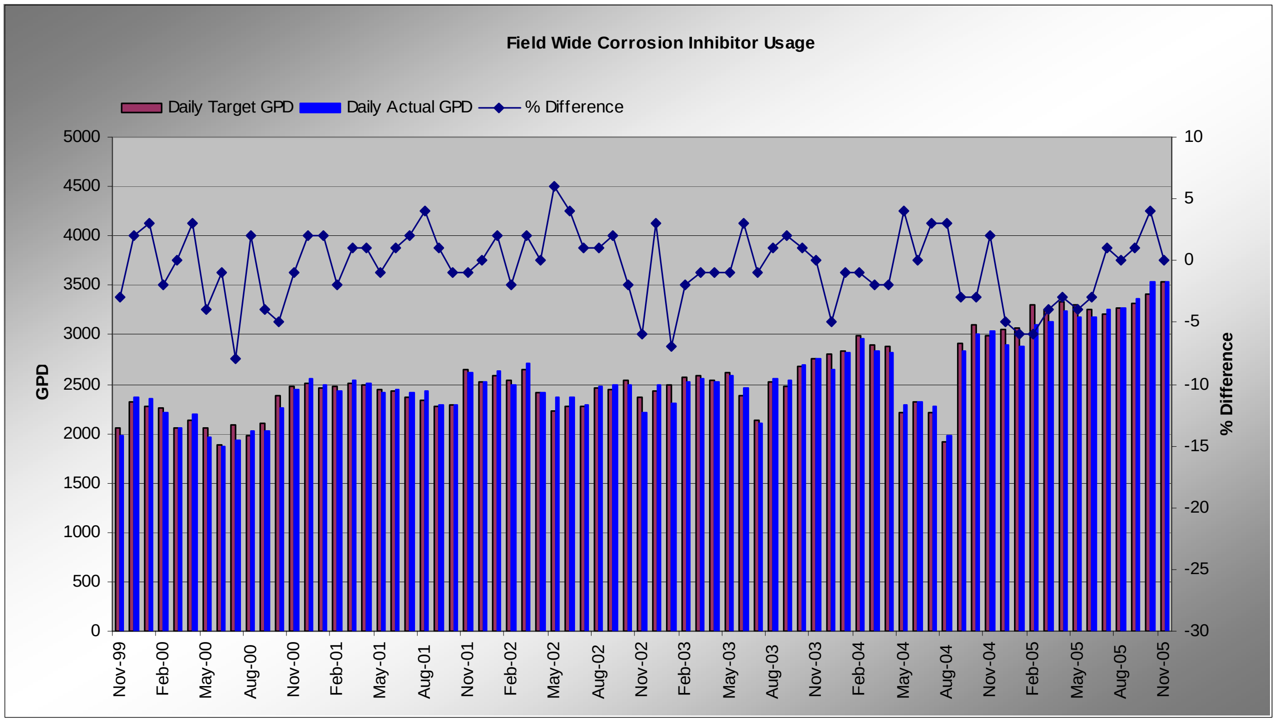

Figure 6. Field-wide Corrosion Inhibitor Use.

For the Kuparuk field, Figure 6 shows the actual number of gallons of corrosion inhibitor pumped per day, the recommended (target) number of gallons of corrosion inhibitor per day, and the percent difference between the two. The average deviation for the year was -1.85%. The large variation seen in the early parts of the year are usually caused by the extreme weather. Several pump upgrades were accomplished in 2005 to accommodate increased volumes.

The mitigation program is described in the inhibitor feedback flow chart, Figure 7 below. Reasons for changes to target inhibitor concentrations are given in Table 3 below.

Table 3 Three-phase Production Cross-Country lines with corrosion rates that exceeded targets and the action that was taken.

Common Line	Probes	Coupons	Inspection	Action Taken
1DPO		x		Increased Target PPM
1EPO			x	Increased Target PPM
1LPO			x	Increased Target PPM
2APO			x	Increased Target PPM
2UPO				Reduced for Baker RE-5273 Test
2VPO				Reduced for Baker RE-5273 Test
2WPO				Reduced for Baker RE-5273 Test
2ZPO			x	Increased Target PPM
3NPO		x		Increased Target PPM
3OPO		x		Increased Target PPM
3QPO		x		Increased Target PPM

Kuparuk Inhibitor Feedback System

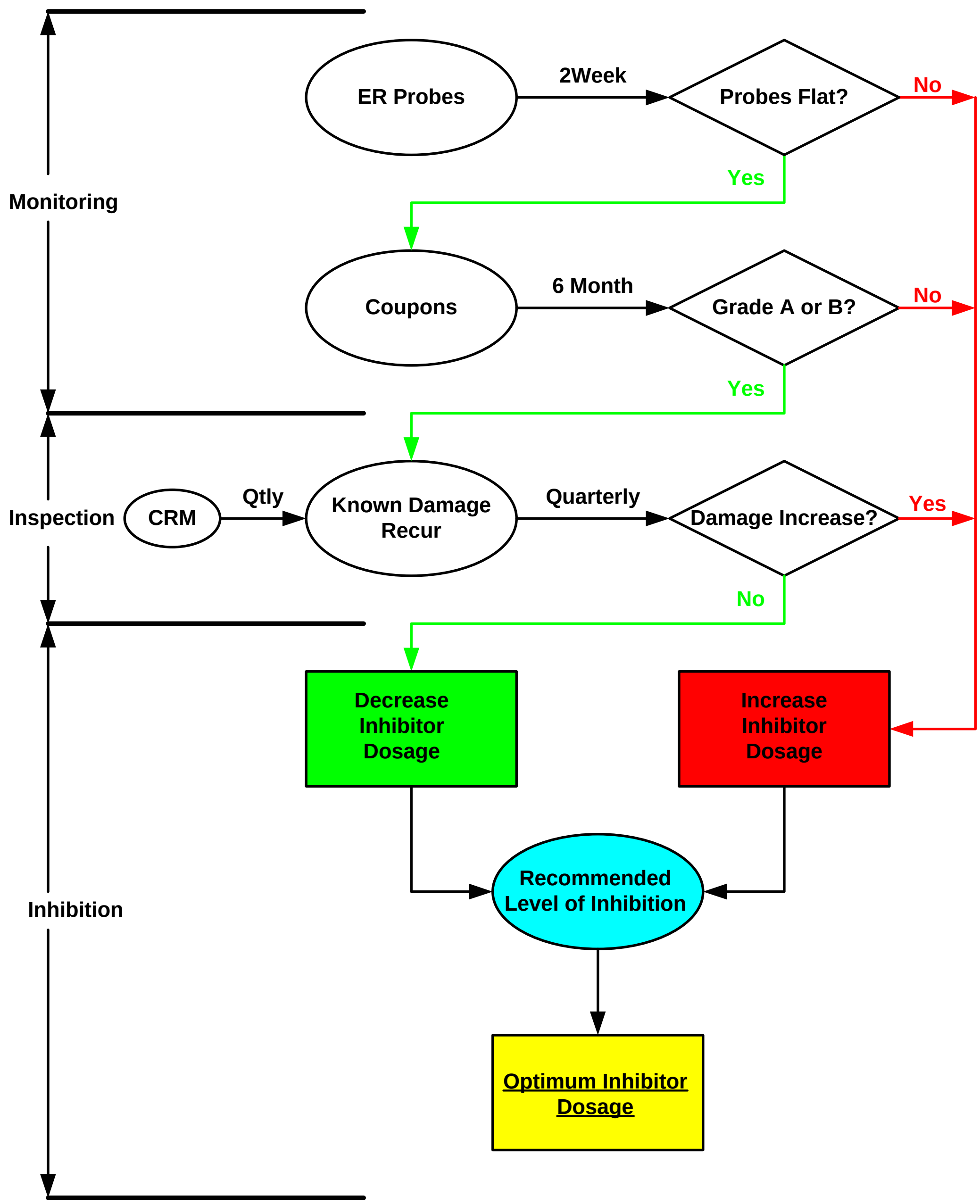

Figure 7. Corrosion Inhibitor Feedback System.

3.1.b Well Line Inspection

We met our primary 2005 goal by completing interval surveys on 133 well lines.

As indicated in Figure 8 below, repair recommendations were initiated on 18 well lines in 2005 because of internal corrosion or erosion damage (11 corroded water injection lines, 6 corroded production lines and 1 eroded production line). Except for the leak that was caused by erosion, the corrosion mechanisms were all underdeposit corrosion. More information on the leaks can be found in section 3.1.g.

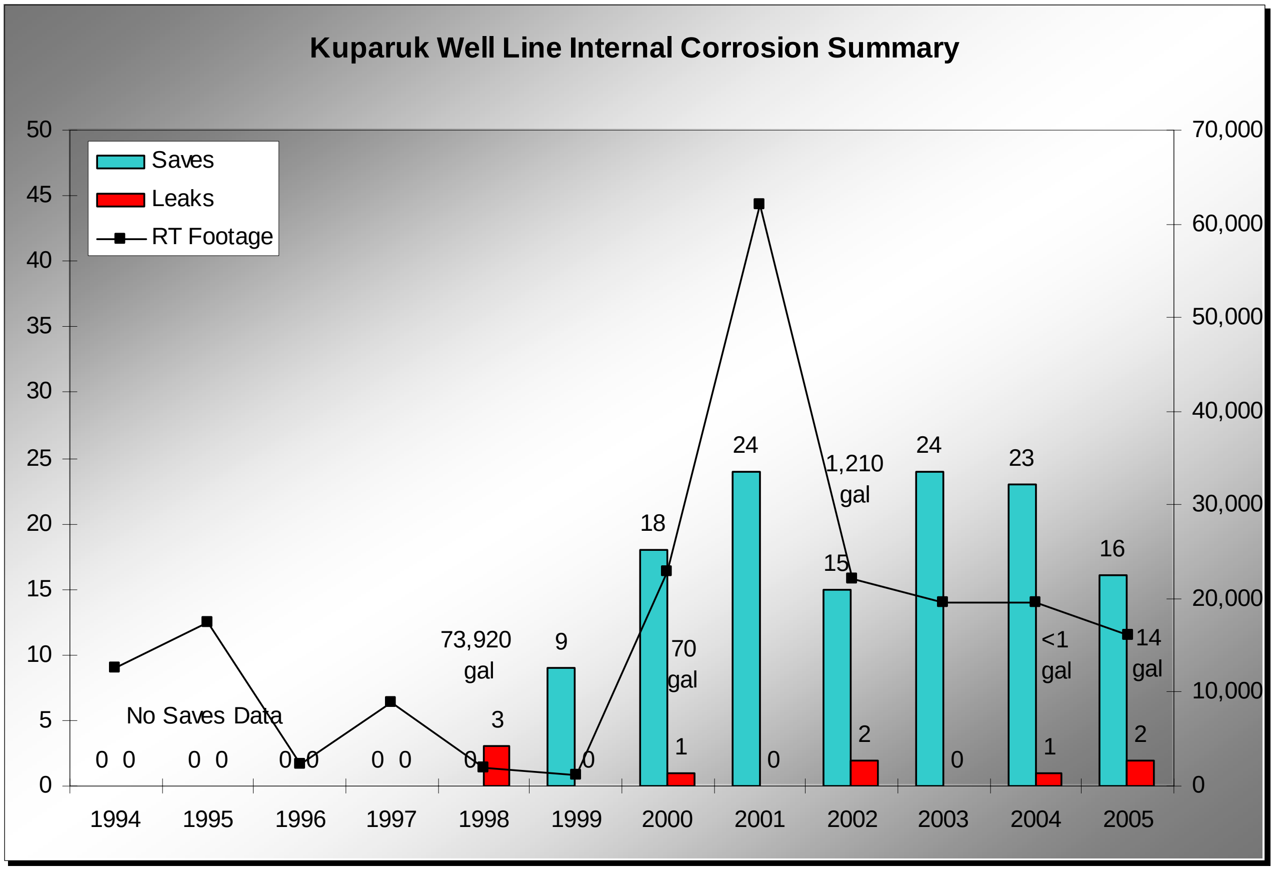

Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2005 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables.

- **RTR of Well Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	8,980	77
Water Injection	5,379	56
Total	14,359	133

The 2005 RTR well line data indicated no new damage trends.

- **Manual RT of Well Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% Of Repeat Radiograph s with Increases
Three-phase Production	199	942	311	20	6
Water Injection	120	798	180	35	19
Total	319	1,740	491	55	11

The 2005 manual RT well line data indicate a possible increasing damage trend in the water injection well lines. The percentage of radiographs showing increased damage increased from 9% to 19% from 2004 to 2005.

- **Manual UT of Well Lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	167	894	769	53	7
Water Injection	65	296	253	31	12
Total	232	1,190	1,022	84	8

The 2005 manual UT well line data indicate a possible increasing damage trend in the water injection well lines. The percentage of radiographs showing increased damage increased from 8% to 12% from 2004 to 2005.

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3.1.c Cross-Country Line Inspection

In 2005 we met our primary cross-country line goals by completing:

- Interval surveys on 33 cross country lines and
- An "On-pad Deadleg Inspection Survey" at all drill sites.

As indicated in Figure 9, 12 repair recommendations were initiated on cross-country lines (8 water injection, 4 production) because of internal corrosion damage in 2005. The corrosion mechanism for all repair recommendations was deadleg/underdeposit corrosion. All three leaks were in the water injection system. More information on the leaks can be found in section 3.1.g.

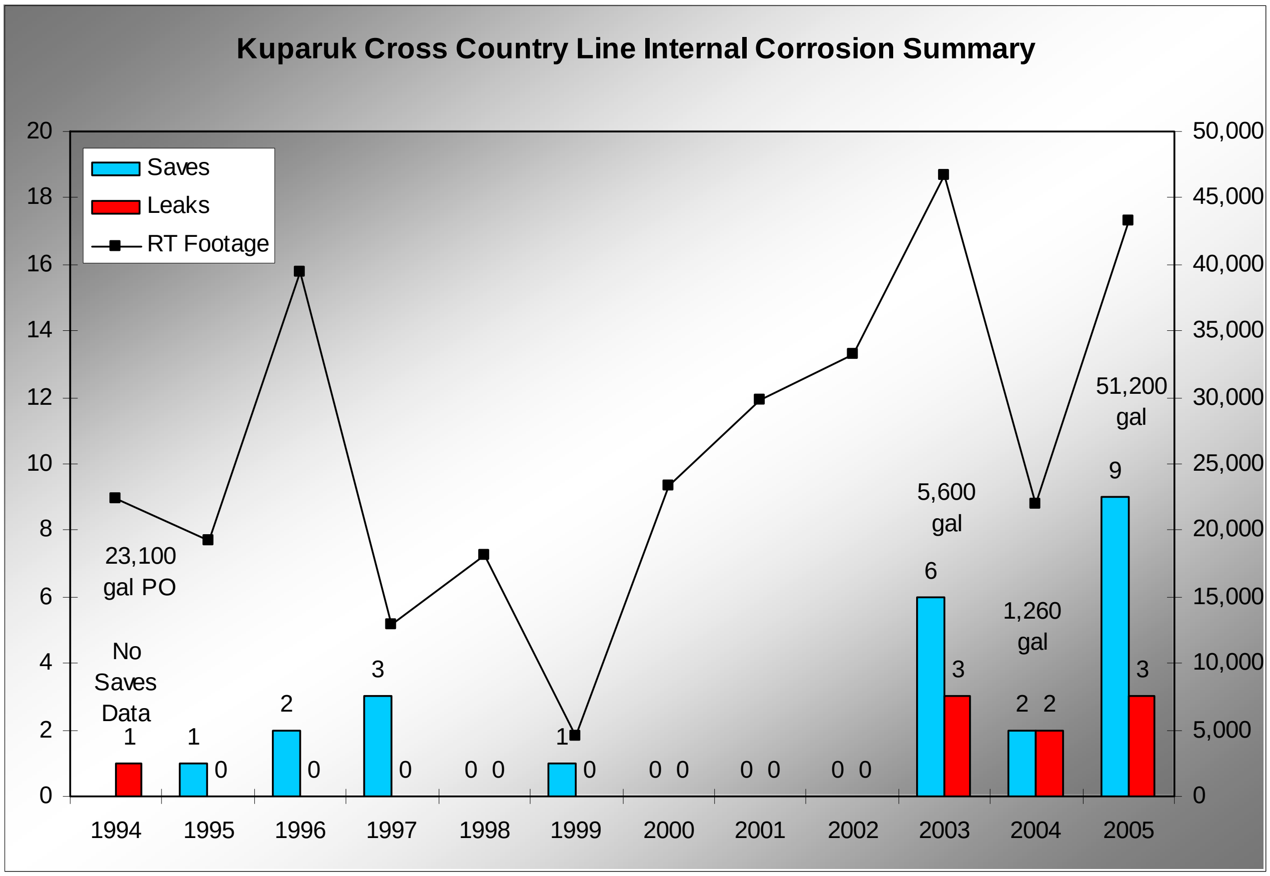

Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2005 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

- **RTR of Cross Country (CC) Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	6,067	8
Water Injection	28,267	25
Total	34,334	33

The 2005 RTR CC line data show an increase in the footage and number of lines inspected. This is a result of the failure analysis of the DS2K water injection line leak in 2005.

- **Manual RT of CC Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% of Repeat Radiographs with Increases
Three-phase Production	115	3,274	533	21	4
Water Injection	52	5,633	70	8	11
Total	167	8,907	603	29	5

The only significant change in these data from 2004 to 2005 was that the 2005 RT CC water injection line data inspection results decreased in the percentage of radiographs indicating increased damage from 27% in 2004 to 11% in 2005; however, the 2004 RT inspection data had a small sample size and we believe that the larger 2005 sample size is more indicative of what is happening in the CC water injection system. In addition, the number of radiographs on water injection system increased and the number of repeat inspections increased due to the DS2K WI line failure analysis.

- **Manual UT of CC lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	64	950	378	20	5
Water Injection	39	414	101	21	21
Total	103	1,364	479	41	9

The only significant change in these data from 2004 to 2005 was that the 2005 UT CC water injection line data indicate an increasing damage trend. The percentage of repeat inspections indicating increased damage jumped to 21% in 2005 from 5% in 2004. In addition, the number of inspections on the water injection system increased and the number of repeat inspections increased due to the DS2K WI line failure analysis.

3.1.d External (Weld-Pack) Program

In 2005 we had several significant accomplishments:

- Completed 4,646 TRT surveys of cross country line and well line weld packs due for recur inspection.
- Completed our goal of inspecting 100 additional Tarn-style weld packs (~257 to date) to ensure this new design is working properly. The weld pack design appears to be performing as planned. No corrosion has been detected.
- Inspection of 100 refurbished weld packs to verify the soundness of the Denso Tape refurbishments. The refurbishment technique appears to be performing as planned.

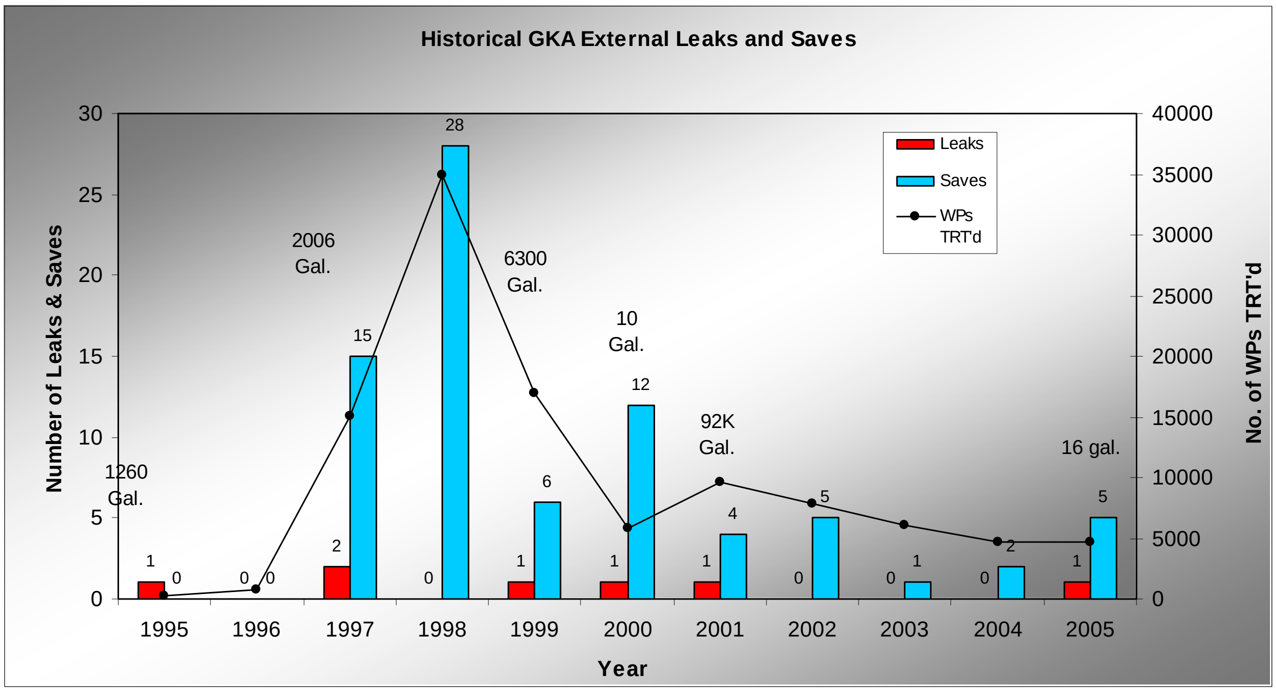

Figure 10. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

Cross-Country Lines (On-Pad and Off-Pad)

The baseline inspection effort for all cross-country lines was completed in 2004. Starting in 2005, the focus changed from making sure that all CUI locations were inspected and included in our inspection program to one of recur inspections priority-based on corrosion risk. A goal of 4,250 CUI locations on cross-country lines over tundra (off-pad) and on-pad was set. A total of 3,299 CUI locations were inspected. The goal was missed mainly because of lost TRT crew time spent on special projects such as follow-up work related to the DS2K WI and DS3J PO leaks. An estimate of the number of CUI locations was generated at the beginning of the year. The actual number of CUI locations turned out to be less than the estimate. Lastly, fewer weld packs were inspected late in the year after the TRT inspection guideline was modified as a result of the enhanced inspections related to the findings from the DS3J PO leak. The new guideline involves inspection at the pipe 6 o'clock position as before, and has been expanded to include a minimum of an inspection at 12 o'clock (the top of the pipe) if medium or heavy water is detected at the 6 o'clock position.

A total of 103 locations on the over-tundra lines were found with corrosion. One location required installation of a temporary sleeve (DS3K PO). A total of 94 cross-country on-pad locations were recur inspected in 2005 using TRT. Only one location (DS3J PO near leak) was found to have corrosion; it was placed on the refurbishment list.

Included in the 3,299 TRT inspections noted above, 157 of the new Tarn-style weld packs were inspected with TRT to gauge how they are holding up in service. A total of six weld packs were found with light-wet insulation. The rest were found to be completely dry. No corrosion under insulation (CUI) was found in any of the areas inspected.

External corrosion at on-pad CUI locations was also found while doing other inspection or maintenance work. This effort resulted in two sleeve repairs (CPF1 MI, 2KHWI @ DS2B).

A change in the way external corrosion locations will be reported was started in 2005. In the past, CUI locations in support saddles over a VSM were counted as one location. This report, and all future reports, break each support saddle location into two distinct pieces with the VSM centerline as the dividing point. The motivation behind this change was to aid in the layout and recur inspections at these locations. This will affect the total reported number of CUI locations by essentially doubling the number of CUI locations associated with saddles.

Well Lines

In 2005, 1,347 well line CUI locations were examined. Our stated goal was 1,500 weld packs (based on inspection of seven lines); the reason for the underestimate in the number of weld packs is the uncertainty in the total count of the well line CUI locations before inspections commenced. The number of CUI locations is estimated based on the length of a typical section of pipe. Corrosion was found at 46 of the 1,347 locations. No piping repairs were required. The corroded weld packs were refurbished.

Table 5: External CUI Inspection Summary for 2005.

Type of Equipment	2005 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines Over Tundra or On-Pad	4,250	3,299	103	3.1	953
Well Lines	1,500	1,347	46	3.4	58
Total	**5,750**	**4,646**	**149**	**3.2**	**1,011**

The number of CUI locations inspected with TRT, the number of CUI locations found corroded, and the percentage of CUI locations corroded for the cross-country lines over tundra, cross-country lines on-pad, and well lines are given in Figures 11, 12, and 13 beginning on the next page.

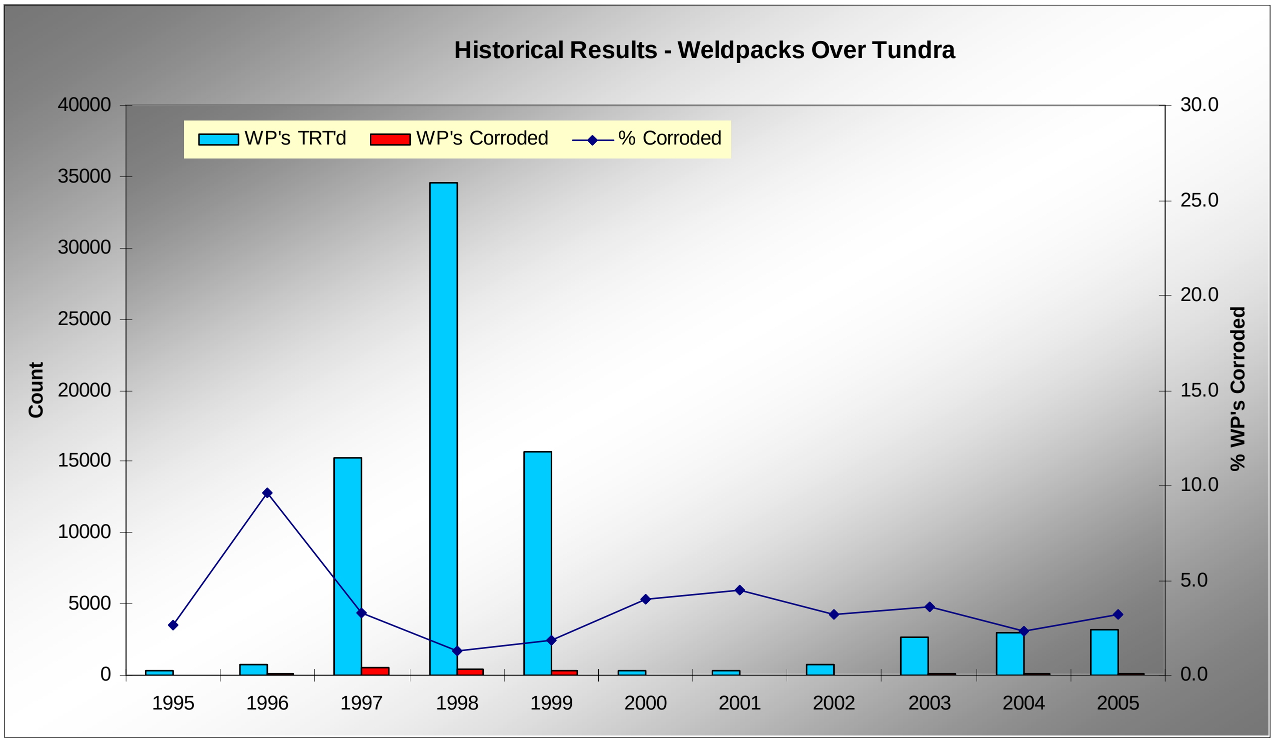

Figure 11. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad).

Figure 11 illustrates the most-complete external corrosion inspection program of the three external corrosion programs. 2002 through 2005 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

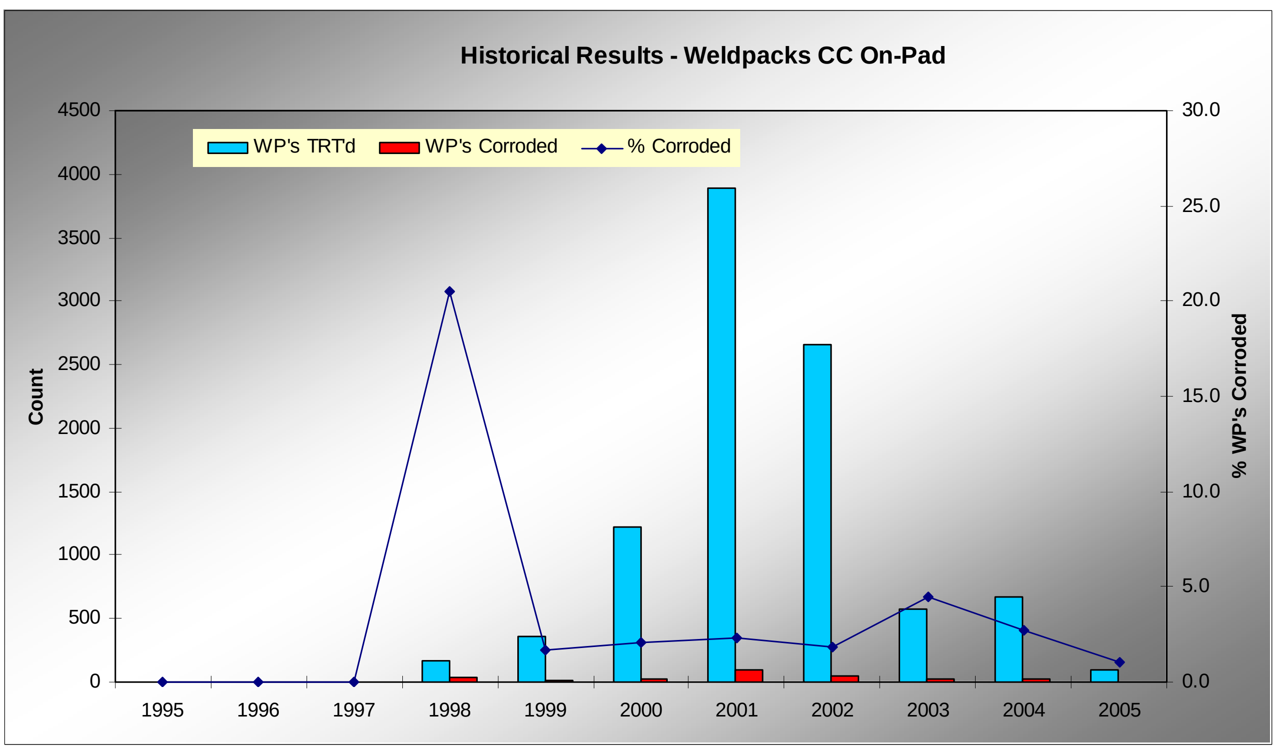

Figure 12. Summary of Weld Packs on Cross-Country Lines on Pads.

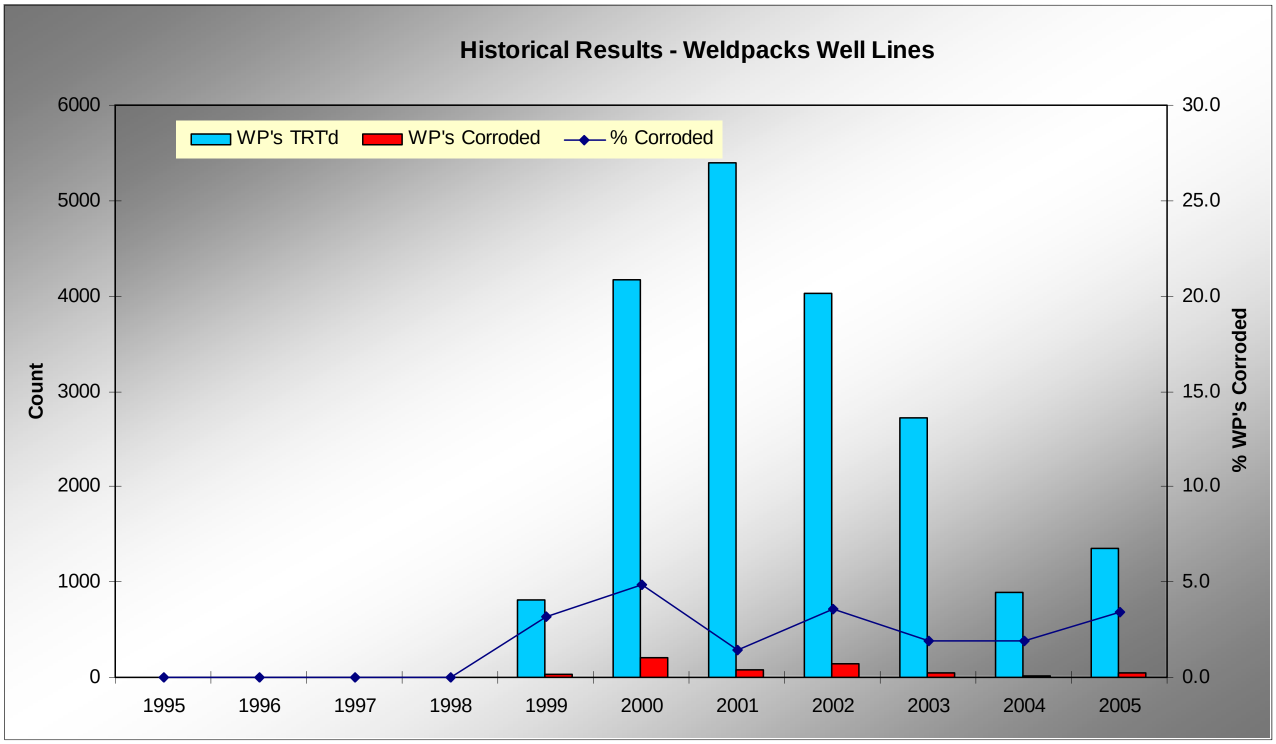

Figure 13. Summary of Weld Packs on Well Lines.

Corrosion Under Insulation Buffer Spike Program

In 2002, a test of “CUI Buffer Spikes” was initiated on 50 over-tundra cross-country weld pack locations. The concept is that by establishing an alkaline environment within the weld pack the corrosion rate can be reduced to an acceptable level at a lower cost than stripping and refurbishing the wet insulation.

The program was expanded later in 2002 by an additional 39 locations to include weld packs on drill site well and facility piping. In addition, two electric resistance probes were installed in two heavy water weld packs at DS1E to monitor potential corrosion activity. The sodium phosphate salt contained in these spikes dissolves in wet insulation and raises the pH to 10. Prior to installation of these spikes, wet insulation measurements fell within a consistent 6 to 7 pH range. During 2003, each of these locations was monitored for pH. The 2003 follow-up inspections showed that the pH did rise in the wet areas of the weld packs. Three locations were also stripped and tested with an indicator dye to verify the pH probe results.

TRT inspections of the buffer spike locations were performed during 2005 and early in 2006. All locations were re-inspected. Seven weld packs indicated an increase in the water content. None of the inspections reported any new corrosion. The survey revealed that 19 of the locations had been inadvertently refurbished. Visual inspection of the exposed pipe in these locations discovered very slight external corrosion (three-to-four percent wall loss) at three of these locations. It is likely that this minor corrosion was present before the buffer spikes were introduced. Corrosion damage that slight would have been difficult to detect using C-Arm (CTRT), especially with water in the insulation.

A pH survey was conducted during the summer of 2005 to test approximately 60 locations. Testing indicated that the spikes were maintaining an alkaline environment inside of the weld packs. An indicator dye check was conducted on two of the weld packs to verify that the pH profile across the insulation thickness was showing a high alkaline environment at the pipe wall. These tests showed that the buffer spikes were maintaining a high pH close to the pipe.

Monitoring of the ER probes at DS 1E indicated low, but not zero, corrosion rates. These probes collect a reading every six hours and the data are downloaded every two weeks.

The buffer spike concept has been tested over a sufficient timeframe to collect meaningful results. A final report on the project is forthcoming from our Bartlesville research center. Review and discussion of the results shall be conducted and a plan determined in 2006.

3.1.e Below Grade Piping Program

This section details the inventory and survey of below grade piping circuits and the results of Specialty Testing. The plans for future inspections are given in section 3.2.e.

In 2005 we had several significant accomplishments:

- Visually inspected and cleaned all debris from all cased below grade pipe circuits.
- Completed our specialty inspection (TWI) scope of work.
- Excavated, inspected, refurbished and repaired (as required) 24 cased below-grade pipe circuits.

The Alaska Department of Environmental Conservation (ADEC) regulations under 18 AAC 75.080 applies to the Kuparuk oilfield facilities operated by ConocoPhillips Alaska, Inc. (CPAI). To meet the requirements of 18 AAC 75.080, CPAI submitted their corrosion control program for below-grade piping in early 1998. The program also included a field-wide inventory of all below-grade piping in the Kuparuk field. ADEC approved the program in written correspondence dated October 26, 1998.

3.1.e (1) Inventory and Survey of Below Grade Locations

GKA has 772 circuits (includes priority 1, priority 2 and priority 3 lines) of below grade piping. Of these locations, one is contained in an utilidor. The remaining circuits are cased lines, the majority of which are either road, gravel pad or caribou crossings.

Utilidor Line

The line in the utilidor (Oily Waste Injection Line, BG ID #286) was taken out of service in 2004. It had been on a two year inspection cycle and was last inspected in 2002. Because it has been taken out of service the 2004 inspection was deferred and no 2005 inspection was done.

Cased Lines

<u>Inspection Status:</u>
The annual visual survey of all the cased lines was conducted in 2005. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

<u>Results and Remedial Action:</u>
Of all GKA below-grade circuits, 107 were found to have pipe in direct contact with gravel/soil or debris in the casing. All locations were remediated in 2005.

3.1.e (2) Results of Specialty Testing

<u>Inspection Status:</u>
In 2005, we completed TWI inspections on 127 GKA priority one circuits. This was the third year of our recurring inspection program where each priority one circuit will be inspected at a maximum ten-year interval.

In 2005 only the long-range ultrasonic system technology from The Welding Institute (TWI) was used. TWI technology is capable of finding evidence of both internal and external corrosion damage.

Results and Remedial Action:

Table 6 shows the results of the specialty testing performed by TWI.

Table 6. Results from the TWI inspections by service.

Service	Number of Cased Circuits Inspected	Incomplete or Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Minor to Moderate and Moderate Anomalies (M)	Number of Moderate to Severe and Severe Anomalies (S)
Oil	13	0	8	3	2	0
Other	114	26	47	34	7	0
Total	127	26	55	37	9	0

The 2005 TWI data indicated no new damage trends.

3.1.e (3) Results of Crossing Digs

After a revised risk assessment of the below-grade piping circuits that included water accumulation points, the number of below-grade piping circuits excavated was increased from eight in 2005 to 24 in 2006.

There were 24 below-grade circuits refurbished in 2005. Twenty-three circuits were excavated and one was replaced without excavation (cut and pulled through casing). Four of these circuits were considered repairs:

- Two repairs were made because of CUI damage only (West Trunk EOR at CPF1 and 1HPO at DS 1H pad). The EOR circuit was replaced and the 1HPO circuit was repaired with a pressure containing sleeve.
- One repair was made because of internal damage only (2KWI at 2H pad). This piping circuit was replaced by cutting and pulling the old pipe from the casing and pulling the new pipe into the casing.
- One repair was made because of a combination of CUI and internal corrosion damage (2KHBWI at the 2B pad crossing). This circuit was repaired with a pressure containing sleeve.
- Twenty of the excavated circuits inspected did not require de-rating, repair, or replacement because only minor or no corrosion damage was found.

For all twenty-four below grade circuits excavated in 2005, the insulation was refurbished and the pipe wrapped with Densyl tape to prevent further corrosion.

3.1.f Other Structural Concerns

Subsidence:

Existing Well Upgrade Program

- In 2005, four steel, conductor-mounted floor kits were installed in well houses at Drill Sites 1E, 2A, and 2Z. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2005, 17 heat tubes were installed at Drill Sites 1E, 2A, 2C, 2H and 3N. Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

New Wells & Producer to Water Injection Well Conversions

- In 2005, 10 newly drilled wells at Kuparuk were installed with insulated conductors.
- In 2005, ten newly drilled wells had heat tubes installed. Of these 10 newly-drilled wells, two had floors with permanent pipe supports.
- In 2005, four existing producers converted to water injection wells or converted to jet pump lift already had insulated conductors and heat tubes and did not require a floor kit.

Wind-Induced Vibration:

As a result of the 3A-I-M eight-inch gas lift line failure that occurred in December 2004 (described in section 3.1.g of the 2004 report), Kuparuk continues to review existing pipelines to evaluate the need for secondary mode vibration dampers.

During original development of the North Slope WIV program, secondary mode WIV failures were deemed highly unlikely and therefore mitigating measures for such events were not established. However, based on the unforeseen December 2004 secondary mode WIV failure on the DS3I 8" GL line, an effort to determine if secondary mode WIV is expected to be a fatigue threat to all the pipelines within the Kuparuk Wind Fan was sanctioned.

Through a comprehensive field-wide inventory of all the pipelines within the current Kuparuk Wind Fan and a more-detailed WIV analysis than had been possible previously, a critical Reynolds Number (R_e) corresponding to the "random shedding" threshold has been established. Vibration modes established below this "random shedding" threshold are referred to as "sub-critical" modes and pipelines subject to these conditions are most susceptible to both primary and secondary mode WIV responses.

As a result of these analyses, up to 440 pipe spans will receive secondary mode WIV protection in 2006. More detailed evaluations will be completed once enhancements are completed to the WIV evaluation model to take into account broad-banded WIV events more typical of higher wind velocities.

3.1.g Corrosion and Structural-Related Spills/Incidents:

- Well 2A-17 production well line leaked in March 2005 because of erosion in a two inch branch line off of the main six inch line at the 2nd elbow (lower) from the well head. The spill volume was less than one gallon of produced fluids and was confined to the well-house floor. No fluids contacted the tundra or the gravel pad. As such, it was determined to not be an ADEC reportable spill. This location is inspected on a regular basis during our well line interval survey. As a result of this leak all other erosion susceptible areas on this line were inspected and no additional erosion was found.

- Well 1G-09 water injection well line leaked in July 2005 because of a combination of internal under-deposit corrosion and CUI damage at a weld pack located in a saddle. The spill volume was determined to be 13 gallons. The spill was reported to ADEC. As a result of this leak the previous internal and external corrosion inspection records were reviewed. The review indicated that this line and the location of the leak had received regularly scheduled inspections within a time frame which should have detected the damage before the leak. As a result of this finding inspection records for several other lines and locations were reviewed under the inspection contractor's QA/QC program. This review resulted in tighter controls regarding RTR inspections of lines with high solid build-up and more coverage of CUI areas when found to be "Medium Wet."

- Drill site 2K water injection line leaked in March 2005 in the below-grade circuit at DS 2H pad because of internal corrosion damage. The spill volume was determined to be 51,198 gallons. The spill was reported to ADEC. As a result of the leak, a formal Failure Analysis that included ADEC and BP representatives was completed on this incident. Several enhancements to our monitoring, inhibition and inspection programs have been initiated based on this report.

- Drill site 2H warm-up line leaked in April 2005 under the 2H manifold building because of internal under-deposit corrosion in a dead-leg. The spill volume was less than one gallon of produced water confined to the pipe surface and the snow on top of the gravel pad. As such, it was determined not to be reportable to ADEC. This location was scheduled to be inspected under our "On-pad Deadleg Inspection Survey" in 2005. Unfortunately the leak occurred before our crews inspected it. We are confident that the damage would have been detected, and the location repaired before the leak, under our current inspection methods and procedures if the location had been scheduled earlier in the year. It should be noted that inspection of all piping similar to this at all drill sites was completed in 2005.

- Drill site 2U warm-up line leaked in December 2005 under the 2U manifold building. The same comments as noted in 2H (directly above) apply to this leak.

- The DS3J produced oil line leaked in October 2005 because of external corrosion at a weld pack located partially in a saddle. The spill of 16 gallons of produced fluids was reported to ADEC. There were three perforations in the weld pack area, with the heaviest corrosion located near the top of the pipe. Corrosion was noted around the entire circumference over two feet of the five-foot corrosion network. The 6 o'clock position of this particular location had been scanned with C-arm TRT (CTRT) in 2001 and determined to have no corrosion. CTRT is not strong enough to inspect the pipe through the saddle so the location would have been scanned right up to the saddle and then picked up again on the other side. The weld pack had been labeled as having CTRT inspection only. This failure has led the Corrosion Department to re-evaluate several aspects of its external corrosion program. Specifically, the layout and labeling guidelines have been reviewed and updated to assure that a CUI location will not be missed. Additionally, the weld pack inspection guidelines have been updated to include inspection of the upper portion of the pipe when medium or heavy wet insulation is detected at the six o'clock position or when a penetration exists in the outer jacket up high on the pipe (e.g., a branch connection, tear, etc.).

- No leaks were caused by subsidence in 2005.

Figures 8, 9, and 10 show the number of leaks and the volumes of leaks as a function of time. Figure 8 depicts the leaks caused by internal corrosion for the well lines. Figure 9 depicts the leaks caused by internal corrosion for the cross-country lines. Figure 10 shows the leaks caused by external corrosion for cross-country lines, well lines, and below-grade piping locations.

3.2 Year 2006 Forecast

3.2.a Monitoring & Mitigation

- Test additional inhibitor formulations.

- Continue to evaluate the biocide program and the maintenance pigging enhancements to the water injections systems.

- Increase biocide and maintenance pigging in the seawater system.

- Expand guideline for use of brush / disk combo cleaning pigs to CPF1 and CPF3.

3.2.b Well Line Inspection

Our recurring inspection program will continue in 2006. No in-service line will go longer than 10 years without some type of inspection.

3.2.c Cross-Country Line Inspection

Our recurring inspection program will continue in 2006. No in-service line will go longer than 5 years without some type of inspection.

Smart pigging is planned for the 30-inch sea water line from the STP to the CW skid.

3.2.d External (Weld-Pack) Program

Cross-country lines over tundra:

- Inspect approximately 3,950 cross-country line weld packs (based on seven lines) as part of our recurring inspection program. This includes CUI locations over tundra as well as on-pad.
- Inspect a minimum of 100 Tarn-style weld packs (insulation not touching the pipe) with TRT to continue to evaluate the efficacy of the design.
- Inspect a minimum of 100 refurbished weld packs to continue to evaluate the performance of the Denso tape system.

Well lines:
Inspect approximately 1,500 well line corrosion-under-insulation locations (based on 130 lines) as part of our recurring inspection program.

3.2.e Below Grade Piping Program

- Continue our annual visual inspection of all (Priority 1, 2, and 3) cased lines. The appropriate GKA field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.

- Continue our recurring TWI inspection program of priority one cased lines.

- Excavate, inspect, refurbish, and repair (as necessary) fifteen to twenty-seven lines in cased crossings.

- Continue to work with TWI and ConocoPhillips R&D to refine inspection data reduction and interpretation.

3.2.f Other

- Continue enhancements to the Kuparuk Corrosion Database.

- Continue to evaluate, and prioritize subsidence mitigation efforts at the existing drill sites.

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4.0 Program Status Summary - WNS

4.1 Year 2005 Overview

4.1.a WNS Monitoring & Mitigation

Average general and pitting coupon corrosion rate data for Year 2005 are presented in Tables 7 and 8.

Table 7. Average general corrosion rates for corrosion coupons by service category.

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average General Corrosion Rate, mpy (target=<3)	Number of Lines with Conformant General Corrosion Rates	Percent of Lines with Conformant General Corrosion Rates
Three-phase Production Cross-Country Lines	1	0.1	1	100
Seawater Cross-Country Lines	1	2.4	1	100
Seawater Injection Cross-Country Lines	0			
Production Well Flow Lines	29	0.5	28	96*
Seawater Injection Well Flow Lines	9	0.1	9	100

* *The one line with greater than 3 mpy CR was due to erosion*

Table 8. Average pitting corrosion rates for corrosion coupons by service category.

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Percent of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Cross-Country Lines	1	2	1	100
Seawater Cross-Country Lines	1	1	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	29	1.8	28	96
Seawater Injection Well Flow Lines	9	4.7	9	100

** NOTE: This coupon location is currently not accessible because of a new piping obstruction.*

4.1.b Well Line Inspection

In 2003, 33 three-phase production lines and 22 water injection lines were inspected; no damage was found.
In 2004, 18 three-phase production lines were inspected at direction changes; no damage was found.
In 2005, 32 well lines were inspected, no damage found.

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4.1.b Cross-Country (CC) Line Inspection

2,900 ft of the CD2 produced crude CC line was inspected with RTR. No damage was identified.

4.1.d External (Weld-Pack) Program

No inspections for external corrosion were performed.

4.1.e Below Grade Piping Program

This section details the inventory and survey of below grade locations and the results of Specialty Testing. The plans for future inspections are given in section 4.2.e.

4.1.e (1) Inventory and Survey of Below Grade Locations

CPAI has 15 locations of below grade piping in the WNS, and 30 associated with WNS at GKA. These locations are cased lines at road or pad crossings.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2005. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

Results and Remedial Action:
Of all the below-grade lines, two lines were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. These two lines are considered to be "direct buried". Locations were excavated, evaluated and a request for waiver, contingent on a stringent inspection program, has been submitted to ADEC. The next inspection of the buried portions will be in 2009.

4.1.e (2) Results of Specialty Testing

No specialty testing was performed in the WNS in 2005. Of the 45 WNS below grade circuits, 10 are smart pigged with the remainder of the line. The remaining circuits will be inspected with TWI at their 10 year (max) interval even though they are externally coated.

4.1.e (3) Results of Crossing Digs

Two lines were excavated and are referenced in Results and Remedial Action above.

4.1.f Other Structural Concerns

Subsidence:

- No concerns identified.

Wind-Induced Vibration:

No problems identified in 2005.

4.1.g Corrosion and Structural-Related Spills/Incidents:

- No leaks were caused by external corrosion in 2005.
- No leaks were caused by wind-induced vibration in 2005.
- No leaks were caused by internal corrosion in 2005.
- No structural or subsidence concerns were identified in 2005.

4.2 Year 2006 WNS Forecast

4.2.a Monitoring & Mitigation

- Pull coupons as scheduled
- Ensure new drill site development provides for adequate monitoring.

4.2.b Well Line Inspection

Inspect 15 lines, 15% of existing total for internal corrosion.

4.2.c Cross-Country Line Inspection

Obtain spot RT of CD1 PC line (on pad).

4.2.d External (Weld-Pack) Program

Cross-country lines over tundra:
No inspections planned.

Cross-country lines on pad:
No inspections planned.

Well lines:
TRT most likely locations for CUI on 20 lines.

4.2.e Below Grade Piping Program

Continue the annual visual inspection of all priority one and two cased lines. The appropriate CPAI field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.

4.2.f Other

Continue Alpine piping layout and piping information database development.

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APPENDIX A
Glossary

Equipment Classification:

- **Well Line** – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.
- **Cross-Country Line** – Pipe from the Drill Site manifold to the Central Processing Facility (CPF).
- **Below-Grade Location** – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

Service Definitions:

- **Three-phase Production** – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.
- **Seawater (SW)** – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration, oxygen stripping using produced gas, and biociding.
- **Produced Water (PW)** – The water separated at the CPF from three-phase production.
- **Mixed Water (MW)** – Produced water and seawater that have been commingled.
- **Gas** – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible Injectant.
- **Produced Oil** – The liquid hydrocarbon separated at the CPF from three-phase production.

Inspection Terminology:

- **CRM –** Corrosion rate monitoring.
- **UT-** Ultrasonic testing
- **RT –** Radiographic testing
- **RTR –** Real time radiographic testing
- **TRT –** Tangential radiographic testing
- **PTI –** Profile Technologies Inc. (Electro magnetic inspection)
- **TWI –** The Welding Institute (Long range UT)\
- **KDR –** Known damage recur inspection
- **Leak** – Through-wall pipe damage that causes loss of product. Product volume may not be sufficient to be classified as a "spill".
- **Save –** When the Corrosion Group recommends a repair before a leak occurs.
- **Below Grade (priority 1) –** These are pipes with a higher probability and consequence of failure. In general they have larger diameters and higher pressures and would probably cause damage to the environment or cause safety concerns if they leaked.
- **Below Grade (priority 2) –** These are pipes with a lower probability or consequence of failure. In general, these have smaller diameters and lower pressures and would probably cause little, if any, environmental damage or safety concern if they leaked. Examples include un-insulated dry gas lines and flare lines.
- **Below Grade (priority 3) –** These are pipes with a low probability and consequence of failure. Examples include decommissioned pipes, pipes in fresh or fire water service and pipes constructed of corrosion resistant materials. In addition, they contain product that would cause little, if any, environmental damage or safety concern the pipe leaked.