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

March 31, 2005

Commitment to Corrosion Monitoring

5th Annual Report to the Alaska Department of Environmental Conservation

Prepared by

ConocoPhillips Corrosion Team

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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 exist where moisture penetrates and is trapped in insulation. Effective management of corrosion at Kuparuk is critical to maintain environmental and facility integrity, reduce field operating costs, and to extend the life of the field infrastructure to meet future needs.

Alpine is ConocoPhillips' newest development and the largest onshore oil field discovered in North America in the past decade. Alpine has a nominal processing capacity of 120,000 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 5th 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

In 2004 we implemented linear array testing which allowed us to inspect all large-diameter cross country water lines that could not be inspected with conventional Real Time Radiography (RTR), with the exception of the 30-inch and the two 24-inch sea water supply lines. This technology allowed us to greatly increase our inspection coverage of 12 water injections lines with diameters of 12” to 16”.

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3.0 Program Status Summary - Kuparuk

3.1 Year 2004 Overview

3.1.a Kuparuk Monitoring & Mitigation

In 2004 we had several significant accomplishments:

- Tested four new corrosion inhibitor formulations.
- Started testing of schmoo-be-gone (SBG) in the DS1E water injection system to evaluate mitigation effectiveness.
- Installed wellhead corrosion inhibitor injection systems for production well lines at three drill sites.
- Improved the existing biocide treatments of the water injection system at CPF2.

Average general and pitting coupon corrosion rate data for Year 2004 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	61	0.09	61	100
Seawater Cross-Country Lines	2	2.6	1	50
Mixed Water Injection Cross-Country Lines	22	1.1	19	86
Production Well Flow Lines	501	0.2	494	99
Mixed Water Injection Well Flow Lines	644	0.8	593	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	61	4.5	53	87
Seawater Cross-Country Lines	2	5.1	2	100
Mixed Water Injection Cross-Country Lines	22	26	11	50
Production Well Flow Lines	501	1.5	471	94
Mixed Water Injection Well Flow Lines	644	9.3	442	69

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

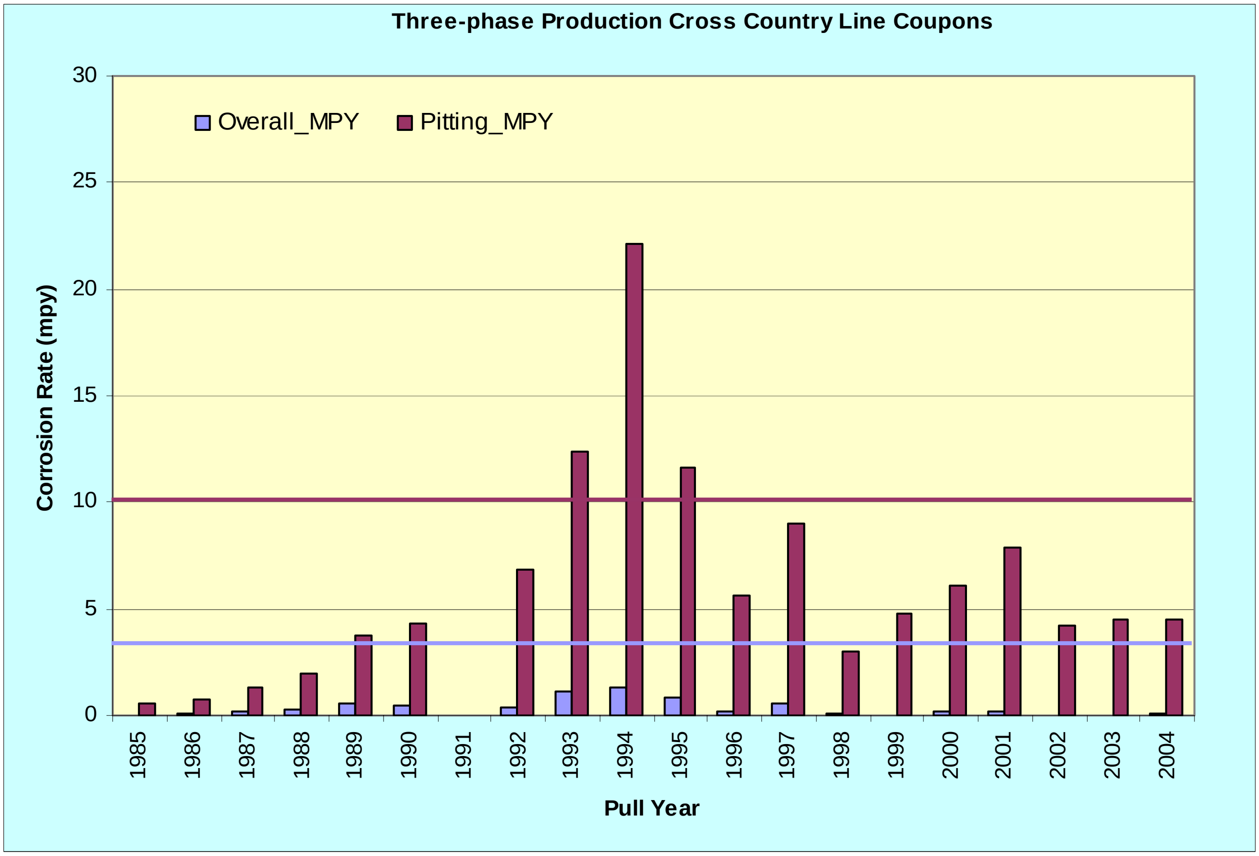

Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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 the 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 2004, 587 corrosion-rate monitoring (CRM) inspections were conducted, with two minor increases found. Other internal inspection data also support the CRM data conclusions and 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 excluding: one corrosion inhibitor test location (2WUVPO); and one location that had increased inspection damage over a 12-month period and that had its corrosion inhibitor concentration increased at the end of 2003 (1L10PO). In 2004, coupon or probe corrosion rates exceeded targets on fifteen lines and action was taken on all fifteen of these lines. In 2004, inspection results indicated minor corrosion had occurred on six lines; corrosion inhibitor concentrations were increased in four of these 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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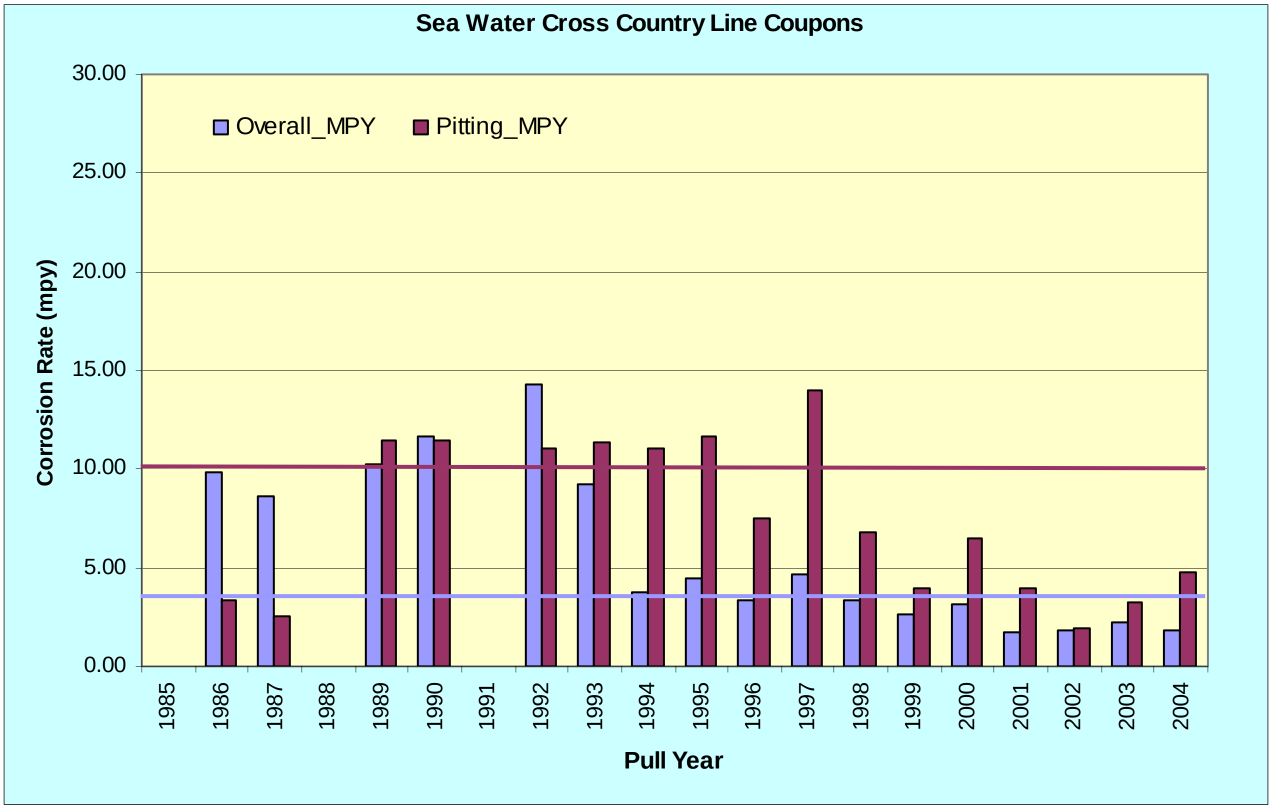

Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Sea Water Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 2 above, shows the average corrosion rates for the sea water cross-country line coupons remained under thresholds in 2004.

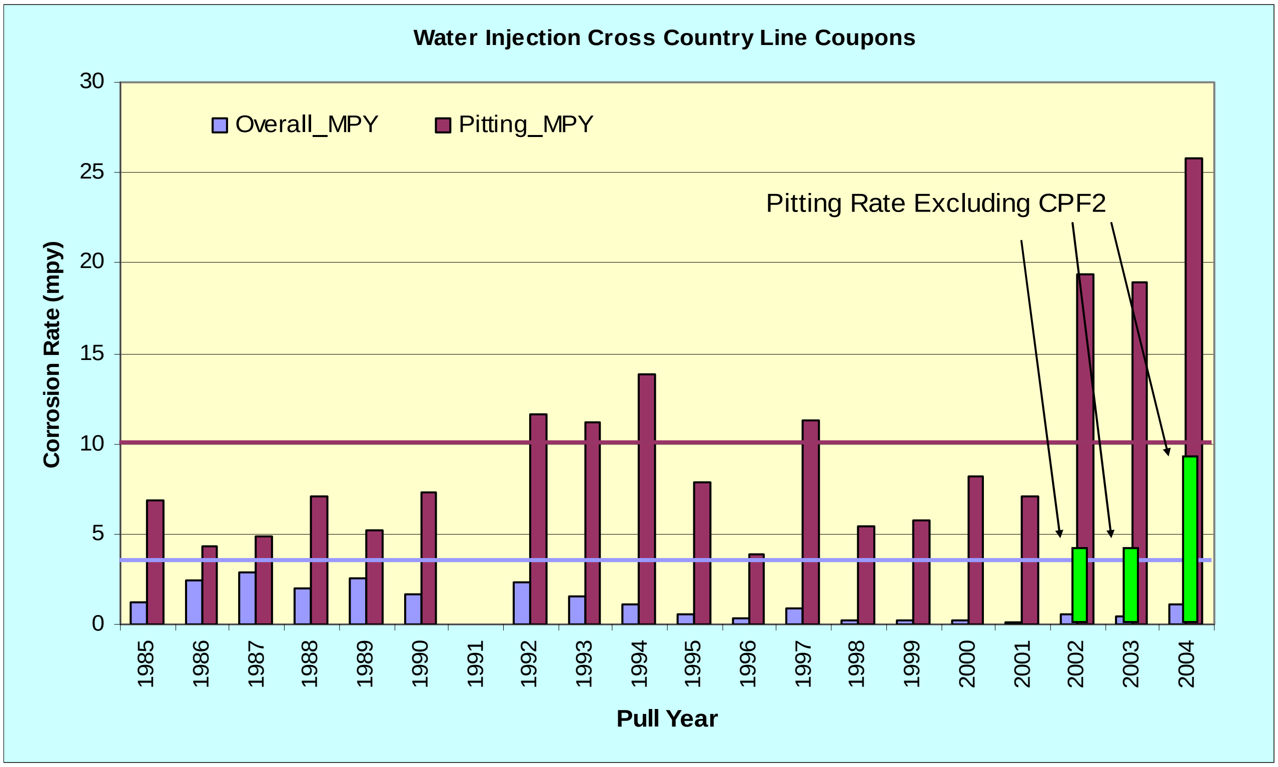

Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Mixed 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. Closer analysis of the data shows that the average pitting rate excluding CPF2 locations is under the threshold. Coupon results are used to prioritize inspection efforts. During the second half of 2004, equipment was installed and procedures were implemented to provide enhanced biocide treatments at CPF2. The first quarter 2005 coupon pulls from CPF2 show that pitting rates are lower than the 2004 average, but are still above threshold. In addition to the biocide treatment enhancements, an additional 80K BWPD of SW has been added to CPF2. This will increase line velocities and is anticipated to help reduce the under-deposit corrosion seen on many of these coupons.

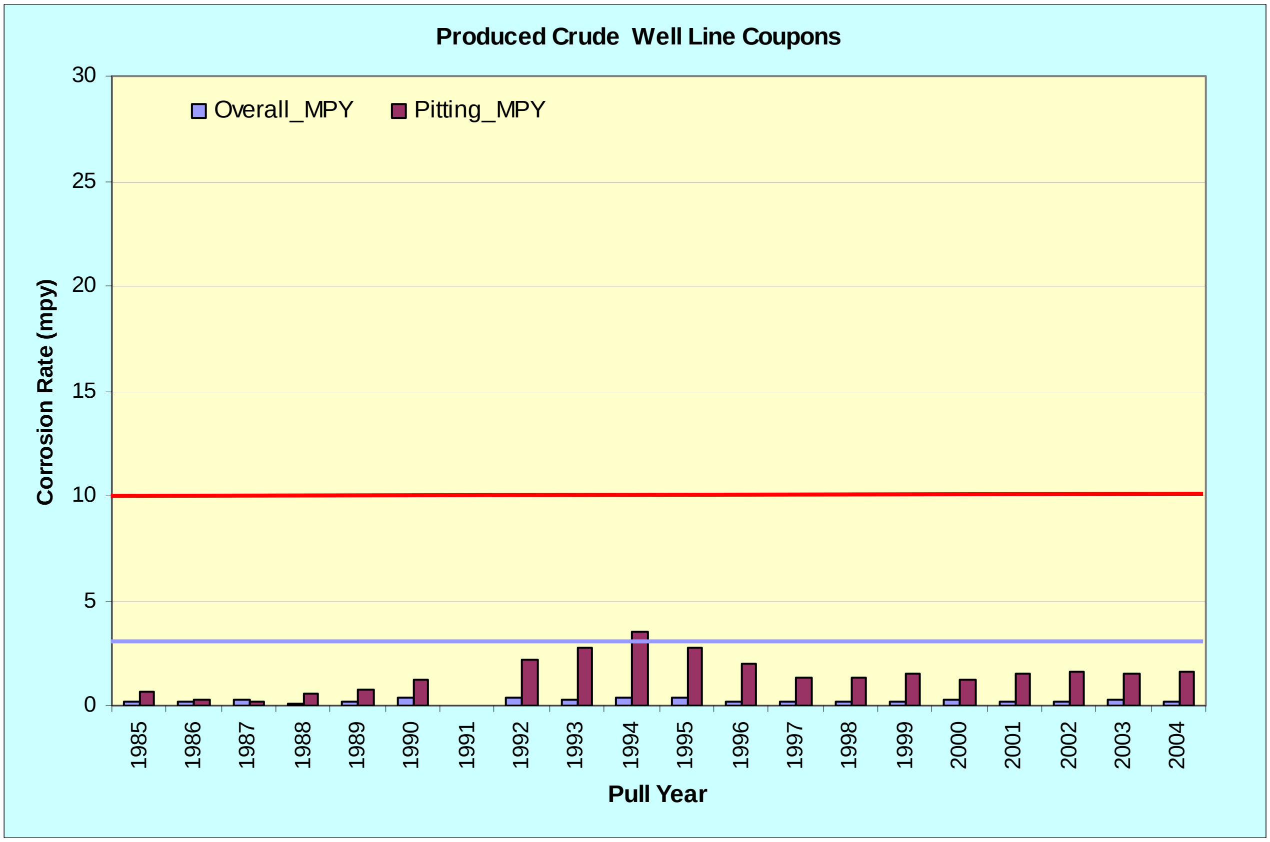

Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

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.

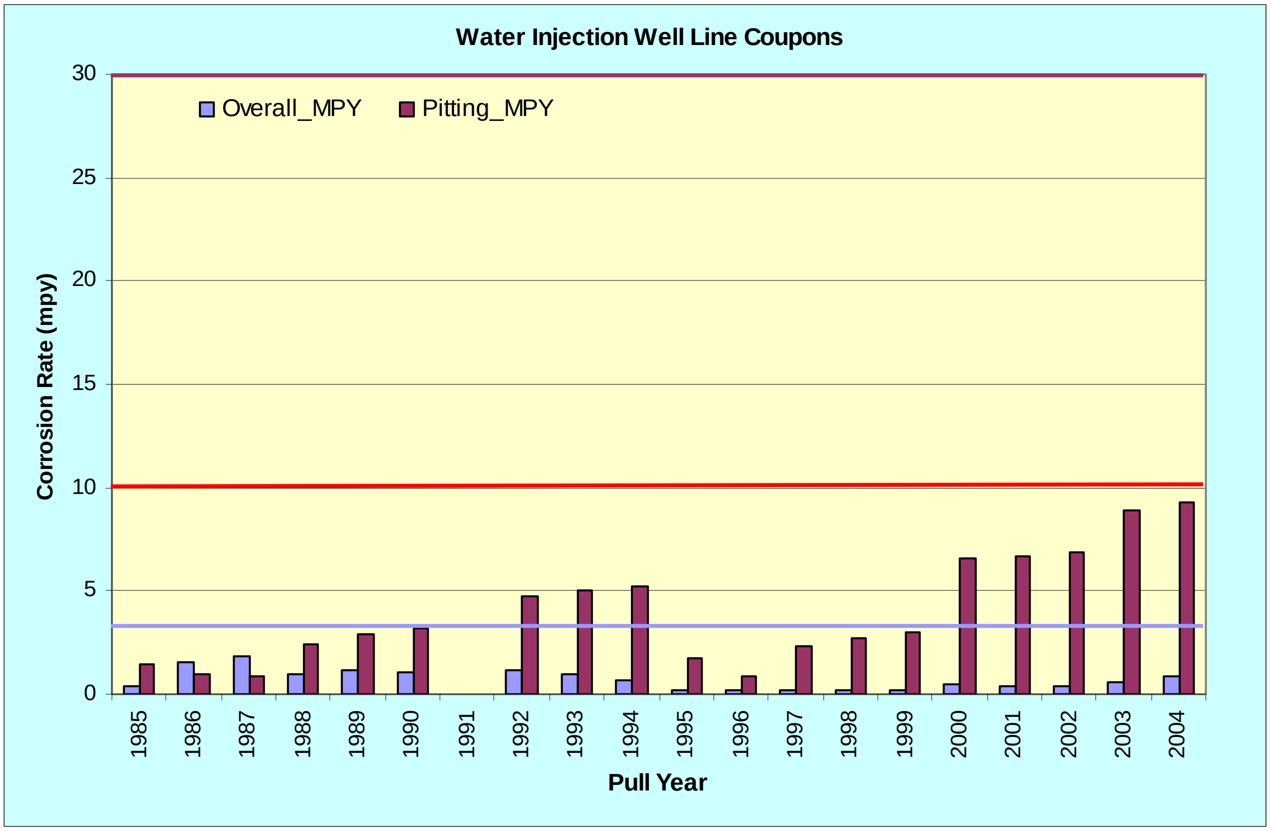

Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

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.

Mitigation:

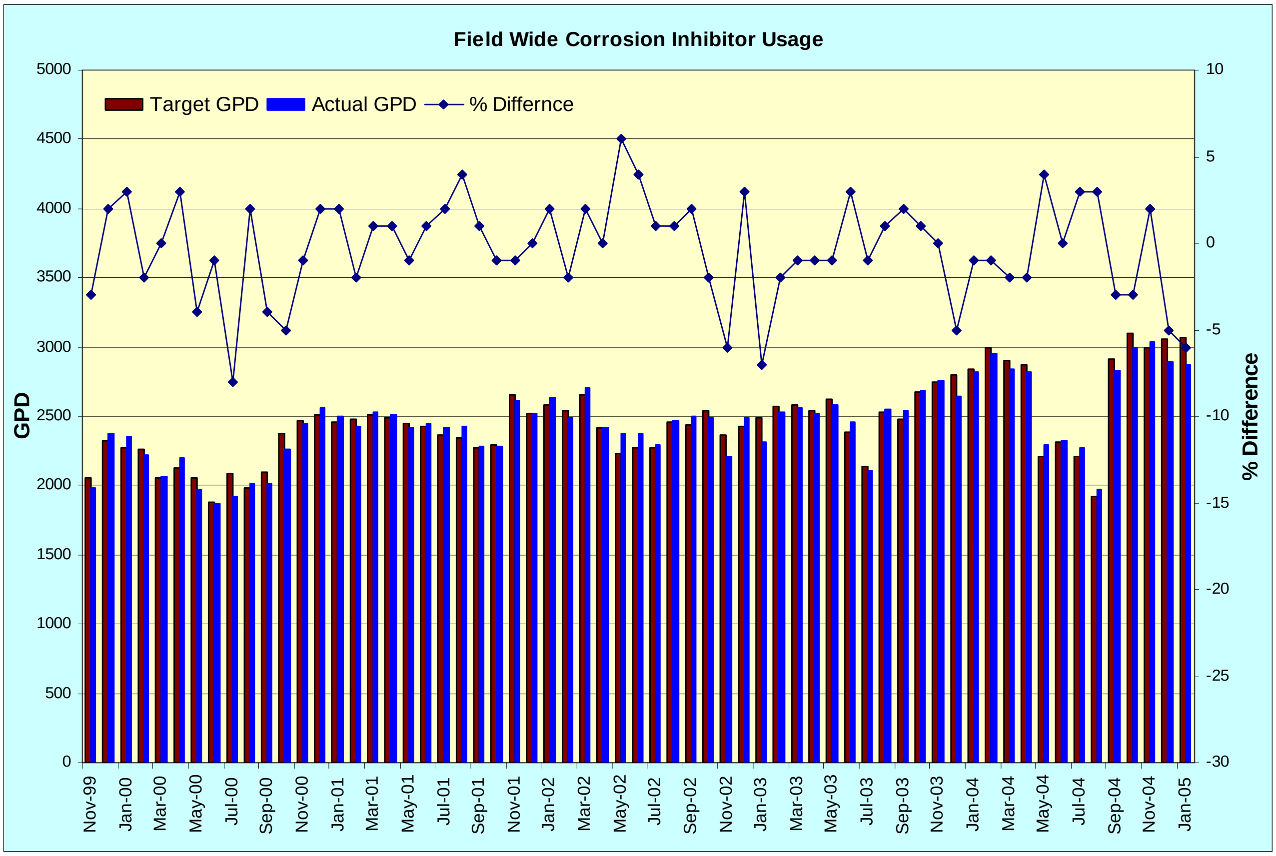

Figure 6. Field-wide Corrosion Inhibitor Use.

For the Kuparuk field, Figure 6 shows the actual number of gallons of corrosion inhibitor pumped per day, the recommended number of gallons of corrosion inhibitor per day, and the percent difference between the two. The average deviation for the year was –0.85%. The larger variation seen in the November and December 2004 data was caused by the extreme weather. The lower usage seen in May through August was due to pumping a more concentrated blend of the same field-wide corrosion inhibitor (the concentration of active components in both blends is the same).

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.

Kuparuk Inhibitor Feedback System

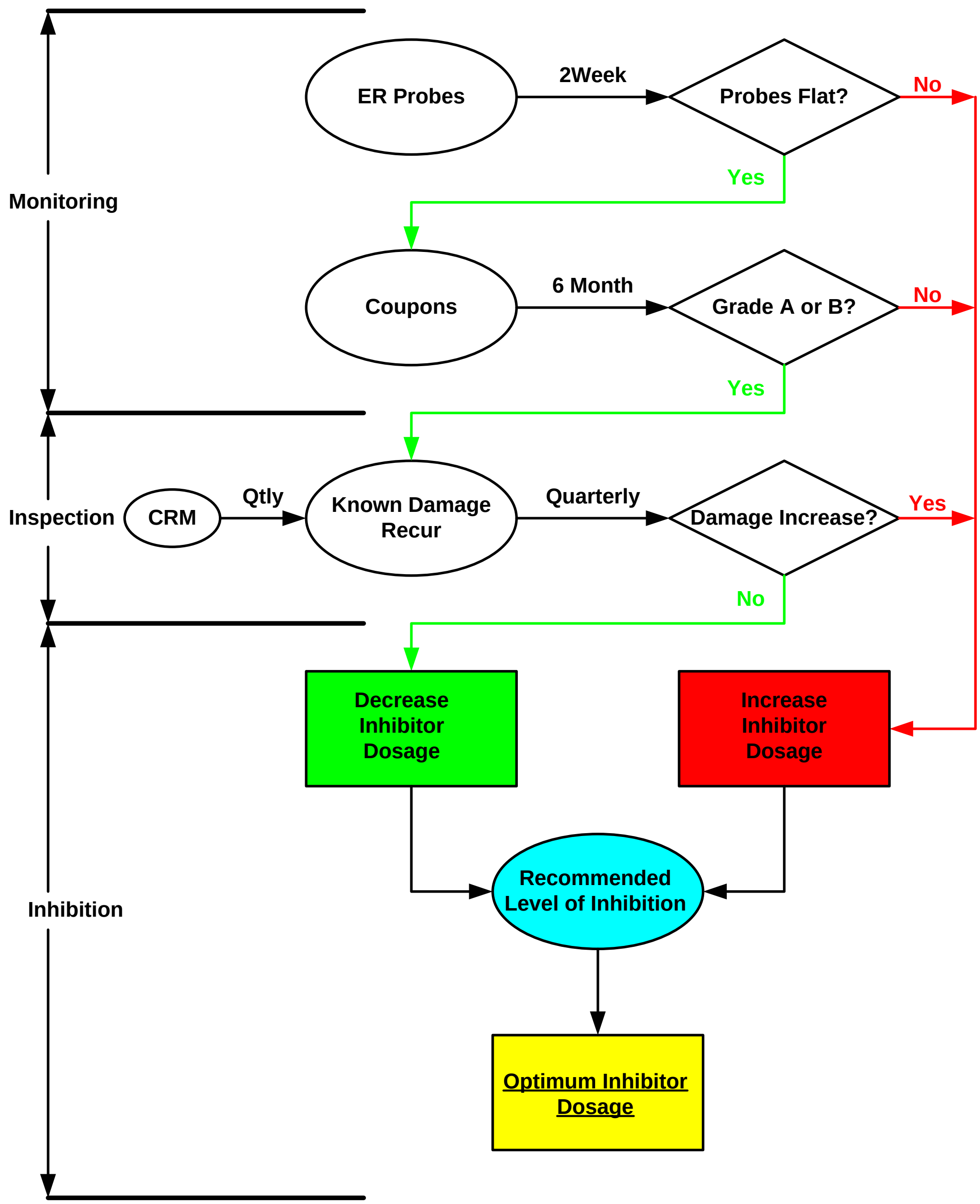

Figure 7. Corrosion Inhibitor Feedback System.

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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
1-2ZPO			x	Increase Target PPM
1DPO		x		Increase Target PPM
1L10PO			x	Hold (see Fig. 1 discussion)
2APO		x		Increase Target PPM
2BPO			x	Increase Target PPM
2NPO		x		Increase Target PPM
2TAMKHPO			x	Increase Target PPM
2WUVPO			x	Hold until after 50B Test
3HPO		x		Increase Target PPM
1BPO	x			Increase Target PPM
1CPO	x			Increase Target PPM
1RPO	x	x	x	Increase Target PPM
2EDPO		x		Increase Target PPM
2TPO	x	x		Increase Target PPM
3CPO		x		Increase Target PPM
3KPO		x		Increase Target PPM
3MIPO		x		Increase Target PPM
3RPO		x		Increase Target PPM
3RQONKPO		x		Increase Target PPM
3WO to CPF2		x		Increase Target PPM

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3.1.b Well Line Inspection

One notable accomplishment in 2005 was that we met our primary 2004 goal by completing interval surveys on 132 well lines.

As indicated in Figure 8 below, repair recommendations were initiated on 24 lines (16 water injection, 8 production) in 2004 because of internal corrosion damage. Except for the leak, the corrosion mechanisms were all underdeposit corrosion. The leak, determined not to be an ADEC-reportable spill, was in a water injection line and was caused by erosion associated with a straightening vane pack. More information on the leak can be found in section 3.1.g.

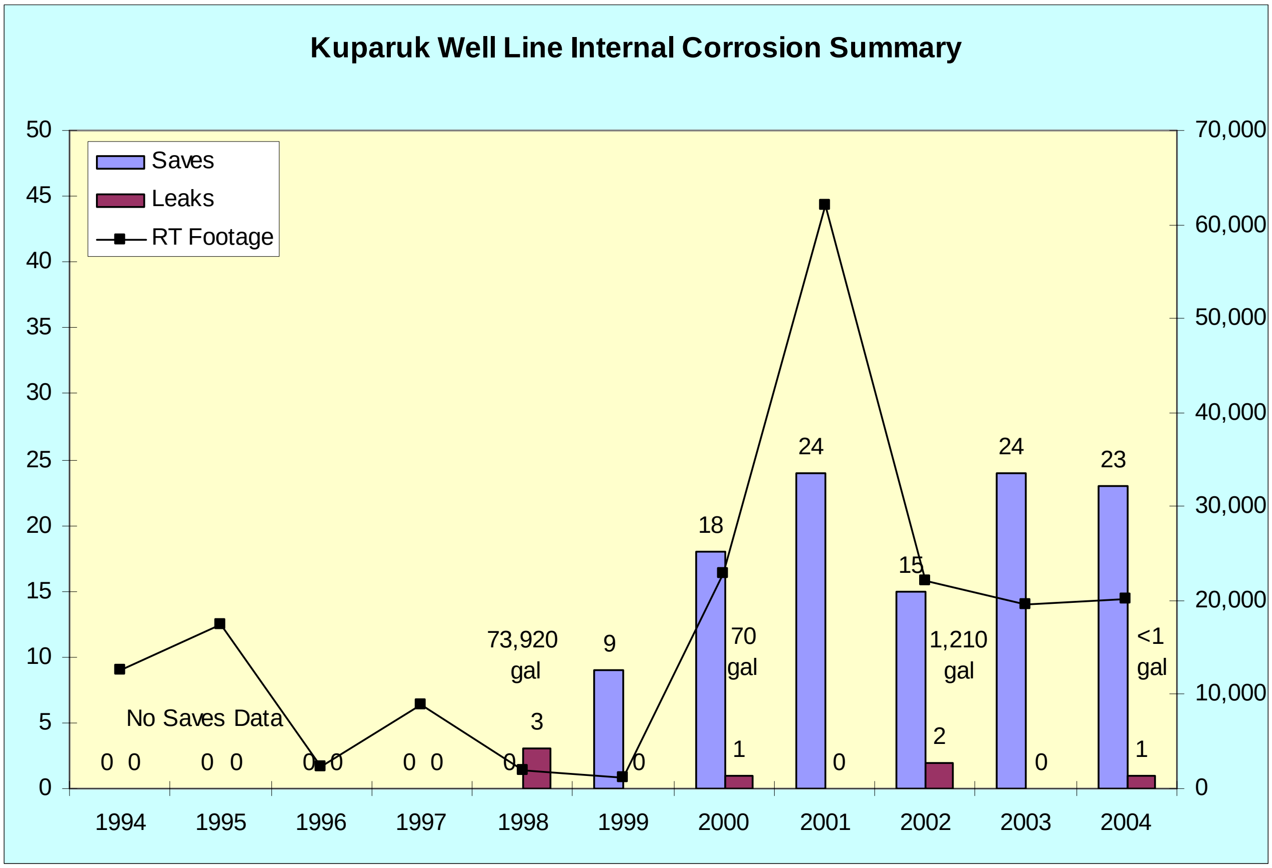

Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2004 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	10,217	56
Water Injection	7,530	44
Total	17,747	100

The 2004 RTR well line data indicated no new damage trends. The number of lines inspected by RTR decreased from previous years because we completed our initial baseline inspection in 2003 and started our interval recur program in 2004.

- **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 Radiographs with Increases
Three-phase Production	196	898	386	16	4
Water Injection	111	1,017	179	16	9
Total	207	1,915	565	32	6

The 2004 manual RT well line data indicated no new damage trends. The number of lines inspected by RT decreased from previous years because we completed our initial baseline inspection in 2003 and started our interval recur program in 2004.

- **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	170	1,442	1,254	93	7
Water Injection	69	512	384	29	8
Total	239	1,954	1,638	122	7

The 2004 manual UT well line data indicated no new damage trends. The number of lines inspected by UT decreased from previous years because we completed our initial baseline inspection in 2003 and started our interval recur program in 2004.

3.1.c Cross-Country Line Inspection

In 2004 we had several significant accomplishments:

- Completed the inspection survey of all over tundra dead-legs and weld-o-lets on cross country pipelines.
- Met our primary 2004 goal by completing interval surveys on 32 cross country lines.

As indicated in Figure 9, four repair recommendations were initiated on cross-country lines (1 seawater injection, 3 production) because of internal corrosion damage in 2004. The corrosion mechanism for the three production lines was deadleg corrosion. The corrosion mechanism for the seawater injection line leak, determined not to be an ADEC-reportable spill, was microbiologically induced corrosion. More information on the leak can be found in section 3.1.g.

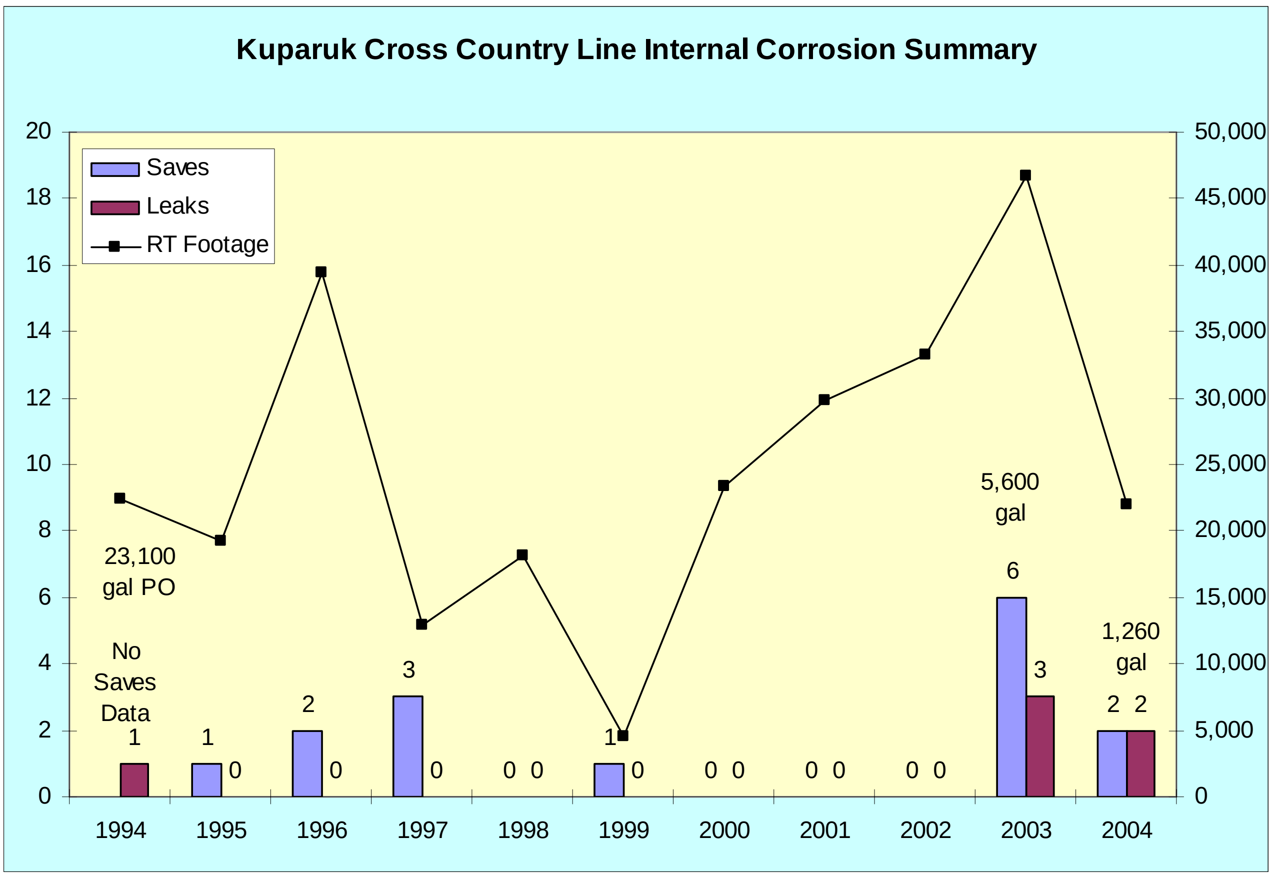

Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2004 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	13,020	21
Water Injection	6,099	10
Total	19,119	31

The 2004 RTR CC line data indicated no new damage trends. The number of lines inspected by RTR decreased from previous years because we completed our initial baseline inspection in 2003 and started our mature recurring program in 2004.

- **Manual RT of CC Lines:**

Service	Number of Lines Inspecte d	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% of Repeat Radiographs with Increases
Three-phase Production	254	2,410	413	10	2
Water Injection	75	387	11	3	27
Total	329	2,797	424	13	3

The 2004 RT CC line data inspection results corroborated the increases seen by monitoring.

- **Manual UT of CC lines:**

Service	Number of Lines Inspected	Number of UT Inspection s	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	103	1,050	678	19	3
Water Injection	36	256	39	2	5
Total	139	1,306	717	21	3

The 2004 UT CC line data indicated no new damage trends.

3.1.d External (Weld-Pack) Program

In 2004 we had several significant accomplishments:

- Completed baseline tangential radiography testing (TRT) survey of all well line weld packs due for inspection, ahead of our scheduled 2005 planned completion date.
- Completed baseline TRT survey of all cross country line weld packs due for inspection.
- Completed our goal of inspecting at least 100 Tarn-style weld packs to ensure this new design is working properly.
- Completed our visual inspection and refurbishment of ten 30" sea water pipeline weld packs.

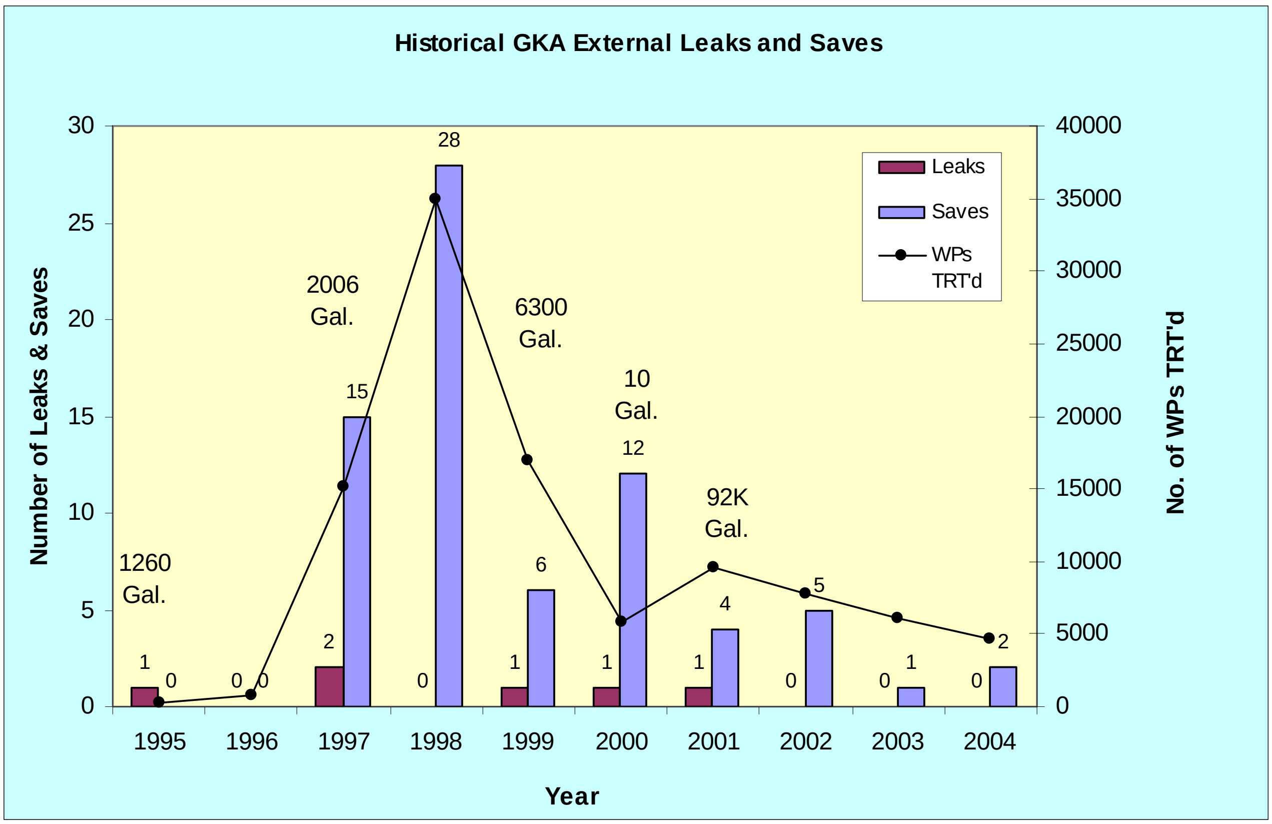

Figure 10. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

Cross-Country Lines (On-Pad)

A total of 672 locations were inspected using tangential radiography (TRT), significantly exceeding the goal of 406 for 2004. Of the 672 locations, none needed repair while 96 locations were refurbished. The baseline inspections on all weld packs due for inspection is now considered complete.

Cross-Country Lines Over Tundra (Off-Pad)

The baseline inspection of these weld-packs was believed complete by year-end 2001. However, in 2003 a walk-down verification survey revealed that several weld pack locations had been missed during the initial layout. In 2004, 3094 CUI locations were inspected, surpassing our goal of inspecting 3020 locations. These numbers include inspections of weld packs that had been inspected previously (recurs), as well as weld packs where documentation of a previous inspection could not be verified Two piping repairs were required as a result of this on-going effort and 354 locations were refurbished. The baseline inspections on all weld packs due for inspection is now considered complete.

Additionally, 111 of the new, Tarn-style weld packs were inspected with TRT to see how they are holding up. All 111 locations had no previous inspection history. 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. This is the first year that we have discovered any water in this style of weld pack; the insulation does not contact the pipe so even though the insulation is wet, it should not cause CUI.

Well Lines

In 2004, 885 well line weld packs were inspected. With this effort, the baseline inspection and documentation of all well line weld packs due for inspection was considered complete. Our stated goal was 1700 weld packs; the reason for the overestimate of the number of weld packs is the uncertainty in the total count of the well line weld packs before inspections commenced. Corrosion was found at 17 (or 1.9%) of the 885 locations. Also during 2004, 38 well line weld pack locations were refurbished.

Table 5: External Weld Pack Inspection Summary for 2004.

Type of Equipment	2004 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines (On-Pad)	406	672	18	2.7	96
Cross-Country Lines Over Tundra (Off-Pad)	3020	3094	71	2.3	354
Well Lines	1700	885	17	1.9	38
Total	**5126**	**4651**	**106**	**2.3** (avg.)	**488**

The number of weld packs TRT'd, number of weld packs corroded, and the percentage of weld packs corroded for the cross-country lines over tundra, cross-country lines on-pad, and well lines are given in Figures 11, 12, and 13.

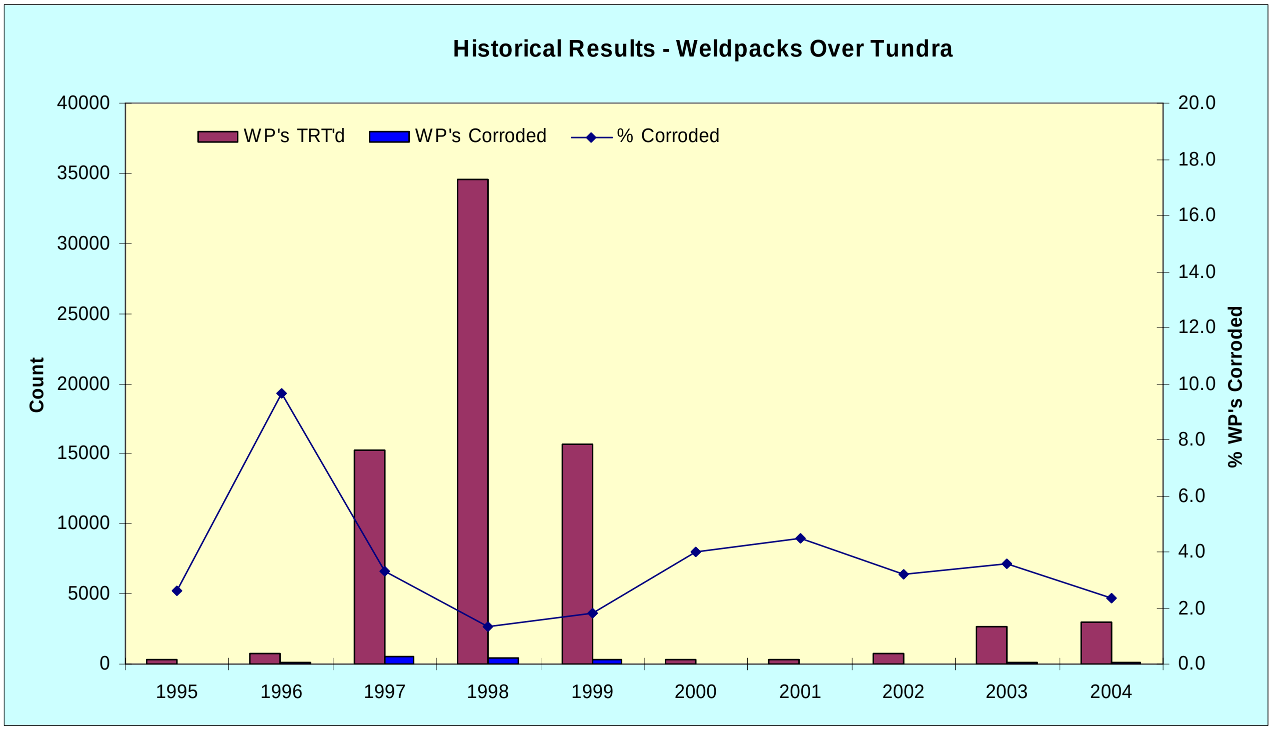

Figure 11. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad).

Figure 11 illustrates the most-complete external corrosion inspection program of the three external corrosion programs. 2002, 2003, and 2004 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

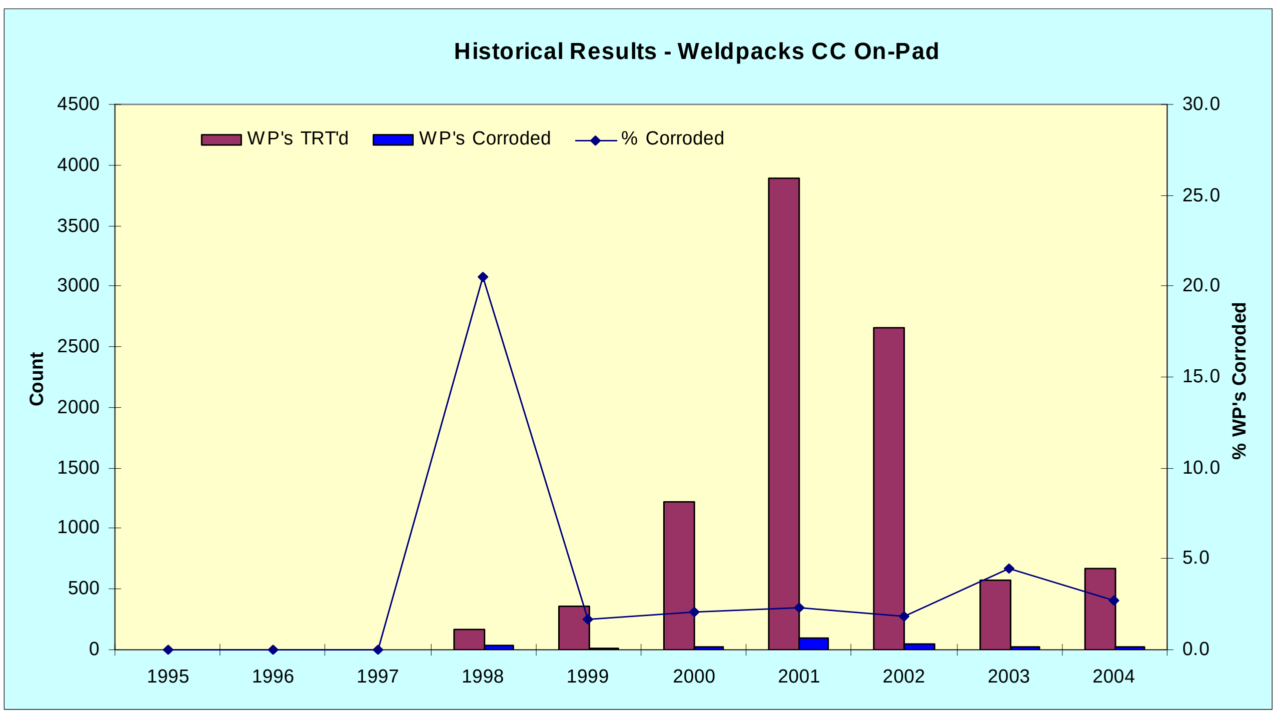

Figure 12. Summary of Weld Packs on Cross-Country Lines on Pads.

Figures 12 and 13 depict the results of the major focus of the external weld pack inspection program in 2004. The cross-country program and the well line weld pack program met milestones in 2004 by completing all of the baseline TRT inspections of all weld packs in their respective areas.

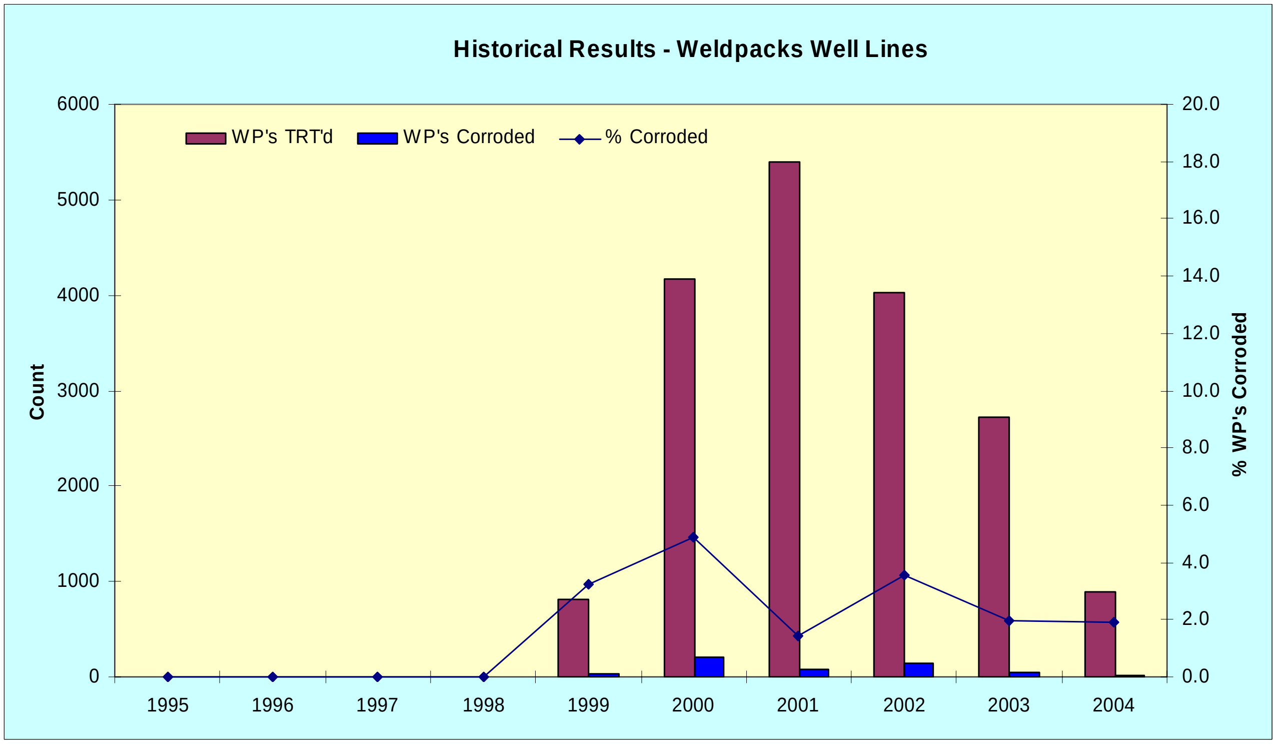

Figure 13. Summary of Weld Packs on Well Lines.

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 program was expanded later in 2002 to include weld packs on drillsite 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. Corrosion of carbon steel is minimized in alkaline conditions. 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 verified with an indicator dye the pH probe results.

TRT inspections were proposed for all buffer spike locations in 2004. These follow-up inspections were not conducted due to priorities elsewhere in the field to complete the baseline weld pack inspection before year-end. The TRT survey has been scheduled for 2005.

Monitoring of the ER probes at DS 1E indicated low, but not zero, corrosion rates.

3.1.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 3.2.e.

In 2004 we had several significant accomplishments:

- Visually inspected and cleaned all debris from all cased below grade pipe locations.
- Completed our specialty inspection (TWI) scope of work.
- Excavated, inspected, refurbished and repaired (as required) nine cased below grade pipe locations.
- Continued to work with TWI by testing a focused ultrasonic inspection method.

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

CPAI has 764 locations (includes priority 1, priority 2, priority 3, and Alpine lines) of below grade piping located in the GKA. Of these locations, one is contained in an utilidor. The remaining locations 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.

Cased Lines

<u>Inspection Status:</u>
The annual visual survey of all the cased lines was conducted in 2004. 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 the below-grade lines, 123 locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. All 123 locations were remediated in 2004.

3.1.e (2) Results of Specialty Testing

<u>Inspection Status:</u>
In 2004, we completed TWI inspections on 63 priority one locations. This was the second year of our recurring inspection program where each priority one pipe will be inspected at a maximum ten-year interval.

In 2004 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.

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Results and Remedial Action:

Tables 6 and show the results of the specialty testing performed by TWI,

Table 6. Results from the TWI inspections by service.

Service	Number of Cased Pipes 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	23	1	16	5	1	0
Other	40	12	11	15	2	0
Total	63	13	27	20	3	0

The 2004 TWI data indicated no new damage trends.

3.1.e (3) Results of Crossing Digs

Nine cased pipes were excavated in 2004:

- One of the nine pipes had a repair recommendation issued because it was found to be derated because of CUI damage. The location was repaired with a pressure containing sleeve.
- Eight of the nine pipes excavated and inspected did not require de-rating, repair, or replacement because only minor or no corrosion damage was found.

For all nine cased pipes that were excavated in 2004, 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 2004, 12 floors with riser piping supports were installed in well houses at Drill Sites 1L, 2C, 2F, 2T, 2V, and 2W. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2004, 24 heat tubes were planned to be installed at Drill Sites 1C, 1E, 1L, 2L, 2N, 2W, 3A, 3F, 3N, and 3R. However, the heat tubes were delayed in manufacturing by the vendor and were installed in March 2005. 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 2004, 16 newly drilled wells at Kuparuk were installed with insulated conductors; of these, 15 had heat tubes installed and one new well was not hooked up.
- In 2004, three newly drilled wells had heat tubes and conductor-mounted steel well house floors installed.
- In 2004, two existing producers converted to water injection wells were upgraded to include heat tubes and steel conductor-supported well house floors.

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), Kuparuk is reviewing existing pipelines to evaluate the need for secondary mode vibration dampers. We are also revising the CPAI criteria and specifications to ensure that both primary and secondary mode WIV are considered.

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

- Well 1Y-02 water injection well line leaked in July because of erosion. The erosion was caused by an obstructed straightening vane which forced produced water to flow around the vane pack rather than through it as designed. The subsequent flow impingement on the pipe wall eventually caused a pinhole leak. The spill volume was less than one gallon which was contained by the well house floor and, as such, it was determined not to be an ADEC reportable spill. No fluids contacted the tundra or the gravel pad. As a result of this leak the vane pack areas on all other high velocity water lines in the GKA were inspected. One other damaged location was found and remediated. In addition, this area will be inspected on all future well line interval inspection surveys.

- Drillsite 3R test separator bypass line leaked in October because of internal deadleg corrosion. The spill volume was less than one gallon which was contained on the gravel pad and, as such, it was determined not to be an ADEC reportable spill. As a result of this leak all similar deadlegs on all other drillsites were inspected. No damage requiring a repair recommendation was found. As a result of our 2003 inspection year, deadlegs on cross country lines were made a high inspection priority. Over-tundra deadlegs were our highest priority due to the environmental risk. The inspection of all over-tundra deadlegs was completed in 2004. On-pad deadlegs are scheduled for inspection in 2005.

- Drillsite 3R water injection line leaked in a non-piggable section of the line between the pig receiver and the well injection header. The leak occurred in January and was caused by microbiologically induced corrosion (MIC). The line had seen both produced water injection and sea water injection; however it was on sea water injection at the time of the leak. The released volume was estimated to be 1,260 gallons, but because the material was sea water released to a sea water environment, it was not an ADEC reportable spill. As a result of this leak the WI supply line to 3R (piggable), the rest of the non-piggable line and all similar lines at all other drillsites were inspected. No repairs and very little damage were found during these inspections.

- No leaks were caused by external corrosion in 2004.

- The eight-inch diameter gas lift pipeline running between CPF3 and DS3I experienced a failure at a pipeline girth weld at ¼ span location (one-quarter of the distance from one support to another support) in December. Aside from insulation and jacketing debris, the area was clean with no liquid spill to the tundra. Subsequent field investigation of this pipeline revealed a second girth weld failure. The failure has been attributed to secondary mode wind-induced vibration (WIV).

  Of the 163 welds inspected with phased array UT, only one other crack was found – also on the 8" line at a ¼ span location. No internal or external corrosion was found on the lines during these or previous inspections. Repairs were completed in late January 2005, and the lines were returned to service on 2/3/05.

  The failed pipe section and the other cracked location were sent to the ConocoPhillips Failure Analysis Lab in Bartlesville for evaluation. The evaluation determined that the crack was caused by high-cycle fatigue. No signs of brittle fracture, over-pressure, or impact were present. The welds were of high quality and exhibited excellent toughness.

  The tuned vibration absorbers on the DS-3I/3M gas lift line were installed in March, 2005.

Currently, work is underway to expand the WIV model to better understand when and how secondary modes of WIV can occur, and to develop more robust predictive tools so that potential recurrence of such a failure can be prevented. Once these tools are in place, other pipeline segments will be evaluated for susceptibility to similar WIV fatigue failure and mitigating actions taken as appropriate.

- No leaks were caused by subsidence in 2004.

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 2005 Forecast

3.2.a Monitoring & Mitigation

- Test four additional inhibitor formulations.

- Evaluate the biocide program changes to the mixed water systems because of the monitoring and inspection data trends.

- Consider internal corrosion inhibition for the mixed water systems.

3.2.b Well Line Inspection

Our recurring inspection program will continue in 2005. No in-service line will go longer than 10 years without an inspection.

3.2.c Cross-Country Line Inspection

Our recurring inspection program will continue in 2005. No in-service line will go longer than 10 years without an inspection.

3.2.d External (Weld-Pack) Program

Inspect all 86 buffer spike locations installed in 2002. Inspect for corrosion using TRT at 3, 6, and 9 o'clock positions. Measure the pH in the buffered weld packs and install ER probes in non-buffered weld packs.

Cross-country lines over tundra:

- Inspect approximately 4200 cross-country line weld packs over tundra as part of our recurring inspection program.
- 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 Densotape system.

Cross-country lines on-pad:
Inspect approximately 50 cross-country line weld packs on-pad as part of our recurring inspection program.

Well lines:
Inspect approximately 1500 well line weld packs as part of our recurring inspection program.

3.2.e Below Grade Piping Program

- Continue our 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.

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

- Excavate, inspect, refurbish, and repair (as necessary) five-to-nine 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.

4.0 Program Status Summary - WNS

4.1 Year 2004 Overview

4.1.a WNS Monitoring & Mitigation

Average general and pitting coupon corrosion rate data for Year 2004 are presented in Tables 4.1 and 4.2.

Table 4.1. 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	1	0.5	1	100
Seawater Cross-Country Lines	1	0.4	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	31	0.1	31	100
Seawater Injection Well Flow Lines	13	0.1	13	100

Table 4.2. 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	1	1	1	100
Seawater Cross-Country Lines	1	4	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	31	0.6	31	100
Seawater Injection Well Flow Lines	13	0.6	13	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.

4.1.b Cross-Country Line Inspection

None performed.

4.1.d External (Weld-Pack) Program

None 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. These locations are cased lines at road or pad crossings. There are an additional 15 crossings, located at CPF2 that are associated with the WNS, but included in the GKA section of this report.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2004. 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, zero locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing.

4.1.e (2) Results of Specialty Testing

No specialty testing was performed in the WNS in 2004.

4.1.e (3) Results of Crossing Digs

None occurred.

4.1.f Other Structural Concerns

Subsidence:

- No concerns identified.
- In 2004, 15 newly drilled wells at Alpine were installed with insulated conductors; of these, 15 had heat tubes installed.

Wind-Induced Vibration:

No problems identified in 2004.

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

- No leaks were caused by external corrosion in 2004.
- No leaks were caused by wind-induced vibration in 2004.
- No leaks were caused by internal corrosion in 2004.
- No structural or subsidence concerns were identified in 2004.

4.2 Year 2005 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

Inspect over 2000 ft of three-phase production lines.

4.2.d External (Weld-Pack) Program

Cross-country lines over tundra:
Complete baseline TRT inspections on the remaining 200 possible CUI locations to verify the new weld pack design is working as anticipated.

Cross-country lines on pad:
Complete baseline TRT inspections on the remaining 200 possible CUI locations to verify the new weld pack design is working as anticipated.

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

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.