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

March 31, 2010

Commitment to Corrosion Monitoring
10th Annual Report to the Alaska Department of Environmental Conservation

Prepared by
ConocoPhillips Corrosion Team

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1.0 OVERVIEW

The purpose of this 10th Annual Report is to communicate the details of the individual programs that implement the ConocoPhillips Alaska (CPAI) 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 are incorporated into this and future North Slope Charter Corrosion Reports.

The Greater Kuparuk Area (GKA) produces approximately 135,000 BOPD from 47 drill sites into three processing facilities. Effective management of corrosion at GKA is critical to maintain environmental and facility integrity, to reduce field operating costs, and to extend infrastructure life to maximize oil recovery.

The Western North Slope (WNS) consists primarily of the Alpine field and produces approximately 90,000 BOPD from four drill sites into one processing facility. The corrosion management system used at GKA has been adapted to WNS.

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

2.0 SIGNIFICANT ENHANCEMENTS TO CORROSION PROGRAMS

A&OI website was launched, which is more comprehensive for program management and regarding interfacing with other groups.

Operations Damage Report (ODR) was migrated to our Corrosion Database (CDB) from a spreadsheet-based tool, enabling better data management and interfacing with Operations.

Implemented pilot mesh radio network system for electrical resistance (ER) probes at Kuparuk.

Implemented a program to upgrade and maintain level gages in chemical tanks.

Commissioned biocide facility to treat individual water injection (WI) lines at CPF2.

Updated the Corrosion Strategy Manual, in which a WI line corrosion mitigation matrix to manage service changes was incorporated.

Automated inspection programs were seasonally adjusted to be active during optimal weather windows thus increasing productivity and minimizing lost time.

Infrared (IR) thermography and wireless crawlers have sufficiently advanced to be incorporated into our core inspection programs.

Implemented the first steps to digital radiography adaptation and installed film digitizing equipment for radiographic (RT) images.

Successfully used an ultrasonic testing (UT) pig for the first time in the GKA.

Implemented temporary upgrades to enable ILI of 2PWI and related flow line circuits.

ILI analyst embedded in the field during the smart pigging runs, increasing speed of reporting and responsible for identifying two imminent threats.

Added three-dimensional microscopy to lab capabilities.

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3.0 SUMMARY OF CPAI PROGRAMS

CPAI had several significant accomplishments in 2009 including the following:

- Completed testing of two new corrosion inhibitors (CI's) at GKA.
- Changed to a better-performing CI at WNS.
- Successfully executed our routine inspection programs in both GKA and WNS.
    - Completed internal interval surveys on 220 well lines scheduled for inspection in 2009. Completed our external interval inspection program on 724 well lines.
    - Completed internal corrosion inspection interval surveys on all flow lines scheduled for 2009.
    - Using conventional inspection techniques and in-line inspection (ILI), completed approximately 20% of the flow line CUI IA's at GKA.
    - Visually inspected all priority 1, 2 and 3 cased below-grade pipe circuits.
    - Completed our specialty inspection Long Range UT (LRUT) scope of work on all below grade circuits scheduled for 2009.
- Successfully ran ILI in 19 WI flow lines (18 at GKA, one at WNS).

4.0 GKA PROGRAM STATUS SUMMARY

A. Monitoring & Mitigation

In 2009 we had several significant accomplishments:

- Carried out two field tests of new corrosion inhibitors.
- Expanded use of more aggressive maintenance pigs.
- Commissioned the CPF2 supplemental biocide batch injection system for water injection lines.

Average general and pitting coupon corrosion rate data for Year 2009 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	Percentage of Lines with Conformant General Corrosion Rates
Three-phase Production Flow Lines	58	0.01	58	100%
Seawater Transfer Flow Lines	2	1.2	2	100%
Water Injection Flow Lines	63	0.15	63	100%
Production Well Lines	575	0.33	565	98%
Water Injection Well Lines	407	0.14	403	99%

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	Percentage of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Flow Lines	58	1.9	57	98%
Seawater Transfer Flow Lines	2	13	1	50%
Water Injection Flow Lines	63	8.3	48	76%
Production Well Lines	575	1.9	554	96%
Water Injection Well Lines	407	5.2	346	85%

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

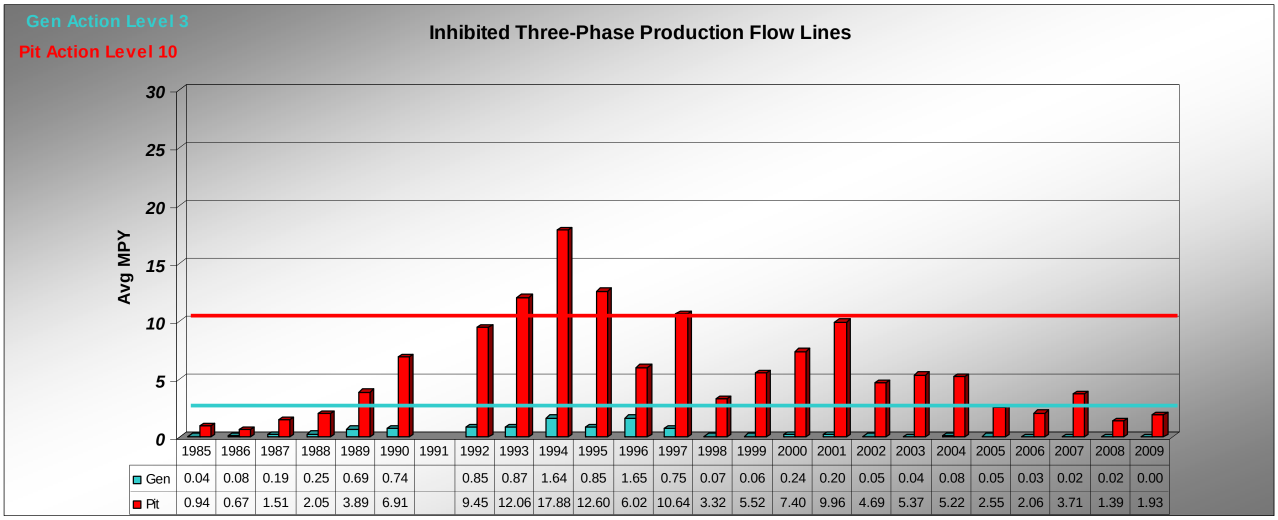

Figure 1. Inhibited Three-Phase Production Flow Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Flow Lines: The monitoring data summarized in 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 line system from CPF3 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 2009, 1703 CRM inspections were conducted, with 15 confirmed increases found. Other internal inspection data supporting the CRM data are discussed in Section B.1.b, below.

Where corrosion rates exceeded targets, CI concentrations were increased and the amount of inspection was increased. In 2009, coupon, probe or inspection-based corrosion rates exceeded targets or revealed increased damage on 10 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.

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

Flow Line	Probes	Coupons	Inspection	Action Taken
1APO			x	Increase Target PPM
1CPO	x			Increase Target PPM
1DPO			x	Increase Target PPM
1EPO	x			Increase Target PPM
1GPO			x	Increase Target PPM
1YPO	x			Increase Target PPM
2EPO	x			Increase Target PPM
2UPO			x	Increase Target PPM
3BPO	x			Increase Target PPM
3SPO			x	Increase Target PPM
10	**5**	**0**	**5**	

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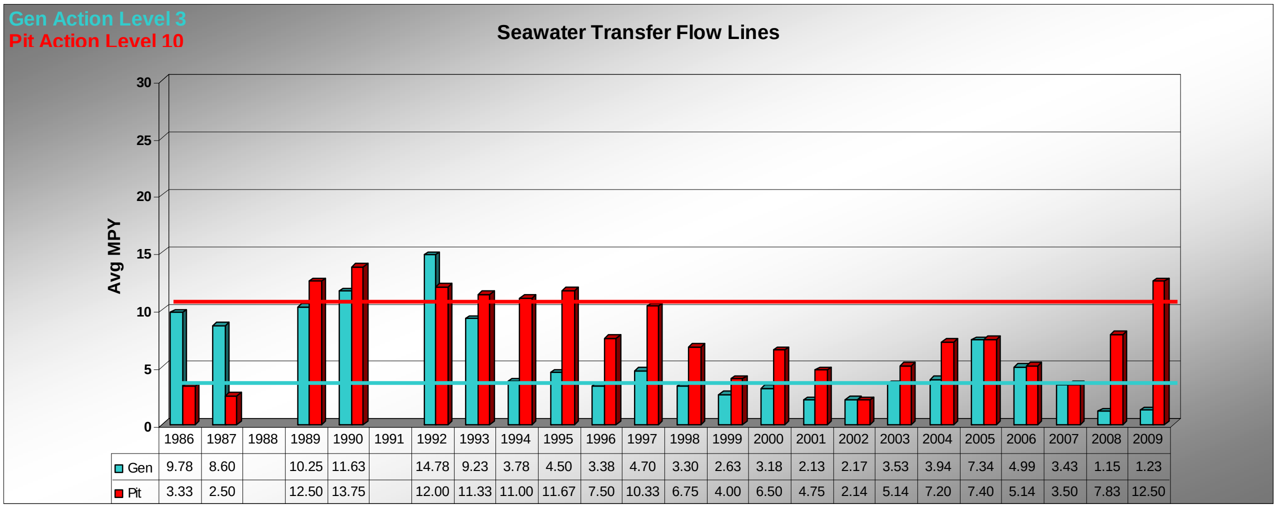
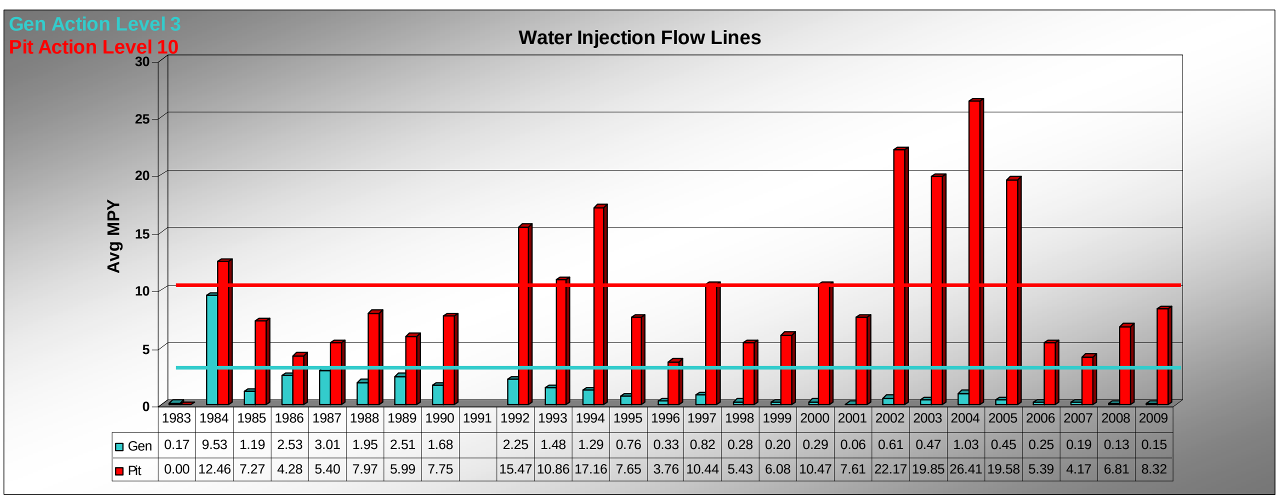


	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Gen	9.78	8.60		10.25	11.63		14.78	9.23	3.78	4.50	3.38	4.70	3.30	2.63	3.18	2.13	2.17	3.53	3.94	7.34	4.99	3.43	1.15	1.23
Pit	3.33	2.50		12.50	13.75		12.00	11.33	11.00	11.67	7.50	10.33	6.75	4.00	6.50	4.75	2.14	5.14	7.20	7.40	5.14	3.50	7.83	12.50

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

Seawater Transfer Flow Lines: The monitoring data summarized in Tables 1 and 2 and presented in Figure 2, show the average corrosion rates for the SW flow line coupons. Average general corrosion rates are below threshold and pitting rates exceed the threshold and mitigation measures are being pursued. Biocide concentration is currently at 1000 ppm following weekly maintenance pigging. There are two coupon locations on the SW system, one at the STP and one on the SW line that supplies Alpine. The STP coupon on the SW discharge had an average pitting corrosion rate of 17 mpy. The Alpine line coupon at CPF2 had an average pitting corrosion rate of 3 mpy.



	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Gen	0.17	9.53	1.19	2.53	3.01	1.95	2.51	1.68		2.25	1.48	1.29	0.76	0.33	0.82	0.28	0.20	0.29	0.06	0.61	0.47	1.03	0.45	0.25	0.19	0.13	0.15
Pit	0.00	12.46	7.27	4.28	5.40	7.97	5.99	7.75		15.47	10.86	17.16	7.65	3.76	10.44	5.43	6.08	10.47	7.61	22.17	19.85	26.41	19.58	5.39	4.17	6.81	8.32

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

Water Injection Flow lines: The monitoring data summarized in Tables 1 and 2 are presented in Figure 3. Increased pigging and biocide have brought the WI flow lines coupon pitting rates under control. Since SW and PW commingling were suspended at CPF2 in 2005, pitting rates have been reduced markedly. Coupon results are used to prioritize inspection efforts. Additional chemical injection systems have been installed on individual lines at CPF1 and CPF2. Better cleaning pig styles have been deployed and alternate pigging technology is under evaluation. These lines also benefit from the weekly biocide treatment of the sand jet systems. Data from the coupon locations installed in water injection flow line drill site manifold headers during 2007, 2008 and 2009 show higher pitting corrosion trends than in the main flow line, based on inspection results. These coupon locations are in non-piggable portions of the system and are subjected to solids as a result of pigging the WI lines. Recurring inspections in the CPF1 water injection flow lines that were treated with biocide after pigging for a year had only one increase in 2009.

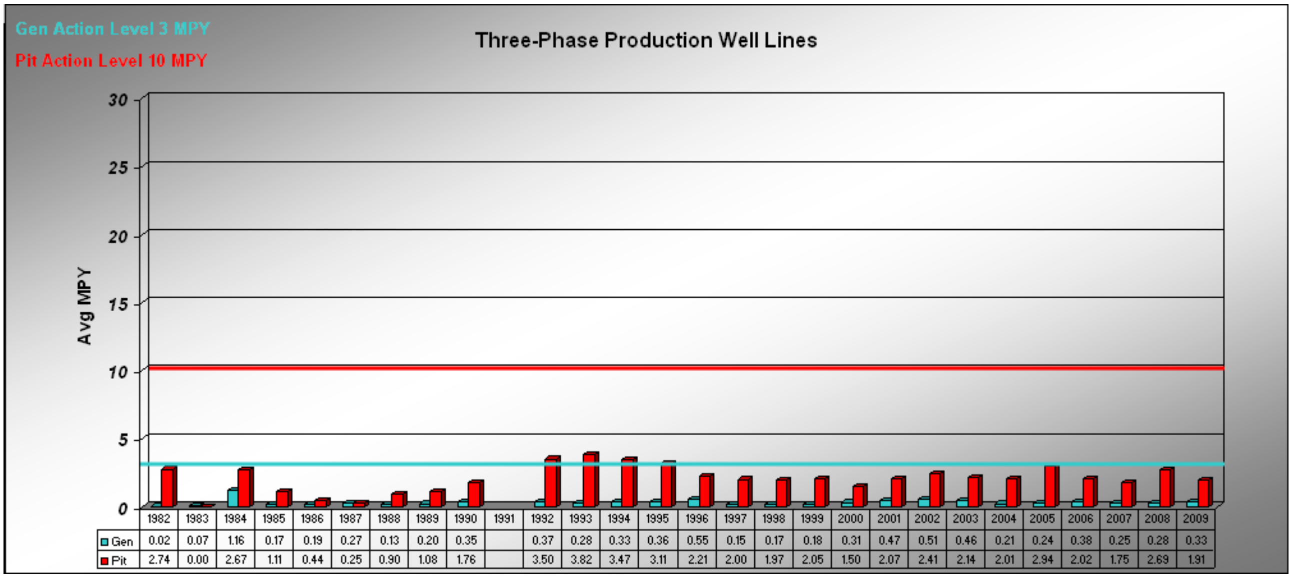


Figure 4. Three-Phase Production Well Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Well 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 indicate that pipe wall corrosion rates are higher. For three-phase production, coupons monitor free flowing fluid and have not shown the predominant, under-deposit corrosion mechanism.

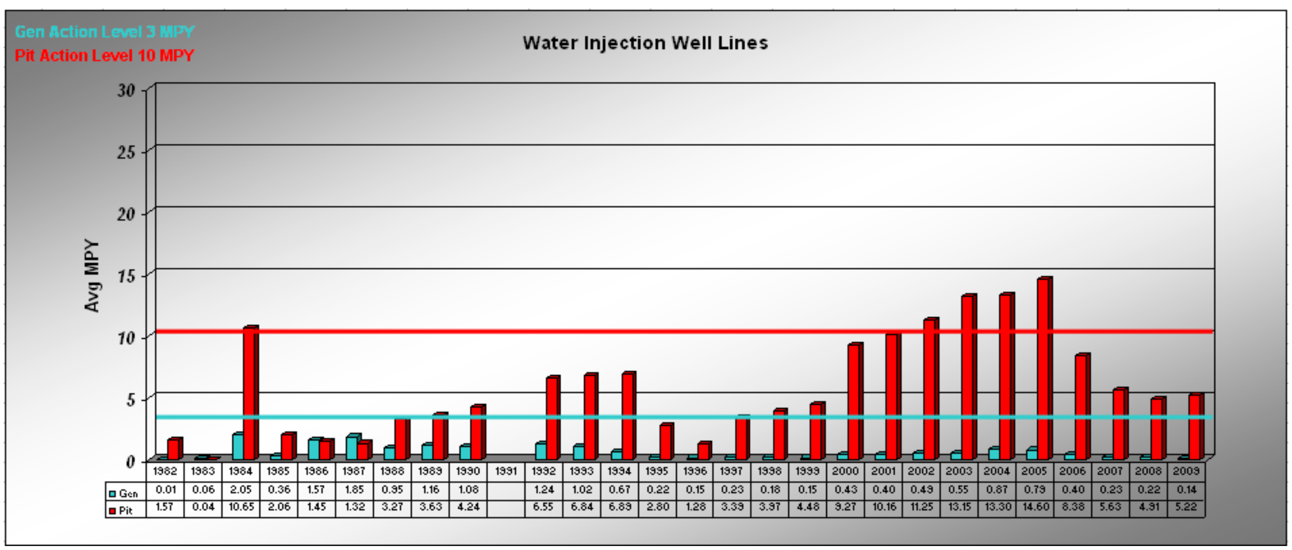


Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates by year.

Water Injection Well Lines: As discussed in section B.1.a, 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 increased velocities from decreasing the riser and well line diameters are contributing to the decrease in coupon corrosion rates.

Mitigation:

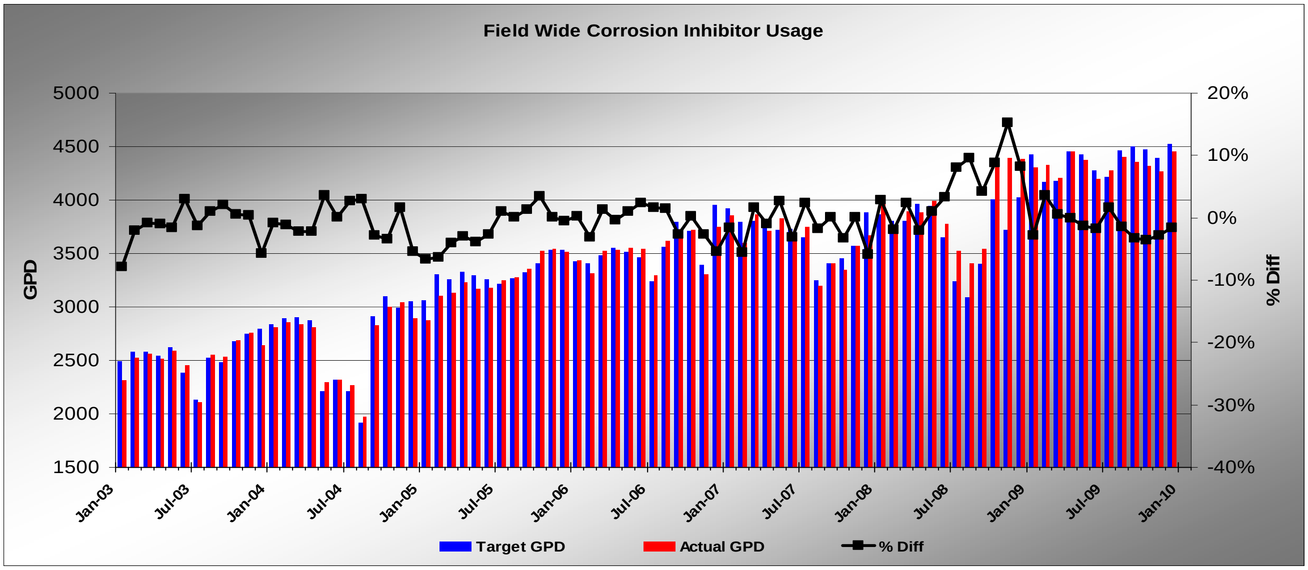


Figure 6. Field-wide Corrosion Inhibitor Use.

Figure 6 shows the actual number of gallons of CI pumped per day, the recommended (target) number of gallons per day and the percent difference between the two. The average deviation for the year was -1%. CI use has increased since 2003 because of higher water cuts and solids. Fluctuations in 2009 were caused mainly by temperature swings that changed production rates and subsequent target CI volumes.

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

Maintenance Pigging:

Service	SW	WI	Oil
2006 Recommended	100	1022	20
2006 Actual	59	731	22
2006%	59%	72%	110%
2007 Recommended	144	1242	25
2007 Actual	75	894	79
2007%	52%	72%	316%
2008 Recommended	141	1002	21
2008 Actual	122	731	50
2008%	87%	73%	238%
2009 Recommended	132	645	28
2009 Actual	79	585	35
2009%	60%	91%	125%

Table 4. Field-wide Maintenance Pigging by Service.

*Notes: 2007 data include the maintenance pig cleaning runs associated with 2PPO ILI.
2009 revised tracking to separate SW transit lines from other WI lines, same as coupon reporting.
The seawater maintenance pigging rates were affected by facility impacts and equipment issues.

For the Kuparuk field, Table 4 shows the actual number and the recommended number of maintenance pig runs conducted by service category. Services tracked are Sea Water (SW), water injection (WI) and Oil (including three-phase production and wet oil). The maintenance pigging frequencies are as follows:

- Weekly for the SW transit lines
- Monthly for CPF WI flow lines
- Monthly for the Wet Oil lines from CPF3 to CPF1 and CPF2, this service is tracked as Oil
- -Phase Produced Crude Flow lines, this service is tracked as Oil pigged as frequently as appropriate.

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Kuparuk Inhibitor Feedback System

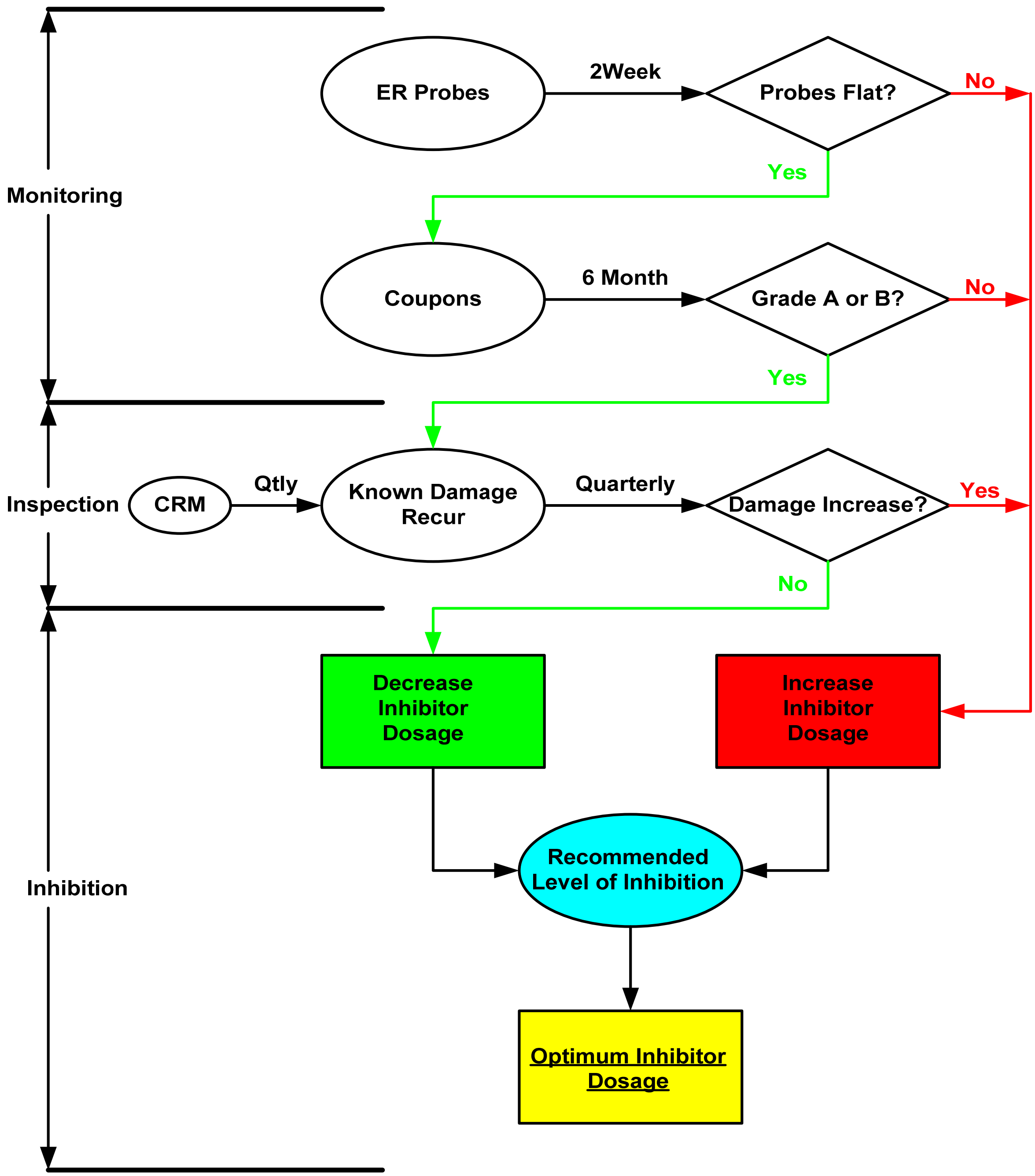

Figure 7. Corrosion Inhibitor Feedback System.

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B. Inspection

B.1 Internal Corrosion Inspections

In 2009 we completed all planned internal inspections.

B. 1.a Well Lines Inspections for Internal Corrosion

We completed our planned 2009 conventional well line internal inspection program which included the carryover from 2008. Interval surveys were completed on the 220 well lines scheduled for inspection in 2009. This included the inspection of 26 four-inch well lines which indicated no significant damage, thus validating our "six-inch to four-inch" line replacement strategy.

As indicated in Figure 8, below, repair recommendations were initiated on 42 well lines (23 WI and 19 PO) in 2009 because of internal corrosion or a combination of internal and external corrosion damage. The predominant corrosion mechanism was associated with solids (under-deposit corrosion or erosion). There were two well line leaks (1A-17 and 1B WI header supply line) caused by internal corrosion or erosion in 2009. More information on the two leaks can be found in Section C below.

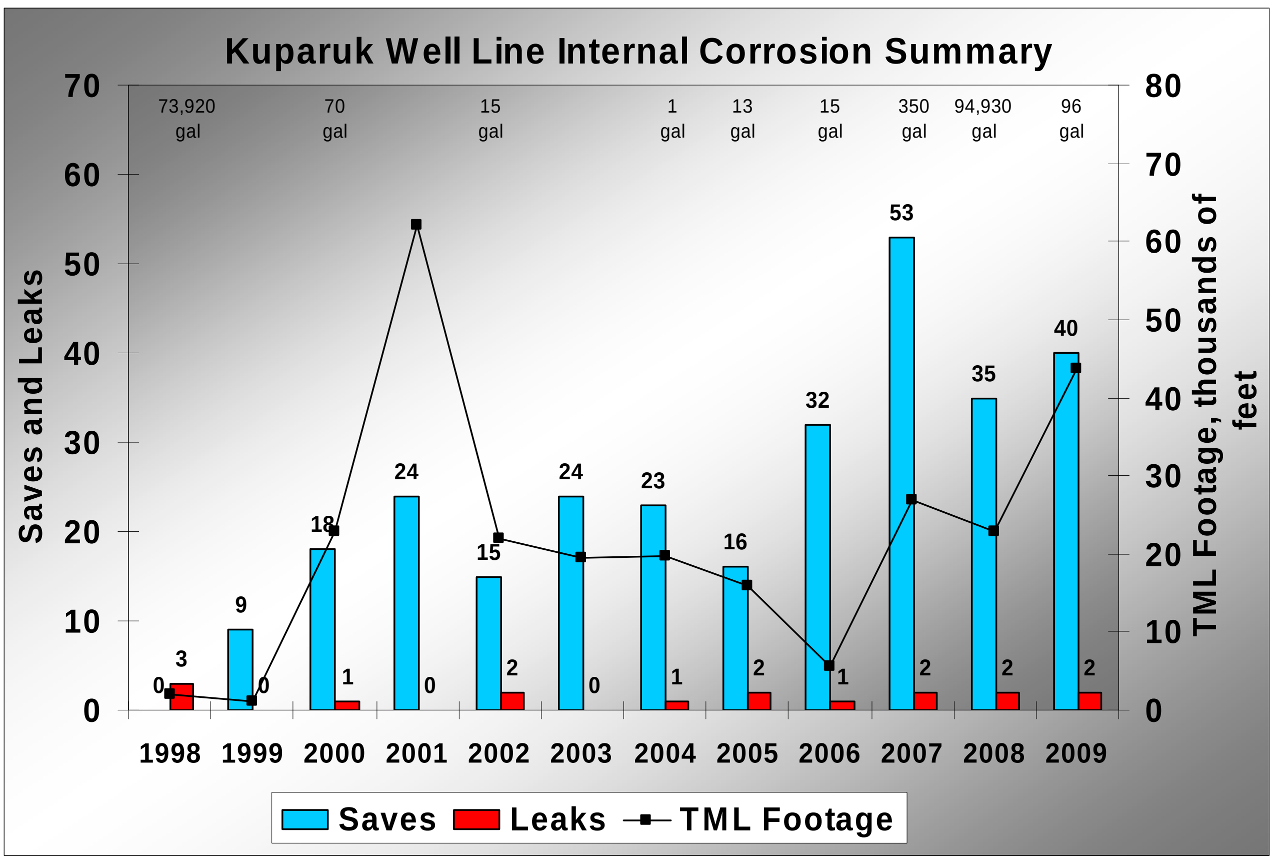

Figure 8. Summary of WI and Three-Phase Production Well Line Internal Corrosion Inspections – RT footage, leaks, and saves by year.

The 2009 results from the RTR / linear array surveys, manual RT, and manual UT are summarized in the following three tables.

- **Interval Surveys (RTR/LA/RT) of Well Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	25,809	156
Water Injection	11,329	64
Total	37,138	220

The 2009 RTR / Linear Array 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	Repeat Radiographs with Increases
Three-phase Production	230	3,548	751	68	9 %
Water Injection	179	2,953	463	46	10 %
Total	409	6,501	1,214	114	9 %

The 2009 manual RT well line data indicated no significant damage trend changes in either the three-phase or the WI well lines.

- **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	Repeat UT Inspections with Increases
Three-phase Production	190	663	376	49	13%
Water Injection	81	286	214	24	11%
Total	271	949	580	73	13%

The 2009 manual UT well line data indicate an increase in the percentage of increases in PO lines from 6% in 2008 to 13% in 2009.

B.1.b Flow Line Inspections for Internal Corrosion

We completed our planned 2009 inspection goal by completing the interval surveys on 33 lines in 2009.

As indicated in Figure 9 below, 19 repair recommendations were initiated on flow lines (ten WI and nine PO) in 2009 because of internal corrosion or a combination of internal and external corrosion damage. The corrosion mechanism for all repair recommendations was either deadleg or solids-related. As a result of ILI, 1RGWI, 2PWI, and 3HAMIWI were shut in and repair recommendations issued as appropriate. There were two flow line leaks (1BCFW and 1EPO line heater bypass) caused by internal corrosion in 2009. More information on the leaks can be found in Section C below.

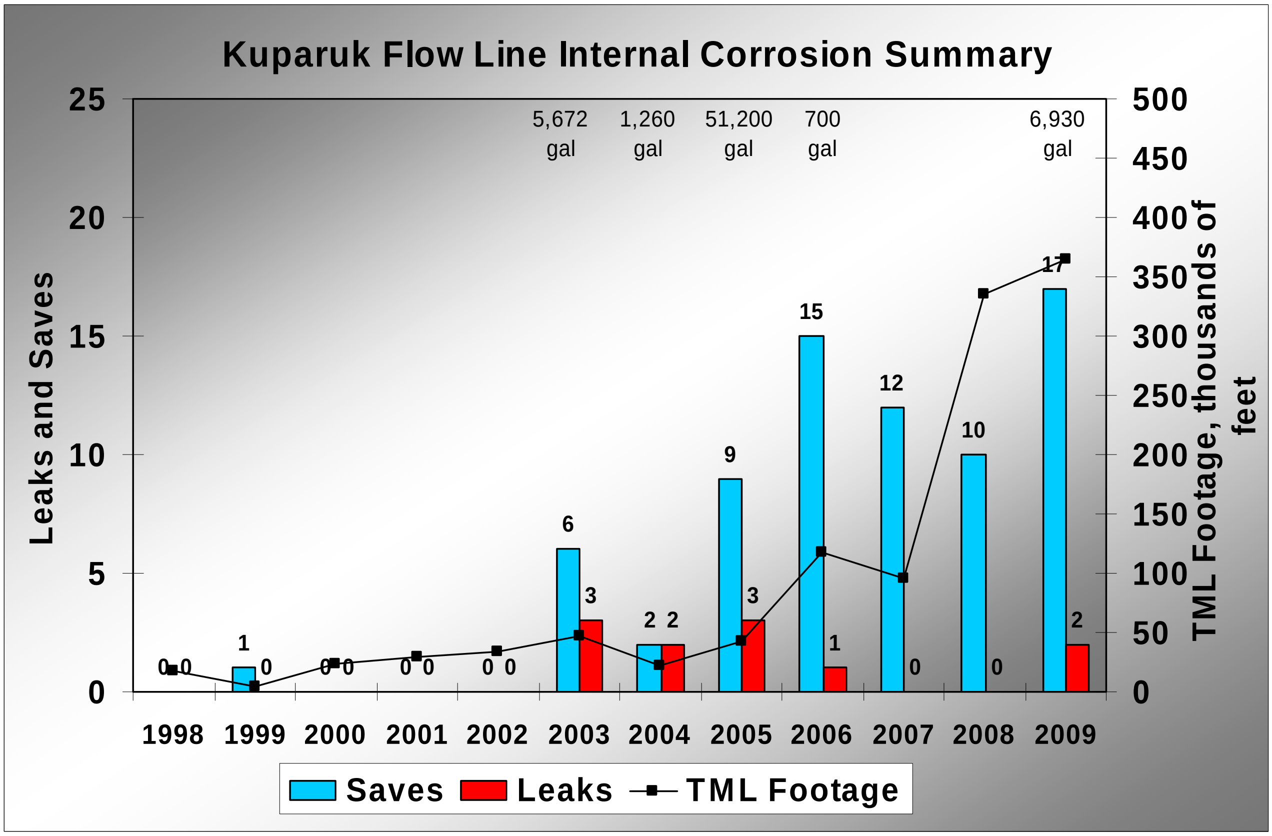

Figure 9. Summary of WI and Three-Phase Production Flow Line Internal Corrosion Inspections – Footage (RT and ILI), leaks, and saves by year.

The 2009 results from the RTR / linear array surveys, ILI, manual RT, and manual UT are summarized in the following three tables:

- **Interval Surveys (ILI/RTR/LA) of Flow Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	22,507	15
Water Injection	332,877	18
Total	355,384	33

The 2009 RTR / linear array inspection results indicated no new damage trends.

- **Manual RT of Flow Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	Repeat Radiographs with Increases
Three-phase Production	103	4,347	1,126	25	2 %
Water Injection	52	5,156	285	6	2%
Total	155	9,503	1,411	31	2 %

The 2009 results from manual RT of flow lines indicated no new significant damage trends.

- **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	Repeat UT Inspections with Increases
Three-phase Production	83	2,141	964	28	3 %
Water Injection	47	1,377	536	43	8 %
Total	130	3,518	1,500	71	5 %

The 2009 manual UT flow line data indicated no new damage trends.

- **ILI of Flow Lines:**

In 2009, a total of 18 WI flow lines were evaluated with ILI at Kuparuk. All of these lines were smart pigged for the first time as part of a multi-year campaign that was initiated in 2008. The high number of first-time ILI runs illustrates CPAI's commitment to continuous improvement of the inspection program.

Table 5 summarizes equipment service, diameter, and length of lines that were evaluated with ILI in 2009.

Table 5. ILI runs in 2009.

Line Name	Service	Diameter (inches)	Line Start	Line End	Length (miles)
1EWI	Water Injection	NPS 8	CPF1	DS1E	1.6
1HWI	Water Injection	NPS 8	DS1B	DS1H	3.4
1LWI	Water Injection	NPS 8	DS1F	DS1L	2.0
1RWI	Water Injection	NPS 6	DS1G	DS1R	2.0
2FWI	Water Injection	NPS 8	CPF 2	DS2F	2.1
2KHBWI	Water Injection	NPS 10	CPF2	DS2B	2.1
2KHWI	Water Injection	NPS 8	DS2B	DS2H	3.1
2PNLWI	Water Injection	NPS 12	4-Corners	DS2L	10.9
2PNWI	Water Injection	NPS 12	DS2L	DS2N	3.4
2PWI	Water Injection	NPS 12	DS2N	DS2P	10.9
2TAMWI	Water Injection	NPS 10	CPF2	DS2A	4.4
3KWI	Water Injection	NPS 8	CPF3	DS3K	4.4
3MIWI	Water Injection	NPS 8	DS3A	DS3I	2.3
3MWI	Water Injection	NPS 8	DS3I	DS3M	1.9
3NWI	Water Injection	NPS 8	CPF3	DS3N	4.3
3RWI	Water Injection	NPS 8	DS3Q	DS3R	1.8
3SGWI	Water Injection	NPS 8	DS3F	DS3G	2.1
3SWI	Water Injection	NPS 8	DS3G	DS3S	5.0

The metal loss features reported by ILI have been prioritized for verification by radiographic and/or ultrasonic inspection. The verification results through 2009 are included in the aggregate inspection data. In 2009, an analyst from the smart pigging vendor was on site during smart pigging and an imminent threat report resulted in 2PWI being proactively shut in.

Additional follow-up of the reported features is an ongoing part of the normal radiographic and ultrasonic inspection program.

In summary, ILI has become an integral part of the overall inspection program.

B.2 External Corrosion Inspections

In 2009 we had several significant accomplishments:

- We completed our 2009 goal of completing CUI inspection on ~20% of the field-wide lines which included inspection of ~124,000 CUI IAs (~75,000 by TRT, ~37,000 by ILI, and ~12,000 by IR) flow line and well line CUI IA’s. The total number of CUI IA’s is now estimated based upon line length for ILI and IR inspection as these NDE methods are much broader screening tools.
- Exceeded our goal of inspecting 100 Tarn-style weld packs (344 inspected by TRT) to ensure this design continues to work as intended. No corrosion has been detected on the piping within the weld pack areas.

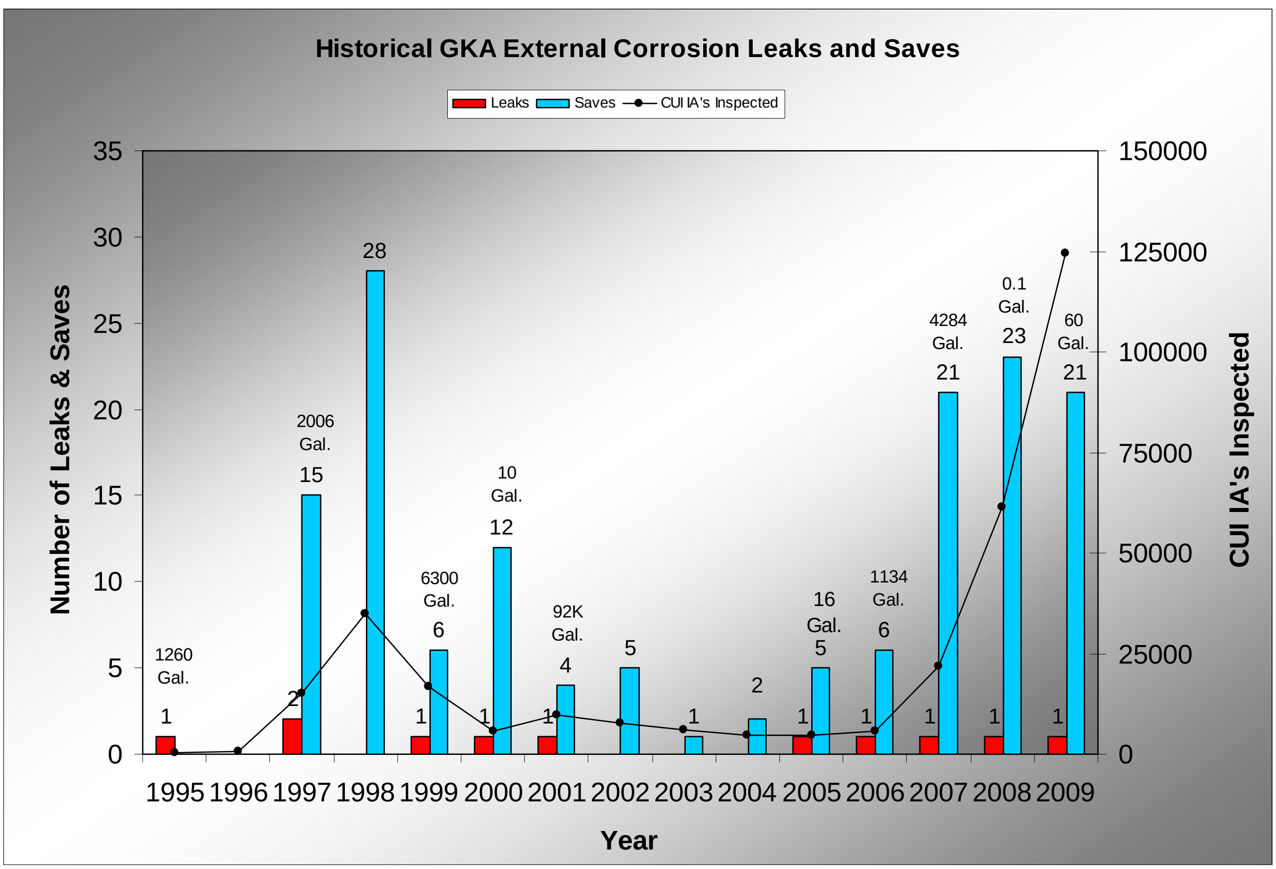

Figure 10. Leaks, saves, number of CUI IA’s inspected with TRT, and volumes of leaks by year.

B.2.a Flow Line (On-Pad and Off-Pad) Inspections for External Corrosion

The focus in 2009 was to continue the field-wide recur of all CUI IA's on cross country flow lines. Each location is currently on a five-year recur interval.

In 2009, ~26% of the field-wide flow line piping was inspected at all CUI IA's using a combination of ILI and TRT. This survey included 90 of the 274 in-service flow lines (~146mi of the total ~558mi). External corrosion was identified at 791 locations (700 of the 791 were located over tundra). The corroded locations were added to the list for follow-up visual inspection (VT) and refurbishment.

No flow line leaks were caused by external corrosion in 2009.

Field-wide, 16 sleeve and/or replacement repair recommendations (saves) were issued as a result of external corrosion damage on flow lines. These recommendations included 9 flow lines [1LFPO, 1LWI, 2EDPO (2 sleeves), 2KHBWI, 2NGI, 2WUVWI, 2ZEOR, 3AGL, 3KPO, 3OPO, 3QTEST (2 replacements) and 3SGFWI (2 sleeves)].

The 2009 CUI inspections noted above included a sampling of the newer Tarn-style weld packs (344 locations) to evaluate how the design is continuing to perform. No water or CUI was found in any of the weld pack locations.

Denso tape continues to be the material of choice to refurbish flow lines and well lines with external corrosion. The 2009 surveys included previously-refurbished weld packs (2,321 locations) to monitor the performance of the Denso product and to check the piping at the insulation interfaces for possible damage. The results showed no evidence of additional corrosion at the area wrapped with tape.

B.2.b Well Line Inspections for External Corrosion

In 2009, we met our goal and completed 724 of the 724 scheduled well lines which were inspected using a combination of TRT and IR inspection. Of these, 211 lines (5,684 CUI IA's) were inspected with conventional TRT and 513 lines (~12,300 CUI IA's) were inspected with IR. External corrosion was identified at 126 locations (2 of the 126 locations were over tundra). The corroded locations were added to the list for follow-up VT and refurbishment.

A significant program change was implemented in 2009 to begin screening well lines with infrared thermography (IR) to detect wet insulation. The change provided positive results which allowed a fast and accurate means of screening large sections of pipe for wet insulation.

Repair recommendations (saves) were issued as a result of external corrosion damage on 4 well lines (2G-10, 2V-02, 2V-04, and 2V-07). One leak was caused by external corrosion in 2009 on well 2A-16GL in 2009.

Table 6: External CUI Inspection Summary for 2008.

Type of Equipment	2009 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Flow lines Over Tundra or On-Pad	~100,000	~106,500	791	0.7%	2,071
Well Lines	~18,000	~18,000	126	0.7%	580
Total	**~118,000**	**~124,500**	**917**	**0.7%**	**2,651**

The number of CUI IA's inspected with ILI, TRT, and IR, the number of CUI IA's found corroded, and the percentage of CUI IA's corroded for the flow line over tundra, flow line on-pad, and well lines are given in Figures 11, 12, and 13.

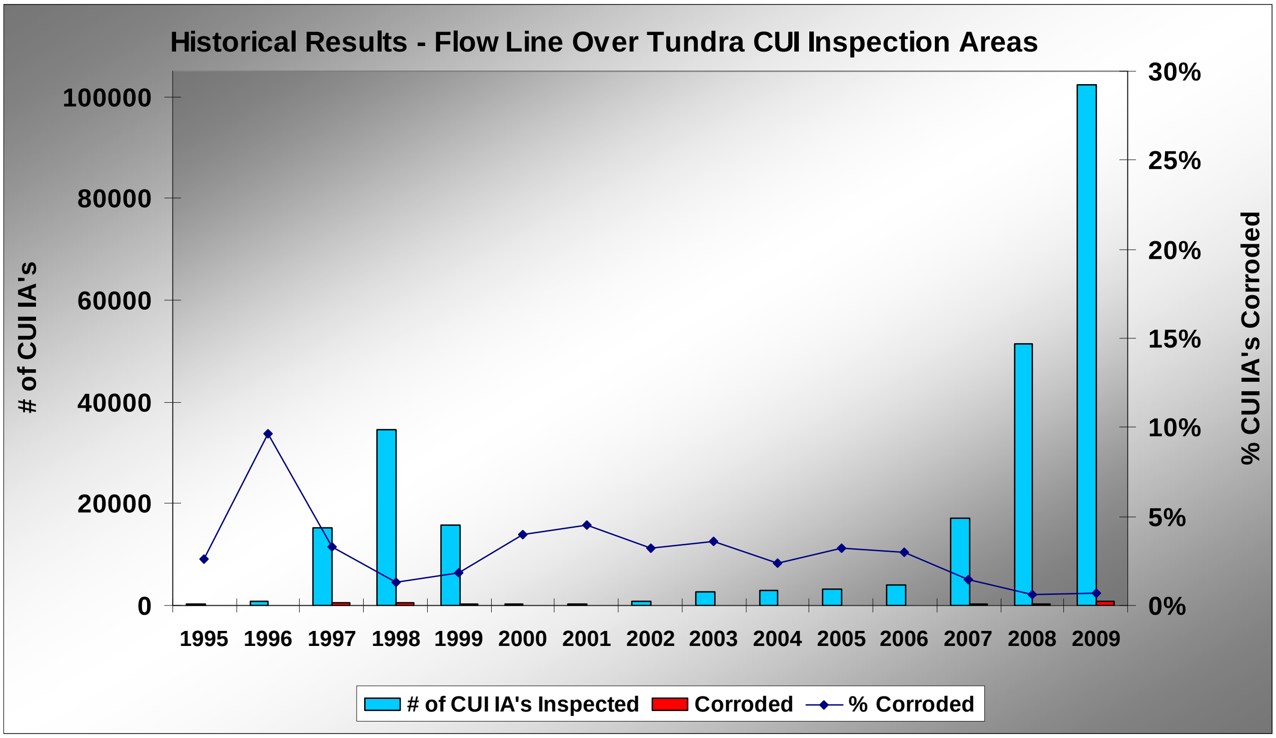

Figure 11. Summary of Flow Line Over-Tundra (off-pad) CUI IA's

Figure 11 illustrates the latest results from the external corrosion inspection program. The 2002 through 2006 values include recur follow-up inspections and clean-up of locations missed or not properly documented during the original base line effort. The increased inspection effort starting in 2007 is representative of our field-wide recur inspection to re-evaluate all locations on a five-year inspection interval. The 2008 and 2009 data include ILI results on flow lines. The 2009 data include IR results on well lines.

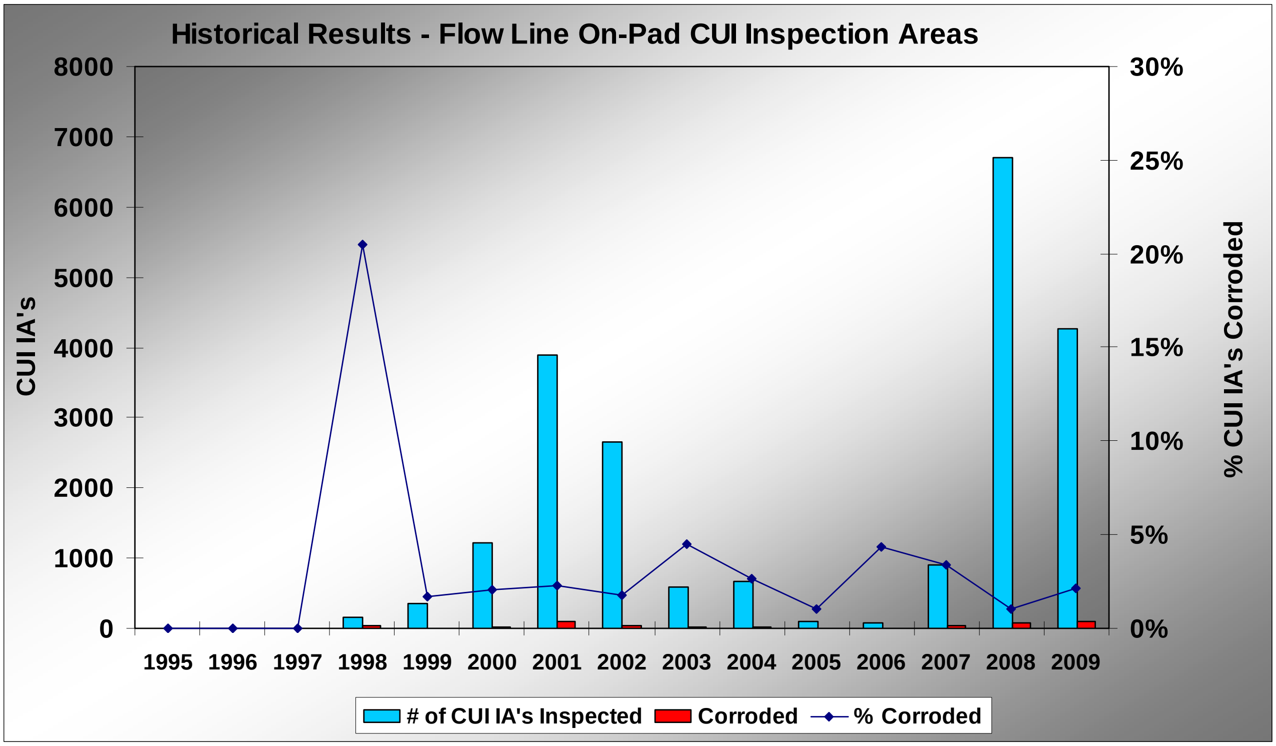

Figure 12. Summary of Flow Line On-Pad CUI IA's

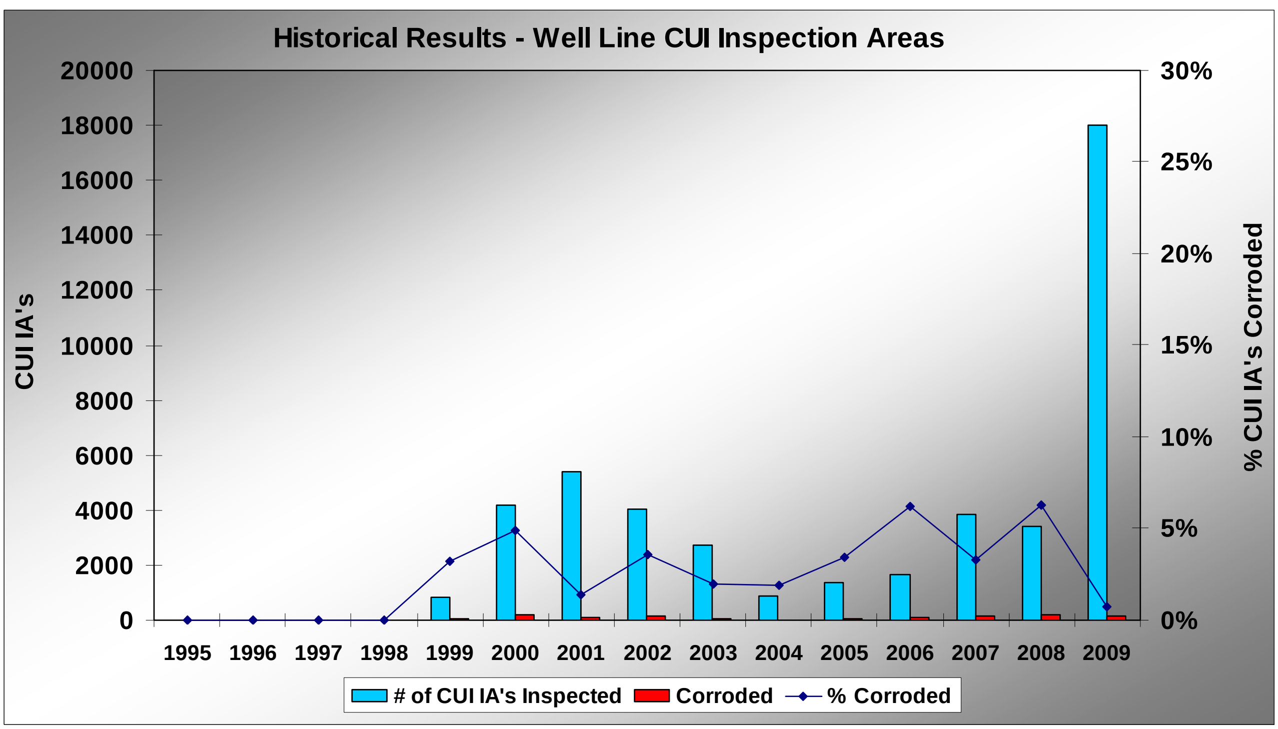

Figure 13. Summary of Well Line CUI IA's

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B.3 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 D.

In 2009 we had several significant accomplishments:

- Visually inspected and cleaned debris from all priority 1, 2 and 3 cased below-grade pipe circuits.
- Completed our specialty inspection [Long Range UT (LRUT)] on 76 circuits.
- Completed ILI on 65 circuits.
- Excavated, inspected, refurbished and / or repaired (as required) 16 cased circuits.

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.

B.3.a Inventory and Survey of Below Grade Locations

GKA has 790 below grade circuits on flow lines. This includes priority 1, 2 and 3 circuits in the GKA (not including WNS circuits on the GKA side of the field). Of these locations, three are contained in utilidors. The remaining circuits are cased lines, the majority of which are either road, gravel pad or caribou crossings.

Utilidor Lines

Recent ADEC regulation changes include the addition of facility piping associated with oil storage tanks. This increased the number of pipelines in utilidors from one to three.

1. The original line is the Oily Waste Injection Line, (BG ID #286). This line 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 has not been inspected since 2002.
2. One of the new lines is the pipeline that transports diesel from the bulk storage tank on CPF1 pad, to the fueling pump on CPF1 pad. This line was inspected in 2008.
3. The other new line is the sister line to #2 above. It provides fuel to an adjacent pump. This was also inspected in 2008.

Cased Lines

<u>Inspection Status:</u>
The annual visual survey of all the cased lines was conducted in 2009. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

<u>Results and Remedial Action:</u>
Of all GKA below-grade circuits, 64 were found to have pipe in direct contact with gravel/soil or debris in the casing. All locations were remediated or work orders were written to do so in 2009.

B.3.b Results of Specialty Testing

<u>Inspection Status:</u>
In 2009, we completed either LRUT or ILI on 141 GKA priority one circuits. This was the seventh year of our recurring inspection program. Most priority one circuits are on a five-year (maximum) re-inspection interval. However, inspection intervals have been extended to 10 years for Priority 1 circuits that are externally coated with protective coatings [fusion-bonded epoxy (FBE) and/or Denso Tape Wrap] and are in non-internally corrosive service.

In 2009 The Welding Institute (TWI) was the only LRUT inspection system used. TWI technology is capable of finding evidence of both internal and external corrosion damage.

Results and Remedial Action:

Table 7 shows the results of the LRUT specialty testing performed by TWI.

Table 7. 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	37	1	5	26	5	0
Other	39	1	10	25	3	0
Total	76	2	15	51	8	0

The 2009 TWI data shows an increase in the minor anomalies found (24 in 2008, 51 in 2009). The number of "Incomplete/Inconclusive" remains low at two.

B.3.c Results of Crossing Refurbishments

Sixteen below grade circuits were refurbished in 2009. Fifteen circuits were excavated and one was replaced without excavation (cut and pulled through casing). Four below grade circuits were repaired in 2008:

- One total replacement (1YWI)
- Three sleeved (2ZEOR, 2 on the STPTOCWSW)

All below grade circuits which were excavated for inspection in 2009 were refurbished and the pipe wrapped with denso tape to prevent future external corrosion.

The below grade circuit replaced without excavation in 2009 was externally coated with fusion bonded epoxy to prevent corrosion.

C. Repairs, Structural Concerns, and Spills/Incidents

Subsidence - surface facilities:

Existing Well Upgrade Program

- In 2009, no conductor-mounted floor kits were installed in existing well houses at Kuparuk. A total of 32 fiberglass floor kits were installed in well houses distributed between CPF1, CPF2, and CPF3 area Drill Sites.
- In 2009, 30 heat tubes were installed at Drill Sites 1D, 2X, and 3B. These heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.
- In 2009, five snow fences were installed at Drill Sites 1H, 3F, 1C, 2V, and 2T. These snow fences are used to cause snow to settle out of wind at ground level adjacent to the drill site. This helps to prevent large accumulations of snow drifting on the well pad piping.

New Wells & Producer to Water Injection Well Conversions

- In 2009, four newly drilled wells in the GKA were installed with insulated conductors and three were installed without insulated conductors.
- In 2009, seven newly drilled wells had heat tubes installed. Of these wells, all seven had conductor-mounted steel floor kits that also provided permanent pipe support and none had fiberglass floor kits with independent permanent pipe supports.

Wind-Induced Vibration:

As a result of the 3MIGI eight-inch miscible injectant 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 dampeners.

As a result of the failure of the eight-inch 2FWI line in 2006 and the eight-inch 2XGI line in 2002, the 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).

In 2009, WIV was observed on the 2WUVWI line so additional sections of the pipeline were mitigated to reflect the changes to the WIV fan azimuths. WIV was also observed on the 2CGI line but since pipeline azimuths are outside the expanded wind fan, the line was put on a watch list.

Corrosion and Structural-Related Spills/Incidents:

- The 1BCFW injection flow line leaked in February of 2009 because of internal corrosion. The spill volume was determined to be 6,930 gallons of mostly contaminated fresh water (camp sewage) with a small amount of oil from the CPF1 Oily Waste stream. The spill was to the tundra adjacent to CPF1. This spill was reported to ADEC. The clean-up and investigation into the cause of the leak are complete. This line was added to this report after recognizing that trace amounts of hydrocarbons exist in the contaminated fresh water system. Activity on this line was therefore not reported in prior years.

- Well 1A-17 piping inside the manifold building choke skid leaked in June of 2009 because of erosion. Although located within a structure, CPAI considers this piping system subject to regulation as facility piping as the structure does not meet secondary containment guidelines outlined in the July 16, 2007 Clarification on the Definition of Facility Piping document (ADEC to CPAI). The spill volume was determined to be 12 gallons of produced crude. The spill was confined to secondary containment and the gravel pad. This spill was reported to ADEC. The clean-up and investigation into the cause of the leak are complete.

- The DS1B WI header supply line leaked in August of 2009 because of a combination of internal and external damage. The spill volume was determined to be 84 gallons of produced water. The spill was partially to the gravel pad and partially to tundra. This spill was reported to ADEC. The clean-up and investigation into the cause of the leak are complete

- Well 2A-16 gas lift line leaked in October of 2009 because of external damage found during a pressure test of the line. The spill volume was determined to be 60 gallons of diesel / crude oil. The spill was confined to gravel pad. This spill was reported to ADEC. The clean-up and investigation into the cause of the leak are complete.

- The DS1E flow line heater bypass line leaked in June of 2009 because of internal damage. The spill volume was less than one gallon and no fluid hit the ground so it was not reported to ADEC. The investigation and repair are complete.

- No flow line leaks were caused by external corrosion in 2009.

- No flow line or well line leaks were caused by subsidence or other structural reasons in 2009.

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.

D. Year 2010 Forecast

D.1 Monitoring & Mitigation

- Test additional CI formulations.
- Continue to evaluate maintenance pigging enhancements to the WI systems.
- Plan installation of inhibitor/biocide injection capacity for the CPF3 WI system.
- Install permanent supplemental CI at CW-skid to treat the 12-inch WO line.
- Continue to evaluate biocide and maintenance pigging in the SW system.
- Add new monitoring locations on WI flow lines.

D.2 Inspection

D.2.a Internal Corrosion Inspections

D.2.a.i) Well Line Inspections for Internal Corrosion

Our recurring inspection program will continue in 2010. Our goal is that no in-service line will go longer than ten years without some type of inspection.

D.2.a.ii) Flow Line Inspections for Internal Corrosion

Our recurring inspection program will continue in 2010. Our goal is that no in-service line will go longer than five years without some type of inspection.

Plan to complete ILI on all piggable WI flow lines.

D.2.b External Program

Flow lines over tundra:

- Inspect approximately 20% of the flow lines for CUI as part of our five-year-interval recurring inspection program. This includes CUI IA's over tundra as well as on-pad.
- Inspect Tarn-style and Denso tape refurbished weld packs as a part of the core CUI program.
- Include all pipe support saddles as CUI IA's and inspect during flow line recur inspections.

Well lines:
Inspect well lines that fall within the model with IR at one-third of all drill sites (~16 of 47 per year) as part of our recurring CUI inspection program. Those well lines that fall outside the model will be inspected with conventional TRT on the same interval as internal corrosion inspections.

D.2.c Below Grade Piping Program

- Evaluate the criteria for inspection interval based on service, internal and external corrosion likelihood, etc. as noted in API 570.
- 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.
- Excavate, inspect, refurbish, and repair (as necessary) approximately 20 cased crossing circuits.
- Continue to work with TWI and ConocoPhillips R&D to refine inspection data reduction and interpretation.

D.2.d Other

- Continue enhancements to the Corrosion Database (CDB).
- Continue to evaluate, and prioritize subsidence and WIV mitigation efforts.

5.0 WNS PROGRAM STATUS SUMMARY

A. WNS Monitoring & Mitigation

In 2009, corrosion inhibitor (CI) storage capacity was increased. A new CI formulation was implemented.

Average general and pitting coupon corrosion rate data for Year 2009 are presented in Tables 8 and 9.

Table 8. 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	Percentage of Lines with Conformant General Corrosion Rates
Three-phase Production Flow Lines	4	0.3	4	100%
Seawater Line from KRU	1	0.1	1	100%
Infield Water Injection Flow Lines	3	0.1	3	100%
Production Well Lines	53	0.5	50	94%
Water Injection Well Lines	19	0.0	19	100%

Table 9. 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	Percentage of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Flow Lines	4	16.8	1	25%
Seawater Line from KRU	1	13.0	0	0%
Infield Water Injection Flow Lines	3	3.6	3	100%
Production Well Lines	53	0.3	53	100%
Water Injection Well Lines	19	2.7	17	89%

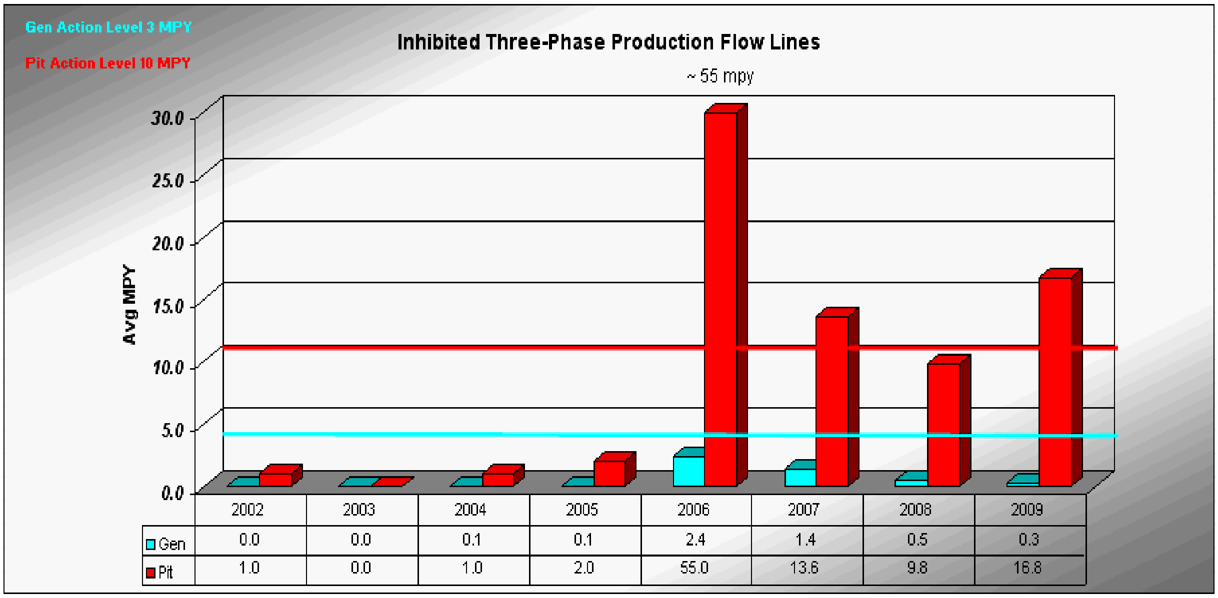

Figure 14. WNS Three-phase Production Flow Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Flow Lines: The monitoring data summarized in Tables 8 and 9 and presented in Figure 14 show that the average pitting corrosion rates in 2009 are above the action level. In response to the coupon and probe corrosion rates, adjustments were made to the CI dosage on the CD1, CD2, and CD3 production lines. In addition, a new CI formulation was implemented in 2009, and a test of another formulation was started.

Table 10. Three-Phase Production Flow lines with corrosion rates that exceeded targets and the action that was taken.

Flow Line	Probes	Coupons	Inspection	Action Taken
CD1PO		x		Increase Target PPM, Test New Formulation
CD2PO	x	x	x	Increase Target PPM
CD3PO		x		Increase Target PPM

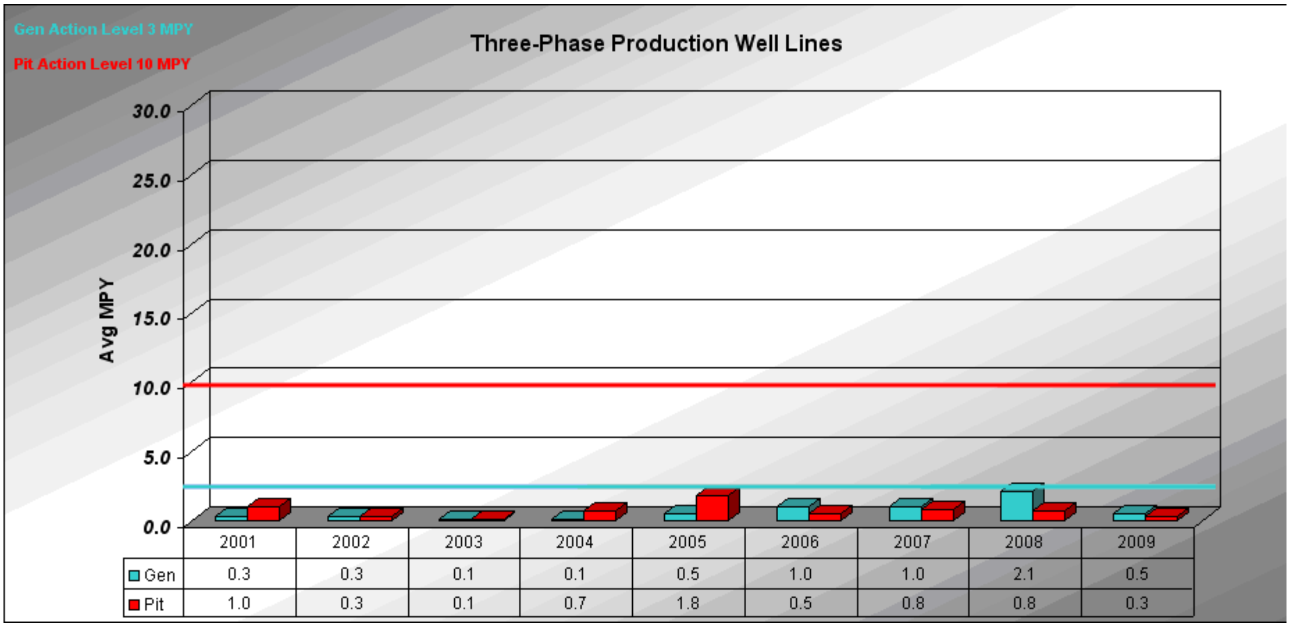

Figure 15. WNS Three-phase Production Well Line Coupons – general and pitting corrosion rates by year.

Three-phase Production Well Lines: The monitoring data summarized in Tables 8 and 9 and presented in Figure 15 show that corrosion rates have not approached action levels in the well lines. Inspection data, discussed in section B.1.a, indicate that significant corrosion damage has not taken place in these lines.

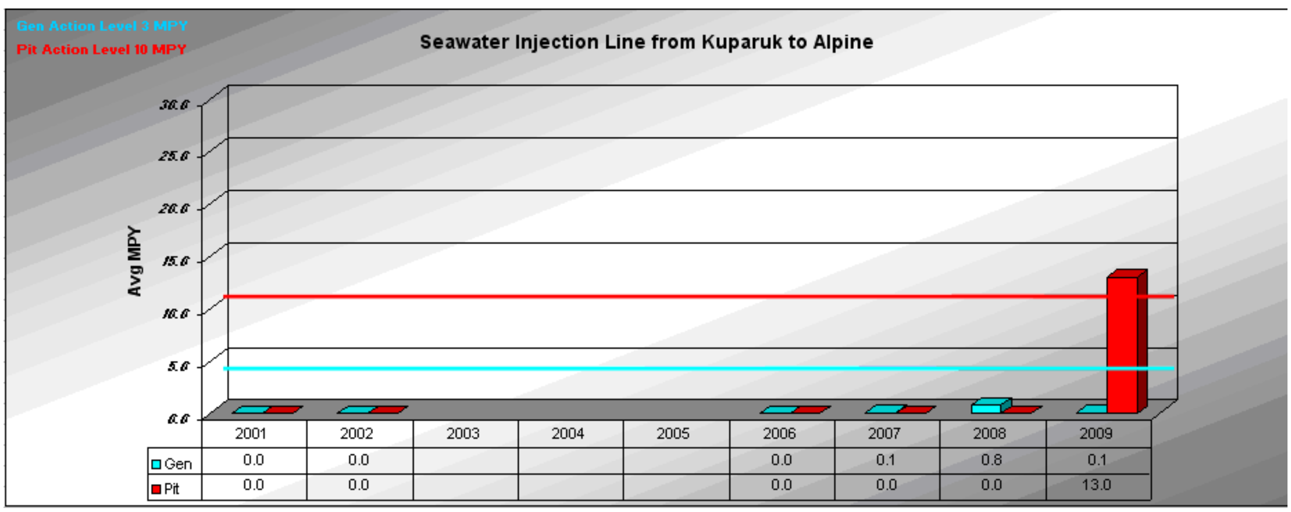

Figure 16. WNS Sea Water Line Coupons – general and pitting corrosion rates by year.

Sea Water Line from Kuparuk to Alpine: The monitoring data summarized in Tables 8 and 9, and presented in Figure 16 above, show the average corrosion rates for the SW flow line coupons. Data collection resumed in 2006 when a coupon fitting was installed to replace the previous location which was obstructed by piping reconfiguration. The pit indicated by the 2009 data is higher than target. Follow-up inspections to in-line inspection indicate no damage in this line.

ConocoPhillips

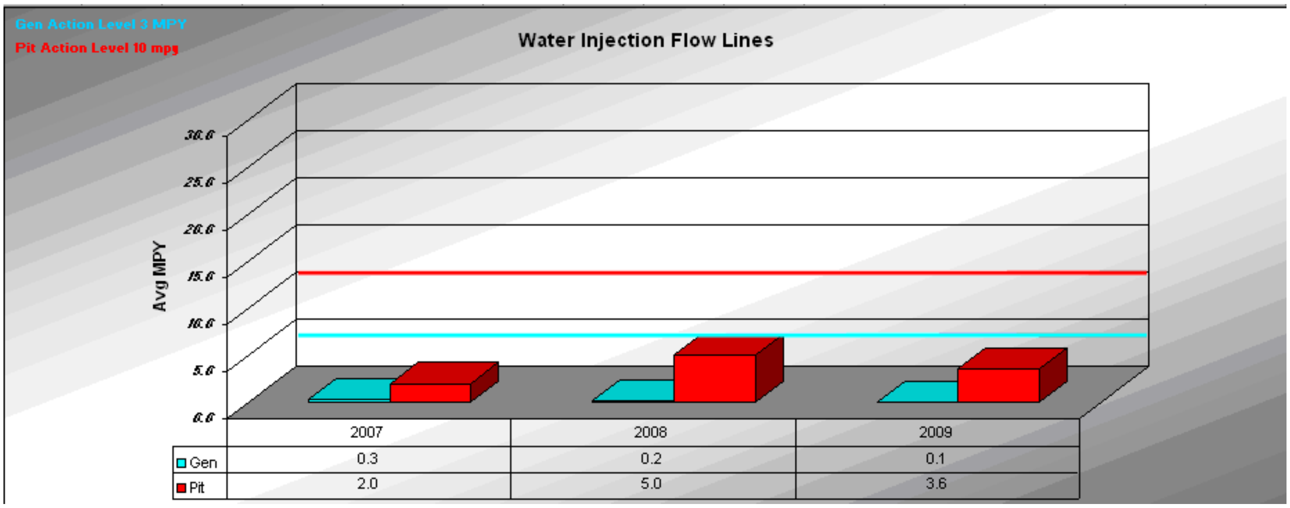

Figure 17. WNS Water Injection Flow Line Coupons – general and pitting corrosion rates by year.

Infield Water Injection Flow lines: The monitoring data summarized in Tables 8 and 9 show the average corrosion rates for the infield WI flow line coupons. Average coupon and probe general and pitting corrosion rates for these lines are minimal. Inspection data, discussed in section B.1.b, indicate that significant corrosion damage has not taken place in these lines.

The infield WI lines are treated with a weekly biocide treatment and monthly maintenance pigging. New cleaning pig styles are being used. In addition, produced water lines are treated with corrosion inhibitor.

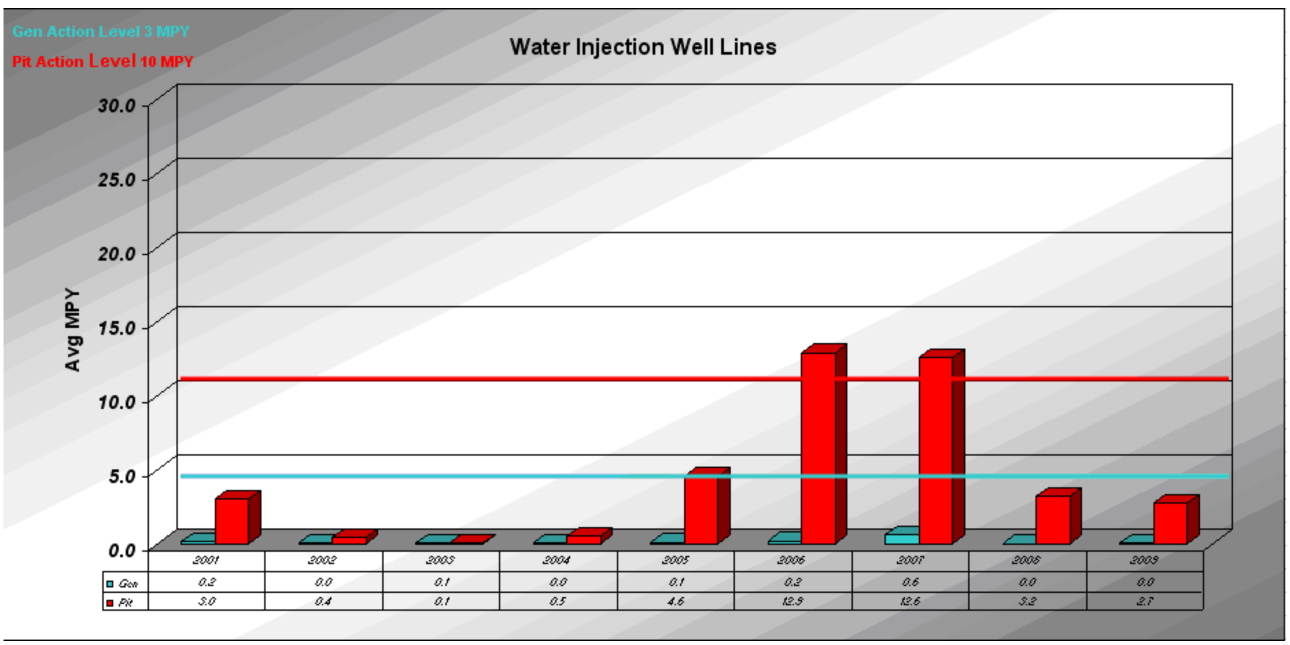

Figure 18. WNS Water Injection Well Line Coupons – general and pitting corrosion rates by year.

Water Injection Well Lines: The monitoring data summarized in Tables 8 and 9 and presented in Figure 18 show that pitting corrosion rates are below the action level. Inspection data presented in Section B.1.a indicate no damage in these lines.

The SW used for injection is filtered, deaerated, and biocided at the Kuparuk STP before being shipped to the WNS. The PW is treated with biocide and corrosion inhibitor in the facility.

Maintenance Pigging:

Table 11. Field-wide Maintenance Pigging by Service.

Service	SW	PW	Oil
2007 Recommended	12	0	1
2007 Actual	15	0	1
2007%	125%	n/a%	100%
2008 Recommended	24	12	1
2008 Actual	31	38	5
2008%	129%	316%	500%
2009 Recommended	24	12	1
2009 Actual	22	41	2
2009%	92%	341%	200%

For the Alpine field, Table 11 shows the actual number and the recommended number of maintenance pig runs conducted by service category. Services tracked are SW, PW and Oil (three-phase production). As of December 2009, the recommended maintenance pigging frequencies were as follows:

- Monthly for the WI Flow Lines to the Drill Sites
- Annually for Three-Phase Produced Crude Flow lines fitted with launchers and receivers.

B. Inspection

B.1 Internal Inspections

B.1.a Well Line Inspections for Internal Corrosion

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, five lines had very slight damage, and no damage was found on the remaining 13 lines.
In 2007, 35 well lines were inspected. Only three lines had slight damage, the worst being 10%.
In 2008, 30 well lines were inspected. The worst damage was less than 10% wall loss.
In 2009, 15 well lines were inspected. The worst damage was less than 50% wall loss. This is on a single line and was caused by erosion from a frac flow back. Monitoring shows no recent increases.

B.1.b Flow Line Inspections for Internal Corrosion

CD3WI was evaluated with ILI in 2009. No indications needing immediate attention were identified. Verification inspections are to be complete by 1st quarter 2010.

CD2PO inspections continue. Damaged locations were identified during the 2008 ILI and these locations continue to be an area of focus. Damage locations with up to 44% wall loss are being monitored. One sleeve was installed on the worst known damage location.

B.2 External Inspections

In 2009, 5089 locations on cross country flow lines and 1073 on drill site lines were inspected for CUI. Two locations had light corrosion and were stripped, inspected and re-furbished. The CD3WI line and the SW Kuparuk to Alpine transfer line were evaluated for CUI using ILI. No significant damage was identified.

B.3 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 D.2.c. The below grade portions of CD3WI were evaluated with ILI. No significant indications were identified.

B.3.a 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 2009. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation jacket in contact with soil) that require remedial action.

Results and Remedial Action:
During the 2009 visual survey, no gravel, soil or debris was found in the casings.

Of all the below-grade lines, two lines have pipe in direct contact with soil. These were replaced with above ground piping and officially removed from service early in 2009.

B.3.b Results of Specialty Testing

No specialty testing was performed in the WNS in 2009. Of the 51 WNS below grade circuits, one was evaluated with ILI.

B.3.c Results of Crossing Digs

No excavations were done in 2009.

C. Repairs, Structural Concerns, and Spills/Incidents

C.1 Subsidence:

No subsidence piping concerns have been identified. Of the 160 wells, only two lack both insulated conductors and heat tubes. One well is without either an insulated conductor or a heat tube. One of the original exploration wells still in operation has a heat tube and lacks an insulated conductor. The first piping support for well piping is located 22 feet from the well, providing an opportunity to identify subsidence events prior to potentially impacting piping integrity.

C.2 Wind-Induced Vibration:

No problems identified in 2009.

C.3 Corrosion and Structural-Related Spills/Incidents:

- No leaks were caused by external corrosion in 2009.
- No leaks were caused by wind-induced vibration in 2009.
- No leaks were caused by internal corrosion in 2009.
- No structural or subsidence concerns were identified in 2009.

D. Year 2010 WNS Forecast

D.1 Monitoring & Mitigation

- Pull coupons as scheduled
- Test corrosion inhibitor (CI) formulations for production service
- Install additional CI storage capacity

D.2 Inspection

D.2.a Internal Corrosion Inspections

D.2.a.i) Well Line Inspections for Internal Corrosion

Inspect 15 lines for internal corrosion.

D.2.b.ii) Flow line Inspections for Internal Corrosion

Conduct interval surveys on 4 lines.

D.2.b.iii) External Corrosion Inspections

Flow lines:
Perform CUI inspections to ensure that lines do not exceed a five-year inspection interval.

Well lines:
TRT inspections are planned on 15 lines, with an emphasis on locations prone to CUI such as insulation jacketing damage or transitions from vertical to horizontal.

D.2.c Below Grade Piping Program

- Evaluate the criteria for inspection interval based on service, internal and external corrosion likelihood, etc. as noted in API 570.
- Visual inspection of all Priority 1, 2, and 3 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 the priority 1 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.

D.2.d 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 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 that 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 bprociding.
- **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
- **VT** – Visual inspection
- **ILI** – In-line inspection (smart pigging)
- **TWI –** The Welding Institute (Long range UT)
- **KDR –** Known damage recur inspection
- **CUI** – Corrosion under insulation
- **CUI IA** – Corrosion under insulation inspection area (Note: this is not necessarily identical to a weld pack)
- **IR**- Infra-red thermography
- **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 than priority 1 lines. 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 if the pipe leaked.