Greater Kuparuk Area (GKA)
Alpine Field
Corrosion Programs Overview

April 1, 2004

Commitment to Corrosion Monitoring
4th 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 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 100,000 BOPD. The Alpine development produces from a pad area of 97 acres, and has two Drill Sites; additional satellite drill sites are planned. The corrosion management system used at Kuparuk is being applied to the Alpine field.

The purpose of this 4th 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.

Because of the large amount of data from corrosion monitoring and corrosion inspections, corrosion coupon exception data and external corrosion inspection and leak/save historical results are contained in Appendix A.

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

2.0 SIGNIFICANT ENHANCEMENTS TO CORROSION PROGRAMS

- Completed an initial Turbulent Flow Survey (TFS) on cross-country three-phase oil lines. This program is designed to schedule fittings, such as elbows and tees, for recurring inspection based on flow characteristics, which may cause velocity assisted corrosion damage. The TFS supplements our RTR inspection program, which is designed to find internal damage in straight runs of pipe.

- Completed a baseline inspection of all well lines and cross-country lines requiring inspection.

- Wellhead corrosion inhibition design specifications have been finalized and new installations are in progress.

- Enhancements to our Bartlesville corrosion inhibitor lab screening and installation of additional monitoring points have allowed for field-testing of four new corrosion inhibitors in 2003.

3.0 Program Status Summary

3.1 Year 2003 Overview

3.1.a Monitoring & Mitigation

Monitoring Kuparuk:
Average general and pitting coupon corrosion rate data for Year 2003 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	62	0.03	62	100
Seawater Cross-Country Lines	2	3.1	1	50
Mixed Water Injection Cross-Country Lines	22	0.4	22	100
Production Well Flow Lines	451	0.3	446	99
Mixed Water Injection Well Flow Lines	551	0.6	521	95

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	62	4.5	54	87
Seawater Cross-Country Lines	2	3.3	2	100
Mixed Water Injection Cross-Country Lines	22	19	12	55[a]
Production Well Flow Lines	451	1.5	433	96
Mixed Water Injection Well Flow Lines	551	8.9	376	68

Notes:
a See graph and discussion on page 8 of this report.

Monitoring Alpine:
Average general and pitting coupon corrosion rate data for Year 2003 are presented in Tables 3 and 4.

Table 3. 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	100
Seawater Cross-Country Lines	1	0.4	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	29	0.1	29	100
Seawater Injection Well Flow Lines	8	0	8	100

Table 4. 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	1.0	1	100
Seawater Cross-Country Lines	1	0.7	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	29	0.1	29	100
Seawater Injection Well Flow Lines	8	0.1	8	100

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

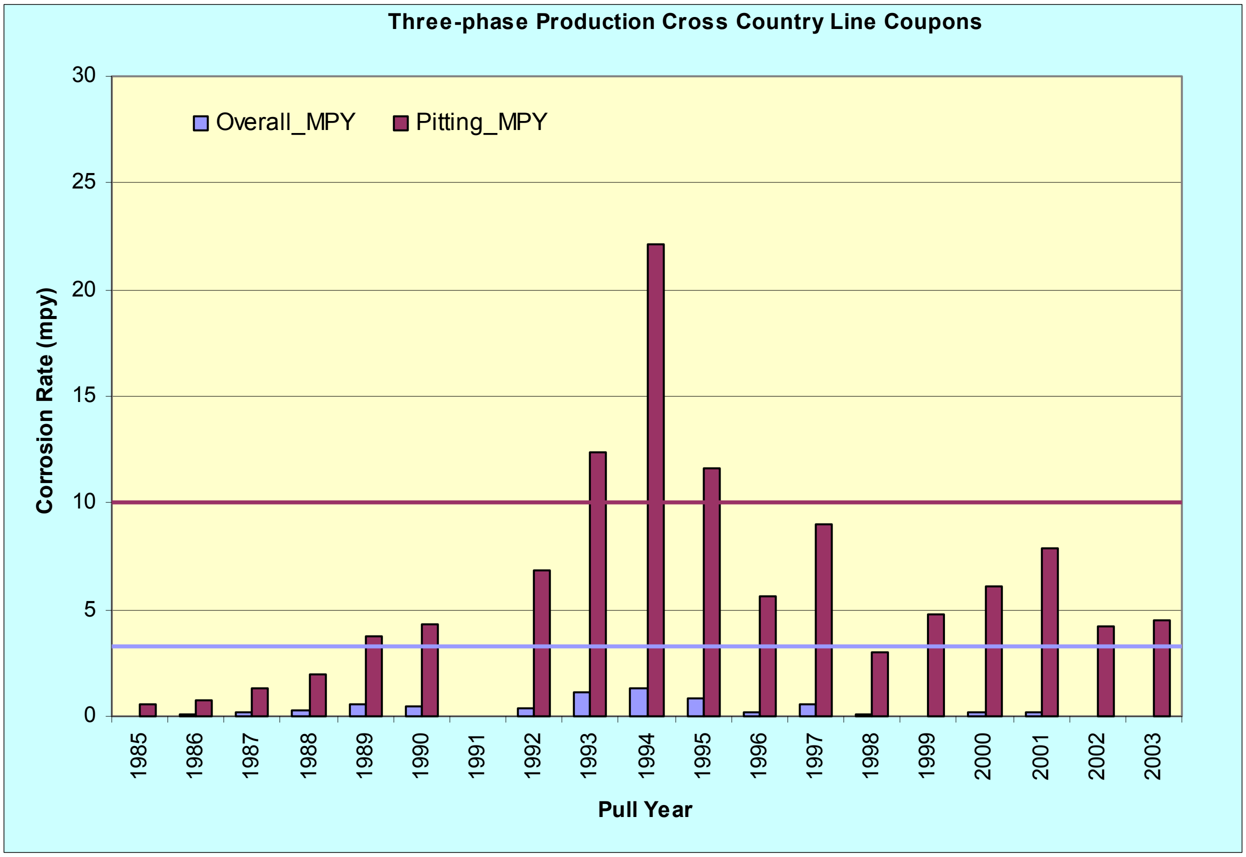

Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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 2003, 584 corrosion-rate monitoring (CRM) inspections were conducted, with five minor increases found (i.e. less than 1% of total CRM inspections resulted in an increase). 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. In 2003, coupon or probe corrosion rates exceeded targets on 17 lines and action was taken on all 17 of these lines. In 2003, inspection results indicated minor corrosion had occurred on five lines; corrosion inhibitor concentrations were increased in all five of these lines. A complete listing of the 22 lines with coupon/probe corrosion rates that exceeded targets or where inspection indicated increased damage, is given Table A1 of Appendix A.

In 2003, the 16-inch CPF3-to-CPF1 Wet Oil Line showed coupon pitting corrosion rates above the threshold of 10 mpy; actual inhibitor concentration was verified and adjusted based on coupon results. Additionally, later in the year this line experienced a lower water cut and the corrosion inhibitor concentration was adjusted.

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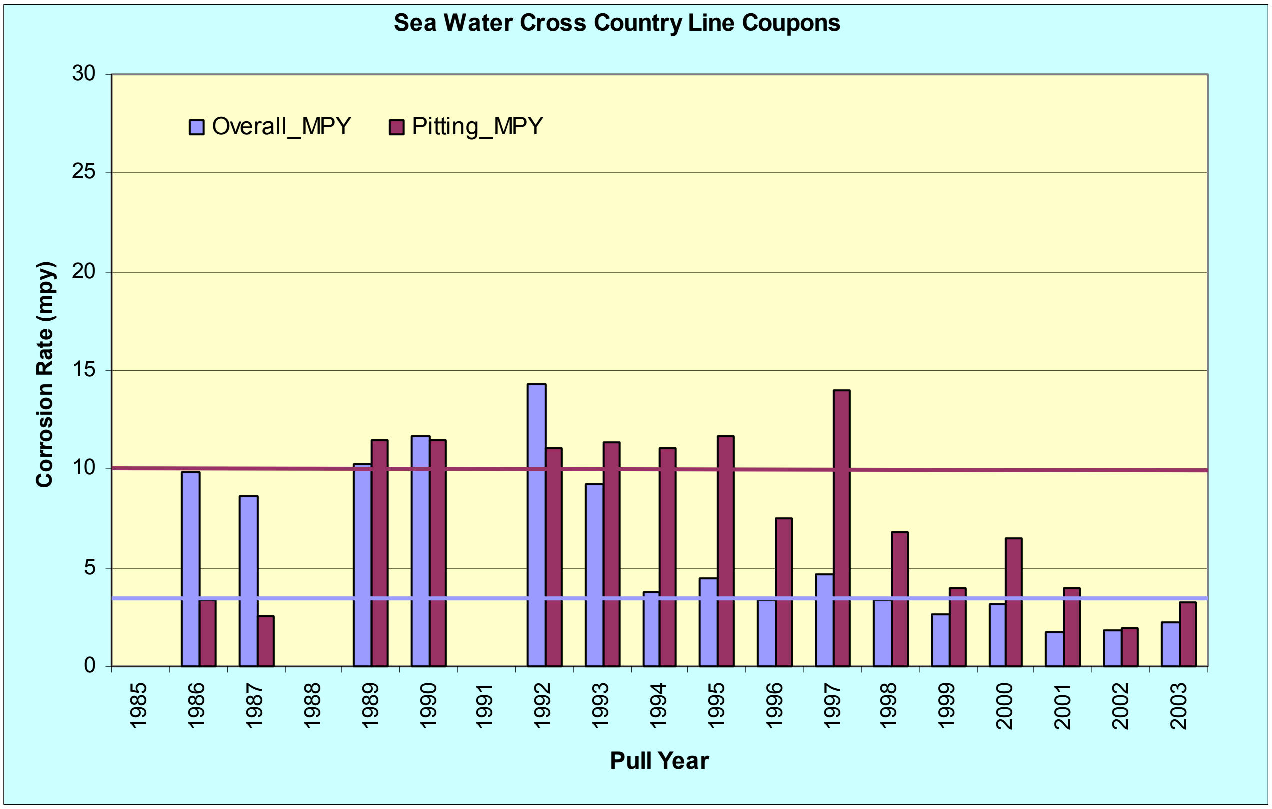

Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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 2003. The coupon location on the 30" STP discharge line showed general corrosion rates above threshold in 2003. This is likely due to short term increased dissolved oxygen levels, the origin of which is under investigation.

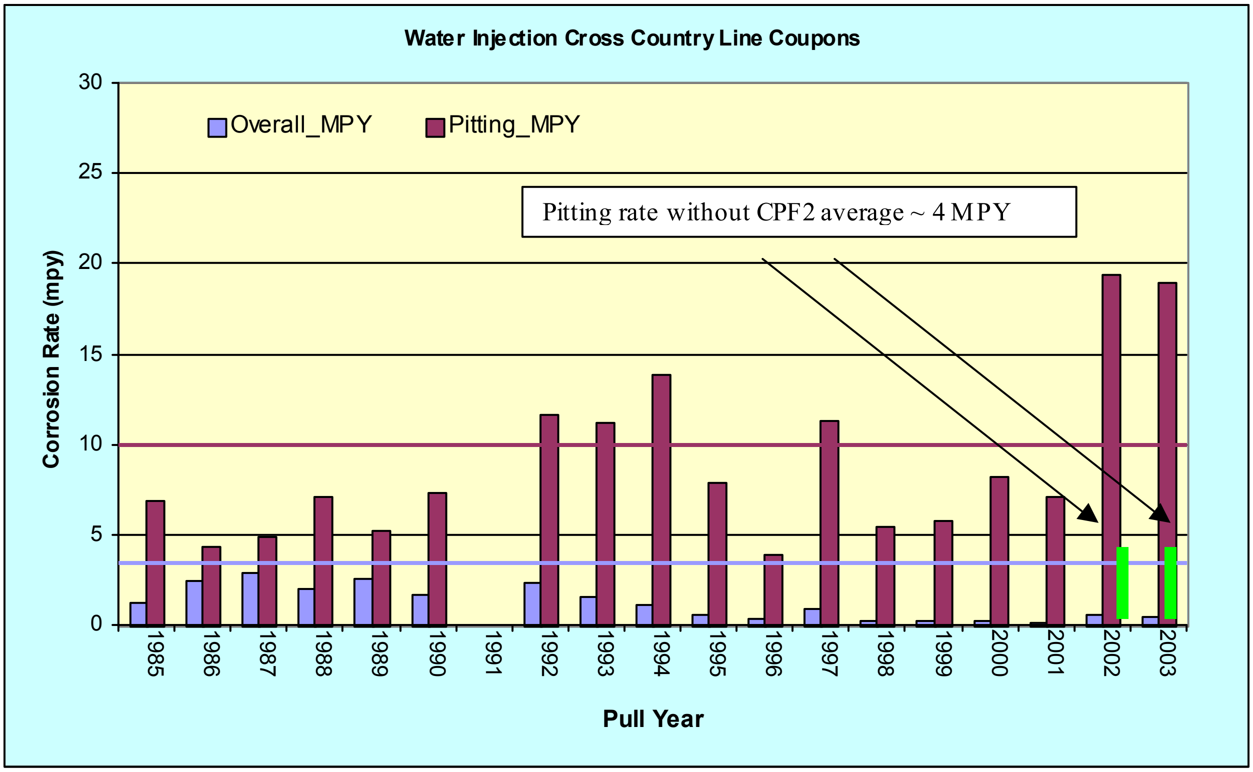

Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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 well under the threshold. Recent inspection data from the CPF2 lines show some damage on three lines. This information, along with coupon results, was used to prioritize 2003 inspection efforts. RTR inspection performed in 2003 included 23,099 feet on 28 cross-country water injection lines. A review of the CPF biocide programs has been conducted and new treatment procedures are in place.

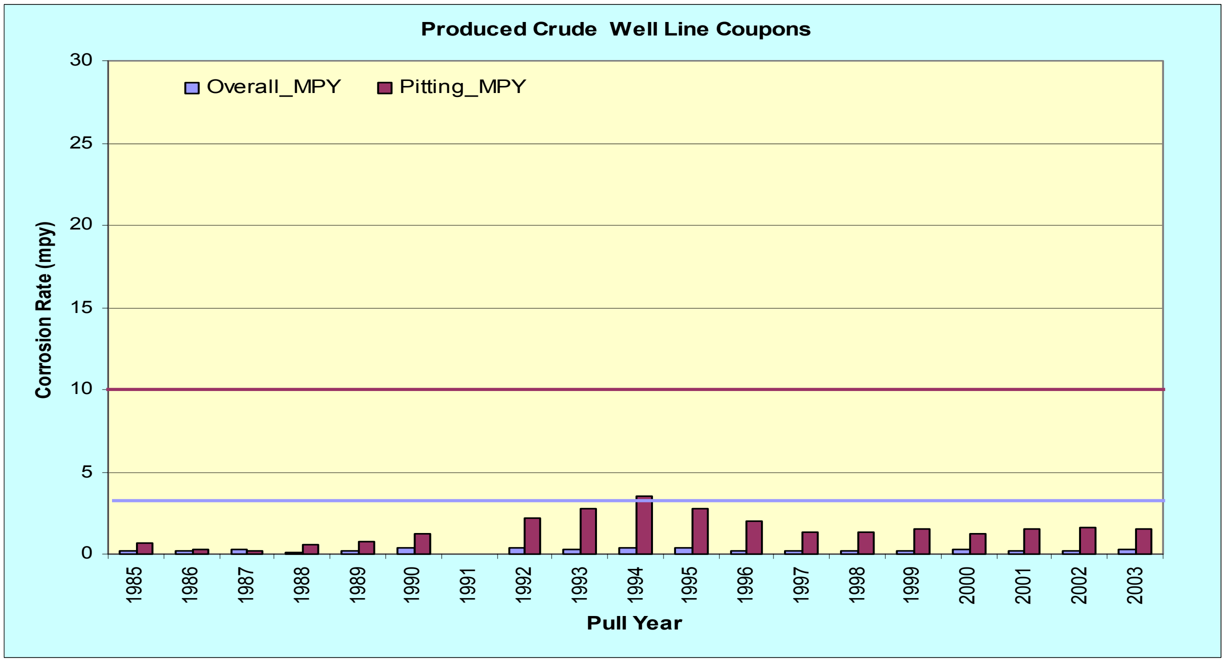

Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

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.

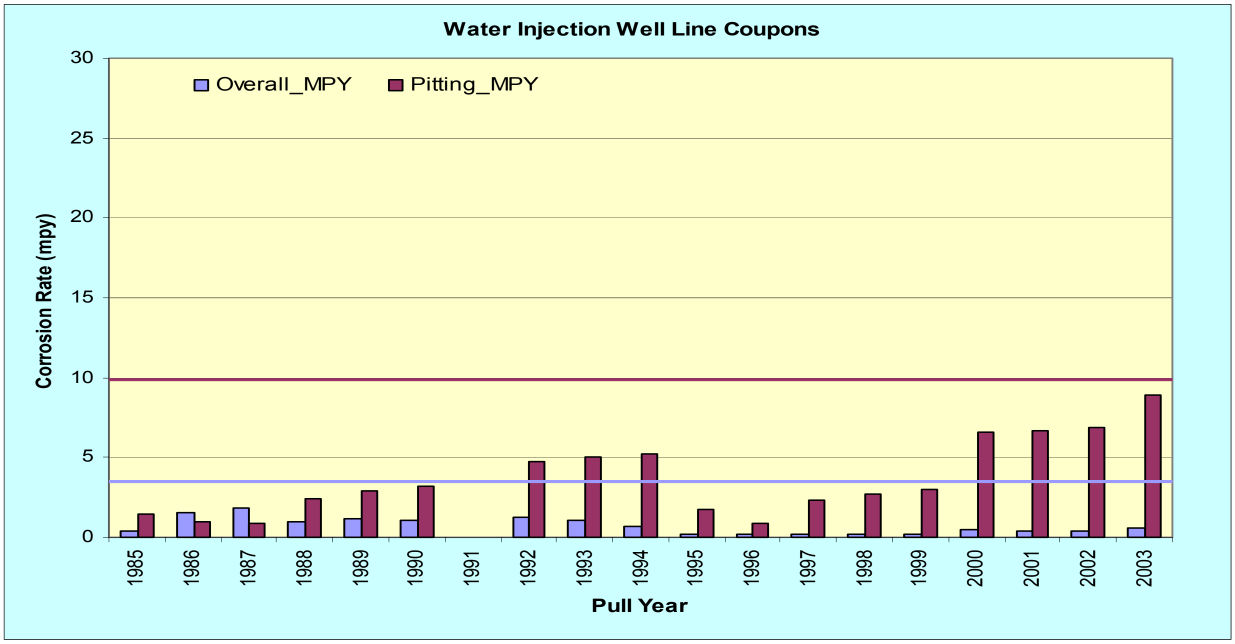

Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

Water Injection Well Flow Lines: There is an increasing trend in the coupon pitting rates. As discussed in section 3.1.b below, the well line inspection data on water injectors show that there are a significant (22) and an increasing number of corrosion related repairs.

Mitigation:

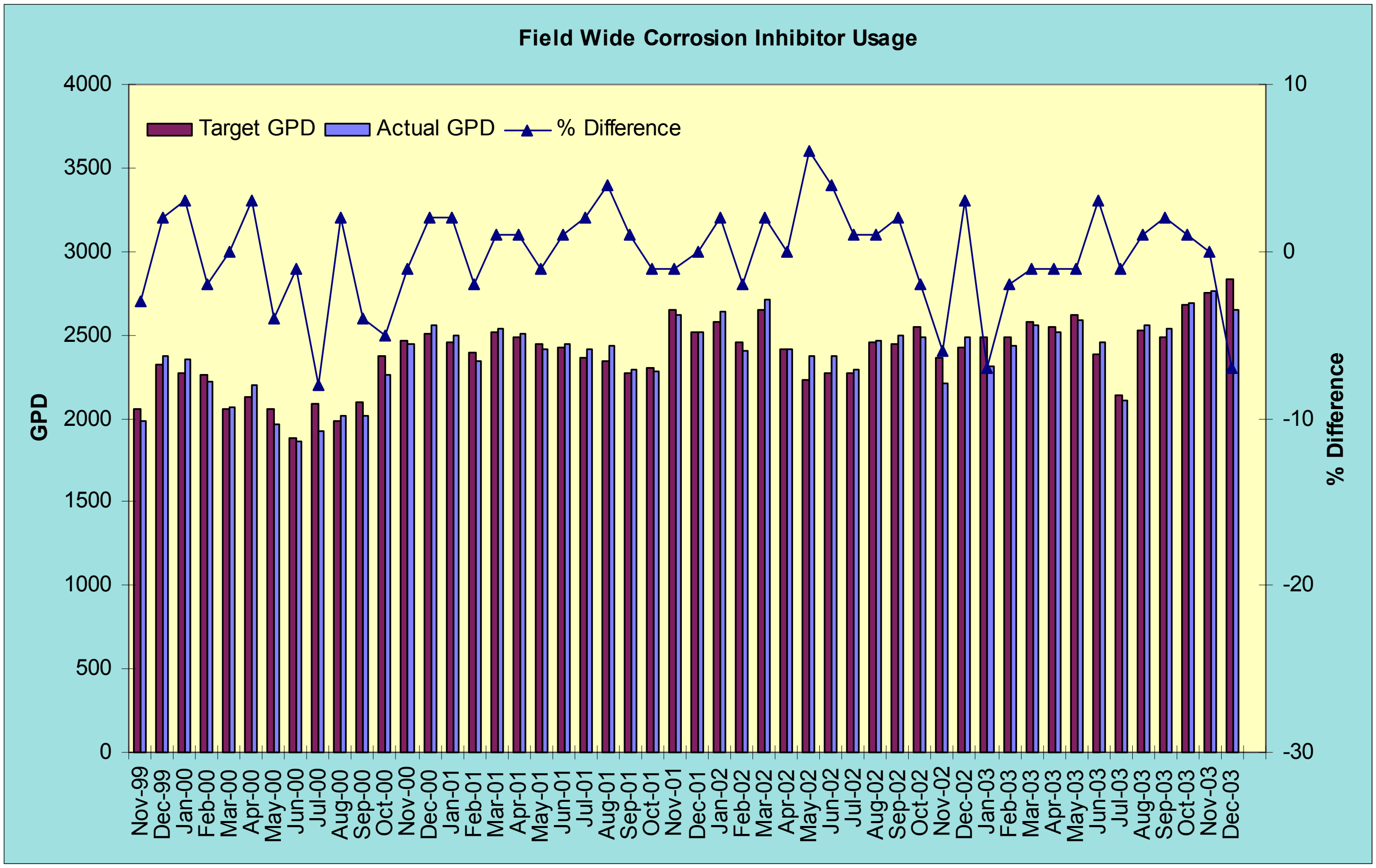

Figure 6. Field-wide Corrosion Inhibitor Use.

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 difference fluctuated around zero percent deviation from the recommended amount of corrosion inhibitor; the average deviation for the year was –1.0%. The larger variation seen in the December 2003 data was caused by the extreme weather that caused delays in routine pump rate checks and refilling of chemical tanks.

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

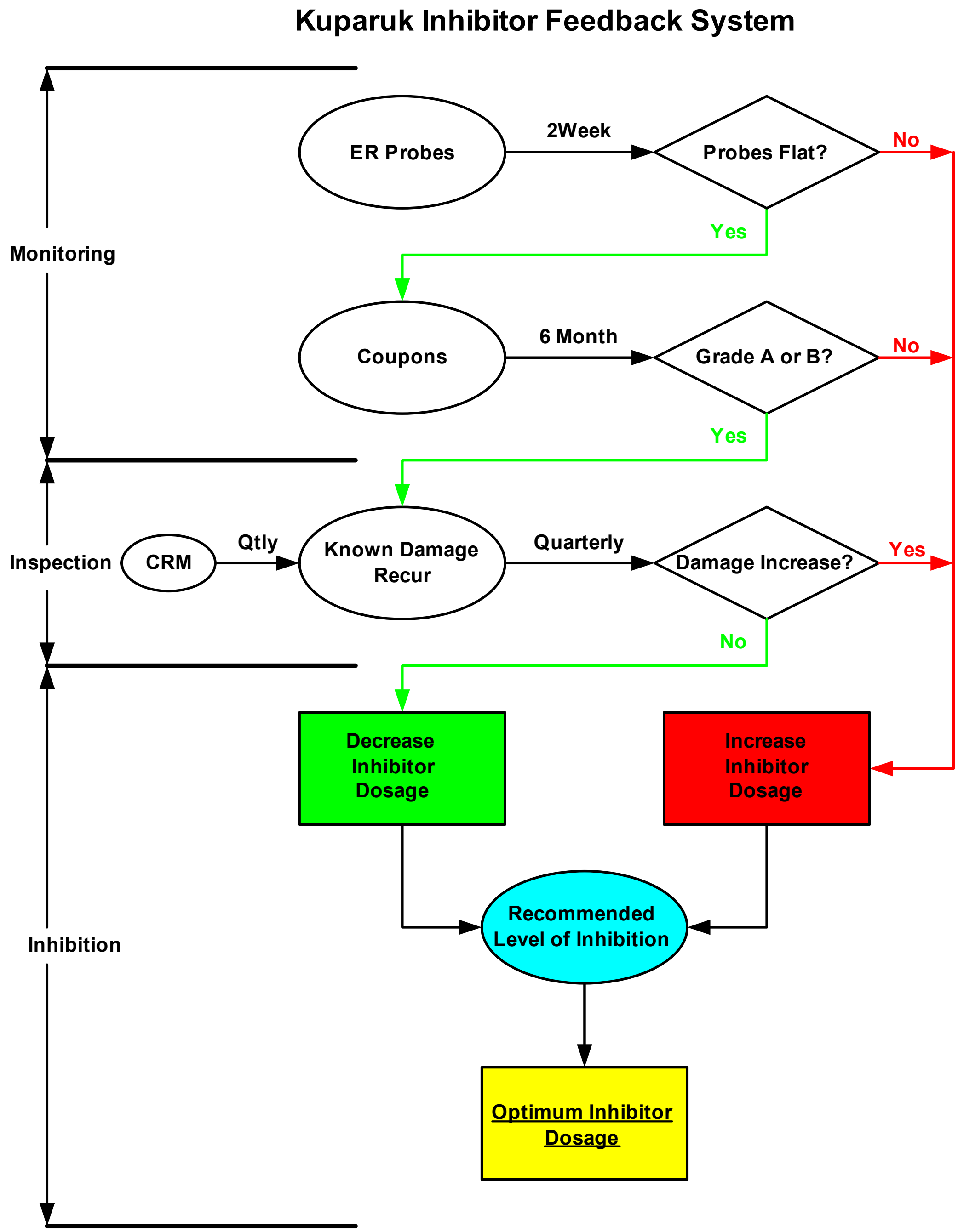

Figure 7. Corrosion Inhibitor Feedback System.

3.1.b Well Line Inspection

As indicated in Figure 8 below, repair recommendations were initiated on 24 lines (22 injection, 2 production) in 2003 because of internal corrosion damage. Repairs typically consist of either installing a sleeve or replacing the de-rated section of line. We met our primary 2003 goal of completing the inspection of all well lines requiring baseline inspection.

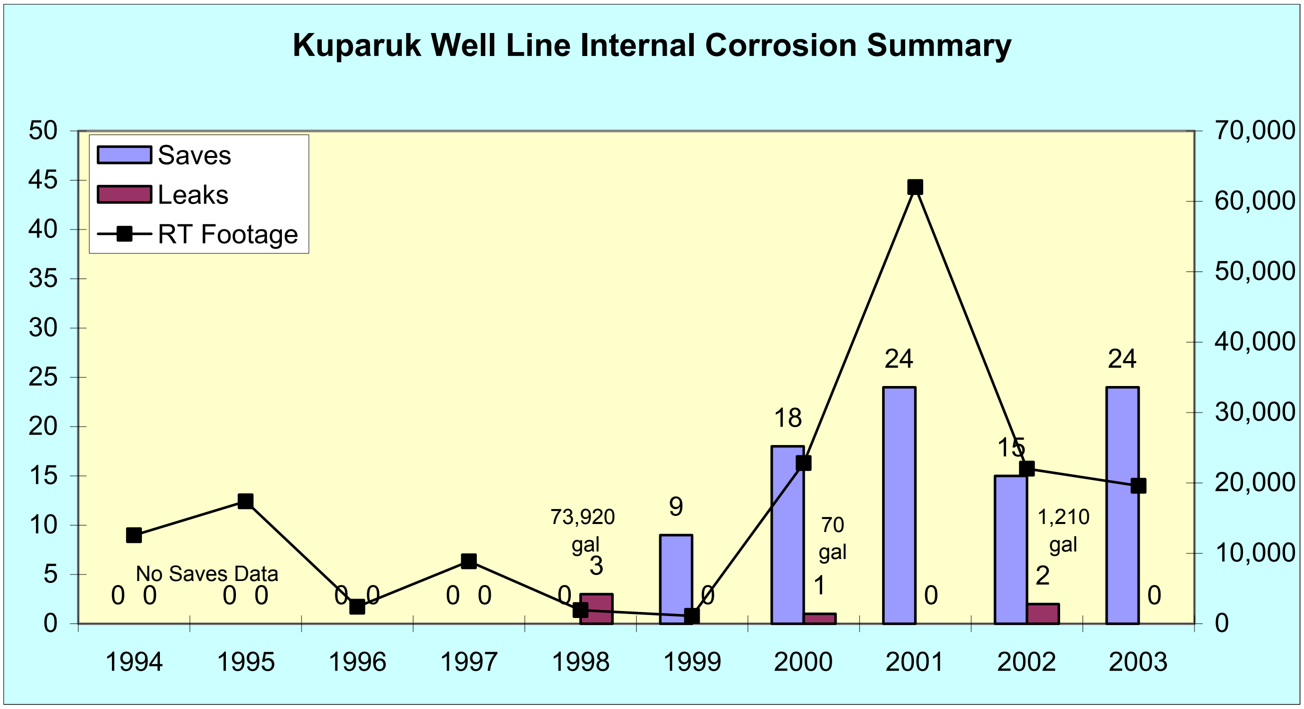

Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2003 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	8,783	104
Water Injection	6,960	76
Total	15,743	180

The 2003 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	344	2,137	856	24	3
Water Injection	208	1,715	334	26	8
Total	552	3852	1,190	50	4

The 2003 manual RT well line data indicated no new damage trends.

• **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	201	1600	1,374	92	7
Water Injection	92	784	553	40	7
Total	493	2,384	1,927	132	7

The 2003 manual UT well line data indicated no new damage trends.

3.1.c Cross-Country Line Inspection

As indicated in Figure 9, nine repair recommendations were initiated on cross-country lines because of internal corrosion damage in 2003. The corrosion mechanisms were deadleg corrosion (five repairs), under deposit corrosion (three repairs) and weld attack on a flowing line (one repair). Because of large increase in repairs we will increase our inspection effort on deadlegs in 2004.

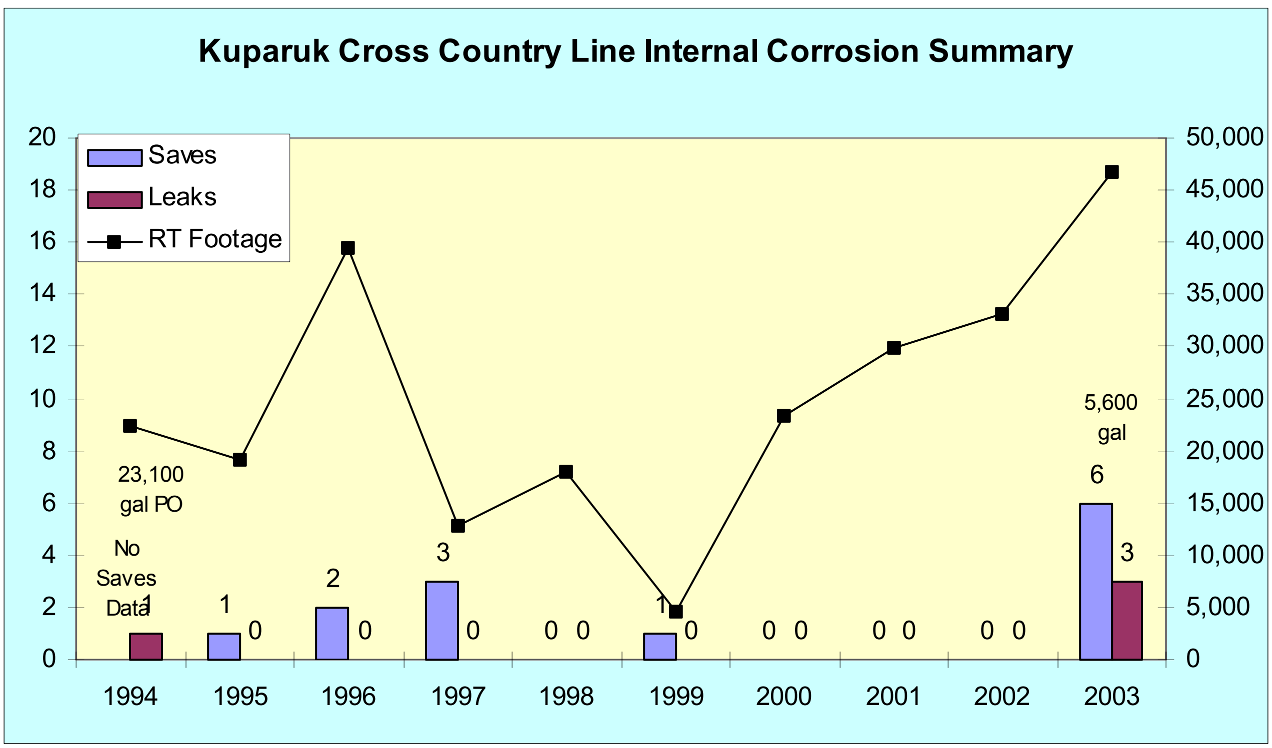

Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2003 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	20,447	31
Water Injection	23,099	28
Total	43,546	59

The 2003 RTR CC line data indicated no new damage trends

- **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	217	2,660	581	10	2
Water Injection	17	563	18	1	6
Total	234	3,223	599	11	2

It should be noted that effective manual RT is limited to those lines water that are less than approximately 10" to 12" outside diameter. The maximum diameter for RT of three-phase production lines depends on the percentage of gas. For water injection service lines that are too large to effectively RT, Kuparuk relies on spot UT. Smart pigging is not an economical option at this time.

- **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	104	2660	789	22	3
Water Injection	30	128	21	8	38
Total	134	2,788	810	30	8

The eight increases on WI lines in 2003 represents a significant jump from previous years. The jump was caused by our increased inspection on one significantly damaged line (2EDCWI). Six of the eight increases were on this line. As a result of our 2003 inspection efforts, 2EDCWI received extensive repairs.

3.1.d External (Weld-Pack) Program

Cross-Country Lines (On-Pad)

In 2003, significant progress was made towards the goal of completing the baseline inspections by the end of 2004. A total of 580 locations were inspected using tangential radiography (TRT), significantly exceeding the goal of 343 for 2003 and placing the overall completion at 96%.

Of the 580 locations inspected in 2003, none of the locations needed repair while 122 locations were refurbished.

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 corrosion-under-insulation (CUI) locations had been missed during the initial layout. In 2003, 2712 CUI locations were inspected. These numbers include inspections of weld packs that had been inspected previously, as well as weld packs where documentation of a previous inspection could not be verified (approximately 1000 locations). No piping repairs were required as a result of this on-going effort and 466 locations were refurbished. Although the goal in 2003 was to inspect 2746 CUI locations, severe weather in mid- to late-December delayed our ATRT inspection work and only 2712 were completed.. During the first four days of 2004, we completed ATRT inspections of 119 CUI locations, bringing the total up to 2831. So, for all intents and purposes, the 2003 goal was surpassed.

Additionally, 100 of the new style weld packs used on the Tarn line were TRT inspected to see how they are holding up. None of the weld packs inspected showed any ingress of water or presence of corrosion, indicating good performance thus far.

Well Lines

During 2003, 2728 well line weld packs were inspected, exceeding the goal of 2500. Corrosion was found at 1.9% of these locations. Also during 2003, 105 well line CUI locations were refurbished.

Table 5: External Weld Pack Inspection Summary for 2003.

Type of Equipment	2003 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines (On-Pad)	343	580	26	4.5	122
Cross-Country Lines Over Tundra (Off-Pad)	2746	2712	97	3.6	466
Well Lines	2500	2728	53	1.9	105
Total	**5589**	**6020**	**176**	**2.92**	**693**

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 10, 11, and 12.

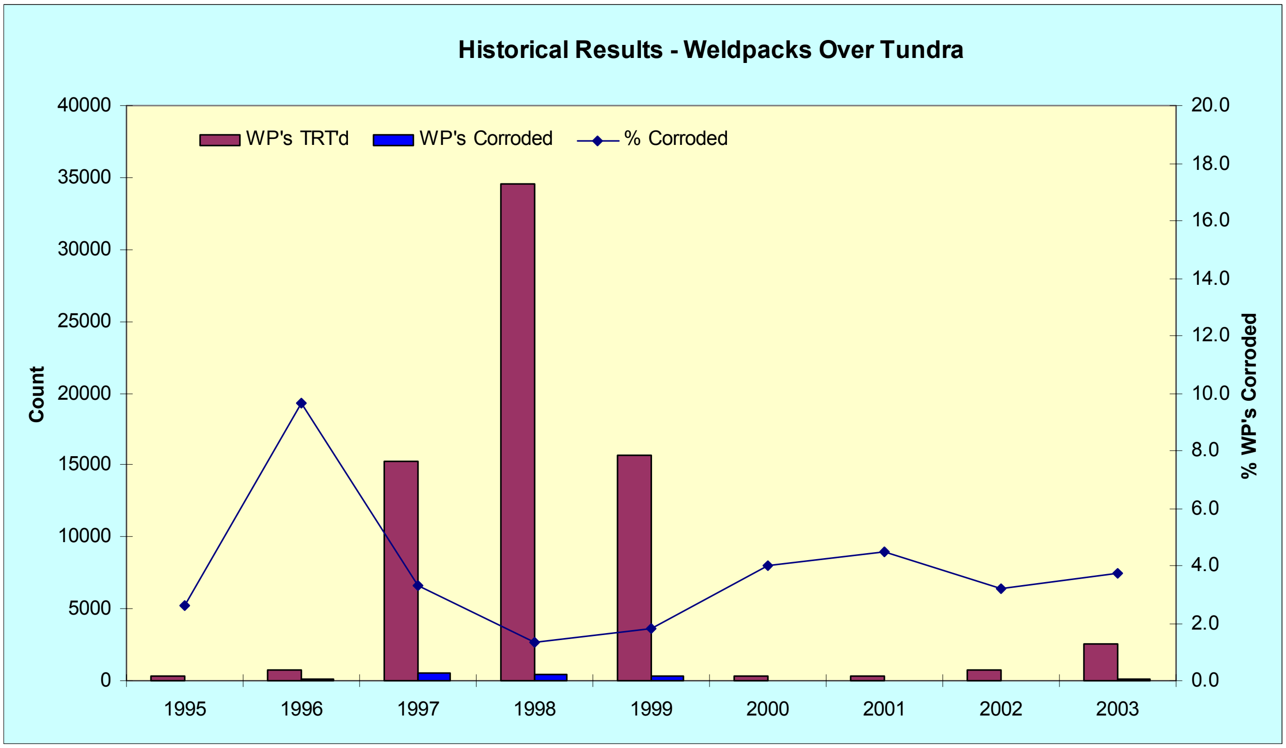

Figure 10. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad).

Figure 10 illustrates the most-complete external corrosion inspection program of the three external corrosion programs. 2002 and 2003 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

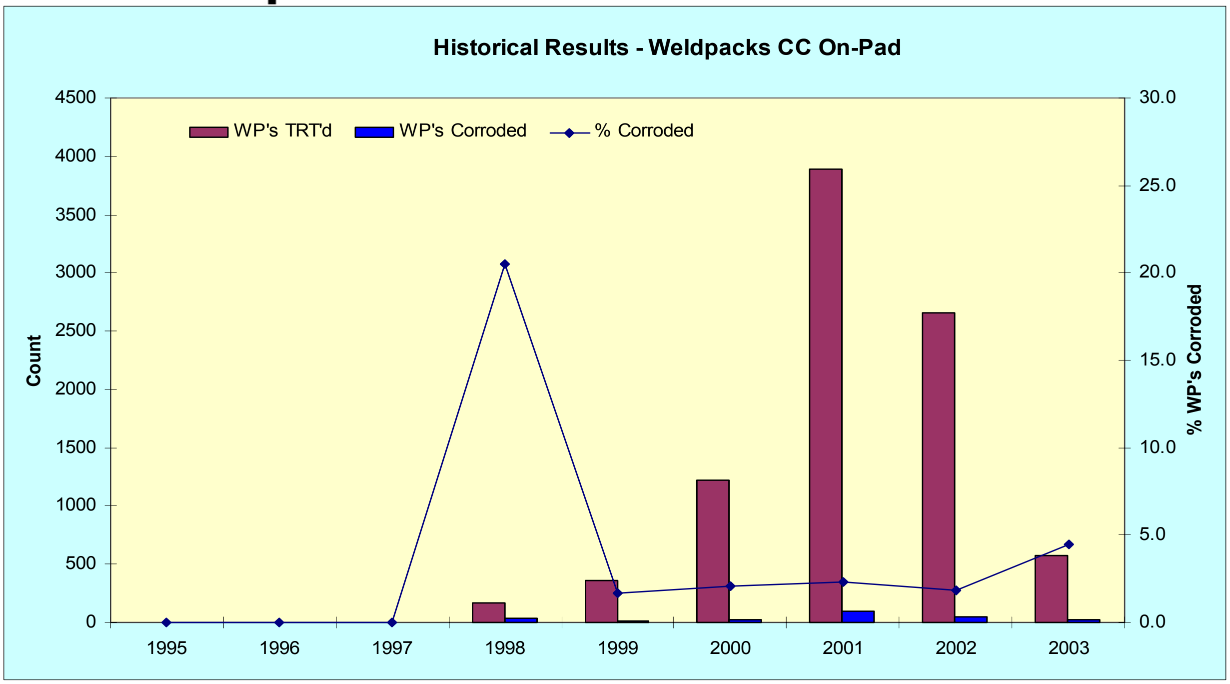

Figure 11. Summary of Weld Packs on Cross-Country Lines on Pads.

Figures 11 and 12 depict the results of the major focus of the external weld pack inspection program in 2003. The cross-country on-pad program is nearing completion and all baseline inspections should be complete by year-end 2004. The well line weld-packs were inspected using a prioritization scheme that examined the oldest, the hottest, and the thinnest-walled lines first. As of year-end 2003, 96% of the cross-country on-pad weld-packs and 91% of the well line weld-packs have received their baseline TRT inspections.

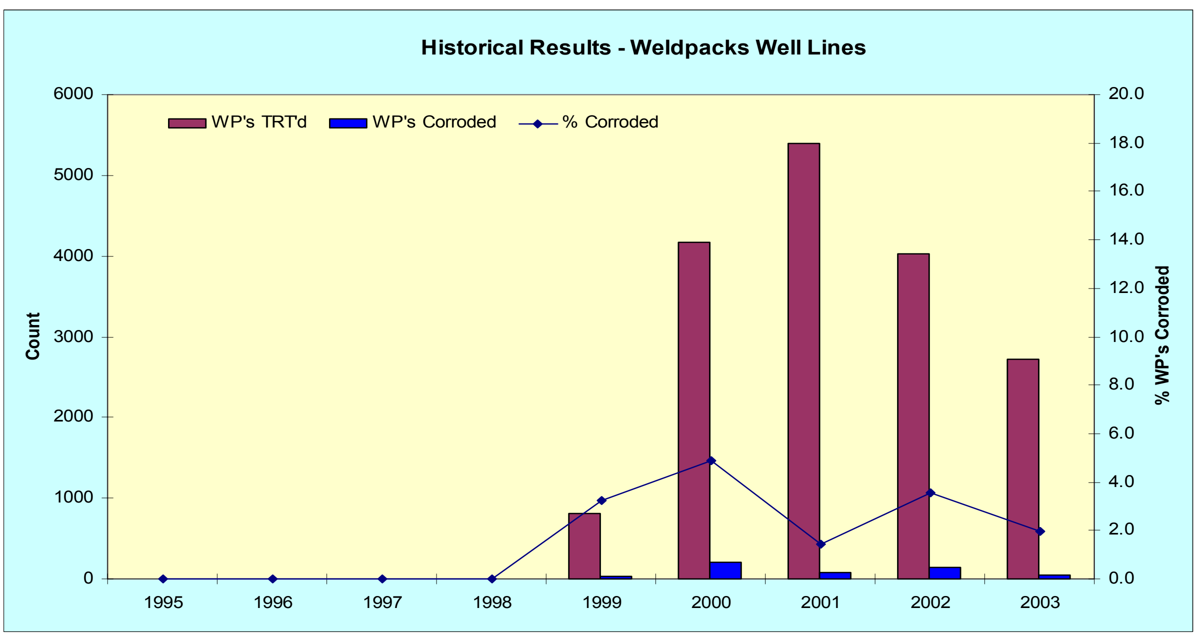

Figure 12. Summary of Weld Packs on Well Lines.

In 2002, a test of “CUI Buffer Spikes” was initiated on 76 locations. 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 increase. The 2003 follow-up inspections showed that the pH did rise in the wet areas of the weld pack. TRT inspection of these areas is scheduled for 2004.

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.

The Alaska Department of Environmental Conservation (ADEC) regulations under 18 AAC 75.080 apply 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 416 locations of below grade (BG) “oil” piping in the GKA and Alpine oil fields. Of these locations, one is contained in an utilidor. The remaining locations are cased lines, the majority of which are either road or caribou crossings. In addition to the “oil” piping, CPAI has 243 significant below grade locations with lines in other services.

Utilidor Line

Inspection Status:
The line in the utilidor (Oily Waste Injection Line, BG ID #286) was inspected in 1999 and again in 2002. The 2002 radiographic inspection showed no change in the damage identified in the 1999 inspection. This line is evaluated for re-inspection every two years.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2003. 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, 45 locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. All 45 locations were remediated in 2003.

3.1.e (2) Results of Specialty Testing

Inspection Status:
In 2003, we completed the PTI/TWI inspections on 82 priority one locations. This was the first year of our recurring inspection program where each priority one pipe will be inspected at a maximum ten-year interval.

Both the long-range ultrasonic system technology from The Welding Institute (TWI) and the electromagnetic wave pulse system from Profile Technologies, Inc. (PTI) were used. Testing with PTI was limited to those lines without a significant risk for internal corrosion. PTI is used to find external electromagnetic anomalies such as external corrosion, but cannot find internal corrosion. The TWI technology was applied to lines with a risk for internal corrosion. TWI was also used to evaluate any positive indications detected by PTI, since PTI finds electromagnetic anomalies and is prone to finding false positives.

In addition to using TWI's long-range ultrasonic system technology, CPAI evaluated the torsional (guided) wave inspection technique from B&E. CPAI has determined that the torsional wave technique offered by B&E is not superior to the TWI long-range ultrasonic system and CPAI will not use the torsional wave technique unless further improvements are made.

Results and Remedial Action:

Tables 6 and 7 show the results of the specialty testing performed by PTI and TWI, respectively.

Table 6. Results from the PTI inspections by service.

Service	Number of Cased Pipes Inspected	Inconclusive Results (I)	Number without any Electromagnetic Anomalies (N)	Number of Electromagnetic Anomalies (E)	Number of Significant Electromagnetic Anomalies (S)
Oil[a]	30	0	18	11	1
Other	3	0	1	2	0
Total	33	0	19	13[b]	1[b]

Notes:

(a) Oil service is defined as natural gas liquids (NGL), oil sales, three-phase production, two-phase production (wet oil), Produced Water, and Mixed Water.

(b) All "S" and "E" locations were inspected with TWI. The two "E" pipes remaining from 2002 were inspected with TWI in 2003.

Table 7. 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[c]	62	8	28	13	8	5
Other	04	0	1	2	0	1
Total	66	8[d]	29	15[e]	8[f]	6[g]

Notes:

(c) Oil service is defined as natural gas liquids, oil sales, three-phase production, two-phase production (wet oil), Produced Water, and Mixed Water.

(d) "I" locations are prioritized based on other local and line concerns, and added as appropriate to the excavation/inspection list.

(e) "L" locations are re-inspected (with PTI and/or TWI) every two years.

(f) "M" locations are added to the excavation candidate list and evaluated for excavation, further inspection, refurbishment and repair during subsequent excavation seasons. The eight "M" pipes found by TWI in 2003 are listed here:

- -ID #71 (14" 1CPO)
- -ID #78 (14" 1EPO)
- -ID #83 (14" 1EPO)
- -ID #231 (24" 1YPO)
- -ID #327 (14" 2DPO)
- -ID #438 (8" 2FWI)
- -ID #458 (12" 2FPO)
- -ID #533 (8" 3R SW Supply line)

(g) "S" locations are added to the excavation candidate list and evaluated for excavation, further inspection, refurbishment and repair during subsequent excavation seasons. The six "S" locations found by TWI in 2003 are listed here:

- -ID #15 (6" 1A Test Line) abandoned in '03 due to extensive internal under deposit corrosion.

-ID #314 (12" 2BPO) was excavated in 2003, scheduled for replacement in 2004.
-ID #331 (12" 2DPO) will probably be excavated in 2004.
-ID #159 (18" 1YRPO) will not be excavated in 2004 because of its large corrosion allowance.
-ID #165 (6" 1A Test) abandoned in '03 due to extensive internal under deposit corrosion.
-ID #573 (30" SW Supply line) will probably not be excavated in 2004 due to a low internal and external corrosion risk factor and the possibility this line will be smart pigged in the near future.

3.1.e (3) Results of Crossing Digs

Eight cased pipes were excavated in 2003:

- Two of the eight pipes had repair recommendations issued. One pipe was found to be derated below the design pressure of the pipe and it was replaced in 2003. The other is not derated yet and is scheduled for replacement in 2004.
- Six of the eight pipes excavated and inspected did not require de-rating, repair, or replacement. Only minor damage was found.

For all eight cased pipes that were excavated in 2003, 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 2003, 22 floors with riser piping supports were installed in well houses at Drill Sites 1D, 2A, 2K, 2T, and 3O. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2003, 65 heat tubes were installed at Drill Sites 1C, 1D, 3F, 3G, 3J, and 3Q. 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 2003, ten new wells brought on line had heat tubes and floors with permanent pipe supports installed. In 2003, 43 new wells were installed with insulated conductors.
- In 2003, all 13 existing producers converted to water injection wells were upgraded to include heat tubes and conductor-supported floors.

Wind-Induced Vibration:

- As a result of the Drill Site (DS) 2X 8" MI line failure that occurred in December 2001, Kuparuk performed a field-wide evaluation of the need for vibration dampeners on existing pipelines. The line that failed is oriented one-degree outside the design wind direction envelope designated for Kuparuk in 1991. Based on this field-wide evaluation, tuned vibration absorbers (TVA's) have been installed on all the lines identified with pipeline sections that did not have WIV mitigation (2B, 2U, and 3G) and that fall within the design wind-direction envelope, with the exception of three lines at DS 3N. The three lines at DS 3N are on the periphery of the design wind-direction envelope and were selected for monitoring to better understand variables associated with WIV and to further validate the orientation of design wind-direction envelope. All hardware has been installed and all equipment has been functionally checked out. Final programming of the data logger will be completed this spring. Once completed, data such as line movement frequency, line movement amplitude, wind speed, and wind direction will be collected for approximately 18 months. The data will them be used to develop a better understanding of the effects of the variables on the propensity for WIV on lines oriented on the periphery of the current design wind-direction envelope.
- An annual inspection of all pipeline vibration dampener (PVD) locations is conducted to verify integrity of the PVD's. This information is sent to the facilities for corrective action. Typically, corrective action consists of replacement of worn elastomers and reinstallation of PVD weights.

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

- 3GFBWI cross country sea water injection line leaked because of internal weld area attack in March of 2003 - The eight-inch line providing sea water to drill sites 3B, 3F and 3G failed because of internal corrosion in a circumferential weld. Total spill volume was 5,600 gallons of sea water on the tundra. Similar damage was found on several other welds and the line was de-inventoried and abandoned in place. None of the other 27 water injection lines inspected by RTR in 2003 had this type of damage.

- 3HAMIPO cross county produced crude oil line leaked because of internal deadleg corrosion in July of 2003 - The two-inch drain line branch off the main line bringing crude oil from drill sites 3I, 3M, 3A and 3H failed because of stagnant flow conditions. The spill volume was less than one gallon on the CPF3 gravel pad. Similar damage has been found on several deadlegs at Kuparuk. There is an ongoing effort to inspect all similar deadlegs.

- 2TABASCOPO cross county produced crude oil line leaked because of internal deadleg corrosion in November of 2003 – The 10" line bringing crude oil from DS 2Tabasco failed because of stagnant flow conditions. The spill volume was less than one gallon on the 2T gravel pad. Similar damage has been found on several deadlegs at Kuparuk. There is an ongoing effort to inspect all similar deadlegs.

- No leaks were caused by external corrosion in 2003.

- No leaks were caused by wind-induced vibration in 2003.

- No leaks were caused by subsidence in 2003.

- On May 24th, 2003 workers driving on the Meltwater/Tarn access road noticed a failure of the Meltwater/Tarn pipeline supports. Investigation revealed that the fillet welds connecting the vertical support member (VSM) cap plate to the horizontal support member (HSM) on 13 pipeline supports (VSM/HSM 997 thru 1025 in the Miluveach River drainage area) had failed causing the four supported pipelines to move from their original as-built positions. There was no release from any of the affected pipelines (24-inch and 16-inch produced oil pipelines, a 12-inch water injection (WI) pipeline, and an 8-inch miscible injectant pipeline), and there was no damage to the tundra or environment.

A qualitative and quantitative assessment of the pipelines by the Field Mechanical/Piping Engineer determined that the sustained stress loads (internal pressure, self-weight, etc.) were within design limits of the piping system for every case evaluated. Based on the combination of favorable qualitative and quantitative results, the pipelines were lifted back into their original centerline positions. No repairs to the pipelines were necessary and temporary cribbing pile installation, to both support and secure the pipelines, were completed without incident.
Initial examination by Engineering Staff personnel indicated fatigue cracking in 12 of the 13 fillet-welds connecting the VSM cap plate to the HSM. The fatigue loading resulted from a combination of wind-induced vibration (WIV) on the pipelines, and forces created by hydraulic slugs in the production pipelines. From a dynamic/cyclic load design basis, selection of a fillet weld as the primary load connection proved to be less robust than anticipated. Upon evaluating support structure designs from past North Slope projects, it was concluded that use of balanced, non-cantilevered support with pre-stressed bolted connections has proven to be the optimal design configuration for all loading conditions (static and dynamic) encountered in a HSM/VSM support structure's lifetime. As such, this type of design has been adopted as a best practice to be implemented to insure that this type of failure is avoided for future support structure designs.

Post-failure, knee-braces were installed on the unbalanced side of the Meltwater/Tarn pipeline system support structure for the approximate 1,100 remaining VSM/HSM supports. This construction effort is nearly complete with all remaining locations, based on accessibility issues over open water, to be completed once winter tundra travel is permitted.

From a field-wide survey, similar welded support installations were discovered on two relatively-short pipelines. However, an engineering analysis confirmed that these supports are fit-for-service under the specific loading conditions characteristic of each pipeline configuration.

Figures 8 and 9, and Figure A1 in Appendix A 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 A1 shows the leaks caused by external corrosion for cross-country lines, well lines, and below-grade piping locations.

3.2 Year 2004 Forecast

3.2.a Monitoring & Mitigation

- Test four additional new inhibitor formulations; first test will be Baker Re-5273 at DS3R. Additionally, we are discussing a possible field-wide test of concentrated blend of Champion RU-276 for the summer months.
- Test schmoo-be-gone in the water injection system for DS1E. Chemical is currently being mixed at Great Western in Fairbanks.
- Consider wellhead chemical injection systems for the production well lines at two more Drill Sites.
- Continued analysis of the CPF2 mixed water and associated systems to determine the cause of higher corrosion rates and possible mitigation options.

3.2.b Well Line Inspection

Our baseline inspection of all six-inch OD, 0.312" and 0.375" wall-thickness well lines that are six years of age or older was completed in 2003. Our recurring inspection program will start in 2004. No line in active oil service will go longer than 10 years without an inspection.

3.2.c Cross-Country Line Inspection

The following enhancements/modifications are planned for 2004:

- Our baseline RTR inspection of all CC lines requiring inspection was completed in 2003. Our recurring inspection program will start in 2004. No line in active oil service will go longer than 10 years without an inspection.

- Our baseline inspection of all elevation-change elbows scheduled as part of the Cross-Country Line Turbulent Flow Survey was completed in 2003. Based on 2003 inspection findings we will add water injection lines to the scope of work for 2004.

3.2.d External (Weld-Pack) Program

Complete evaluation of the initial CUI Buffer Spike test and determine the way forward.

Cross-country lines over tundra:

- Complete baseline TRT inspections on the remaining 711 CUI locations that were identified by the walk down verification survey completed in 2003.

- Complete recur TRT inspections on approximately 2210 CUI locations; use results to help fine-tune the prioritization scheme for future recurring inspections. Continue to monitor Denso tape protocol.

- Complete approximately 100 TRT inspections on the Tarn weld pack design established in 1997.

- Complete visual inspections of ten previously Medium Wet weld packs in saddles on large diameter sea water lines. Strip, inspect and refurbish these directly without performing TRT inspections because of the lengthy shot times involved.

For cross-country lines on-pad, inspect the remaining weld packs without a baseline inspection (approximately 500) to meet the goal of YE 2004 completion.

For well lines, inspect more than 50% of the remaining weld packs without a baseline inspection. This supports the goal of YE 2005 completion.

3.2.e Below Grade Piping Program

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

- Continue recurring PTI/TWI inspections of priority one cased lines.

- Excavate, inspect, refurbish, and repair (as necessary) five-to-nine lines in road 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 Alpine piping layout and piping information database development.

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

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APPENDIX A

Table A1. Three-phase Production Cross-Country lines with corrosion rates that exceeded targets and the action that was taken.

Common Line	Coupons	Probe Rate	Insp Incr	Action Taken
1EPO			x	Actual CI Rate increased, CI pump repaired
1L10"PO	x			Target CI Rate increased
1RPO	x			No CI change, due to temp CI test
2EPO	x			Target CI Rate increased
2GPO			x	Target CI Rate increased
2TPO		x		Target CI Rate increased
2TAMKHPO			x	Target CI Rate increased
2UPO			x	Target CI Rate increased
2WUPO	x			Target CI Rate increased
2XPO			x	Target CI Rate increased
3HPO	x			Target CI Rate increased
3HAMIPO		x		Target CI Rate increased
3MIPO	x			Target CI Rate increased
3BFGSPO		x		Target CI Rate increased
3CPO	x			Target CI Rate increased
3IPO	x			Target CI Rate increased
3QRONKPO	x	x		Target CI Rate increased
3KPO	x			Target CI Rate increased
3OPO		x		Target CI Rate increased
3QRONKCPO		x		Target CI Rate increased
3QROPO	x			Target CI Rate increased
3WOto1	x			Target CI Rate increased

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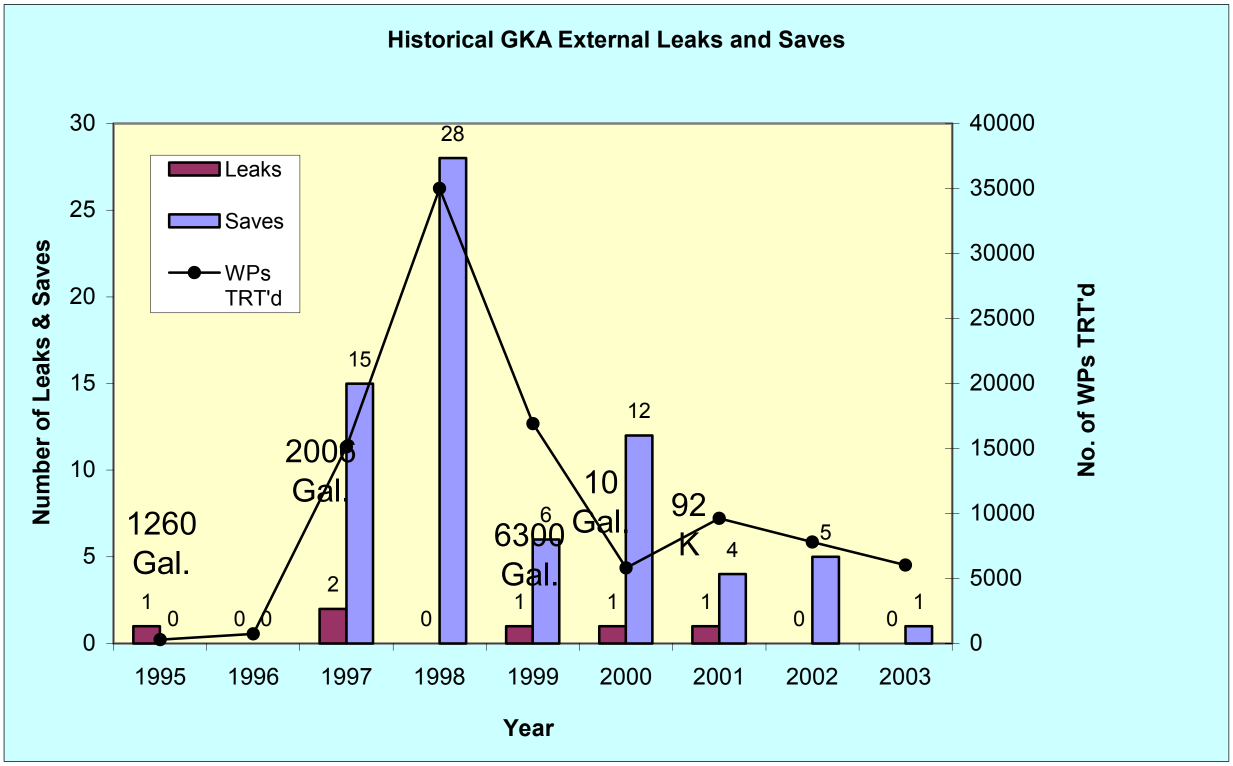

Figure A1. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

Note: The leak in 2001 due to external corrosion was located in a weld pack in a below-grade piping segment, and as such, would not have been detected by the TRT inspection program. The location had not yet received PTI/TWI inspection.

APPENDIX B
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.