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

March 30, 2007

Commitment to Corrosion Monitoring
7th Annual Report to the Alaska Department of Environmental Conservation

Prepared by
ConocoPhillips Corrosion Team

ConocoPhillips

Table of Contents

1.0 OVERVIEW

The purpose of this 7th 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.

There are over $3 Billion in capital assets in the Greater Kuparuk Area (GKA). The GKA produces approximately 170,000 BOPD. The internal corrosion potential in Kuparuk lines continues to rise as water production and H_2S levels increase. Additionally, an external corrosion potential exists where moisture penetrates into breaches in the insulation jacketing and is trapped in the insulation. Effective management of corrosion at Kuparuk is critical to maintain environmental and facility integrity, to reduce field operating costs, and to extend the life of the field infrastructure to meet future needs.

Alpine is ConocoPhillips Alaska's newest development and the largest onshore oil field discovered in North America in the past 15 years. There are roughly $1.5 Billion in capital assets at Alpine. Alpine has a nominal processing capacity of 145,000 BOPD. The Alpine development produces from four Drill Sites. The corrosion management system used at Kuparuk is being applied to the Alpine field.

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

2.0 SIGNIFICANT ENHANCEMENTS TO CORROSION PROGRAMS

Linear array continues to be a valuable tool for detection of corrosion damage in large diameter water injection flow lines.

Infrared thermography evaluation as a screening tool for wet pipeline insulation has produced encouraging results.

Significant progress was made in improving the field-wide pigging program by adding personnel, tracking solids removed, and monitoring bacteria in water-injection lines.

All CPF2 water injection flow lines now have corrosion monitoring access fittings.

Profile drawings have been incorporated into the inspection tool box to better define low points.

The number of below grade refurbishments has continued to increase into the range of 30 circuits per year.

The 12-inch and 16-inch wet oil flow lines were smart pigged and the frequency of maintenance pigging of these lines has increased to once a month.

The 30-inch sea water line from STP to the CW Skid was smart pigged.

The Kuparuk Wind Fan was expanded five degrees in both directions to include all pipeline segments with azimuths oriented from N50° W to N35° E (original wind fan was N45° W to N30° E).

ConocoPhillips

3.0 Program Status Summary - Kuparuk

3.1 Year 2006 Overview

3.1.a Kuparuk Monitoring & Mitigation

In 2006 we had several significant accomplishments:

- Tested two new corrosion inhibitor formulations and placed one new inhibitor in a larger scale test.
- Enhanced the maintenance pigging program for the field-wide water injection system by monitoring bacteria and solids in pigging returns.
- Additional corrosion monitoring access fittings were installed on all CPF2 Water Injection flow lines.
- Evaluated the merits of Acrolein batch treatment as a potential additive mitigation measure for WI lines. After considering the limitations of the treatment, we concluded that it was not practical for flow lines, the primary target for such application. We will continue to evaluate other alternatives.

Average general and pitting coupon corrosion rate data for Year 2006 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 Flow Lines	57	0.03	57	100
Seawater Flow Lines	2	5.0	1	50
Mixed Water Injection Flow Lines	24	0.3	24	100
Production Well Flow Lines	540	0.4	534	99
Water Injection Well Lines	406	0.4	395	97

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 Flow Lines	57	2.1	57	91
Seawater Flow Lines	2	5.1	2	100
Mixed Water Injection Flow Lines	24	5.4	20	83
Production Well Lines	540	2.0	520	96
Water Injection Well Lines	406	8.4	320	79

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

ConocoPhillips

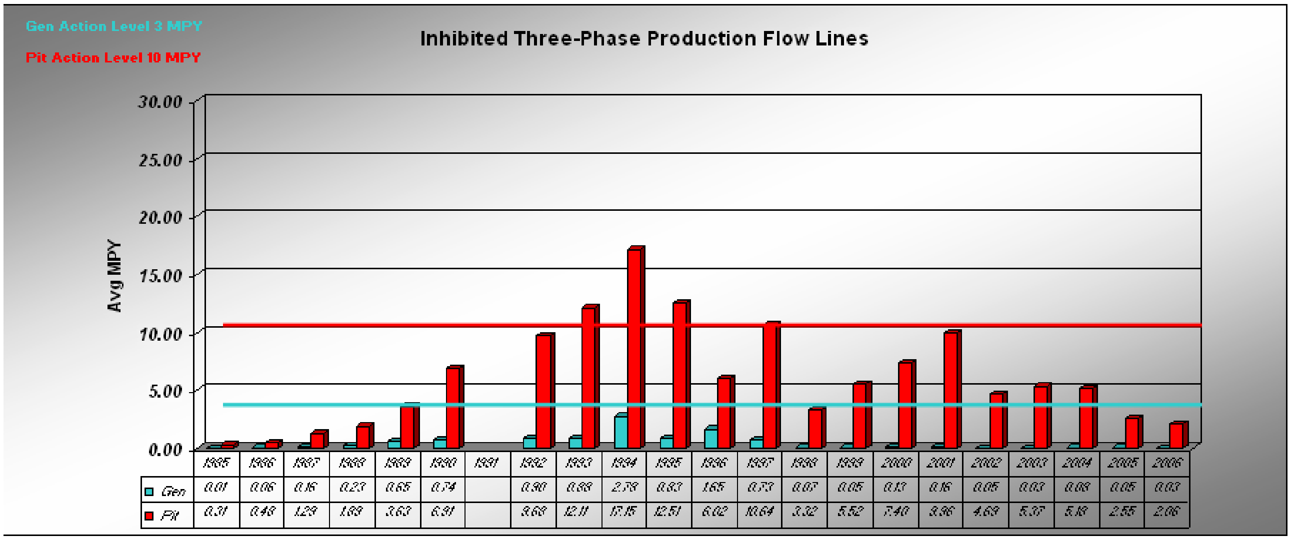


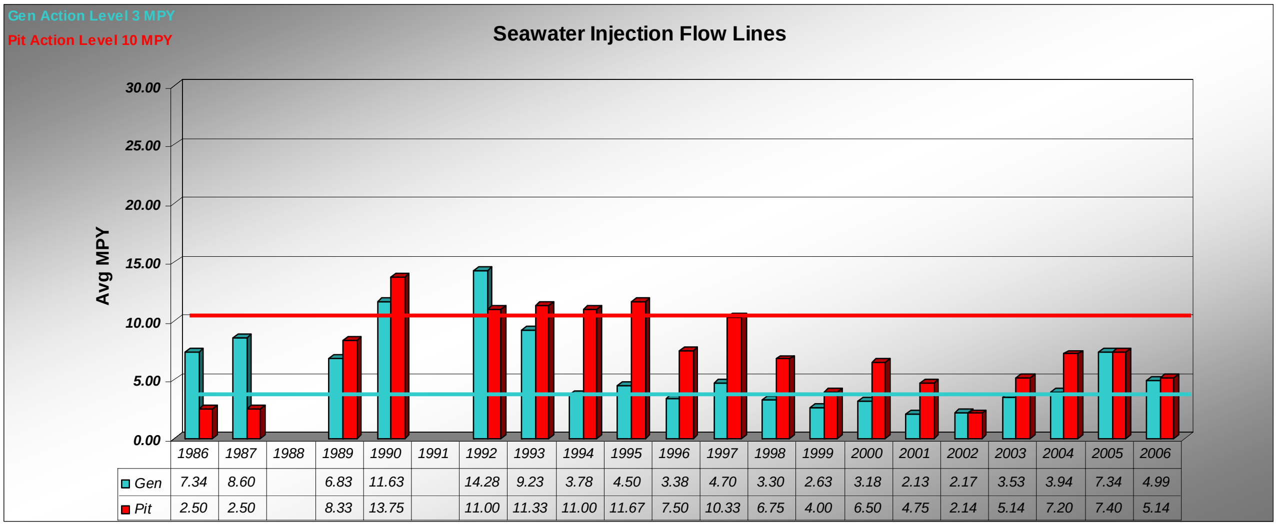
Figure 1. Inhibited Three-Phase Production Flow Line Coupons – general and pitting corrosion rates by year.

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

Recurring corrosion-rate monitoring (CRM) inspections also support the conclusion that corrosion is under control in the three-phase production flow lines. In 2006, 535 CRM inspections were conducted, with 4 minor increases found. Other internal inspection data supporting the CRM data are discussed in section 3.1.c, below.

Where corrosion rates exceeded targets, corrosion inhibitor concentrations were increased and/or the amount of inspection was increased. In 2006, coupon, probe or inspection-based corrosion rates exceeded targets or revealed increased damage on 15 lines. In 2006, inspection results indicated minor corrosion had occurred in eight of these fifteen 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.

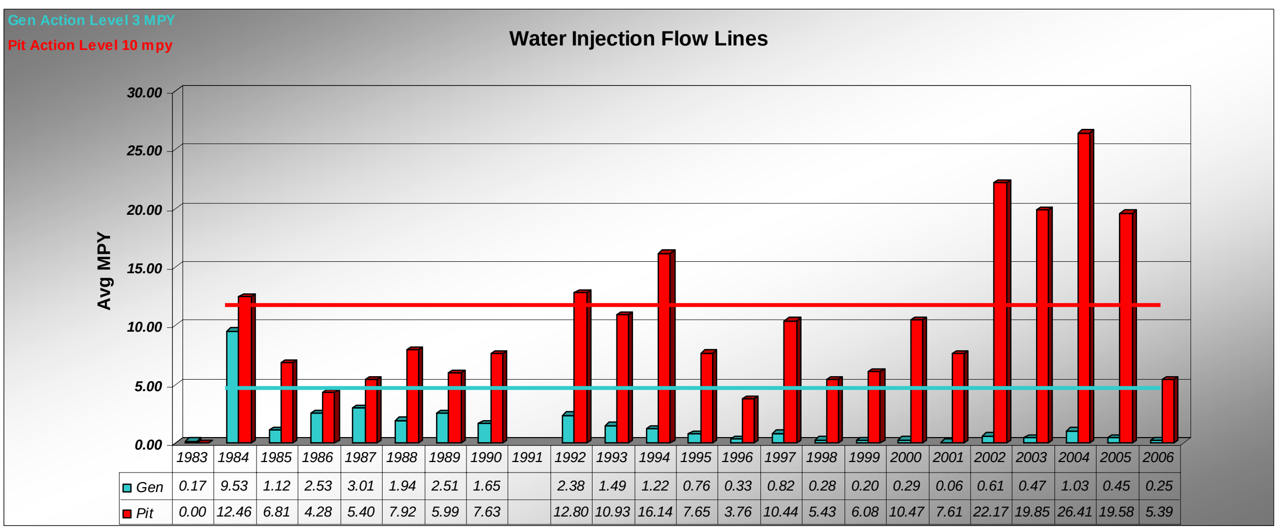
ConocoPhillips



	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gen	7.34	8.60		6.83	11.63		14.28	9.23	3.78	4.50	3.38	4.70	3.30	2.63	3.18	2.13	2.17	3.53	3.94	7.34	4.99
Pit	2.50	2.50		8.33	13.75		11.00	11.33	11.00	11.67	7.50	10.33	6.75	4.00	6.50	4.75	2.14	5.14	7.20	7.40	5.14

Figure 2. Seawater Injection Flow Line Coupons – general and pitting corrosion rates by year.

Sea Water Flow Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 2 above, show the average corrosion rates for the sea water flow line coupons. Average general corrosion rates are above the threshold and pitting rates for the field are below the threshold. Biocide concentration was doubled and pigging frequency increased in early 2006.



	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gen	0.17	9.53	1.12	2.53	3.01	1.94	2.51	1.65		2.38	1.49	1.22	0.76	0.33	0.82	0.28	0.20	0.29	0.06	0.61	0.47	1.03	0.45	0.25
Pit	0.00	12.46	6.81	4.28	5.40	7.92	5.99	7.63		12.80	10.93	16.14	7.65	3.76	10.44	5.43	6.08	10.47	7.61	22.17	19.85	26.41	19.58	5.39

Figure 3. Water Injection Flow Line Coupons – general and pitting corrosion rates as by year.

Water Injection Flow lines: The monitoring data summarized in Kuparuk Tables 1 and 2 is presented in Figure 3. Increased pigging and biocide have brought the WI flow lines pitting rates under control. Since seawater and produced water commingling were suspended at CPF2 in 2005, pitting rates have been reduced markedly. Coupon results are used to prioritize inspection efforts. During 2005 additional equipment was installed and procedures were implemented to provide enhanced biocide treatments at CPF2. Cleaning pigs were upgraded to include brushes in addition to the disks and the pigging procedures changed to included multiple (three) pig runs per monthly cleaning cycle.

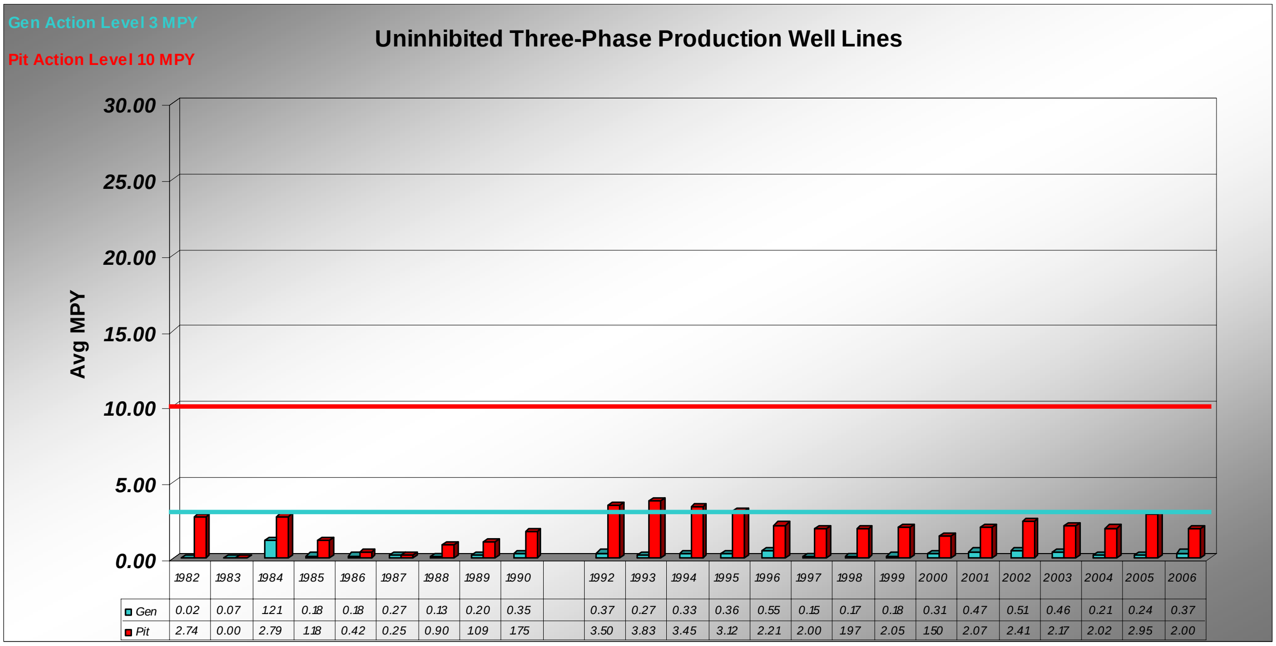


Figure 4. Uninhibited Three-Phase Production Well Line Coupons – general and pitting corrosion rates by year.

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.

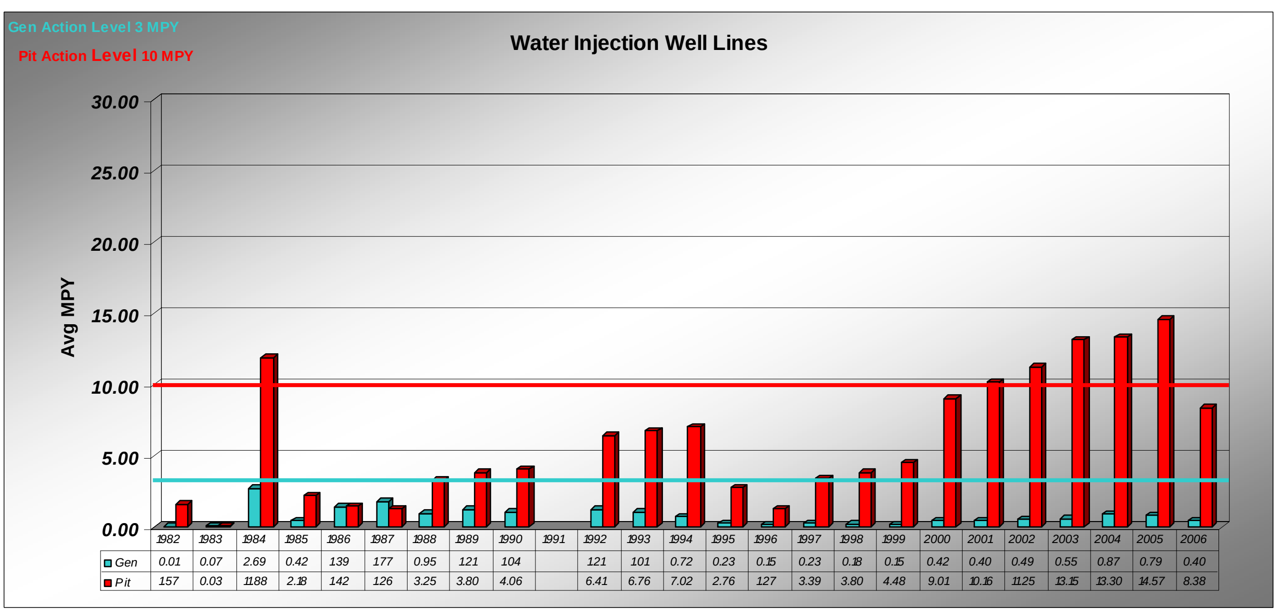


Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates by year.

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 Flow Line Coupons. We believe that corrosion in the water injection well lines is exacerbated by additional solids accumulating in the well lines because of low flow rates and improved pigging upstream of the well lines.

Mitigation:

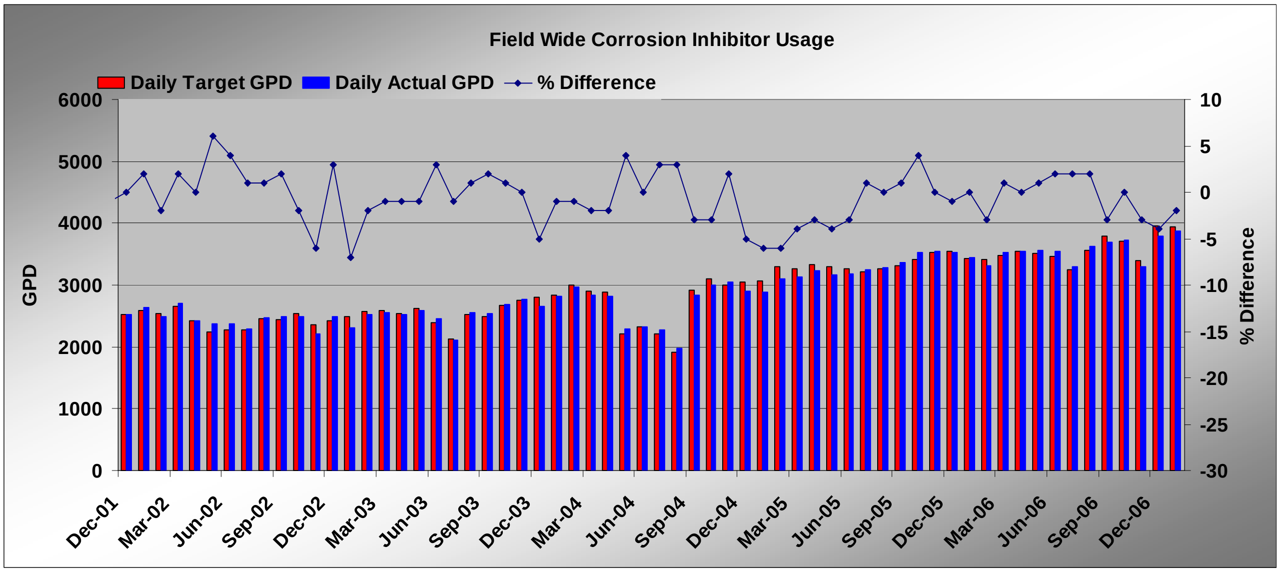


Figure 6. Field-wide Corrosion Inhibitor Use.

For the Kuparuk field, Figure 6 shows the actual number of gallons of corrosion inhibitor pumped per day, the recommended (target) number of gallons of corrosion inhibitor per day and the percent difference between the two. The average deviation for the year was -0.42%. Corrosion inhibitor use has increased since 2003 mainly because of field-wide water rate increases and increased corrosion rates caused by water and solids handling.

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.

In addition to chemical mitigation, the use of four-inch diameter well lines has been shown to reduce the corrosion rates in both three-phase production and WI services. The GKA continues to use four-inch pipe for new and replacement well lines.

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

Common Line	Probes	Coupons	Inspection	Action Taken
1APO			x	Increased Target PPM CI
1BPO	x	x		Increased Target PPM CI
1CPO	x			Increased Target PPM CI
1CPO	x			Increased Target PPM CI
1DPO		x		Increased Target PPM CI
1LFPO			x	Increased Target PPM CI
1QPO	x			Increased Target PPM CI
1RPO	x		x	Increased Target PPM CI
1YPO			x	Increased Target PPM CI
2APO		x	x	Increased Target PPM CI
2FPO	x		x	Increased Target PPM CI
2HPO		x		Increased Target PPM CI
2MPO	x	x		Increased Target PPM CI
2PPO	x			Increased Target PPM CI
2XPO			x	Increased Target PPM CI
3WO			x	Increased Target PPM CI

Kuparuk Inhibitor Feedback System

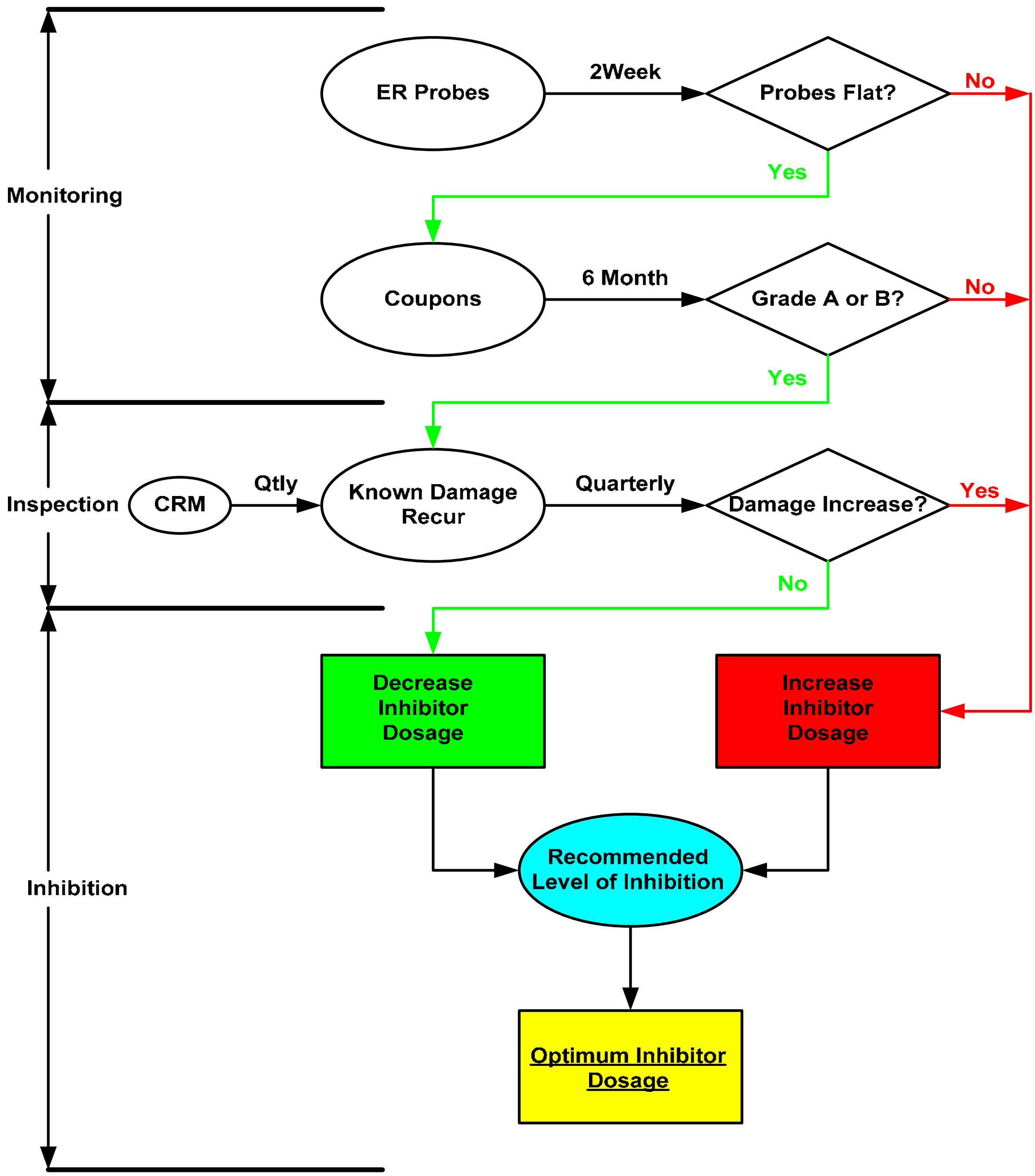


Figure 7. Corrosion Inhibitor Feedback System.

3.1.b Well Line Inspection

We did not meet our original 2006 goal of completing interval surveys on 132 well lines; however we did complete surveys on all 15 well lines that were due for inspection in 2006. The remaining 117 lines will be inspected as they come due in future years. The original goal was not completed because all extra inspection efforts were diverted to an increased flow line scope of work. However, no well lines that were due for inspection were not inspected in 2006.

As indicated in Figure 8 below, repair recommendations were initiated on 33 well lines in 2006 because of internal corrosion or a combination of internal and external corrosion damage (19 water injection lines and 14 production lines). The 32 saves resulted primarily from the Known Damage Recur (KDR) program that was unaffected by other inspection program priorities. The predominant corrosion mechanism was associated with solids (under-deposit corrosion or erosion). More information on the leak can be found in section 3.1.g.

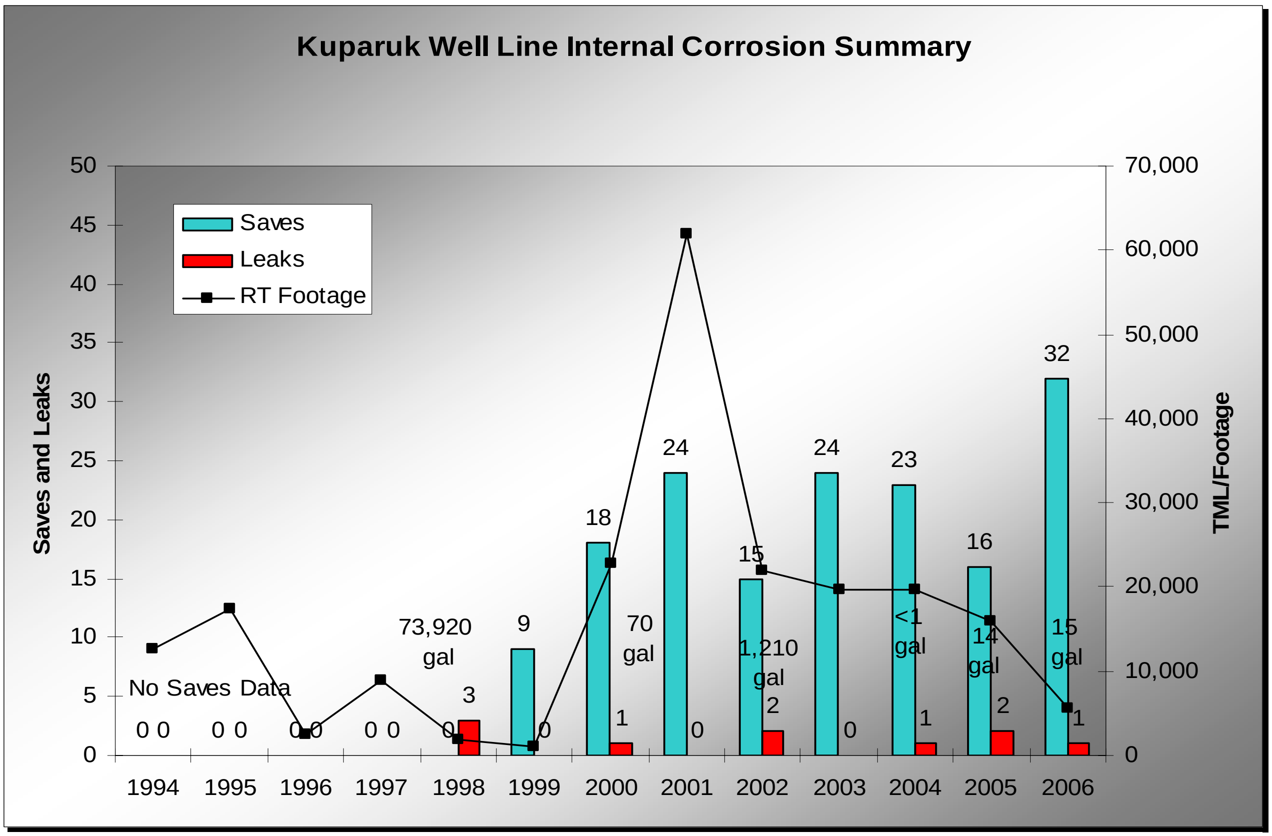


Figure 8. Summary of WI and Three-Phase Production Well Line Internal Corrosion Inspections – RT footage, leaks, and saves by year.

The 2006 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	1,124	5
Water Injection	2,431	10
Total	3.555	15

The 2006 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	186	1,041	471	47	10 %
Water Injection	112	961	275	77	28 %
Total	298	2,002	746	124	17 %

The 2006 manual RT well line data indicate a continuing increasing damage trend in the water injection well lines. The percentage of radiographs showing increased damage increased from 9% in 2004 to 19% in 2005 and then to 28% in 2006.

- **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	117	1,296	1,054	47	4 %
Water Injection	55	246	165	22	13 %
Total	172	1,542	1,219	69	6 %

The 2006 manual UT well line data indicated no new damage trends.

3.1.c Flow Line Inspection

In 2006 we exceeded our original flow line interval inspection goal of 33 flow lines by completing interval surveys on 66 lines. The significant expansion in the flow line inspection program was a result of increased focus on risk management of flow lines. In addition, the 30-inch sea water line from the STP to the CW Skid was smart pigged; no internal corrosion damage was found on this line.

As indicated in Figure 9 below, 16 repair recommendations were initiated on flow lines (7 water injection and 9 production) in 2006 because of internal corrosion damage. The corrosion mechanism for all repair recommendations was deadleg or solids-related corrosion. The leak was in the production system. More information on the leak can be found in section 3.1.g.

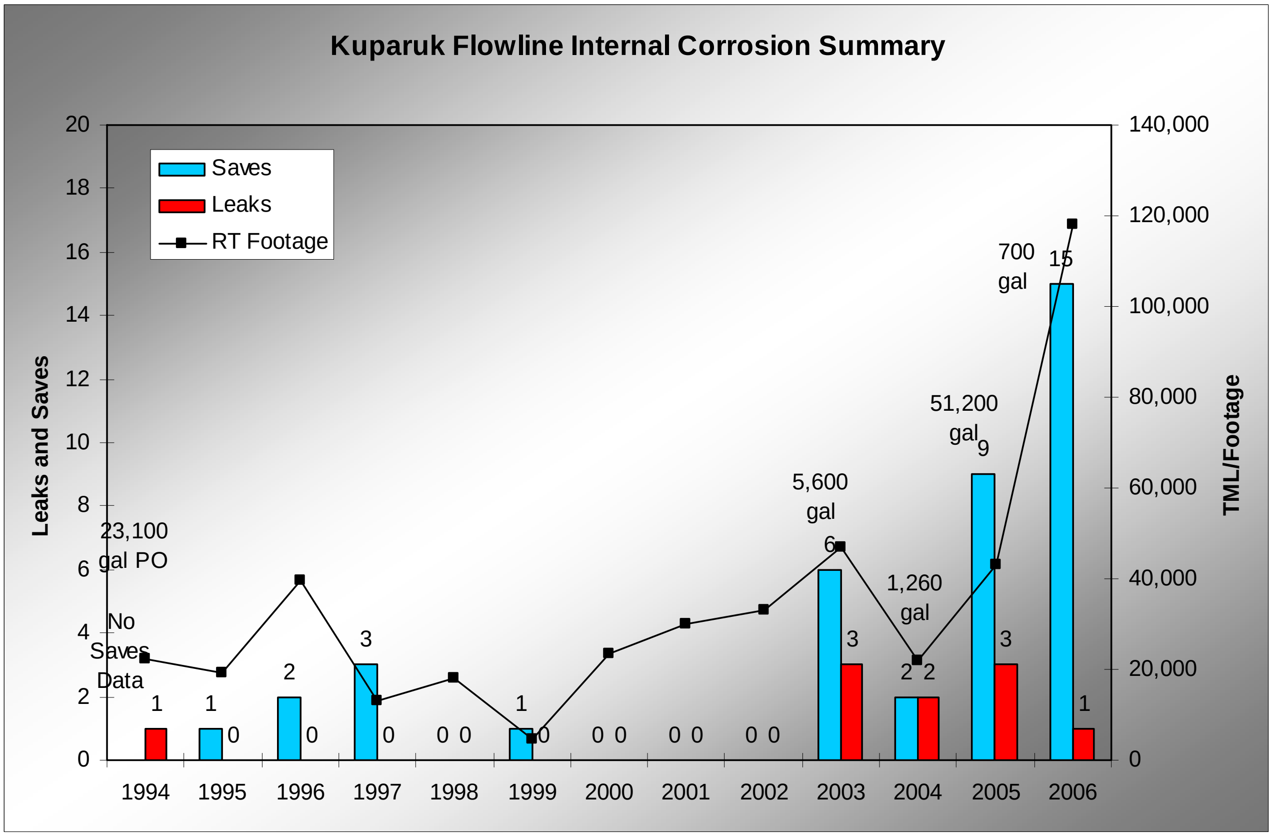


Figure 9. Summary of WI and Three-Phase Production Flow Line Internal Corrosion Inspections – RT footage, leaks, and saves by year.

The 2006 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

- **RTR of Flow line:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	59,402	38
Water Injection	51,187	28
Total	110,589	66

The 2006 RTR CC inspection results supported our hypothesis that low lying areas are more susceptible to corrosion especially in lines that are subject to low flow velocity and not maintenance pigged.

- **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	94	4.007	651	24	4 %
Water Injection	40	5.566	158	5	3 %
Total	134	9,573	809	29	4 %

The only significant change in the data from 2005 to 2006 was a decrease in the percentage of repeat radiographs with increased damage in the water injection system from 11% in 2005 to 3% in 2006.

- **Manual UT of Flow 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	70	749	349	18	5 %
Water Injection	42	1,140	283	24	8 %
Total	112	1,889	632	42	7 %

The 2006 manual UT flow line data indicated no new damage trends.

The 12-inch and 16-inch wet oil lines were smart pigged in 2006; because of sensor problems, the 16-inch wet oil line was smart pigged again in early-2007. Other than previously-known locations, no anomalies were found that indicated possible de-rating damage. Final reports of the smart pig runs were not received in 2006.

3.1.d External Program

In 2006 we had several significant accomplishments:

- Completed 5,610 TRT surveys of flow line and well line weld packs due for recur inspection. The overall goal for 2006 was 5,450 locations.
- Completed our goal of inspecting 100 Tarn-style weld packs (~357 to date) to ensure this new design is working properly. The weld pack design appears to be performing as planned. No corrosion has been detected on the piping within the weld pack areas.
- Completed our goal of inspecting 100 refurbished weld packs to verify the soundness of the Denso Tape refurbishments. The refurbishment technique appears to be performing well.
- Smart pigged the 30-inch sea water line from the STP to the CW Skid.

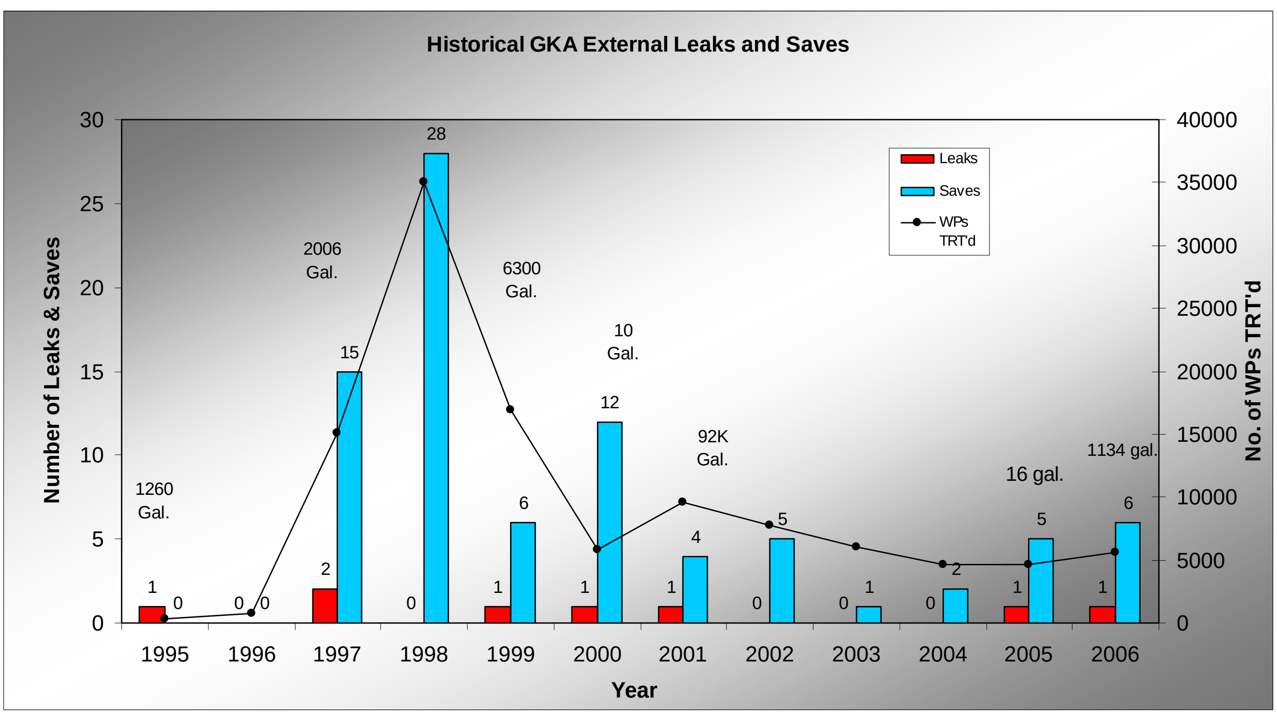


Figure 10. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks by year.

Flow Lines (On-Pad and Off-Pad)

The baseline inspection effort for all flow lines was completed in 2004. The focus in 2006 was to continue performing recur inspections based on the corrosion potential of selected lines. A goal of approximately 3,950 CUI locations on flow lines over tundra (off-pad) and on-pad was set. A total of 3,938 CUI locations were inspected. Crews continued to follow their guideline of inspecting at 12 o'clock as well as 6 o'clock on weld packs found to have heavy to medium water. This technique is expected to reduce the likelihood of missing corrosion that might have formed higher up on the pipe when there is little to no indication of corrosion at 6 o'clock.

Of the 3,869 CUI locations TRT inspected on the over-tundra lines a total of 118 locations were found with corrosion. Four flow line locations required installation of temporary sleeves (one on CPF3 to CW Skid Wet Oil, two on 3R PO, one on 3N PO). Of the 69 CUI locations TRT inspected on the on-pad, only three exhibited corrosion damage and were placed on the refurbishment list. No temporary sleeves were installed on these lines. No leaks were reported from flow lines because of external corrosion.

Included in the 3,938 TRT inspections noted above, 97 of the new Tarn-style weld packs were inspected with TRT to gauge how they are performing. A total of 11 weld packs were found with light to medium water inside the clamshell insulation (no water was found in the factory applied insulation). No corrosion under insulation (CUI) was found in any of the areas inspected.

Denso tape continued to be the material of choice to refurbish flow line and well lines with external corrosion. Evidence collected through inspection of 100 refurbished weld packs showed that this technique appears to perform well. No evidence of additional corrosion has been documented at these locations. This sampling technique is expected to continue in future years to detect any weaknesses.

The 30-inch sea water line from the STP to the CW Skid was smart pigged in 2006; smart pig data show that there are no internal corrosion locations and forty-six networks of external corrosion. One external corrosion network at the STP end of the line was excavated and 90% wall loss was found; this location was repaired and is available for subsequent external inspections.

The 12-inch and 16-inch wet oil lines were smart pigged in 2006; because of sensor problems, the 16-inch wet oil line was smart pigged again in early-2007. Other than previously-known locations, no anomalies were found that indicated possible de-rating damage. Final reports of the smart pig runs were not received in 2006.

Well Lines

In 2006, 1,672 CUI locations were inspected with TRT. Of these, 12 locations were located over the tundra. Corrosion was found in 104 of these locations, none of which was over the tundra. Our stated goal was 1,500 weld packs (based on inspection of 160 lines). One leak required repair (WI well 2X-08) and resulted in a spill volume of 1,134 gallons of produced water (reported to ADEC). The corroded weld packs were added to the refurbishment list.

Table 5: External CUI Inspection Summary for 2006.

Type of Equipment	2006 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Flow lines Over Tundra or On-Pad	3,915	3,938	121	3.1	997
Well Lines	1,500	1,672	104	6.2	76
Total	**4,415**	**5,610**	**225**	**4.0**	**1,073**

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

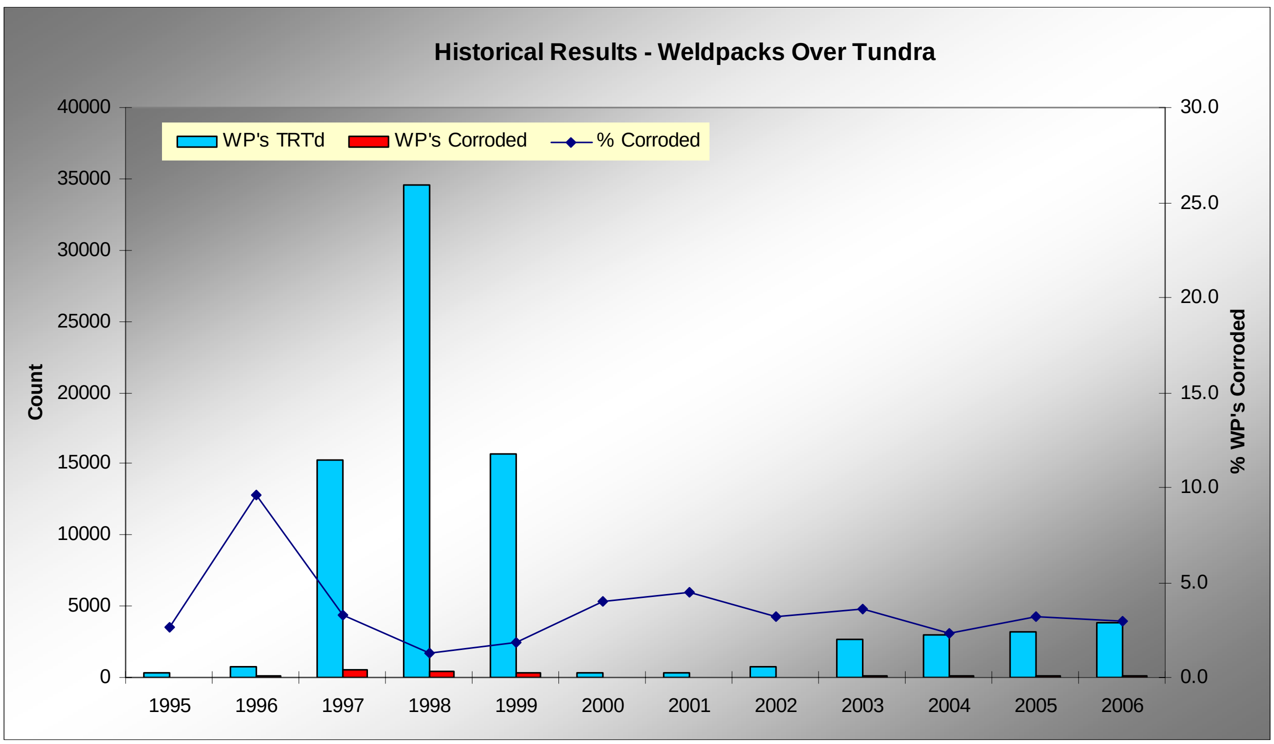


Figure 11. Summary of Flow Line Over-Tundra (off-pad) Weld Packs.

Figure 11 illustrates the latest results from the external corrosion inspection program. 2002 through 2006 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

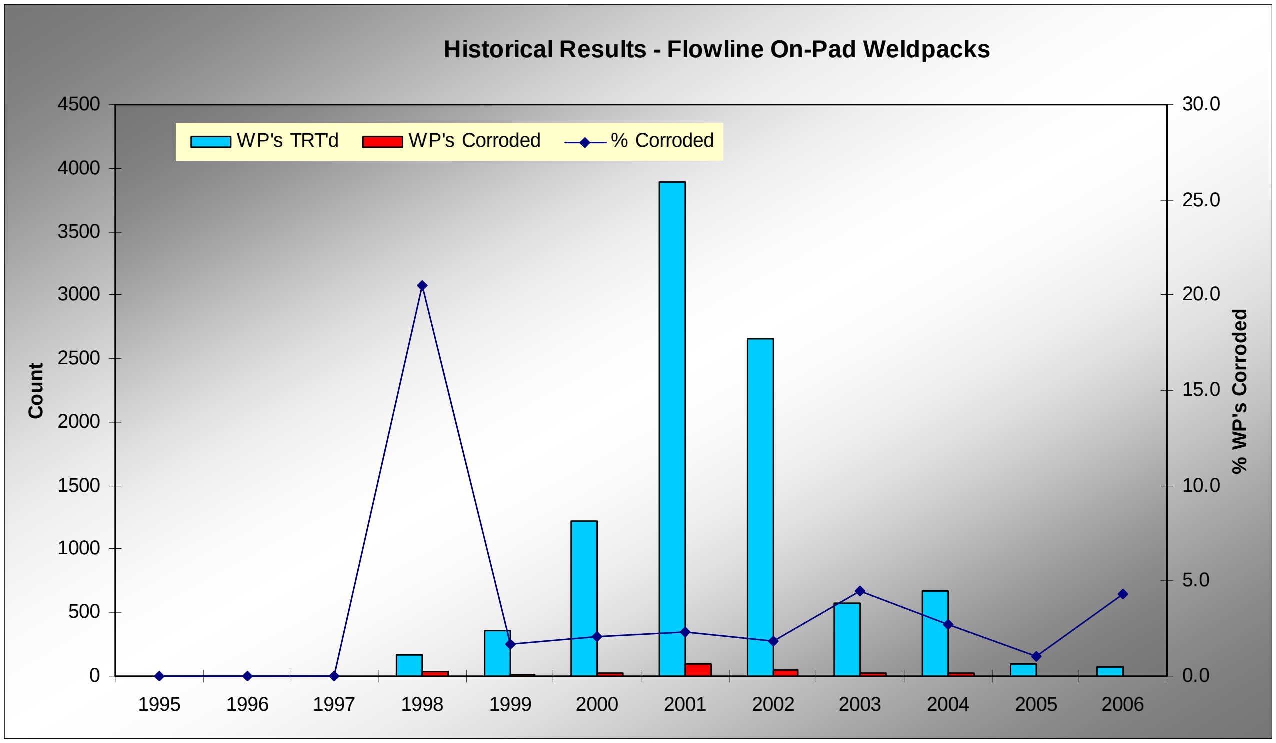


Figure 12. Summary of Flow Line On-Pad Weldpacks.

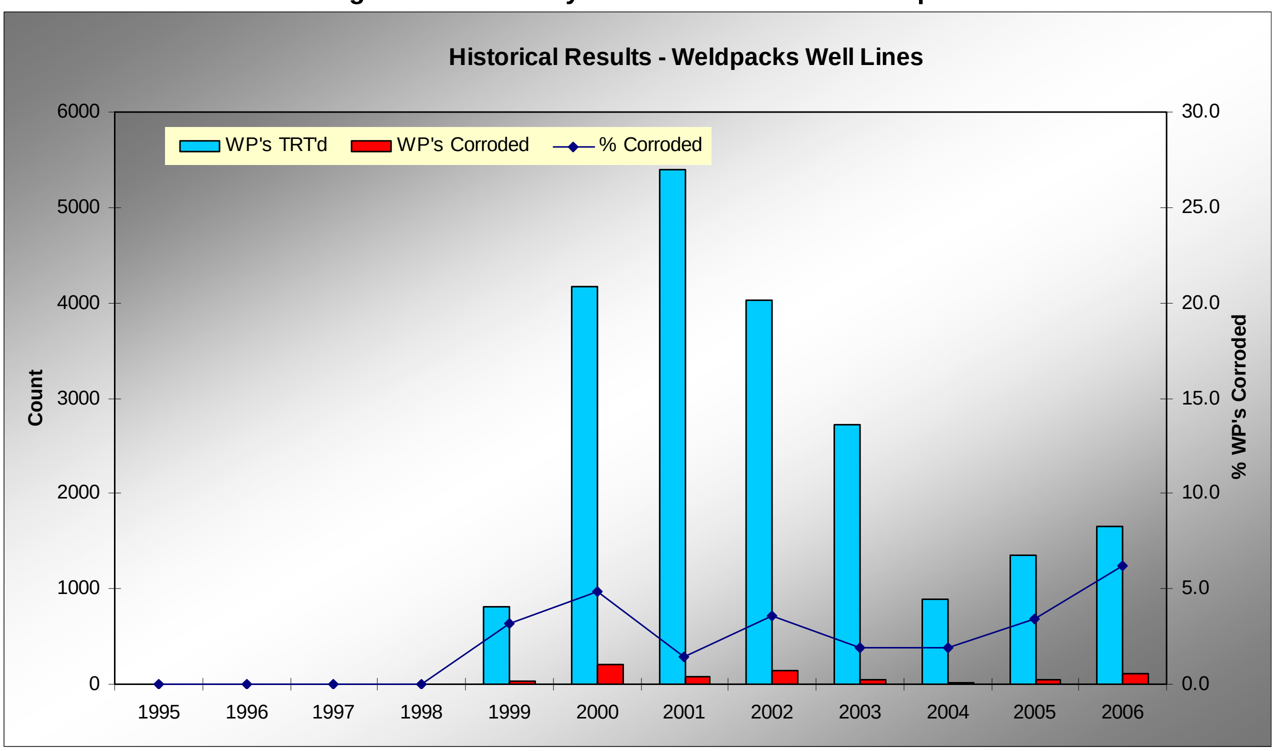


Figure 13. Summary of Weld Packs on Well Lines.

Corrosion Under Insulation Buffer Spike Program

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

The final report issued in 2006 indicates that the buffer spikes have been a technical success, but the refurbishment program is more effective than any interim mitigation afforded by the buffer spikes. In those locations that have been refurbished with Denso tape and new insulation, no water or corrosion has been found at the pipe surface. We believe that refurbishment provides effective long-term mitigation.

3.1.e Below Grade Piping Program

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

In 2006 we had several significant accomplishments:

- Visually inspected and cleaned all debris from all 771 cased below grade pipe circuits.
- Completed our specialty inspection (TWI) scope of work on 132 below grade circuits.
- Excavated, inspected, refurbished and / or repaired (as required) 31 cased below-grade pipe circuits.

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

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

GKA has 771 circuits (includes priority 1, priority 2 and priority 3 lines) of below grade piping. Of these locations, one is contained in an utilidor. The remaining circuits are cased lines, the majority of which are either road, gravel pad or caribou crossings.

Utilidor Line

The line in the utilidor (Oily Waste Injection Line, BG ID #286) was taken out of service in 2004 because it was no longer needed for operations. It had been on a two year inspection cycle and was last inspected in 2002. Because it has been taken out of service, it was not inspected in either 2004 or 2006.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2006. 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 GKA below-grade circuits, 106 were found to have pipe in direct contact with gravel/soil or debris in the casing. All locations were remediated in 2006.

3.1.e (2) Results of Specialty Testing

Inspection Status:
In 2006, we completed TWI inspections on 132 GKA priority one circuits. This was the fourth year of our recurring inspection program where each priority one circuit was inspected at a maximum ten-year interval.

In 2006 only the long-range ultrasonic system technology from The Welding Institute (TWI) was used. TWI technology is capable of finding evidence of both internal and external corrosion damage.

Results and Remedial Action:

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

Table 6. Results from the TWI inspections by service.

Service	Number of Cased Circuits Inspected	Incomplete or Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Minor to Moderate and Moderate Anomalies (M)	Number of Moderate to Severe and Severe Anomalies (S)
Oil	49	5	28	19	6	1
Other	83	7	34	24	7	1
Total	132	12	62	43	13	2

The 2006 TWI data showed a drop in "Incomplete / Inconclusive" results from 26 in 2005 to 12 in 2006. The two severe locations have been excavated and inspected; no repairs were necessary.

3.1.e (3) Results of Crossing Refurbishments

The number of below-grade piping circuits refurbished increased from 24 in 2005 to 31 in 2006. Twenty-six circuits were excavated and five were replaced without excavation (cut and pulled through casing). Eight of the 26 circuits are considered "repairs" because they have either been repaired, have been recommended for repairs, or the repair action is pending:

- Five repairs were recommended because of extensive internal damage to the above ground portion of the line (3 circuits on the 2GWI line and 2 circuits on the 2XWI line).
- One repair was made to the 30" seawater line from STP because of external damage only.
- Two repairs were recommended because of internal damage only (2KHWI at 2H pad and 1QWI at a caribou crossing). The 2KHWI damage was repaired by external weld overlay, and the 1QWI replacement is still pending.

For all 31 below grade circuits excavated or replaced-without-excavation in 2006, the insulation was refurbished and the pipe wrapped with Denso tape to prevent further corrosion.

3.1.f Other Structural Concerns

Subsidence:

Existing Well Upgrade Program

- In 2006, no conductor-mounted floor kits were installed in existing well houses at Kuparuk. A total of 15 fiberglass floor kits were installed in well houses at Drill Sites 1Y, 1C, 1D, and 1E.
- In 2006, 15 heat tubes were installed at Drill Sites 2M, 3C, 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 2006, 14 newly drilled wells at Kuparuk were installed with insulated conductors.
- In 2006, 21 newly drilled wells had heat tubes installed. Of these 21 newly-drilled wells, seven had floors with permanent pipe supports.
- In 2006, one existing producer converted to water injection wells already had an insulated conductor and heat tubes and did not require a floor kit.

Wind-Induced Vibration:

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

During original development of the North Slope wind-induced vibration (WIV) program, secondary mode WIV failures were deemed highly unlikely and therefore mitigating measures for such events were not established. However, based on the unforeseen December 2004 secondary mode WIV failure on the -I-M eight-inch gas lift line line, an effort to determine if secondary mode WIV is expected to be a fatigue threat to all the pipelines within the Kuparuk Wind Fan was sanctioned.

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

As a result of these analyses, a total of 367 pipe spans were equipped with secondary mode WIV mitigation (Tuned Vibration Absorbers, TVA’s) in 2006. More detailed evaluations will be completed once enhancements are completed to the WIV evaluation model to take into account broad-banded WIV events more typical of higher wind velocities.

Because of the failure of the DS2F 8” WI line in 2006 and the DS2X 8” MI line in 2002, the Kuparuk Wind Fan was expanded five degrees in both directions to include all pipeline segments with azimuths oriented from N50° W to N35° E (Original Wind Fan N45° W to N30° E). This resulted in a total of 922 additional pipeline segments requiring primary mode WIV mitigation (TVA’s). Essentially all TVA’s have been installed with a small number to be completed (approximately two days work required) in April when the back-ordered materials arrive. Prior to installing the TVA’s on these segments shear-wave ultrasonic testing (UT) was performed on a percentage of welds within each segment. This was a progressive inspection that parallels the progressive weld examination method as established in the ASME B31 Piping Codes. This inspection revealed that no detrimental indications existed in any welds that were inspected other than several welds in the DS2F 8” WI line. There were a total of four (4) welds identified as having rejectable indications in the DS2F 8” WI line; two (2) welds had linear indications and two (2) welds contained original construction defects. All four (4) welds were replaced (i.e., cut out and re-welded) prior to installing the TVA’s.

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

- The 3M-06 water injection well line leaked in September of 2006 because of internal under-deposit corrosion. The spill volume was 15 gallons of sea water that was confined to the gravel pad. No fluids contacted the tundra. As such, it was determined to not be an ADEC reportable spill.

- The 2M produced oil flow line leaked in March of 2006 because of internal corrosion damage. The spill volume was 700 gallons of produced fluids onto the tundra. The spill was reported to ADEC. As a result of this leak CPAI conducted a “Physical Causes Failure Analysis” in which ADEC subject matter experts participated. The results have been released to ADEC.

- Well 2X-08 water injection well line leaked in June 2006 because of CUI damage at a span between two weld packs. The spill volume was determined to be 1134 gallons, and was reported to ADEC. As a result of this leak the previous internal and external corrosion inspection records were reviewed. The review indicated that this portion of the line had been inspected with real-time radiography and it was noted that the insulation appeared to contain water. No follow-up tangential radiography was performed. Consequently, the RTR guidelines have been revised to include a requirement that all notes on RTR reports indicating water in the insulation shall have additional inspection performed. This includes flow lines and drillsite lines.

- The DS2F Gas/Miscible Injection (GI/MI) Line leaked in January of 2006 as a result of weld failures due to WIV. The result was a 466,000 SCF gas release and an associated 23 gallon natural gas liquid (NGL) spill. A total of four (4) welds were verified as visibly leaking when the insulation was removed and the line was pressured with nitrogen. All welds were removed and sent to Bartlesville for failure analysis; this failure analysis is on-going. In addition to the removal of these four (4) welds, all welds in this segment (i.e., all pipe welds oriented in the same azimuth) were inspected using shear-wave UT. This UT inspection revealed “rejectable linear indications” on three (3) welds in this segment, and all three (3) welds were replaced (i.e., cut out and re-welded) prior to re-commissioning the line.
- No leaks were caused by subsidence in 2006.

Figures 8, 9, and 10 above 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 flow lines. Figure 10 shows the leaks caused by external corrosion for flow lines, well lines, and below-grade piping locations.

3.2 Year 2007 Forecast

3.2.a Monitoring & Mitigation

- Test additional inhibitor formulations.
- Install additional inhibitor storage capacity at several Drill Sites.
- Continue to evaluate maintenance pigging enhancements to the water injections systems.
- Plan installation of inhibitor/biocide injection capacity for the water injection system.
- Continue to evaluate biocide and maintenance pigging in the seawater system.
- Install new monitoring locations on water injection lines.

3.2.b Well Line Inspection

Our recurring inspection program will continue in 2007. No in-service line will go longer than 10 years without some type of inspection.

3.2.c Flow Line Inspection

Our recurring inspection program will continue in 2007. No in-service line will go longer than 5 years without some type of inspection.

Smart pigging is planned for the 2P three-phase production line.

3.2.d External Program

Flow lines over tundra:

- Inspect approximately 16,000 flow line CUI locations (based on fifty lines) as part of our recurring inspection program. This includes CUI locations over tundra as well as on-pad. This represents a significant increase in CUI inspections from previous years based on the implementation of API-570 guidelines to this 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 Denso tape system.

Well lines:
Inspect approximately 3000 well line corrosion-under-insulation locations (based on 130 lines) as part of our recurring inspection program. This essentially doubles the number of CUI inspections.

3.2.e Below Grade Piping Program

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

- Continue our recurring TWI inspection program of priority one cased lines. Starting in 2007, the inspection interval will be changed from 10 years to 5 years. By inspecting 20% of the 620 priority 1 cased below grade piping circuits each year all circuits will meet this criterion by the end of the 2008 inspection year.

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

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

3.2.f Other

- Continue enhancements to the Kuparuk Corrosion Database.

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

ConocoPhillips

4.0 Program Status Summary - WNS

4.1 Year 2006 Overview

4.1.a WNS Monitoring & Mitigation

In 2006 we completed a test of a new corrosion inhibitor formulation for three-phase production flow lines.

We also enhanced monitoring of the water injection system by instituting bacteria monitoring of the pigging returns in the seawater injection line from Kuparuk to Alpine.

Average general and pitting coupon corrosion rate data for Year 2006 are presented in Tables 7 and 8.

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

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average General Corrosion Rate, mpy (target=<3)	Number of Lines with Conformant General Corrosion Rates	Percent of Lines with Conformant General Corrosion Rates
Three-phase Production Flow Lines	2	2.4	2	100
Seawater Flow Lines	1	2.4	1	100
Seawater Injection Flow Lines	0**			
Production Well Flow Lines	29	1.1	27	93*
Water Injection Well Flow Lines	10	0.2	10	100

* *Of the two lines with greater than 3 mpy CR, one was 3.8 mpy and the other was due to erosion.*

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

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Percent of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Flow Lines	2	55	0	0
Seawater Flow Lines	1	3.0	1	100
Seawater Injection Flow Lines	0**			
Production Well Flow Lines	29	0.5	29	100
Water Injection Well Flow Lines	10	13	5	50

*** NOTE: This coupon location is currently not accessible because of a piping obstruction, however two ER probes indicate a corrosion rate of <1mpy.*

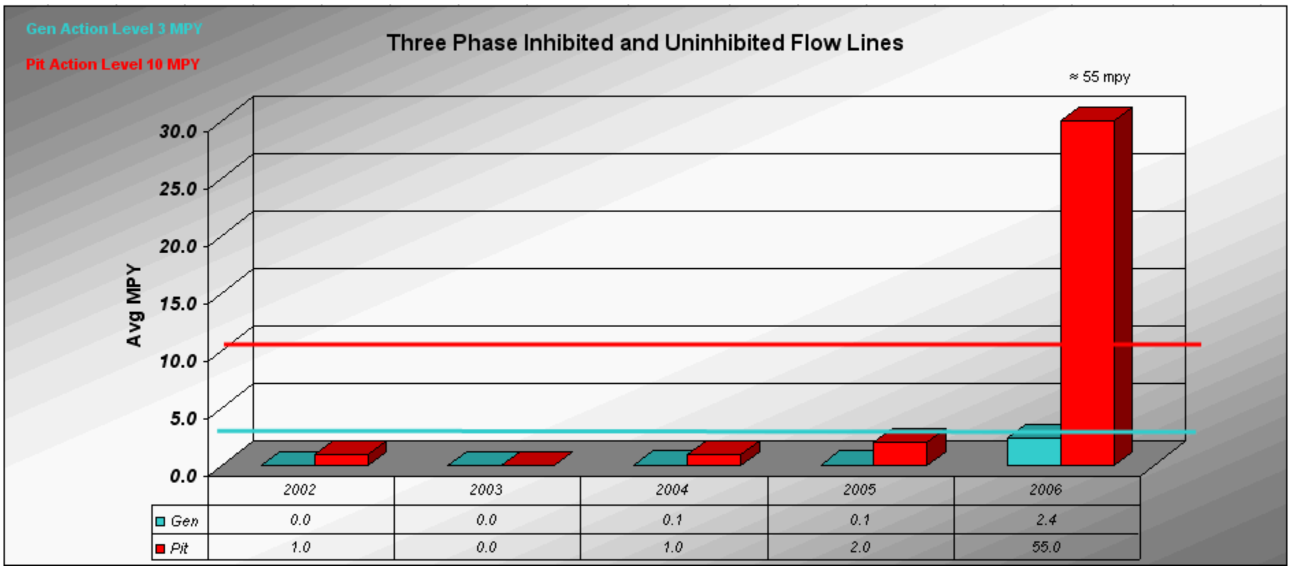


Figure 13. WNS Three-phase Production Flow Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Flow Lines: The monitoring data summarized in WNS Tables 7 and 8 and presented in Figures 13 show that pitting corrosion rates exceeded the action level.

In response to the coupon and probe corrosion rates, corrosion inhibitor concentrations in the CD1 line were increased several times. In addition, a new corrosion inhibition formulation was tested in December 2006.

The pitting corrosion rate in one coupon in the CD2 line was also high. This line did not receive corrosion inhibition treatment in 2006. Corrosion inhibitor injection facilities had been planned to coincide with water breakthrough at this drillsite. The actual water production rate outpaced the forecasted water rate significantly. To respond to the unexpected water rate, the installation of the injection facilities has been accelerated.

Figure 14. WNS Three-phase Production Well Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Well Lines: The monitoring data summarized in WNS Tables 7 and 8 and presented in Figures 14 show that corrosion rates have not approached action levels in the well lines. Inspection data, discussed in section 4.1.b, indicates that significant corrosion damage has not taken place in these lines.

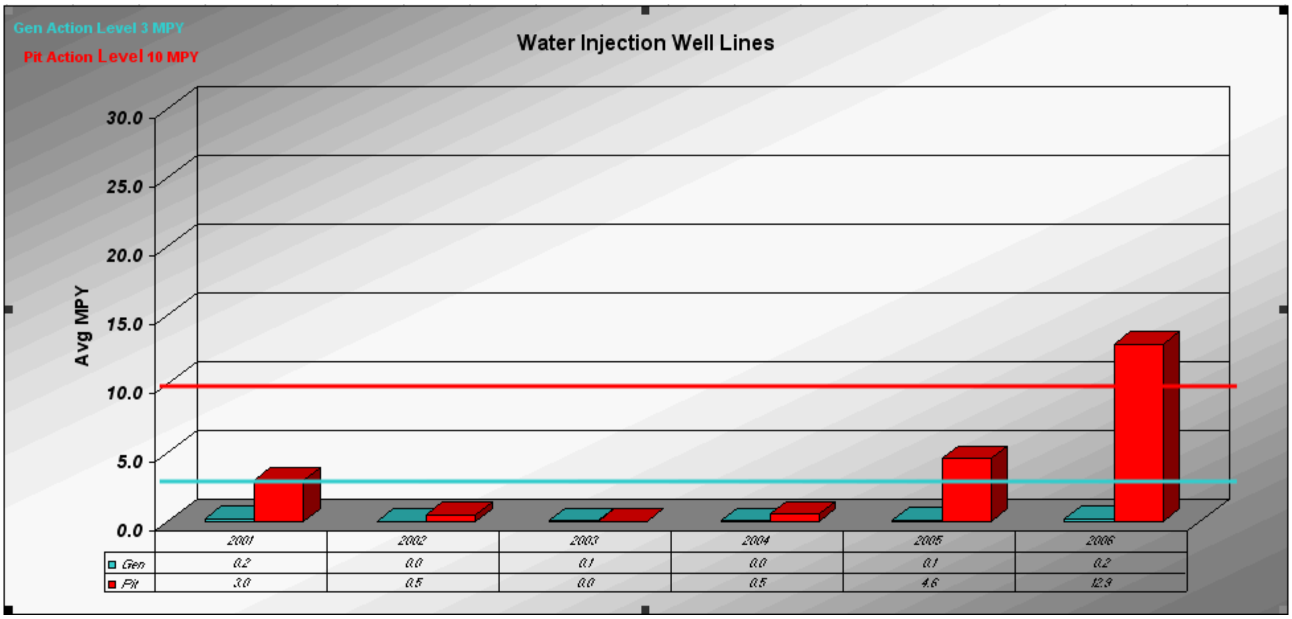


Figure 15. WNS Water Injection Well Line Coupons – general and pitting corrosion rates by year.

Water Injection Well Lines: The monitoring data in Figure 15 show that corrosion may be beginning in the injection wells in the WNS. Inspection data presented in section 4.1.b do not indicate damage in these lines, but given Kuparuk's experience with corrosion-related repairs, WNS inspection programs will continue to look for damage in the injectors.

The seawater used for injection is filtered, deaerated, and biocided at Kuparuk before being shipped to the WNS. The improvements made in maintenance pigging both at Kuparuk and in the WNS may have increased the amount of solids carrying through the system to the injection well lines.

The produced water is biocided in the facility. Some mixed water (produced and sea water) is injected only at drill site CD1. Scale inhibitor is added to the produced water in the facility in sufficient quantities to inhibit the production of adherent scale in the mixed water system.

4.1.b Well Line Inspection

In 2003, 33 three-phase production lines and 22 water injection lines were inspected; no damage was found.
In 2004, 18 three-phase production lines were inspected at direction changes; no damage was found.
In 2005, 32 well lines were inspected, no damage found.
In 2006, 19 well lines were inspected. One production line had 26% wall loss, 5 lines had very slight damage, and no damage was found on the remaining 13 lines.

4.1.c Flow Line Inspection

Manual RT of approximately 5% of the CD1 three-phase production line was completed as planned. Damage up to 15% wall loss was found on this line.

In addition, manual RT was completed on the CD2 three-phase production line, and the CD1 and CD2 water injection lines. No damage was found.

ConocoPhillips

4.1.d External (Weld-Pack) Program

In 2006 we completed inspections of the Tarn-style weld packs on 20 well lines to ensure the new design is working properly. The weld pack design appears to be performing well. No corrosion has been detected on the piping within the weld pack area.

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

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2006. 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:
During the 2006 visual survey, no gravel, soil or debris was found in the casings, and no other problem conditions were identified.

Of all the below-grade lines, two lines have pipe in direct contact with soil. These two lines are considered to be "direct buried". These locations were excavated and evaluated in 2005. ADEC granted a waiver on these two lines, contingent on a stringent inspection program. The next inspection of the buried portions will be in 2009.

4.1.e (2) Results of Specialty Testing

No specialty testing was performed in the WNS in 2006. Of the 51 WNS below grade circuits, 12 are smart pigged with the remainder of the line.

4.1.e (3) Results of Crossing Digs

No excavations were done in 2006.

4.1.f Other Structural Concerns

Subsidence:

No concerns identified.

Wind-Induced Vibration:

No problems identified in 2006.

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

- No leaks were caused by external corrosion in 2006.
- No leaks were caused by wind-induced vibration in 2006.
- No leaks were caused by internal corrosion in 2006.
- No structural or subsidence concerns were identified in 2006.

4.2 Year 2007 WNS Forecast

4.2.a Monitoring & Mitigation

- Pull coupons as scheduled
- Install corrosion inhibitor injection system at the CD2 drillsite
- Test additional inhibitor formulation

4.2.b Well Line Inspection

Inspect 30 lines, 25% of existing total for internal corrosion.

4.2.c Flow line Inspection

Inspect with linear array 1400 ft of the CD2 water injection line

Inspect with manual RT the CD2 three-phase production line.

4.2.d External (Weld-Pack) Program

Flow lines over tundra:
Inspections of 200 Tarn-style weld packs planned

Flow lines on pad:
No inspections planned

Well lines:
TRT inspection planned on 40 lines, at the locations that are most likely to have CUI

4.2.e Below Grade Piping Program

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

After the first ten years of service and every five years thereafter, the priority one and two cased lines will be evaluated using NDE. Each below grade section of these lines is externally coated, delaying the onset of external corrosion and allowing more time before the initial inspection.

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.
- **Flow 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 is 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 (PO)** – 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.