PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

Greater Kuparuk Area (GKA) Corrosion Programs Overview

March 28, 2002

Commitment to Corrosion Monitoring
2nd Annual Report to the Alaska Department of Environmental Conservation

Prepared by
Kuparuk Corrosion Team

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1.0 OVERVIEW

There are over $4MMM in capital assets in the Greater Kuparuk Area (GKA). Over the past few years, the corrosivity of the produced fluids at Kuparuk has increased to a level that has the potential to cause internal corrosion damage to the facilities. The corrosivity is increasing as water production and H_2S levels increase. External corrosion has also become a potential problem on aging pipeline systems. 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. This corrosion management system is also being applied to the new Alpine field.

The purpose of this 2nd Annual Report is to communicate the details of the individual programs that implement the Kuparuk Corrosion Strategy. In addition to the requirements of the North Slope Charter Agreement between Phillips 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, Appendix A has been added. Appendix A contains corrosion coupon exception data and external corrosion inspection and leak/save historical results.

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

2.0 SIGNIFICANT ENHANCEMENTS TO CORROSION PROGRAMS

After the 1HBWI line failure on 15 April 2001, the corrosion programs at Kuparuk were re-evaluated to determine what changes, if any, were warranted. Two significant changes to the corrosion programs were made:

- The Below-Grade Piping Program (detailed in Section 3.1.e) was accelerated for 2001 and 2002. The specialty-testing program was increased to enable a base line inspection of all the significant below-grade piping by year-end 2002. The cased pipe excavation program was also expanded to allow timely field-verification of anomalies identified with piping inspected by the specialty techniques.
- The inspection program for internal corrosion on well lines was increased for 2001. Based on inspection data accumulated to date, it was determined that accelerating the well line inspection program would provide incremental risk-reduction benefits.

3.0 Program Status Summary

3.1 Year 2001 Overview

3.1.a Monitoring & Mitigation

Monitoring:
Average general and pitting coupon corrosion rate data for Year 2001 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	0.1	60	98
Seawater Cross-Country Lines	2	2.1	1	50
Mixed Water Injection Cross-Country Lines	22	0.1	22	100
Production Well Flow Lines	386	0.2	380	98
Mixed Water Injection Well Flow Lines	471	0.4	453	96

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	7.9	48	81
Seawater Cross-Country Lines	2	4.3	2	100
Mixed Water Injection Cross-Country Lines	22	7.1	18	82
Production Well Flow Lines	386	1.6	369	96
Mixed Water Injection Well Flow Lines	471	6.6	371	79

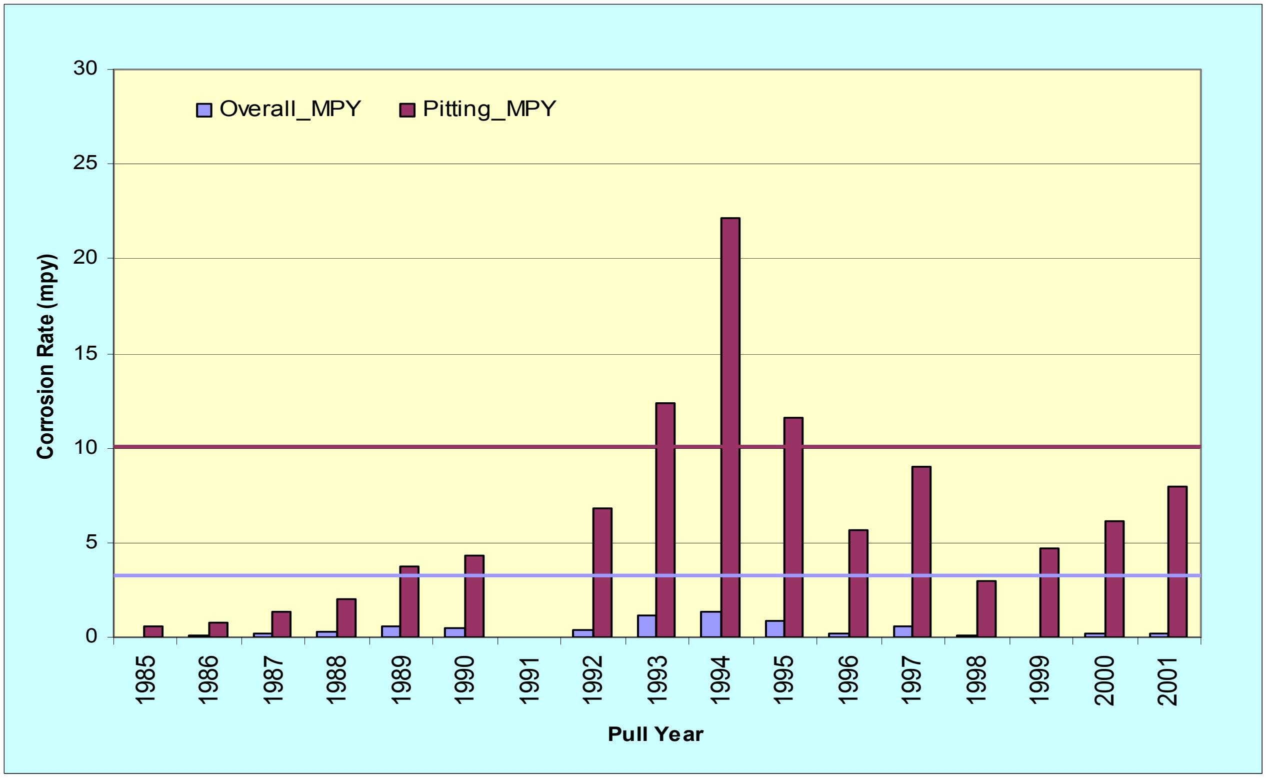

Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Cross-Country Lines: The monitoring data summarized in 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.

Recurring CRM inspections also support the conclusion that corrosion is under control in the three-phase production cross-country lines. In 2001, 464 corrosion-rate monitoring (CRM) inspections were conducted, with 11 minor increases found (i.e. less than 3% of total CRM inspections resulted in an increase). Ongoing internal inspection data support these CRM data 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 2001, coupon or probe corrosion rates exceeded targets on 19 lines and corrosion inhibitor concentrations were increased on all 19 of these lines. In 2001, inspection results indicated minor corrosion had occurred on nine lines that did not have coupons that exceeded the target corrosion rates; corrosion inhibitor concentrations were increased in all nine of these lines. A complete listing of the 28 lines with corrosion rates that exceeded targets is give in Table A1 of Appendix A.

In 2001, the 24” Wet Oil Line that was operating under low flow conditions was decommissioned. The other three wet oil lines continued to have significant general and pitting coupon corrosion rates. In all three of these wet oil lines, the corrosion inhibitor target rates were increased. A real time radiographic inspection was performed on the 12” CPF2 Wet Oil Line in 2001, revealing no significant damage.

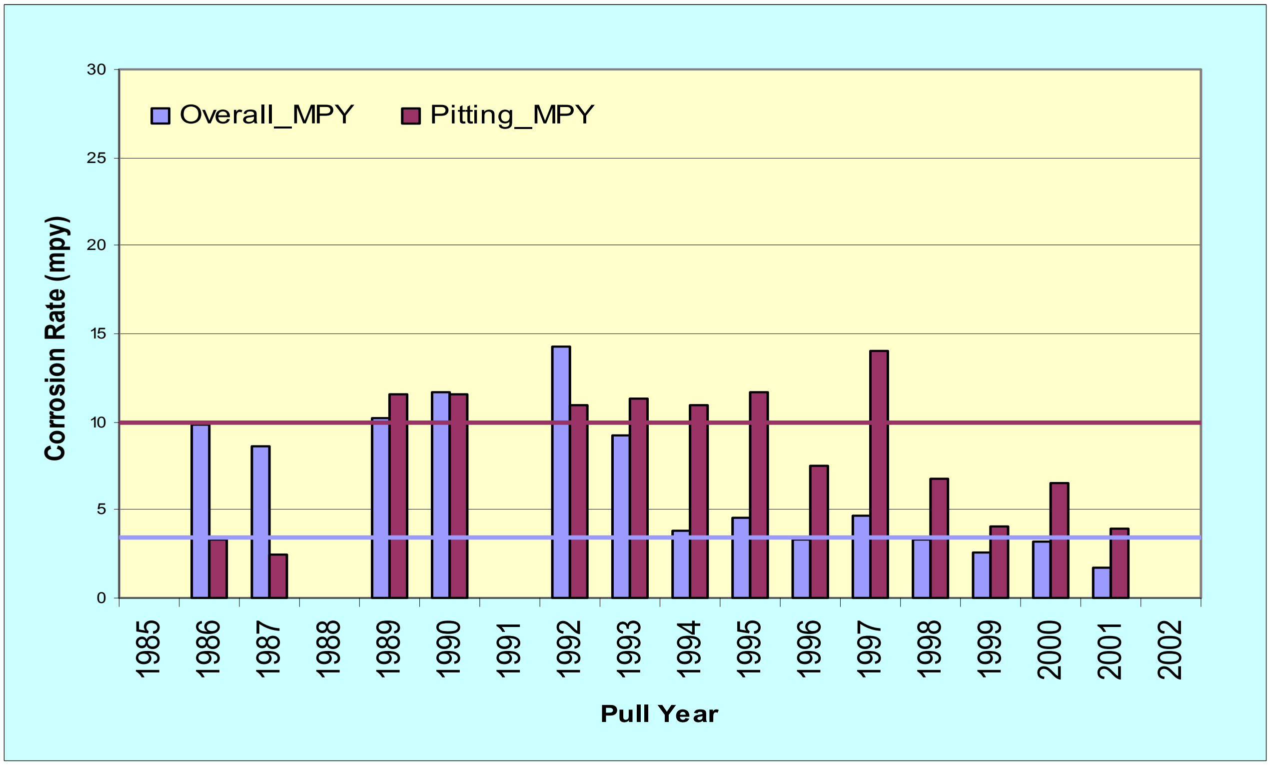

Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Sea Water Cross-Country Lines: The monitoring data summarized in Tables 1 and 2 and presented in Figure 2 above, suggest that although the two sea water cross-country lines had some coupon corrosion rates above target thresholds in 2001, the average corrosion rates have remained low, and well under the targets. Inspection data suggest that, in seawater service, corrosion tends to manifest itself in un-piggable, relatively stagnant sections of line (such as dead legs and headers).

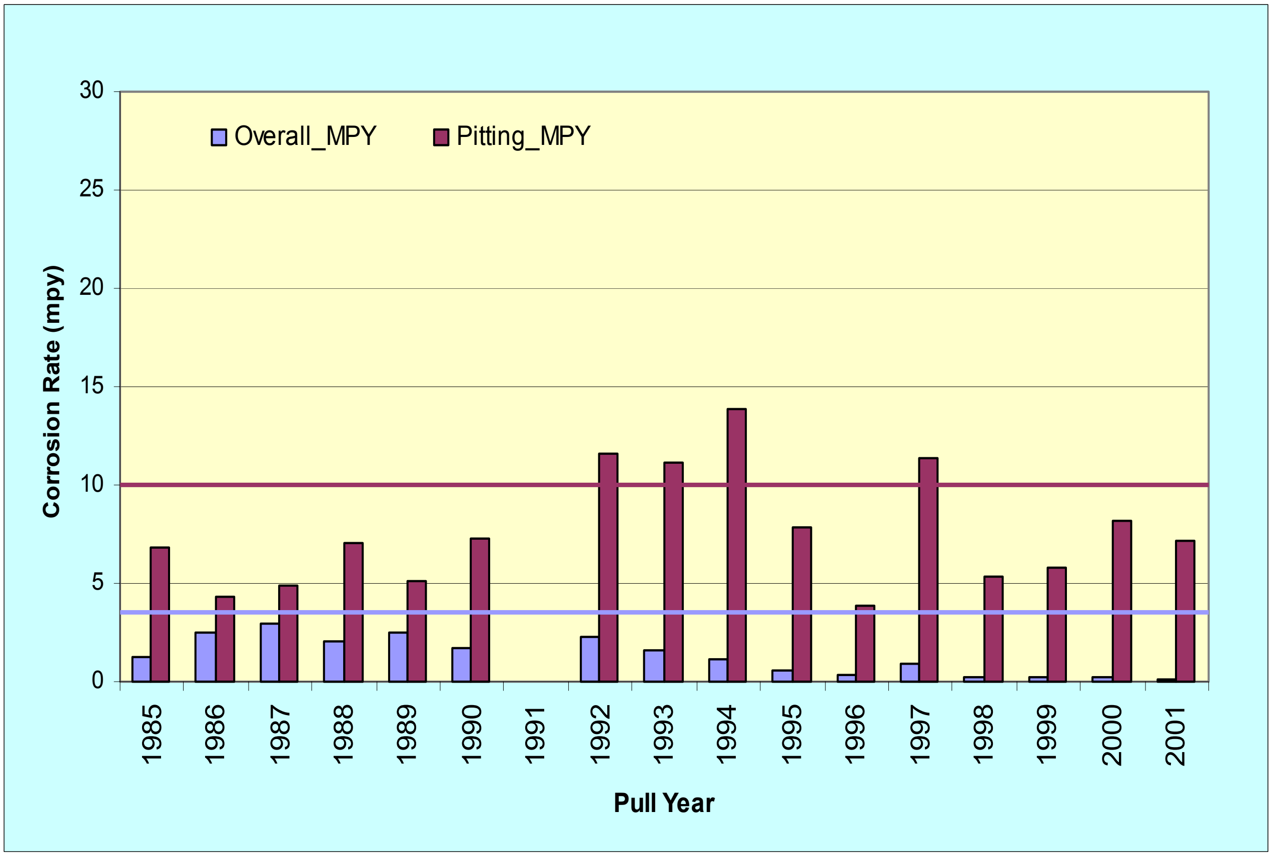

Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Mixed Water Injection Cross-Country Lines: The monitoring data summarized in Tables 1 and 2 and presented in Figure 3 suggest that pitting and general corrosion coupon rates are under control; however, inspection data suggest that, in this service, corrosion tends to manifest itself primarily in un-piggable, relatively stagnant sections of line (such as on well lines verses common lines, dead-legs verses mainline segments, etc.). This information helps to prioritize ongoing inspection efforts. General corrosion rates have improved steadily over the last 15 years, and are within the target range, while the pitting rates remain below target levels, and at approximately the historical average.

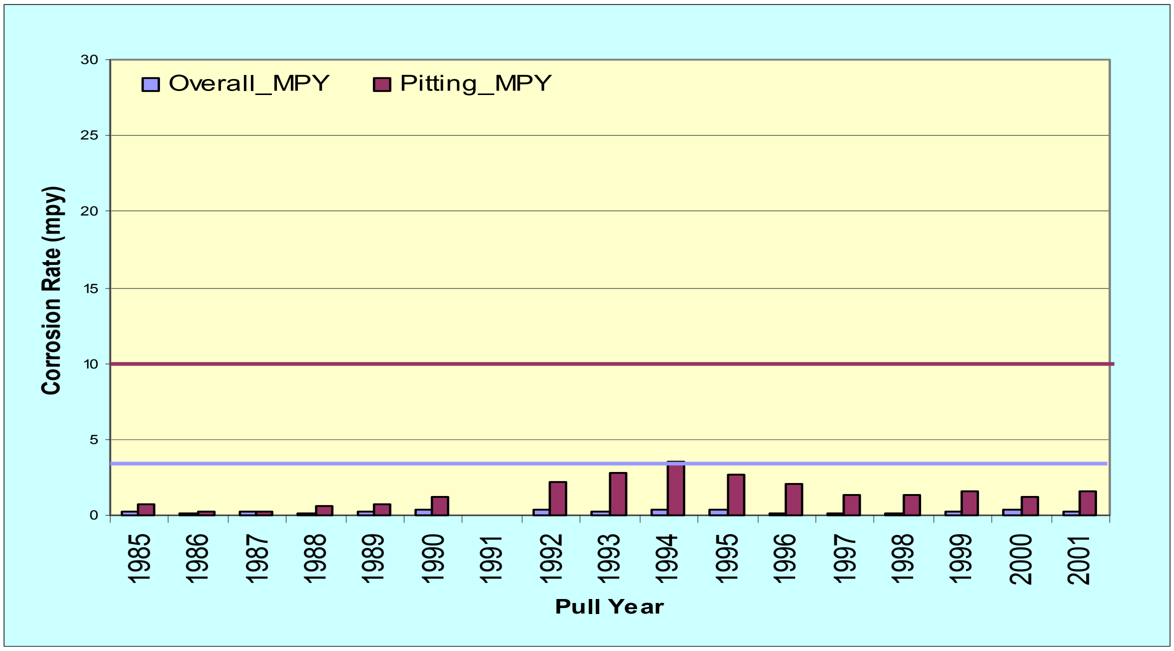

Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production and Mixed Water Injection Well Flow Lines: While the monitoring data summarized in Tables 1 and 2 and presented in Figures 4 and 5 suggest that corrosion rates are below targets, inspection data indicates that higher rates are actually being experienced. 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.

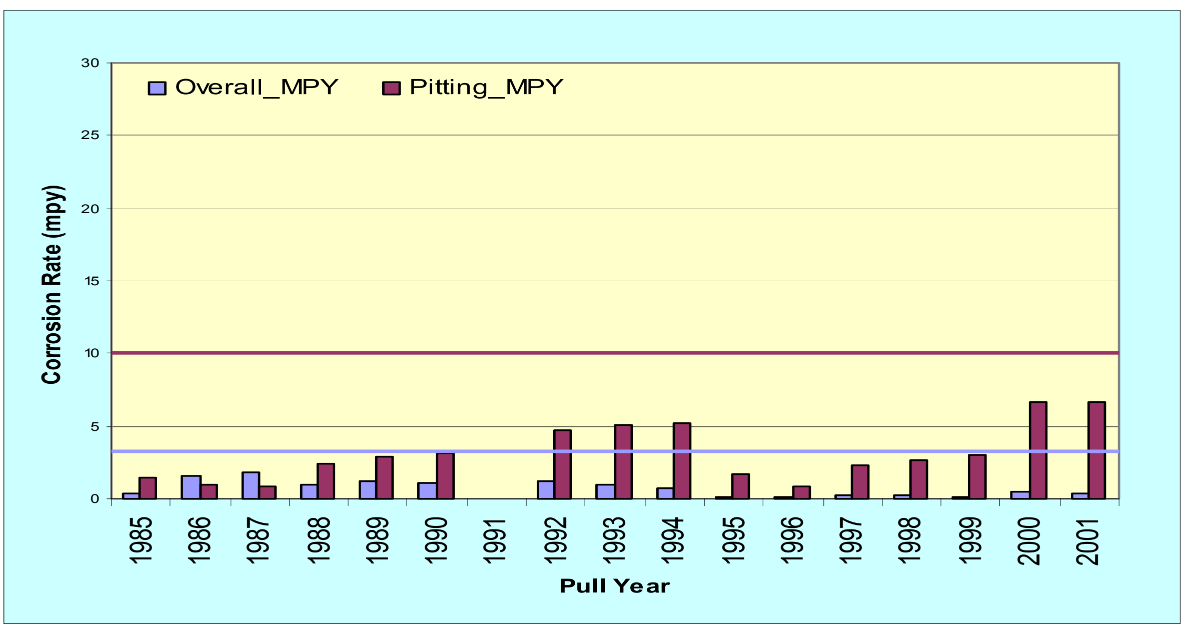

Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

Mitigation:
In 2001, the field-wide corrosion inhibitor used was Cortron 2000-25. A new corrosion inhibitor, Cortron 2001-19, passed the laboratory evaluation criteria and was field-tested to confirm its performance. As a result of the field performance tests, 2001-19 was not implemented as the field-wide corrosion inhibitor. Additionally, field-wide use of Cortron 2000-25 will be discontinued in 2002 because of poorer performance than Cortron RU-276. Cortron RU-276 will become the field-wide corrosion inhibitor in 2002.

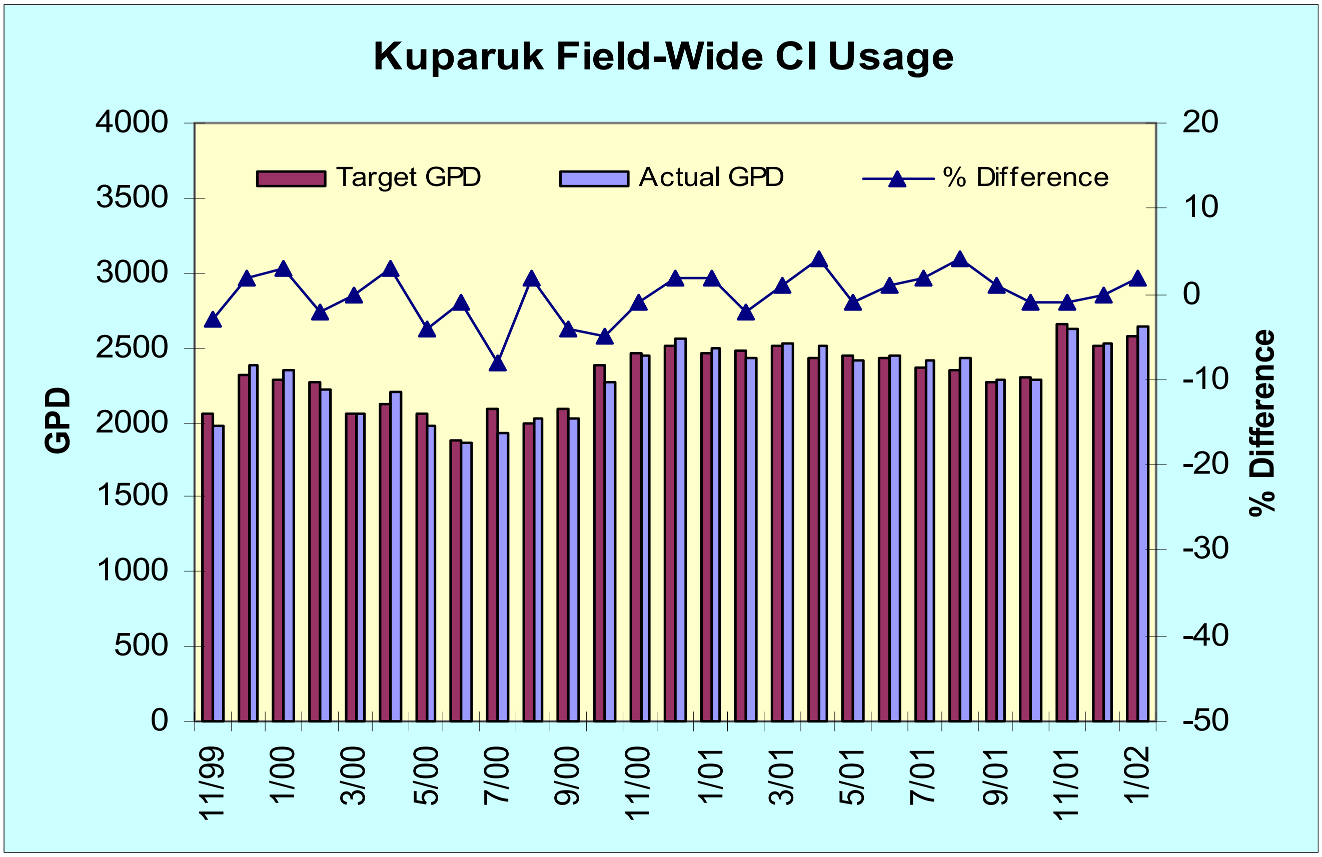

Figure 6. Field-wide Corrosion Inhibitor Use – actual amount of corrosion inhibitor used per day, recommended amount of corrosion inhibitor used per day, and the percent difference between the actual and the recommended amounts.

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 0.7%.

The metrics for the mitigation program are described in the inhibitor feedback flow chart, Figure 7 below, the monitoring data table in Appendix "A", and discussions above.

Kuparuk Inhibitor Feedback System

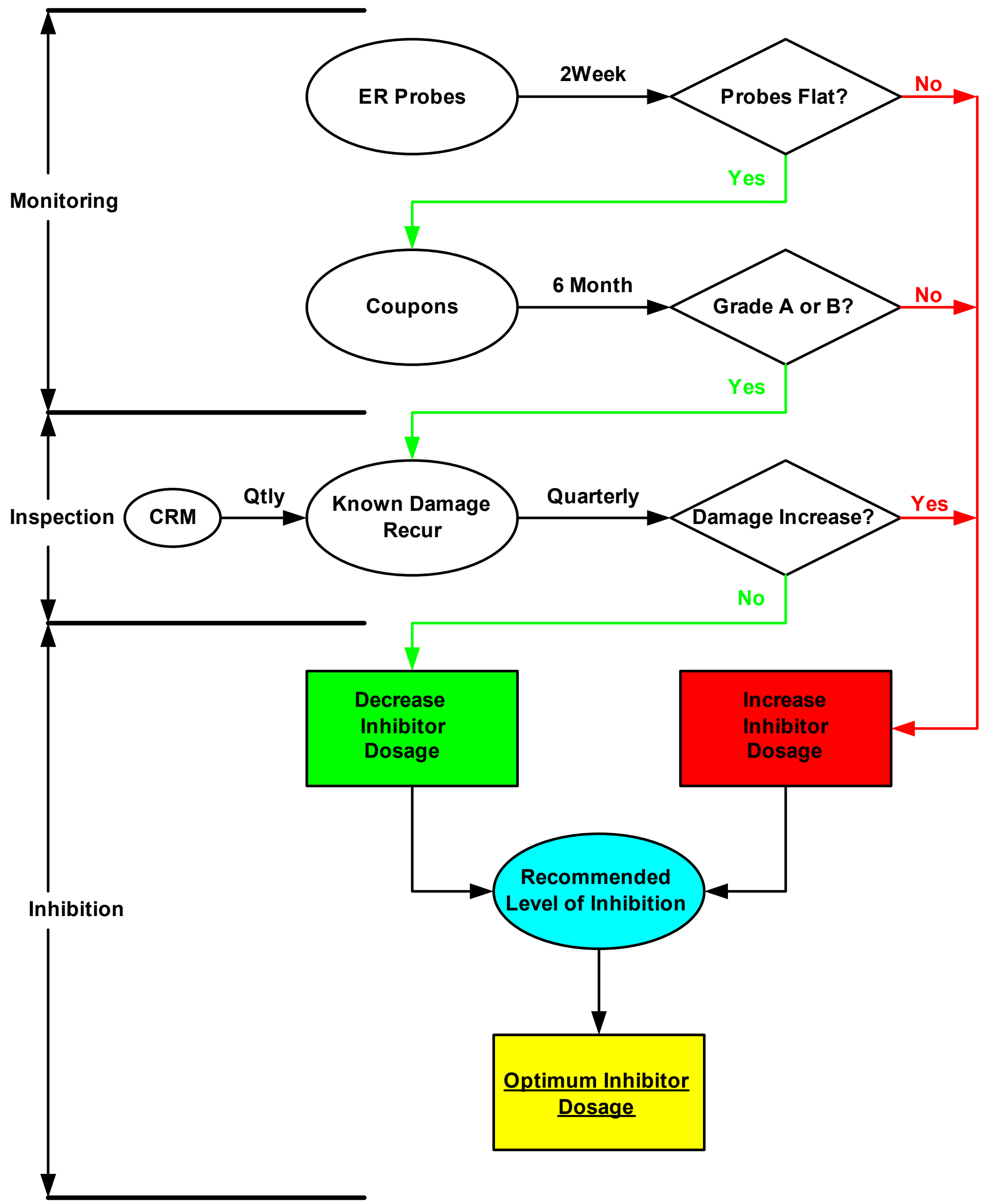

Figure 7. Corrosion Inhibitor Feedback System.

3.1.b Well Line Inspection

As indicated in Figure 8 below, repair recommendations were initiated on 24 lines (17 injection, 7 production) in 2001 because of internal corrosion damage. Repairs typically consist of either sleeves or replacement of the de-rated section of line. Figure 8 also shows that the number of inspections on the well lines has increased dramatically since 1999, but the number of repair recommendations has increased at a lower rate.

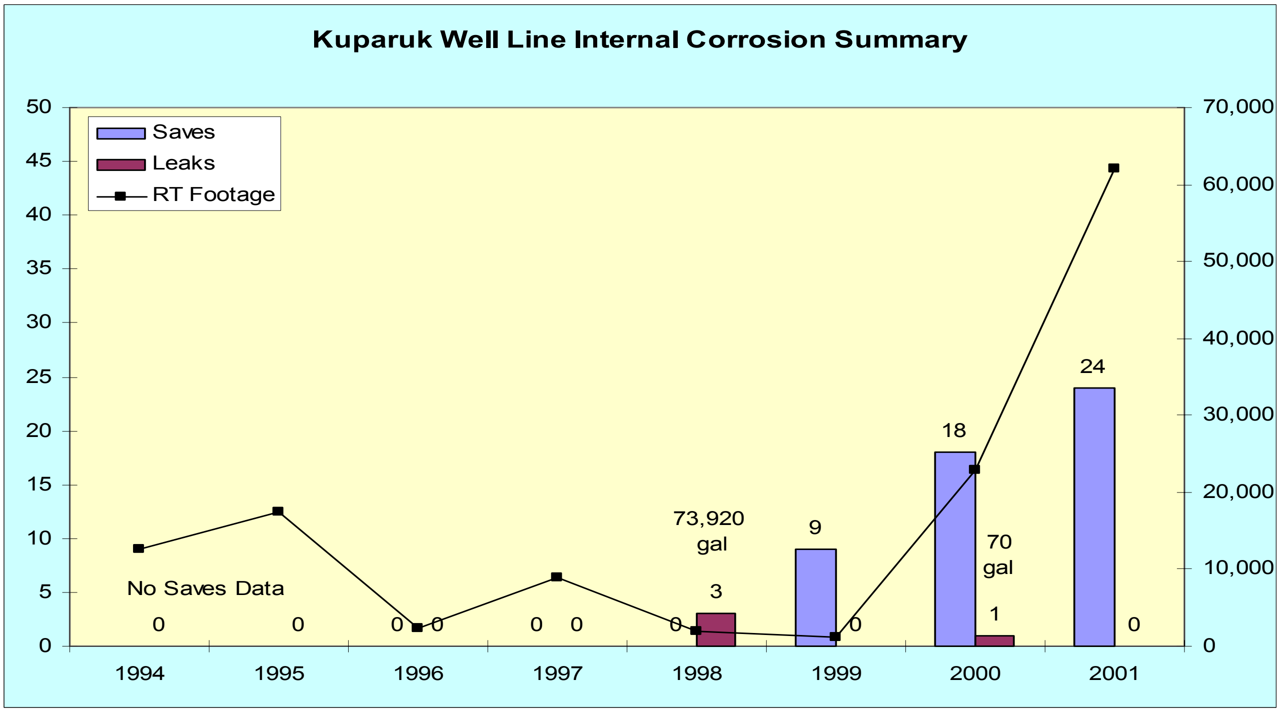

Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2001 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables.

- RTR:

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	36,000	299
Water Injection	22,500	132
Total	58,500	431

- Manual RT:

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	252	2,122	350	21	6
Water Injection	97	1,400	209	25	12
Total	349	3,522	559	46	8

- Manual UT:

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	300	2,588	1,144	103	9
Water Injection	56	680	201	14	7
Total	356	3,268	1,345	117	9

UT locations that were previously reported in conjunction with the External corrosion inspection program are now included in the data above.

3.1.c Cross-Country Line Inspection

As indicated in Figure 9, no (0) repair recommendations were initiated on cross-country lines because of internal corrosion damage in 2001. Inspection results in Figure 9 show that the corrosion mitigation programs are adequately protecting the three-phase lines and the water injection lines.

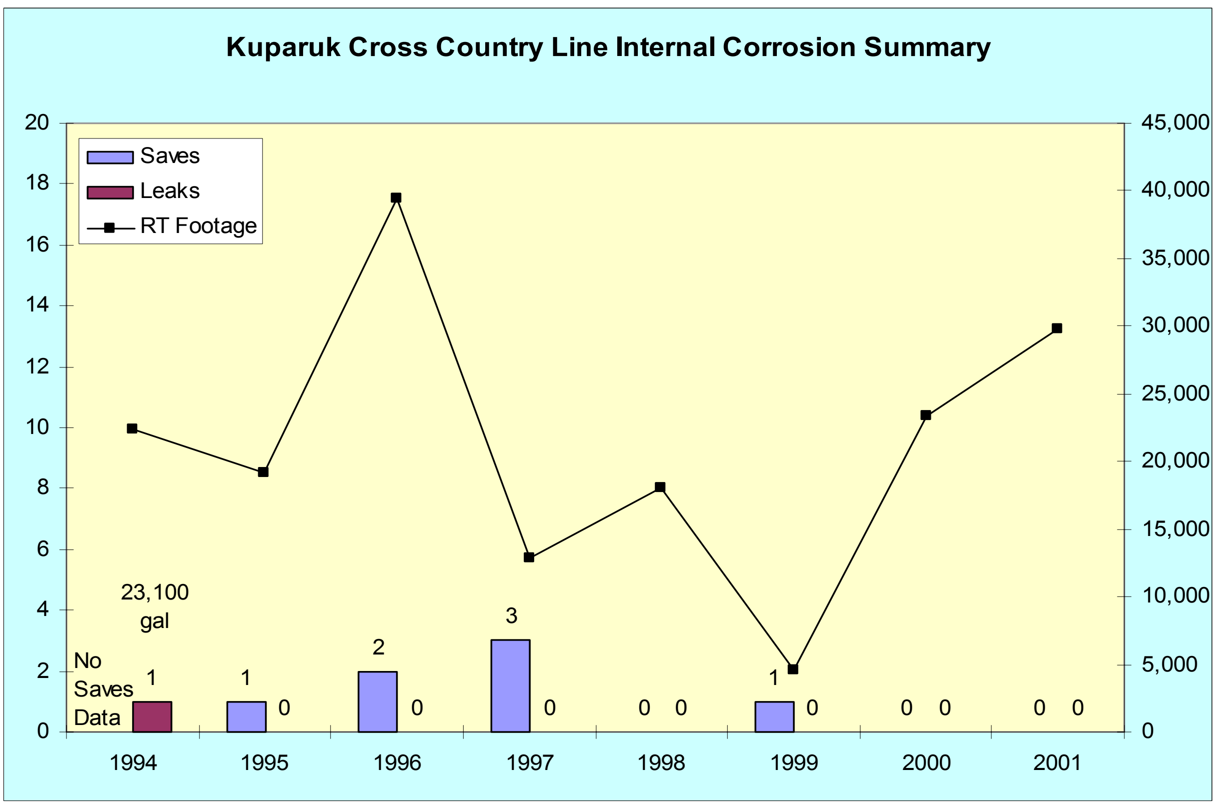

Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2001 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

- RTR:

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	15,000	13
Water Injection	13,000	24
Total	28,000	37

RTR inspection results from water injection cross country lines showed few locations with damage that needed to be re-inspected with RT or UT. There are few repeat inspections from manual RT and manual UT because there are few locations that have more than 30% damage, the trigger for re-inspection with RT or UT.

- Manual RT:

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	100	998	600	18	3
Water Injection	23	821	20	0	0
Total	123	1819	620	18	3

Manual RT is limited to those lines that are less than or equal to 8" outside diameter. For water injection service lines that are larger than 8" outside diameter, Kuparuk relies on spot UT. Smart pigging for corrosion may also be possible on some of the water injection lines at Kuparuk; plans for 2002 include evaluating smart pigging for Kuparuk's water injection lines.

- Manual UT:

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	79	787	567	17	3
Water Injection	28	74	1	0	0
Total	107	861	568	17	3

Internal UT locations that were previously reported in conjunction with the External corrosion inspection program are now included in the data above.

3.1.d External (Weld-Pack) Program

In 2001, tangential radiographic (TRT) inspection of the weld packs on cross-country lines over tundra was completed. Also for 2001, TRT was performed on approximately 44% of the weld packs on cross-country lines on pads and approximately 22% of the weld packs on well lines. Table 3 details the number of locations inspected with TRT, the number of corroded locations found, the percentage of corroded locations found, and the number of locations refurbished. Note that in Table 3 the number of locations refurbished exceeds the number of corroded locations discovered for each category because weld packs with heavy-wet insulation are proactively refurbished, even if no corrosion is present.

Of the cross-country locations inspected in 2001, three locations were sleeved. Of the well line locations inspected, two locations were repaired.

Table 3. External Weld Pack Inspection Summary for 2001, including number of locations inspected, number of corroded locations, percentage of locations corroded, and number of locations refurbished by the type of line.

Type of Equipment	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines – On-Pad	3919	102	2.6	257
Cross-Country Lines – Over Tundra (Off-Pad)	292	13	4.5	338
Well Lines	5489	64	1.2	227
Total	**9700**	**179**	**1.9**	**822**

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.

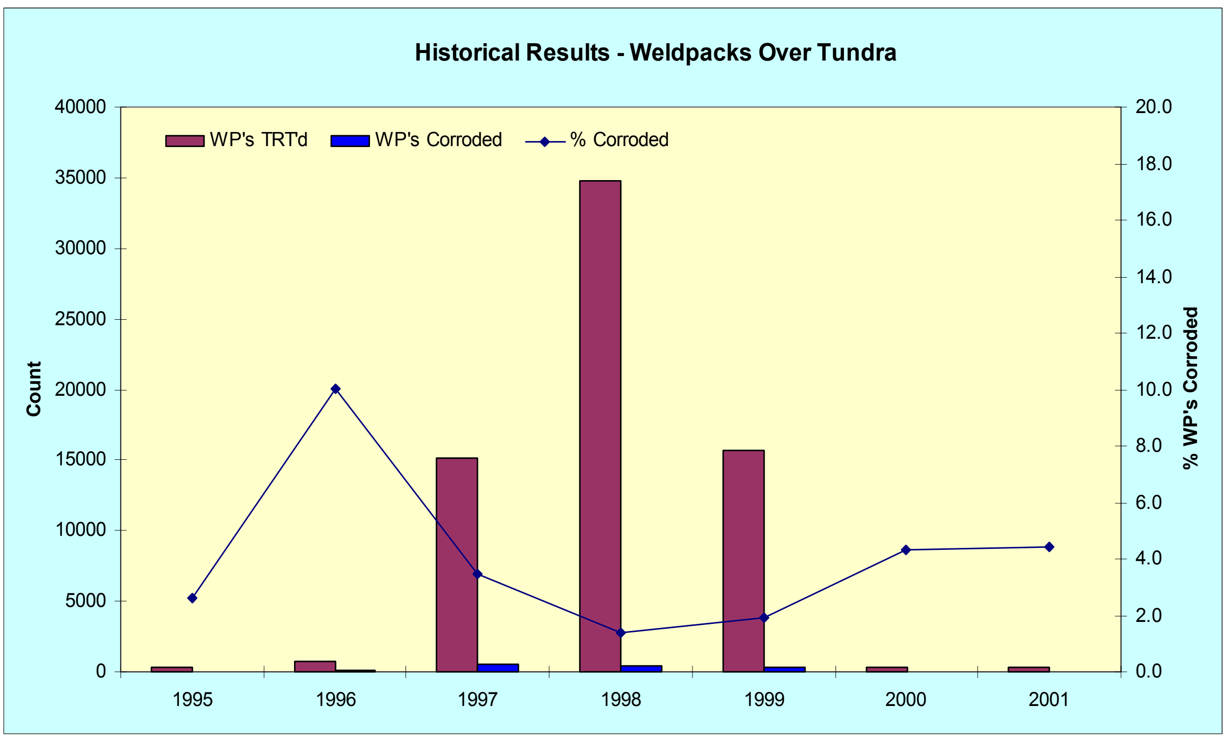

Figure 10. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad) – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

Figure 10 illustrates the most-mature external corrosion inspection program of the three external corrosion programs. By the end of 2001, all weld packs on cross-country lines over tundra had received their first, baseline TRT inspection. A prioritized recur inspection program for these weld packs is scheduled to begin in 2003.

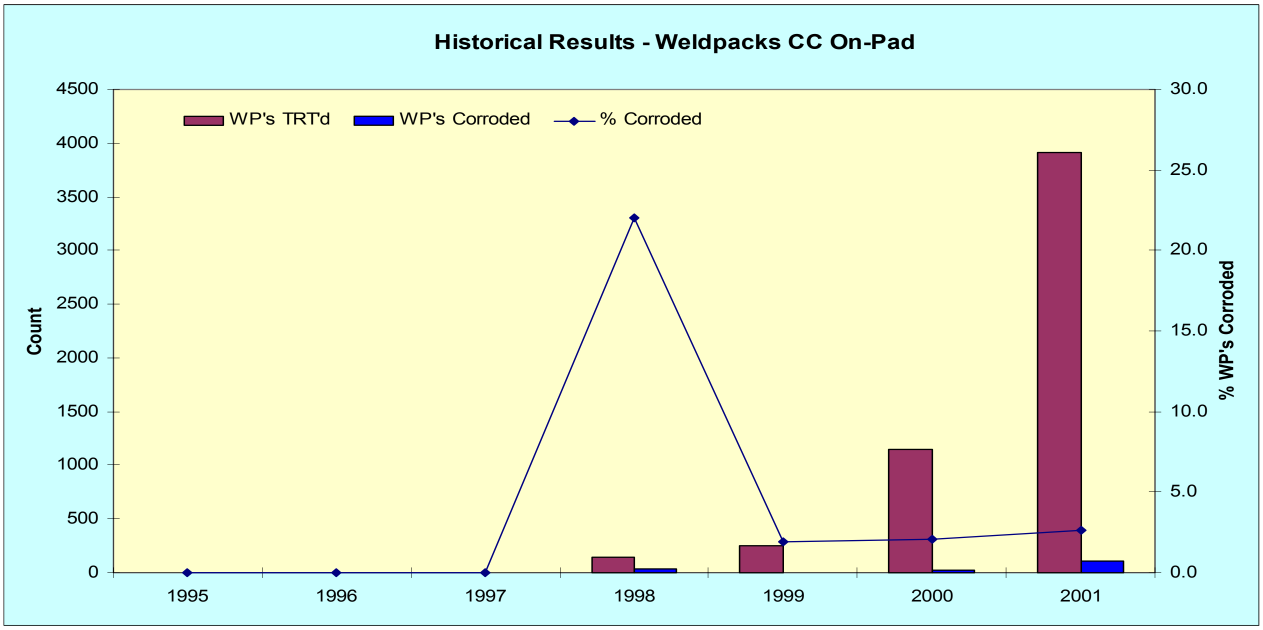

Figure 11. Summary of Weld Packs on Cross-Country Lines on Pads – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

Figures 11 and 12 depict the results of the major focus of the external weld pack inspection program in 2001. The cross-country on-pad weld packs were inspected using a prioritization scheme based on the historical corroded to wet ratios of the over-tundra portions of the cross-country lines. The well line weld packs were inspected using a prioritization scheme that examined the oldest, the hottest, and thinnest-walled lines first. Based on the results in Figure 12, it appears that the worst weld packs have been inspected and the risk of a future leak has been minimized. Continued inspections in 2002 will confirm if this hypothesis is correct. As of Year-End 2001, 61% of the cross-country on-pad weld packs and 43% of the well line weld packs have received their baseline TRT inspection.

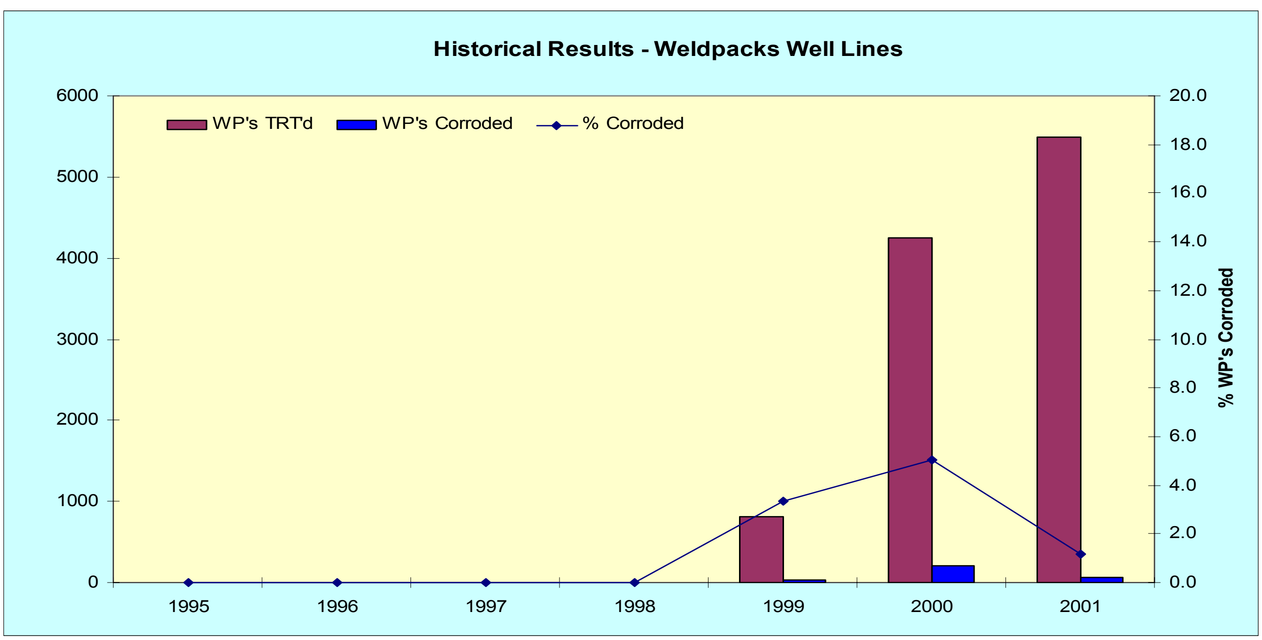

Figure 12. Summary of Weld Packs on Well Lines – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

3.1.e Below Grade Piping Program

In 2001, ADEC and Phillips Alaska, Inc., agreed to consolidate the Below Grade Piping Program report with the Commitment to Corrosion Monitoring Report. 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 Phillips Alaska, Inc. (PAI). To meet the requirements of 18 AAC 75.080, PAI 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

PAI has 431 locations of below grade “oil” piping in the GKA oil fields. Of these, one is contained in a utilidor. The remaining locations are cased lines, the majority of which are either road or caribou crossings. In addition to the “oil” piping, PAI has 210 significant below grade locations with lines in other services.

Utilidor Line
Inspection Status:
The one line in a utilidor was inspected in 1999 and the results were reported in 2000.

Cased Lines
Inspection Status:
The annual visual survey of all the cased lines was conducted in 2001. 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 oil lines, 52 locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. Of the 52 locations requiring remediation, the Corrosion inspector cleaned 40 locations. Twelve other locations required more extensive gravel work by others; these 12 locations were cleaned by the Roads and Pads group and reinspected by the Corrosion inspector.

3.1.e (2) Results of Specialty Testing

Inspection Status:
In 2001, 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, PAI evaluated the guided-ultrasonic (GUL) inspection technique from MQS-Cooperheat. PAI has determined that the GUL technique is not superior to the TWI long-range ultrasonic system and PAI will not use the GUL technique unless further improvements are made.

Results and Remedial Action:
Tables 4 and 5 show the results of the specialty testing performed by PTI and TWI, respectively.

Table 4. Results from the PTI inspections by service.

Service	Number of Cased Pipes Inspected	Number without any Electromagnetic Anomalies (N)	Number of Electromagnetic Anomalies (E)	Number of Significant Electromagnetic Anomalies (S)
Oil[(a)]	88	71	15	2
Other	106	87	18	1
Total	194	158	33[(b)]	3[(b)]

Notes:

(a) Oil service is defined as natural gas liquids, 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, except for two pipes with "E," the results of which were received after TWI had left the North Slope. These will be inspected with TWI in 2002.

Table 5. Results from the TWI inspections by service.

Service	Number of Cased Pipes Inspected	Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Moderate Anomalies (M)	Number of Severe Anomalies (S)
Oil[(c)]	52	3	44	3	1	1
Other	22	3	17	1	0	1
Total	74	6[(d)]	61	4[(e)]	1[(f)]	2[(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) All "I" locations will be prioritized based on other local and line concerns, and added as appropriate to the excavation/inspection list.

(e) All "L" locations will be re-inspected every two years.

(f) "M" location will be excavated and inspected in 2002.

(g) One "S" location was excavated and inspected in 2001. The other "S" location is in a line that is now abandoned.

3.1.e (3) Results of Crossing Digs

Nine cased pipes were excavated in 2001:

- Two of the nine pipes had moderate external damage. One of the two is now out-of-service. The other, an NGL line, was repaired with a sleeve.
- Seven of the nine pipes excavated and inspected did not require de-rating, repair, or replacement. Only minor damage was found.

For the eight cased pipes that were excavated in 2001 and remained in service, 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 2001, 16 floors with riser piping supports were installed in well houses at Drill Site 2M. Well house floors are supported by the well conductor and provide table riser piping supports.
- More than thirty heat tubes were installed at 1A, 1C, 2A, 2K, 2N, 3G. 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

- All new wells brought on line in 2001 had heat tubes, and floors with permanent pipe supports, installed as part of their packages.
- All existing producers converted to water injection wells were also upgraded to include heat tubes and floors with permanent pipe supports.

Wind-Induced Vibration:

- As a result of the DS2X 8" MI line failure which occurred in December 2001 (described below), Kuparuk is in the process of reviewing existing pipelines to evaluate the need for vibration dampeners. The line that failed is oriented 1-degree outside the design wind direction envelope designated for Kuparuk in 1991. To date, we have identified one area that falls within the design wind direction envelope but does not have dampeners installed. We plan on covering these sections of lines in 2002. We are also reviewing the existing PAI specification to determine if it needs to be revised to include a larger degree area than is currently specified.
- Engineering performs an annual inspection of all vibration dampener (PVD) locations 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

- 1HBWI External Corrosion Water Injection Line Leak – 4/15/01 – The 10-inch injection line serving drill sites 1H and 1B failed due to external corrosion at a weld pack in a cased road crossing, spilling 92,000 gallons of produced water. This road crossing had not yet been inspected using electromagnetic wave (PTI) or long-range ultrasonic (TWI) techniques. Prior to the spill, 149 above-grade weld packs on this line had been inspected with no de-rating damage found. The eight above-grade weld packs remaining to be inspected were completed in 2001 with no de-rating damage found.

- No leaks were caused by internal corrosion in 2001.

- DS 2X Miscible Injectant Line Incident – 12/31/01 – The eight-inch miscible injection line serving Drill Site 2X developed a crack at a weld, possibly due to wind-induced vibration. We are still awaiting metallurgical analysis results to rule out the possibility of a weld defect. No liquids were spilled. This line was oriented one degree outside of the susceptible wind direction for the Kuparuk field. As noted above, we are evaluating other line segments that are without PVD's and close to the susceptible wind direction to determine the need for PVD installation.

- No leaks were caused by subsidence in 2001.

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 both cross-country and well lines.

3.2 Year 2002 Forecast

3.2.a Monitoring & Mitigation

- Convert the field wide corrosion inhibitor back to Cortron RU-276.
- Test new corrosion inhibitors in an effort to improve corrosion inhibition technology.
- Test schmoo-be-gone in the water injection system for one drill site.
- Develop and implement wellhead chemical injection systems for the production well lines at select drill sites.
- Decrease wet oil line corrosion exposure through increased maintenance pigging and inhibitor adjustments.

3.2.b Well Line Inspection

Based on the 2001 well line inspection programs, the following enhancements/modifications are planned for 2002:

- Inspect approximately 200 well lines at Kuparuk.
- The strategy for RTR inspection consists of performing an "initial inspection" for each line. If significant damage is found during this stage of the inspection, a "100%" inspection is then performed on the line. (Note: this is never actually 100% due to saddles, etc.). If no significant damage is found on the initial inspection of a line, the inspection crew will proceed to the next targeted line. A 25% line target was used as the "initial" footage in 2001. The plan for the 2002 inspection program is to maintain the same percentage of the initial target area.

3.2.c Cross-Country Line Inspection

Based on the 2001 cross-country line inspection programs, the following enhancements/modifications are planned for 2002:

- Maintain an equivalent level of RTR inspection as in 2001.
- Continue to implement the risk-ranked Elbow Inspection Program that increases the effectiveness of the produced crude (three-phase) cross-country line inspection program. The purpose of this program is to identify higher-risk areas on a given line, taking into account flowing conditions and pipeline geometries, so that more effective inspection schedules can be established.
- Evaluate the possibility of smart pigging cross-country water injection lines larger than 8" outside diameter.

3.2.d External (Weld-Pack) Program

- Inspect approximately 17% of well line weld packs (approximately 4,000 weld packs). All well line weld packs will be inspected by YE 2005.
- Inspect 20% of the of CC <u>On-Pad</u> weld packs (approximately 1,780 weld packs). All CC On-Pad weld packs will be inspected by YE 2004.

3.2.e Below Grade Piping Program

- Visually inspect all of the cased lines. The appropriate PAI 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.

- Complete the first-pass inspection of the remaining priority 1 cased lines using PTI and/or TWI techniques. There are approximately 150 cased lines that will require inspection in 2002. Based on the results from TWI and PTI, certain lines will be excavated.

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

3.2.f Other

- Complete enhancements to the Kuparuk Corrosion Database.

- Continue to review existing Kuparuk pipeline locations to assure correct placement of WIV dampeners.

- Continue Alpine piping layout and piping information database development.

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

- Continue to evaluate snow fences to minimize snow accumulation on well lines.

APPENDIX A

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

Common Line	Date	Coupon Grade	Probe Rate	Inspection	Insp Incr	Action Taken
1-2Z1QGPO	06/18/01	A	<0.5 mpy		yes	Raised target inhibition
1-2Z1QPO	11/12/01	NA	NA		yes	Raised target inhibition
1APO	11/12/01	A	<0.5 mpy		yes	Raised target inhibition
1BPO	11/06/01	D	>0.5 mpy			Raised target inhibition
1DPO	11/06/01	D	<0.5 mpy			Initiated inhibition 12/01
1GPO	07/01/01	C	>0.5 mpy	yes	yes	Raised effective inhibiton
1L10PO	11/05/01	D	<0.5 mpy		yes	Raised target inhibition
1QPO	11/05/01	D	<0.5 mpy			Raised target inhibition
1RPO	Jan, July, Nov	F, D	> 1 mpy	yes	yes	Raised target inhibition
1YPO	11/02/01	A	<0.5 mpy		yes	Raised target inhibition
1YRPO	11/15/01	A	<0.5 mpy		yes	Raised target inhibition
24" WO at 1Q	Feb, June	D, C	> 1 mpy			Raised target inhibition then line taken out of service
2HPO	11/16/01	B	<0.5 mpy		yes	Raised target inhibition
2KPO	11/03/01	D	<0.5 mpy			Raised target inhibition
2TAMKHPO	11/10/01	A	<0.5 mpy		yes	Raised target inhibition
2TPO	11/03/01	D	>0.5 mpy			Raised target inhibition
2UPO	02/07/01	A	<0.5 mpy		yes	Raised target inhibition
3CPO	11/02/01	D	<0.5 mpy			Raised target inhibition
3GFPO	07/01/01	C	>0.5 mpy	no		Raised target inhibition
3GPO	11/01/01	C	<0.5 mpy			Raised target inhibition
3HPO	Aug, Nov	D, F	<0.5 mpy	yes		Raised target inhibition
3M	08/13/01	D	<0.5 mpy	no		Raised effective inhibiton
3MIPO	11/01/01	C	<0.5 mpy			Raised target inhibition
3OPO	07/01/01	A	>0.5 mpy			Raised target inhibition
3RPO	11/02/01	C	<0.5 mpy			Raised target inhibition
3RQOPO	07/01/01	D	>0.5 mpy	yes	yes	Raised target inhibition
XCL/WO at CPF1 w. of flare pit	11/05/01	D	<0.5 mpy			Raised target inhibition
XCL/WO at CPF2	May, Nov	F, C	<0.5 mpy			Raised target inhibition

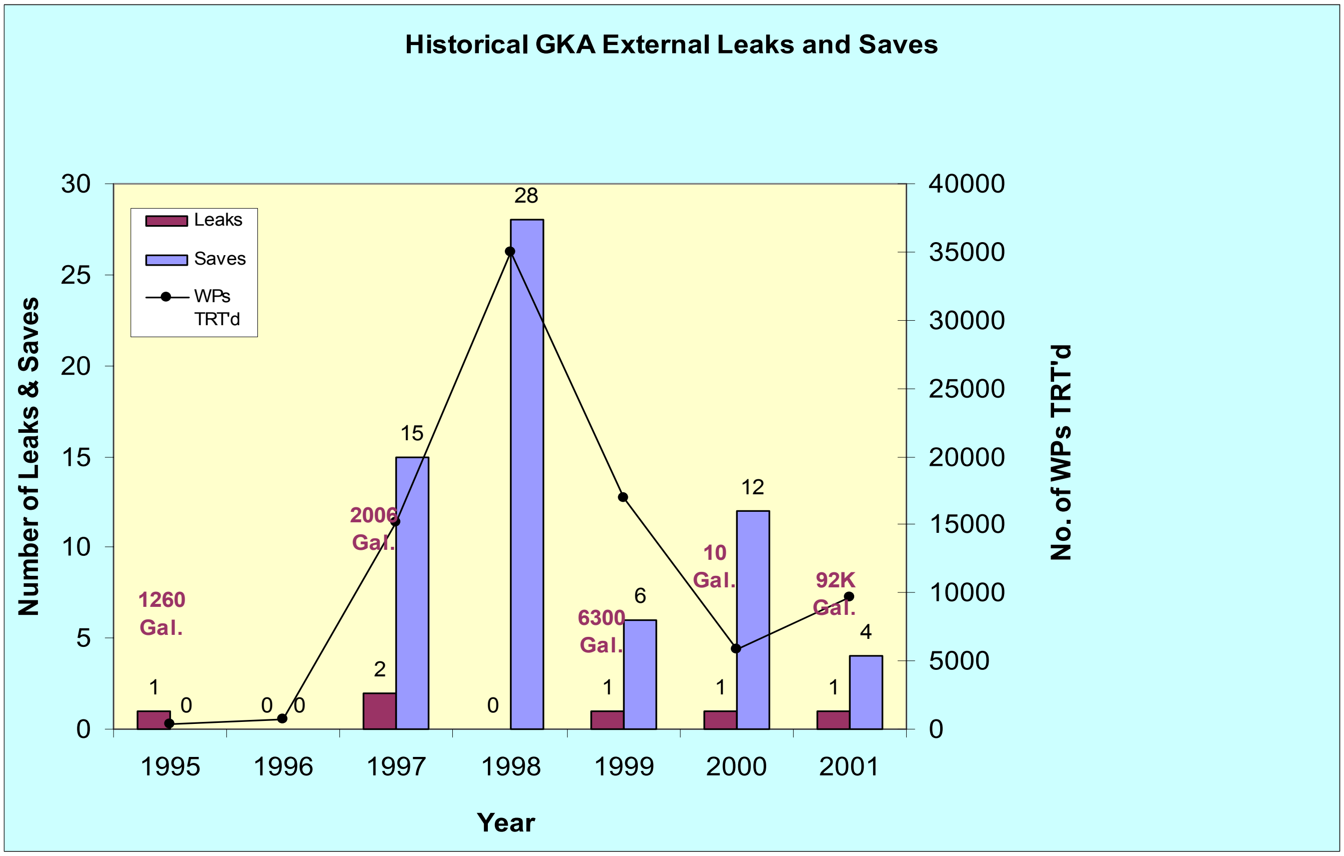

Figure A1. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

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.