ALASKA LEGISLATURE COMMITTEE FILES, 2005-2006 8672

11971 SENATE RESOURCES

The concentration of inhibitor in the water phase provides a relative measure of the effectiveness of the chemical used to control corrosion. However, such data can be misleading as the types of corrosion inhibitors used can vary from year to year (GPB Table D.1). As more effective chemicals are developed, volumes and concentrations will change depending on the individual product's performance characteristics. There has also been a shift from batch treatments to continuous injection of chemical at the wellhead. The latter is more efficient in terms of protection achieved per gallon of chemical and therefore lower chemical usage would be expected. However, the ultimate measure of whether or not enough corrosion inhibitor is used can only be determined by consideration of other factors such as corrosion monitoring data and/or the amount of active corrosion detected by the inspection program.

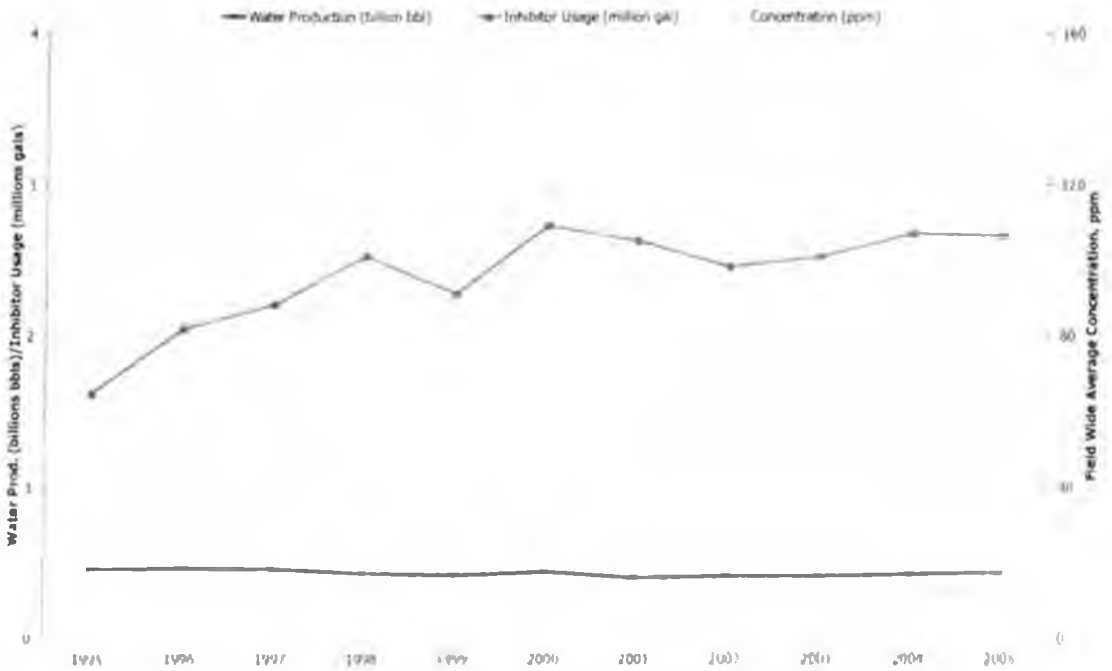
Year	H_2O Production 10^6 bbl/yr	Water Cut %	CI Usage 10^6 gal/yr	CI Concentration ppm
1995	455	59	1.62	85
1996	460	62	2.05	106
1997	457	62	2.21	115
1998	426	66	2.53	141
1999	416	68	2.28	130
2000	438	70	2.73	148
2001	398	70	2.63	157
2002	407	71	2.45	143
2003	408	72	2.52	147
2004	422	74	2.67	151
2005	431	76	2.66	147

GPB Table D.2 Summary of the Chemical Usage History

The decline in average concentration is due to the chemical plugging event during 4Q2004 through 1Q2005.

The advances in the development of more effective corrosion inhibitors is counteracted by the increasing water cuts associated with an aging oil field and increased flow velocities due to increased gas rates. These changes generally increase the amount of chemical required to control corrosion. As GPB Figure D.2 shows, the volume of corrosion inhibitor has increased since 1995 while the water volumes have remained relatively constant.

The metrics in GPB Figure D.2 deal with chemical usage at the field level but much of the chemical optimization activity focuses on injecting the correct amount of corrosion inhibitor to each piece of equipment. The inhibitor requirement is driven by factors such as water cut, water volume, flow regime, and condition of the equipment and varies over a wide range, from a few parts per million (ppm) to several hundred ppm. For 2005 the target chemical usage was 2.71 million gallons as compared to actual usage of 2.66 million gallons; or 98.1% of the target volume.

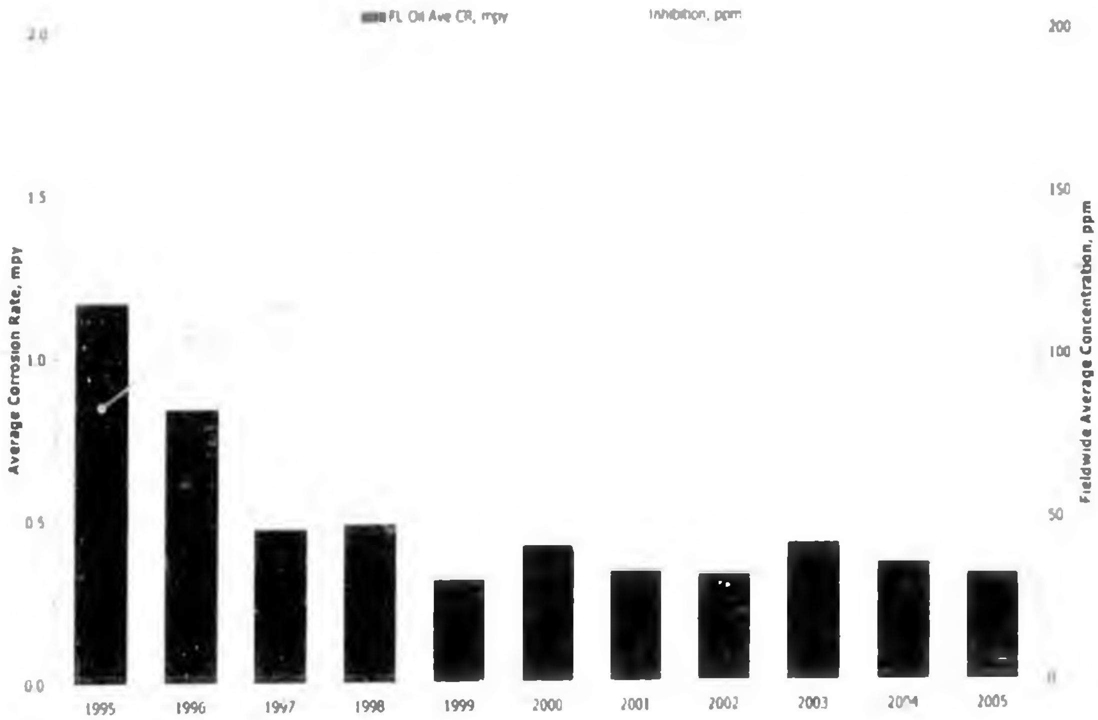


GPB Figure D.2 Field Wide Chemical Usage

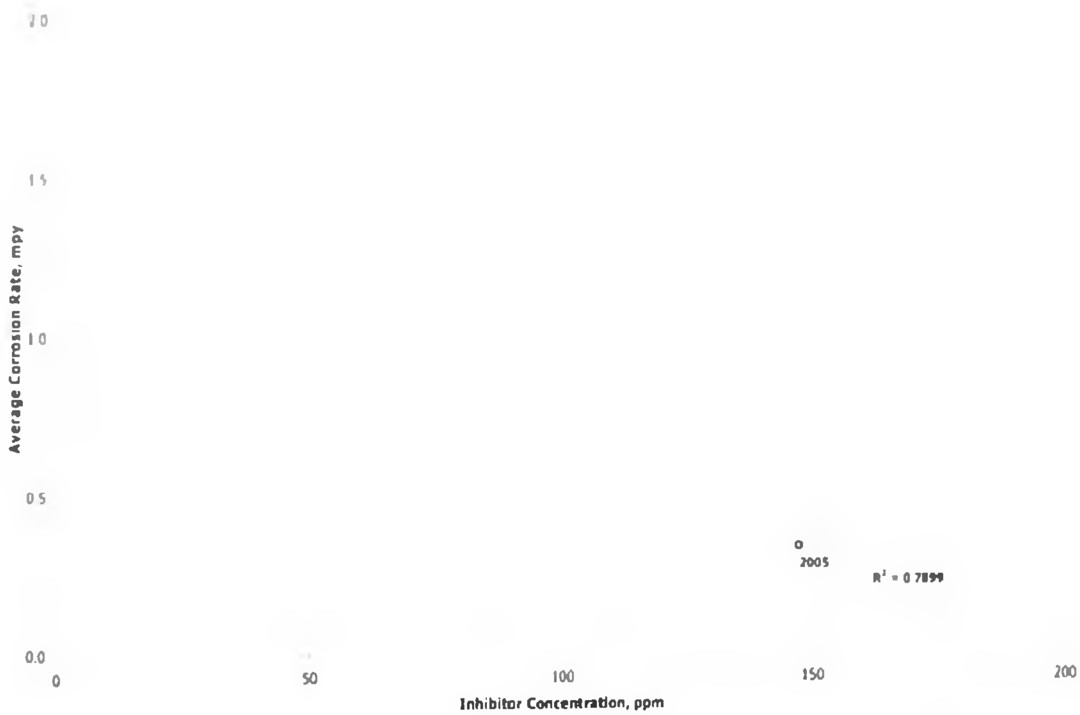
Section D.5 Corrosion Inhibition and Corrosion Rate Correlation

As discussed in Section C.1, the reduction in corrosion rates in the 3-phase production system flow lines and well lines are largely attributable to the implementation of an aggressive corrosion inhibition program across GPB.

GPB Figure D.3 shows the correlation between the increased level of corrosion inhibitor and the reduction in average corrosion rate from 1995. As might be expected, the decline in average corrosion rate correlates with the increase in corrosion inhibition levels over time. The inhibition levels have increased ~80% from 1995 to 2005, with a field-wide average concentration of 85 ppm to 147 ppm. As a result the corrosion rates have fallen from 1.4 mpy in 1995 to ~0.3 mpy in 2005.



GPB Figure D.3 Average Corrosion Rate Versus Inhibitor Concentration



GPB Figure D.4 Corrosion Inhibitor Concentration vs. Average Corrosion Rate

GPB Figure D.4 shows the annual field-wide average corrosion inhibitor concentrations versus annual average corrosion rates for 3-phase production flow lines. The figure shows how additional corrosion inhibitor has reduced the average corrosion rate through time, but also shows an inherent limitation of corrosion inhibition as the minimum corrosion rate (or maximum corrosion inhibitor efficiency) is approaching an asymptote of ~0.25 mpy.

Section D.6 Chemical Optimization Summary

In summary, chemical optimization covers a number of different areas from chemical testing and development to field-wide deployment of new products delivering improved levels of corrosion control more cost effectively. However, all this activity is ultimately directed toward one end — the reduction in corrosion rate. The effectiveness of the chemical optimization program in delivering improved corrosion rates is clearly demonstrated.

Section E

External/Internal Inspection

Section E External/Internal Inspection

The inspection program encompasses piping, piping components, pressure vessels and tanks across GPB. Radiographic imaging or ultrasonic flaw evaluation makes up the majority of inspection techniques. However, there are specialized techniques in use for specific applications. The details for these techniques are shown in Appendix 3, Table 11.

A number of factors contribute to the selection and allocation of inspection resources including, but not limited to, current equipment condition, current known rate (from inspection or corrosion monitoring) of wastage, operational risks associated with transported fluids, active or passive corrosion mitigation, operation, design and age of the equipment.

Section E.1 External Inspection

This section summarizes the inspections performed to detect external corrosion and the results of those inspections. GPB Table E.1 summarizes the CUI inspection program for the period 1995 to 2005 separated by service and equipment type and the aggregate data.

These data suggest there is some dependence of external corrosion occurrence based on service type. This dependence is driven in part by the difference in operating temperature between services. However, there is as much variability in damage occurrence is found based on the location and orientation of the weld-pack location. For additional information about CUI, refer to Appendix 3.3.4.

The CUI program covers all cross-country flow lines and well lines. There are approximately 300,000 weld packs at GPB, of which approximately 200,000 are off-pad and 100,000 are on-pad.

In order to manage CUI, a recurring inspection program has been implemented as the best method to identify equipment and locations susceptible to CUI. Prioritization of inspection surveys is determined by configuration, average temperature of the equipment, age of equipment, health, safety, environment (HSE), and/or the last time a complete inspection was completed. As a result of findings from inspections, the extent or recurring frequency of any additional examinations is determined.

	Flow Line			Well Line			Aggregate		
Service	# Insp.	# Corr	% Corr	# Insp.	# Corr	% Corr	# Insp.	# Corr	% Corr
3-Phase Oil	49,429	3,054	6%	51,757	1,899	4%	101,186	4,953	5%
Processed Oil	6,084	252	4%	-	-	-	6,084	252	4%
Gas	55,032	2,572	5%	28,804	304	1%	83,836	2,876	3%
Other	61	3	5%	1,471	38	3%	1,532	41	3%
Water	25,623	1,981	8%	11,216	346	3%	36,839	2,327	6%
Total	**136,229**	**7,862**	**6%**	**93,248**	**2,587**	**3%**	**229,477**	**10,449**	**5%**

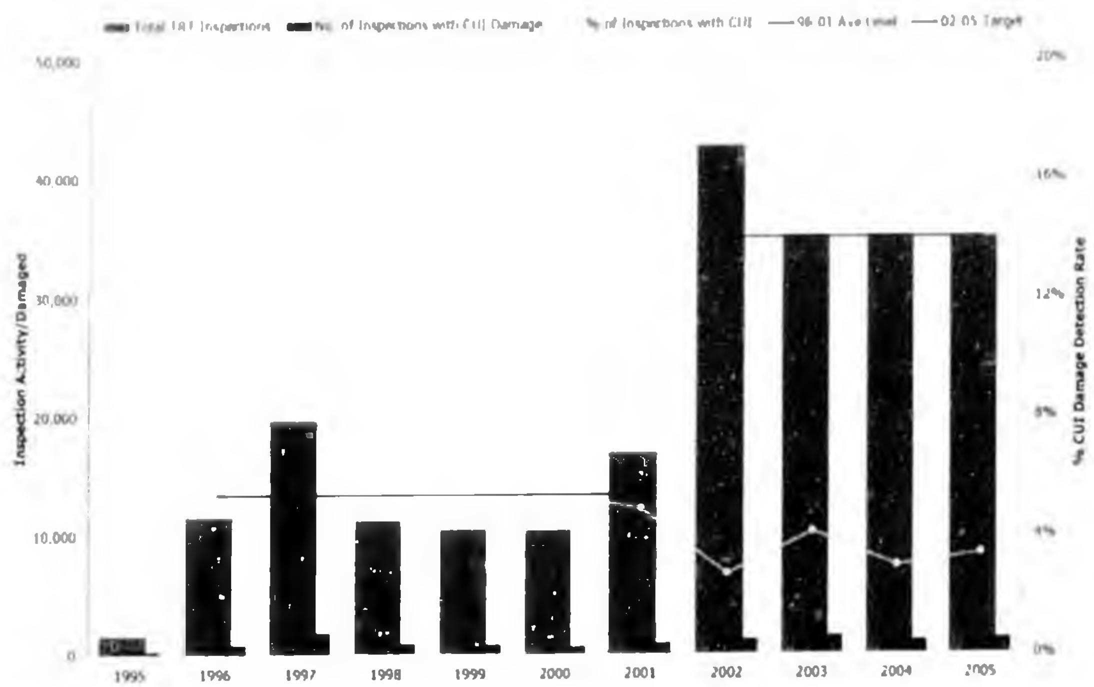
GPB Table E.1 CUI Inspections by Service Type, 1995-2005

Section E.1.1 External Inspection Program Results

GPB Table E.2 and GPB Figure E.1 show the number and results of the external corrosion inspections performed from 1995 through 2005. The data includes all the Tangential Radiographic (TRT) techniques applied to detect external corrosion, including Automated-TRT (ATRT), and C-Arm Fluoroscopy (CTRT).

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Well Line											
Activity Level	-	36	1,677	935	2,376	5,240	12,862	23,969	10,854	13,955	21,344
Corrosion Detected	-	6	235	65	80	243	704	352	140	361	402
% Corroded		17%	14%	7%	3%	5%	5%	1%	1%	3%	2
Flow Line											
Activity Level	1,498	11,456	17,888	10,290	8,132	5,173	3,966	18,727	24,293	21,156	13,650
Corrosion Detected	249	776	1,499	748	643	318	115	781	1,298	671	770
% Corroded	17%	7%	8%	7%	8%	6%	3%	4%	5%	3%	6%
GPB Overall											
Activity Level	1,499	11,492	19,565	11,225	10,508	10,413	16,828	42,696	35,147	35,111	34,994
Corrosion Detected	249	782	1,734	813	723	561	819	1,133	1,438	1,032	1,172
% Corroded	17%	7%	9%	7%	7%	5%	5%	3%	4%	3%	3%

GPB Table E.2 External Corrosion Activity and Detection Summary



GPB Figure E.1 External Corrosion Activity and Detection Summary

In general, the inspection levels over the period 1996 to 2001 remained relatively constant at an average of ~13,000 per year. In 2002 the activity level was increased substantially, targeting 35,000 inspections per year. In 2005, the activity level was at the target of 35,000 inspections.

There was a slight increase in CUI damage detected in 2005 as compared to 2004. Overall, the percentage of locations found with damage has fallen from an initial high of >15% to a field-wide average of 3-4% in recent years.

Section E.1.2 Cased Piping Survey Results

A long-term management strategy consisting of; repeat examinations, analysis of results and corrective action as warranted has been implemented for cased piping segments. Currently, the preferred test methodologies are either guided wave and/or in-line inspection (ILI) in order to determine the presence of an active corrosion mechanism. Potential metal loss areas are reported and severity is semi-quantified as non-relevant (i.e. no metal loss), minor, moderate, or significant. Distinction from previous examinations is reported as no change (NC) or an increase (I). An increase may be associated with active corrosion, therefore additional verification would be required to determine the appropriate response.

The 2005 program consisted of repeat examinations/monitoring and excavation. GPB Table E.3 shows the inspection results for cased pipe segments. There were 79 cased segments evaluated primarily using guided wave technology. Of the 79 inspected segments, 2 had moderate anomalies and 12 had slight anomalies. The number of inspected piping segments did not meet target due to a shortage of specialized materials utilized with magnetostrictive guided wave technique. The supplier for the cobalt based probes (ferromagnetic strips), which are permanently affixed to the pipeline, were unable to meet the demand during 2005. Material availability is not expected to be an issue during 2006.

			Anomaly Type				
Service	**Inspection Method**	**NC or I**	**Non Relv**	**Minor**	**Mod**	**Sig**	**Anomaly Action**
Gas	G-Wave	NC	24				G-Wave Monitor
	G-Wave	NC			1		Evaluate for Excavation
	G-Wave	NC		2			Evaluate for Excavation
	G-Wave	NC		1			G-Wave Monitor
Oil	G-Wave	NC	27				G-Wave Monitor
	G-Wave	NC		1			Evaluate for Excavation
	G-Wave	I		1			Evaluate for Excavation
	ILI	NC	1				G-Wave Monitor
	ILI	NC		4			G-Wave Monitor
PO	G-Wave	NC		1			Smart Pig 2006
PW/SW	G-Wave	NC	13				G-Wave Monitor
	G-Wave	NC			1		Evaluate for Excavation
	G-Wave	NC		2			G-Wave Monitor
Inspection Totals		**79**	**65**	**12**	**2**	**0**	

GPB Table E.3 Cased Pipe Survey Results

In summary, the strategy and execution will continue to develop as the program is refined and more information and/or experience with emerging long-range inspection technologies are gained. As a result of 2005 cased pipe survey, five segments are being evaluated for excavation in 2006.

Section E.1.3 Excavation History

Excavations of cased pipeline segments are typically performed when inspection data indicates the likelihood of an active corrosion mechanism or significant degradation that cannot be mitigated by any other means (e.g. CUI).

In 2005, six cased segments were excavated and the subsequent inspections were used to verify monitoring results. There was one mechanical repair required, one location with external corrosion that was mitigated and four locations with no corrosion damage.

Since 1992, there have been 56 cased pipeline segments at road and/or animal crossings excavated in GPB. Two of these excavations were as a result of loss of containment; the remaining 54 excavations were verification of inspection results. GPB Table E.8, at the end of this section, shows 46 were found with external corrosion damage, 9 were found with no external corrosion damage, and one location with coincidental internal and external corrosion.

The identification of potential damage areas through the inspection program and subsequent actions of monitoring and/or excavation, gives confidence that inaccessible pipe segments can be effectively managed to minimize loss as a result corrosion degradation.

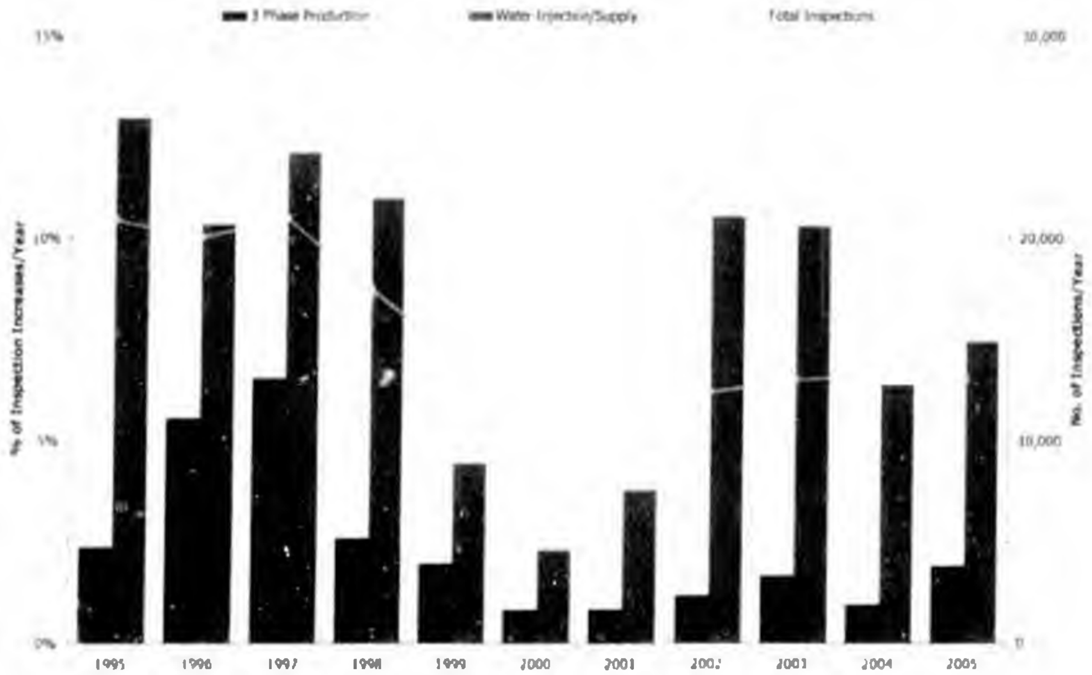
Section E.2 Internal Inspection Program Results

The results presented in this section are aggregate data obtained from flow line and well line inspections. The program results are presented in terms of the number of locations that show an increase in corrosion damage since the last inspection as a percentage of the total number of repeat inspections,

$$\text{\% Increases} = \frac{\text{Locations with active corrosion}}{\text{Total \# of reinspected locations}} \times 100$$

The percentage increases is therefore a high level measure of the amount of active corrosion in any given system.

GPB Figure E.2 shows the percentage of inspection increases (%I's) and the number of inspections per year for the flow lines segregated by 3-phase production and water injection (seawater and produced water) service.



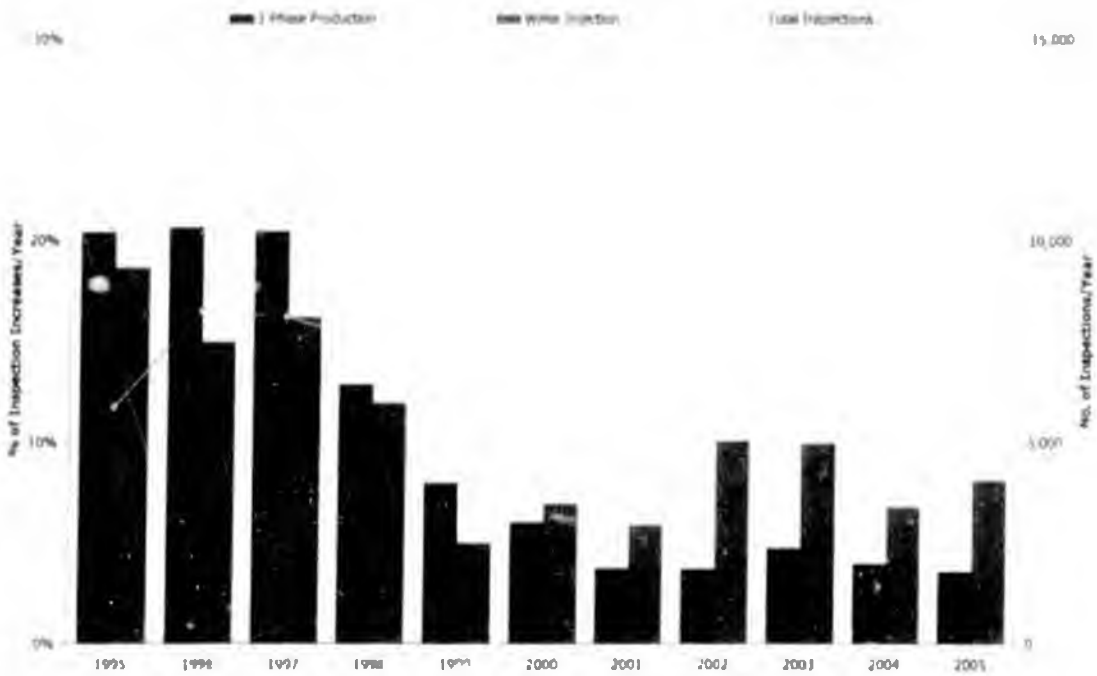
GPB Figure E.2 Flow Line Internal Inspection Increase by Service

The percentage of inspection increases in the 3-phase system declined considerably from 1997 to a historical low in 2000-2001. Since that time, there has been a slight increasing trend in locations showing active corrosion. While this increasing trend is still comparatively low, focus must be maintained on the 3-phase system to ensure continued good performance. The increase from last year can partially be attributed to active corrosion found in one flow line, PTMCLS0102. In response to these increases, additional corrosion inhibitor was added and operational changes were made to alter the flow characteristics within the pipeline.

The water injection system continues to be an area where improvement is required to realize a similar level of corrosion control as the 3-phase system. Section C.2.2 details several improvements that were made to the PW system in 2005. Since inspection is a lagging indicator, it will likely be 18 months before notable changes in %I's are evident.

GPB Figure E.3 shows the %I's trend and the number of inspections per year for the well lines. For 3-phase well lines, over the long term, there is a decrease in corrosion activity as measured by %I's. Over the past 5-years the %I's has remained at 4-5%.

For the water system, the trends for well lines are similar to flow lines. As with the flow lines, improvements in the chemical mitigation program for the PW system are expected to augment the level of corrosion control in the near future.



GPB Figure E.3 Well Line Internal Inspection Increase by Service

Section E.3 Correlation between Inspection and Corrosion Monitoring[8]

Inspection and corrosion monitoring have different characteristics; in particular, inspection techniques are comparatively insensitive but are the most accurate as they measure actual wall loss. In contrast, corrosion monitoring is more sensitive but less accurate as a measure of corrosion rate as the weight loss coupon is not an integral part of the pipe wall. Refer to Table 12 for additional information regarding these techniques.

Therefore, in order to have good confidence in the results from the corrosion-monitoring program, it is necessary to show a correlation between the monitoring program and the results of the inspection program. The following section describes the correlation between inspection and monitoring programs for the 3-phase production system.

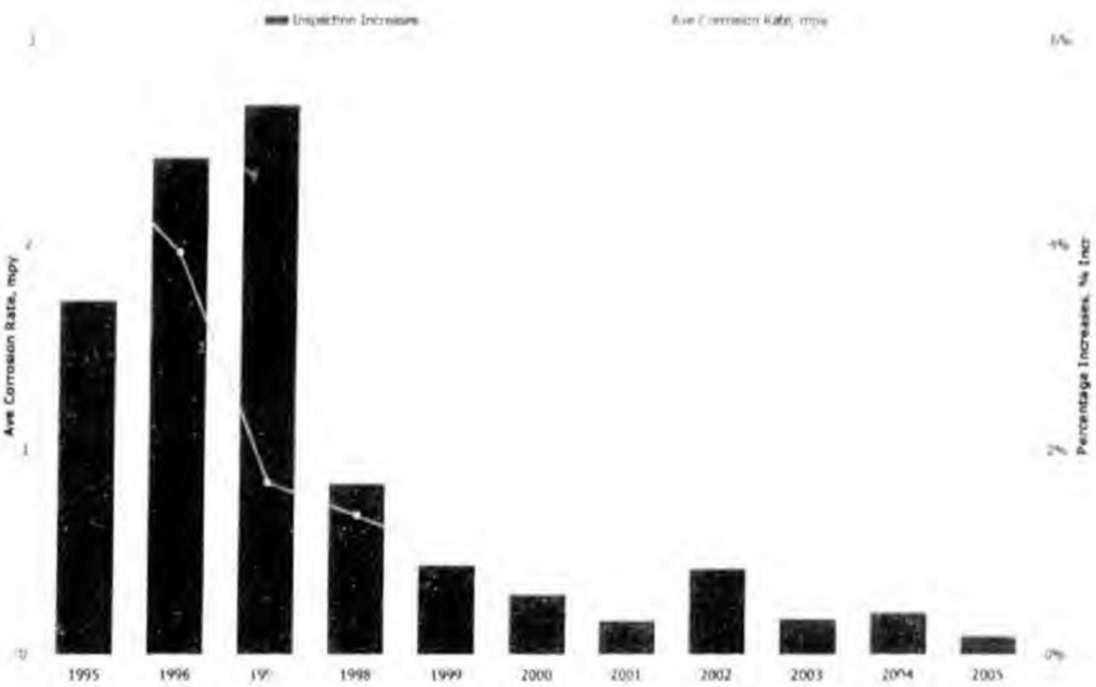
GPB Figure E.4 shows a similar decreasing trend in average corrosion rate from WLC and the percentage of increases found in the inspection program for the 3-phase well line and flow line. It should be noted that the inspection results included in the analysis are not the full data set but has been refined to include only that data which has an inspection interval (time since last inspection) of less than 730 days (two years). Also, the indicated reporting year has been changed to reflect the mid-point of the inspection interval rather than the time of inspection as in the other figures in this report. This change in the reporting time compensates for the fact that corrosion is occurring over the entire time interval between inspections. Similarly, the weight loss coupon corrosion rates are reported as the mid-point of the exposure period not the removal date.

---

[8] In addition to Charter Work Plan, this information supplied to provide additional context and help in understanding BPXA's corrosion management activities

From the correlation between inspection and corrosion monitoring, a number of important conclusions can be drawn:

- Corrosion monitoring is considered a leading indicator and inspection is considered a lagging indicator. This is supported by the data which shows ~2 year lag between corrosion monitoring and inspection changes.
- As the corrosion rates decrease due to the effectiveness of the inhibition program, then further program optimization will be driven by the information gained from the corrosion monitoring program rather than the inspection program.
- Timely optimization of the chemical program can not be reliant on feedback from the inspection data but must be managed through the corrosion monitoring program.
- Because of the lower sensitivity of the techniques used in the inspection program, the corrosion rates in the 3-phase flow lines are below the detection limits for inspection; therefore corrosion rate monitoring becomes a function of the coupon program leaving inspection as a confirmation and integrity assessment tool.



GPB Figure E.4 Correlation of Corrosion Rate and %Increases, 3-phase Production

A similar degree of correlation exists between the corrosion monitoring and the inspection data for the water injection systems. GPB Figure E.2 and GPB Figure E.3 show similar trends in both the flow lines and well lines which is also reflected in the corrosion monitoring data depicted in GPB Figure C.16 and GPB Figure C.17.

In summary, the data in this section shows the correlation between the inspection data and the corrosion monitoring data. This in turn, allows the corrosion monitoring data to be used with confidence to manage the chemical treatment program in a timelier manner.

Section E.4 In-line Inspection

In-line inspection (ILI) tools, or smart pigs are important tools to have available for the management of the long-term integrity of the flow lines., However, ILI is not always the most appropriate or applicable for GPB because of the operating conditions, design and accessibility of the pipelines to manual methods of NDE.

Magnetic flux leakage (MFL) type tools are frequently used at GPB where pigging facilities and process environment allow. Refer to Appendix 3.3.6 for additional information related to ILI at GPB.

ILI was performed on three 3-phase production flow lines. GPB Table E.4 summarizes equipment service, diameter, and length.

Equipment	Service	Diameter	Previous ILI	From	To	Length (miles)
E-36	3 Phase	24	1999	E Pad	GC1	2.9
W-74	3 Phase	24	1997	W Pad	EWE Junction	0.8
Z-74	3 Phase	24	1997	Z Pad	EWE Junction	3.3

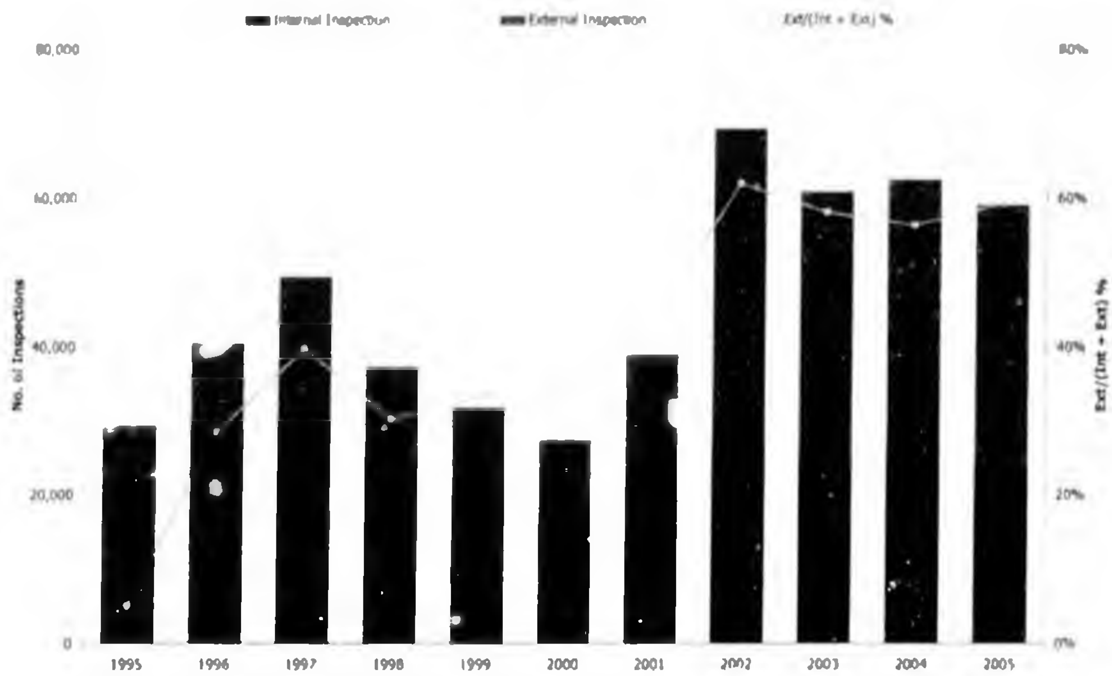
GPB Table E.4 Completed Smart Pig Assessments

The reported metal loss features have been prioritized for verification by radiographic and/or ultrasonic inspection. The verification results through 2005 are included in the aggregate inspection data. Additional follow-up of the reported features is an ongoing part of the normal radiographic and ultrasonic NDE activity at GPB.

In summary, ILI will continue to be used to assist and complement the overall inspection program.

Section E.5 Internal/External Inspection Comparison

GPB Figure E.5 and GPB Table E.5 summarizes the level of internal and external inspection activity across GPB since 1995 for both cross-country flow lines and well lines. The inspection activity for both the internal and external programs has been relatively consistent over the past four years.



GPB Figure E.5 Internal and External Inspection Activity for Flow and Well Lines

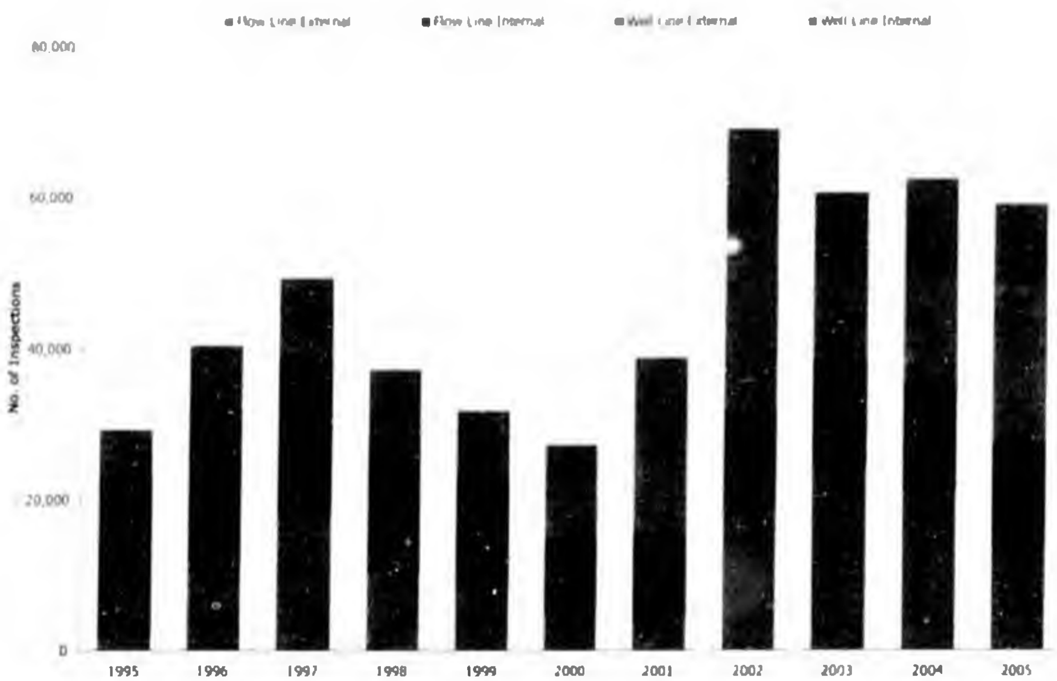
Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
External	1,498	11,492	19,565	11,225	10,508	10,413	16,828	42,696	35,147	35,111	34,994
Internal	27,727	28,911	29,771	25,929	21,261	16,851	21,955	26,411	25,490	27,285	24,049
Total	29,225	40,403	49,336	37,154	31,769	27,264	38,783	69,107	60,637	62,396	59,043
$\frac{Ext}{(Ext + Int)}$ %	5%	28%	40%	30%	33%	38%	43%	62%	58%	56%	59%

GPB Table E.5 Internal and External Inspection Activity Breakdown

GPB Table E.6 and GPB Table E.7 show the split between flow line and well line inspections for both the internal and external programs. The overall inspection activity is running at ~60,000 inspections per year, in line with the 2002 increased emphasis on external corrosion detection.

	Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Flow Line	External	1,498	11,456	17,888	10,290	8,132	5,173	3,966	18,727	24,293	21,156	13,650
	Internal	21,669	20,502	21,262	18,183	14,913	9,607	11,639	13,299	14,209	14,296	14,092
	Total	23,167	31,958	39,150	28,473	23,045	14,780	15,605	32,026	38,502	35,452	27,742
	Ext / (Ext + Int) %	6%	36%	46%	36%	35%	35%	25%	58%	63%	60%	49%
Well Line	External		36	1,677	935	2,376	5,240	12,862	23,969	10,854	13,955	21,344
	Internal	6,058	8,409	8,509	7,746	6,348	7,244	10,316	13,112	11,281	12,989	9,957
	Total	6,058	8,445	10,186	8,681	8,724	12,484	23,178	37,081	22,135	26,944	31,301
	Ext / (Ext + Int) %	0%	0%	16%	11%	27%	42%	55%	65%	49%	52%	68%
Grand	**Total**	29,225	40,403	49,336	37,154	31,769	27,264	38,783	69,107	60,637	62,396	59,043
	FL / (FL + WL) %	79%	79%	79%	77%	73%	54%	40%	46%	63%	57%	47%

GPB Table E.6 Internal and External Inspection Activity Summary by Flow/Well Line



GPB Figure E.6 Internal and External Inspection Activity Summary by Flow/Well Line

Section E.6 Inspection Summary

In summary, the main conclusions from the inspection section are,

- The external corrosion inspection program completed 34,994 items in 2005. Approximately 3% of these inspections showed damage, which is consistent with the overall average in recent years.

- The cased piping survey is continuing to evolve into a process of monitoring and corrective action.
- A unified internal inspection philosophy and program structure has been implemented across GPB with a total program size of approximately 60,000 items, split between field and facility piping.
- The inspection results for both the flow line and well line 3-phase systems show improved performance in the long term. 2005 flow line data continue a slight increasing trend in active corrosion, while the well line %I's data are consistent at 4-5% for the past 5 years.
- The water injection systems show a long term improving trend from 1995 through 2001. There has been an increase in the corrosion activity since 2002. Several corrective actions have been implemented since then to address the increased activity. During 2005, significant changes to the chemical inhibition program for PW system were implemented.
- The results of the inspection program and the weight loss coupon program from the 3-phase oil service were shown to be strongly correlated. The reduction in corrosion activity from both measures being attributable to the implementation of an aggressive and increasing corrosion inhibition program in the 3-phase service since 1995.

BU	Type	Service	Result	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
GPB	FL	OIL	I	368	923	1,154	394	240	67	60	102	152	101	175
GPB	FL	OIL	NC	15,148	15,702	16,460	14,802	11,935	8,150	7,015	8,601	8,966	10,428	9,013
GPB	FL	OIL	NL	3,615	2,118	1,969	441	357	146	1,780	2,017	1,944	810	1,706
GPB	**FL**	**OIL**	**Total**	**19,131**	**18,743**	**19,583**	**15,637**	**12,532**	**8,363**	**8,855**	**10,720**	**11,062**	**11,339**	**10,894**
GPB	FL	WTR	I	171	124	154	192	72	17	43	138	176	107	141
GPB	FL	WTR	NC	1,148	1,075	1,119	1,557	1,551	720	1,091	1,172	1,533	1,571	1,752
GPB	FL	WTR	NL	422	114	134	88	75	61	351	377	217	218	278
GPB	**FL**	**WTR**	**Total**	**1,741**	**1,313**	**1,407**	**1,837**	**1,698**	**798**	**1,485**	**1,687**	**1,926**	**1,896**	**2,171**
GPB	**FL**	**Total**	**Total**	**20,872**	**20,056**	**20,990**	**17,474**	**14,230**	**9,161**	**10,340**	**12,407**	**12,988**	**13,235**	**13,065**
GPB	WL	OIL	I	630	904	875	600	311	264	212	274	323	290	232
GPB	WL	OIL	NC	2,455	3,479	3,405	4,074	3,608	4,120	5,500	7,131	6,516	7,034	6,313
GPB	WL	OIL	NL	962	1,745	1,961	699	570	506	2,458	3,402	2,252	2,390	1,231
GPB	**WL**	**OIL**	**Total**	**4,047**	**6,128**	**6,241**	**5,373**	**4,489**	**4,890**	**8,170**	**10,807**	**9,091**	**9,714**	**7,776**
GPB	WL	WTR	I	225	262	201	216	74	127	79	125	147	152	107
GPB	WL	WTR	NC	984	1,493	1,041	1,595	1,418	1,709	1,265	1,122	1,334	2,091	1,217
GPB	WL	WTR	NL	616	358	622	217	177	254	496	531	359	522	535
GPB	**WL**	**WTR**	**Total**	**1,825**	**2,113**	**1,864**	**2,028**	**1,669**	**2,090**	**1,840**	**1,778**	**1,840**	**2,765**	**1,859**
GPB	**WL**	**Total**	**Total**	**5,872**	**8,241**	**8,105**	**7,401**	**6,158**	**6,980**	**10,010**	**12,585**	**10,931**	**12,479**	**9,635**
GPB	**Total**	**Total**	**Total**	**26,741**	**28,297**	**29,095**	**24,875**	**20,388**	**16,141**	**20,350**	**24,992**	**23,919**	**25,714**	**22,700**

Note: I = Inspection Increase
NC = No Change
NL = New Inspection Location

GPB Table E.7 Flow and Well Line Inspection Data

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
1992	COTU Access Road	FS1 to FS2 12" MI Distribution	10% external wall loss	Insulation/coating/tape repair
1995	S Pad West Entrance Crossing	S Pad 24" 3 Phase Production	61% external wall loss	Sleeve/insulation/coat repair
		S Pad 14" Produced Water	36% int/ext wall loss	Sleeve/insulation/coat repair
		S Pad 10" Gas Lift	34% external Wall Loss	Insulation/coating repair
		S Pad 8" Miscible Injection	41% external wall loss	Replaced segment/FBE
	GC1 Main Entrance	Distribution 24" Gas Lift	29% external wall loss	Insulation/coating repair
		Y Pad 24" 3 Phase Production	24% external wall loss	Insulation/coating repair
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	42% external wall loss	Sleeve/insulation/coat repair
		Y Pad 24" 3 Phase Production	26% external wall loss	Insulation/coating repair
1996	GC-1 Spine Road	Distribution 24" Gas Lift	53% external wall loss	Sleeve/insulation/coat repair
		D Pad 24" 3 Phase Production	33% external wall loss	Insulation/coating repair
		Y Pad 24" 3 Phase Production	18% external wall loss	Insulation/coating repair
		Distribution 20" Produced Water	8% external wall loss	Insulation/coating repair
	E Pad Entrance	E Pad 24" 3 Phase Production	21% external wall loss	Insulation/coating repair
	GC3 to FS3 Caribou Crossing	Distribution 24" Gas Lift	No corrosion damage	None
	FS1 to FS2 Caribou Crossing	Distribution Natural Gas 30"	11% external wall loss	Insulation/coating/tape repair
		Sales Oil 30"	14% external wall loss	Insulation/coating/tape repair
		Distribution 24" Gas Lift	No corrosion damage	None
		Distribution 32" Sea Water	No corrosion damage	None
1998	S Pad East Entrance Crossing	S Pad 10" Gas Lift	~80% wall loss - ext rupture	Replaced segment
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	9% external wall loss	Insulation/coating repair
	GC2 to GC1 Q Pad Rd Crossing	Distribution 34" Natural Gas	No corrosion damage	Insulation/FBE coated

GPB Table E.8 Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2000	S Pad East Entrance Crossing	S Pad 24" 3 Phase Production S Pad 14" Produced Water S Pad 8" Miscible Injection	~60% external wall loss ~50% external wall ioss 25% external wall loss	Replaced segment/coat repair Replaced segment/coat repair Sleeve/insulation/coat repair
2003	GC2 to GC1 Caribou Crossing	Y Pad 24" 3 Phase Production	Leak -external corrosion	Partial excavation/sleeve repair
	X Pad Pipeline Access Rd Crossing	X Pad 24" 3 Phase Production	~75% external wall loss	Partial excavation/sleeve repair
	F Pad Pipeline Access Rd Crossing	F Pad 24" 3 Phase Production	24% external wall loss	Partial excavation/none
	NGI Pad Road Crossing	NGI Pad 14" Gas Cap Injection	58% external wall loss	Replaced segment
2004	WGI to West Dock Road Crossing	AGI Pad 16" Gas Cap Injection	no corrosion damage	none
	CCP Pad Road Crossing	CCP/NGI-NGL 4" NGL	10% external wall loss	partial excavation/insulation tape repair
	GC1 Entrance Road Crossing	D Pad 24" 3 Phase Production	16% external wall loss	partial excavation/insulation tape repair
	GC1 to F Pad Caribou Crossing	F Pad 24" 3 Phase Production	21% external wall loss	partial excavation/insulation tape repair
	GC1 to GC2 Road Crossing	U Pad 6" Gas Lift Supply	5% external wall loss	partial excavation/insulation tape repair
	F Pad/Frontier Camp Rd Crossing	F Pad 24" 3 Phase Production	16% external wall loss	partial excavation/insulation tape repair
	F Pad Pipeline Access Rd Crossing	F Pad 24" 3 Phase Production	18% external wall loss	partial excavation/insulation tape repair
	GC1 to G Pad Caribou Crossing	G Pad 6" 3 Phase Production	no corrosion damage	none

GPB Table E.8 (Continued) Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2004	Q Pad Access Road Crossing	GC3/GC2 12" MI Supply	9% external wall loss	partial excavation/insulation tape repair
		H Pad 24" 3 Phase Production	24% external wall loss	partial excavation/insulation tape repair
		Y Pad 12" PW Supply	39% external wall loss	partial excavation/insulation tape repair
	Q Pad Spur Road Crossing	Y Pad 12" PW Supply	12% external wall loss	partial excavation/insulation tape repair
	West Dock to GC1 Road Crossing	K Pad 24" 3 Phase Production	8% external wall loss	partial excavation/insulation tape repair
	GC2 to N Pad Caribou Crossing	N Pad 24" 3 Phase Production	37% external wall loss	partial excavation/insulation tape repair
	CCP Pad Road Crossing	NGI Pad 14" Gas Cap Injection	14% external wall loss	partial excavation/insulation tape repair
	S Pad Entrance Road Crossing	S Pad 24" 3 Phase Production	10% external wall loss	partial excavation/insulation tape repair
		S Pad 14" Produced Water	11% external wall loss	partial excavation/insulation tape repair
	U Pad Road Crossing	U Pad 6" Production Well Line	18% external wall loss	partial excavation/insulation tape repair
		U Pad 3" Gas Lift Well Line	16% external wall loss	partial excavation/insulation tape repair
	X Pad to B Pad Caribou Crossing	X Pad 24" 3 Phase Production	5% external wall loss	partial excavation/insulation tape repair
		X Pad 8" MI Supply	17% external wall loss	partial excavation/insulation tape repair
2005	X Pad Pipeline Access Road	X Pad 24" 3 Phase Production	24% external wall loss	insulation tape repair
	GC-1 Spine Road	Distribution 24" Gas Lift	30% external wall loss	sleeve/insulation/tape repair

GPB Table E.8 (Continued) Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2005	GC-1 Spine Road	D Pad 24" 3 Phase Production	34% external Wall Loss	insulation tape repair
		Y Pad 24" 3 Phase Production	no corrosion damage	insulation tape repair
		Distribution 28" Produced Water	no corrosion damage	insulation tape repair
		GC1-GC2 24" 3 Phase Tie-line	no corrosion damage	insulation tape repair

GPB Table E.8 (Continued) Cased Piping Excavation History

Section F

Repair Activities

Section F Repair Activities

The repair activities shown in GPB Table F.1 include a total of 71 repairs as compared to 132 in year 2004. The larger number of repairs in 2004 was due to injection system upgrades and application of a unified FFS criterion across GPB East and GPB West equipment. The number of repairs for 2005 are consistent with the recent average. GPB Figure F.1, GPB Figure F.2, GPB Figure F.3, and GPB Table F.2, show the 6-year trend in repairs grouped by service, damage mechanism, and equipment, respectively.

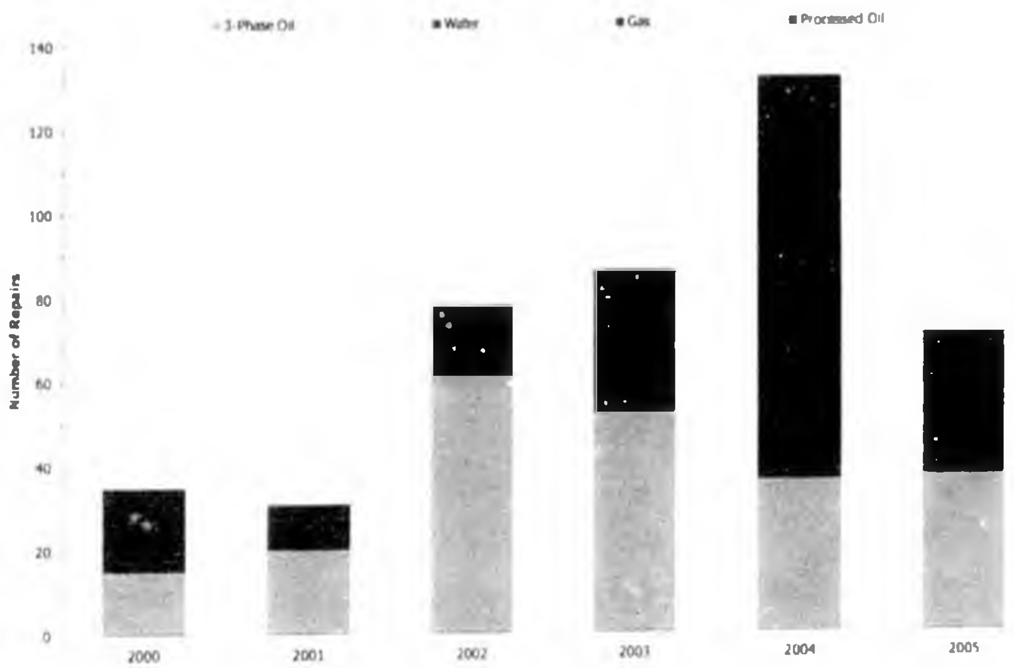
Service	Type	Internal	External	Mechanical	Total
3-Phase Oil	FL	1	27	1	29
	WL	1	7	-	8
Water	FL	5	-	1	6
	WL	5	7	1	13
Gas	FL	-	4	4	8
	WL	-	4	3	7
Processed Oil		-	-	-	0
Total		**12**	**49**	**10**	**71**

GPB Table F.1 Repair Activity

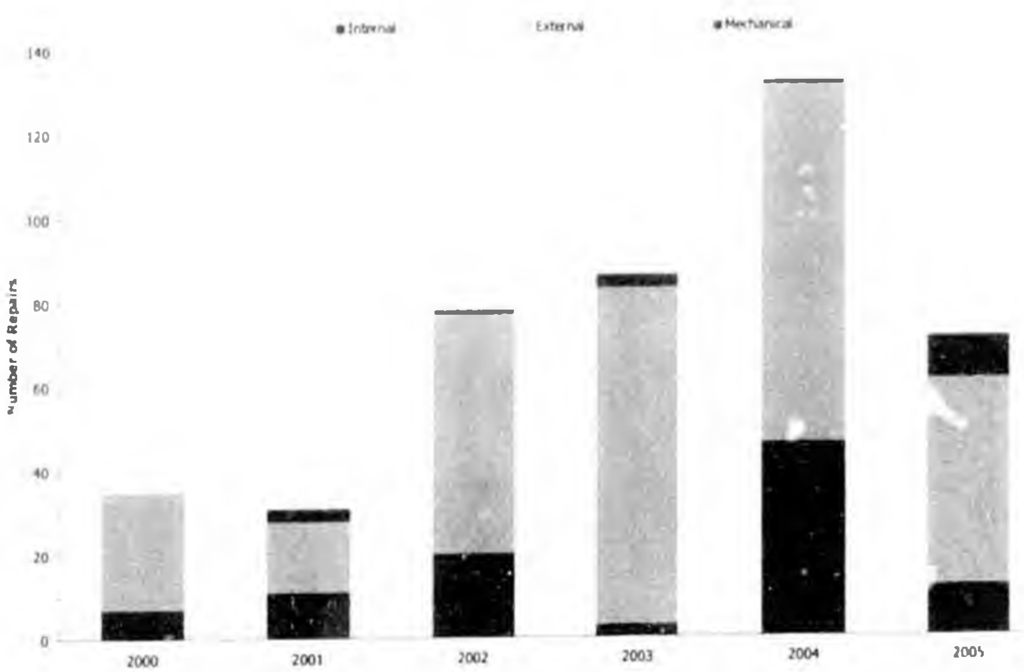
There were 49 repairs associated with external corrosion which is lower than the number of repairs in 2003 and 2004.

There were 10 repairs associated mechanical anomalies. Five repairs were due to heavy equipment damage, four repairs were due to snow loading or freezing conditions, and one repair was due to fatigue at a girth weld.

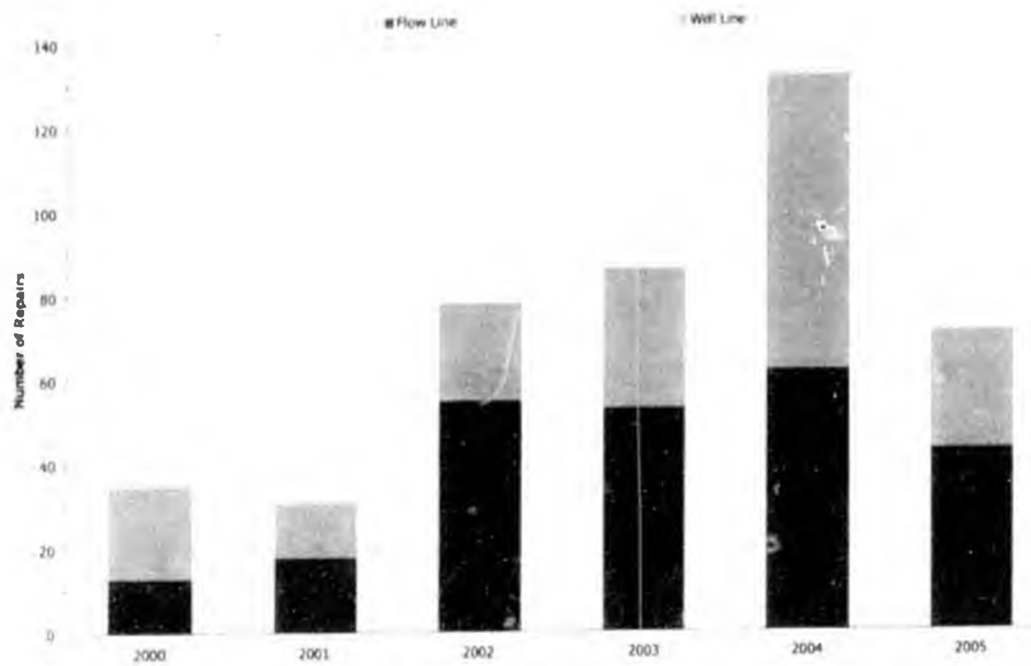
Ten of twelve repairs due to internal corrosion were on the water injection system (SW or PW). The remaining two repairs were on the 3-phase production system.



GPB Figure F.1 Repairs by Service



GPB Figure F.2 Repairs by Damage Mechanism



GPB Figure F.3 Repairs by Equipment

	3-Phase Oil		Water		Gas		Processed Oil	Total
	Flow Line	Well Line	Flow Line	Well Line	Flow Line	Well Line	Flow Line	
2000								
Internal	2	5	-	-	-	-	-	7
External	1	7	2	7	8	3	-	28
Mechanical	-	-	-	-	-	-	-	-
Total	3	12	2	7	8	3	-	35
2001								
Internal	2	4	1	1	-	-	3	11
External	7	5	3	-	2	-	-	17
Mechanical	-	2	-	-	-	1	-	3
Total	9	11	4	1	2	1	3	31
2002								
Internal	8	7	1	4	-	-	-	20
External	35	11	6	1	4	-	-	57
Mechanical	-	-	-	-	1	-	-	1
Total	43	18	7	5	5	0	-	78
2003								
Internal	-	3	-	-	-	-	-	3
External	28	20	-	1	23	8	-	80
Mechanical	1	-	-	-	1	1	-	3
Total	29	23	-	1	24	9	-	86
2004								
Internal	5	5	23	13			-	46
External	13	13	9	1	12	37	-	85
Mechanical	-	-	1				-	1
Total	18	18	33	14	12	37	-	132
2005								
Internal	1	1	5	5	-	-	-	12
External	27	7	-	7	4	4	-	49
Mechanical	1	-	1	1	4	3	-	10
Total	29	8	6	13	8	7	-	71
Grand Total	**133**	**90**	**52**	**41**	**59**	**57**	**3**	**435**

GPB Table F.2 Historical Repairs by Service

Section G

Corrosion and Structural Related Spills and Incidents

Section G Corrosion and Structural Related Spills and Incidents

Section G.1 Corrosion Related Leaks

This section summarizes the corrosion and structural related incidents that occurred in 2005 and provides a historical perspective on the leaks (loss of containment) and saves (repairs before leak of non-FFS equipment).

GPB Table G.1 summarizes the equipment, failure mechanism and volume of leaks that occurred in 2005. Of the 6 leaks that occurred in 2005, 1 was associated with external corrosion, 2 with internal corrosion, and 3 with mechanical failures.

Service	Location	Type	Date	Mechanism	Volume
Seawater	DS11	WL	13-Feb-05	Internal	~270 gallons
Gas	D-06	WL	17-Mar-05	Mechanical	N/A
Gas	DS14	FL	12-Apr-05	Mech/Fatigue	~1,260 gallons[1]
Oil	M-pad	FL	15-Apr-05	Mechanical	~4 gallons
Gas	DS16	WL	27-Jul-05	CUI	N/A
Seawater	DS11	WL	30-Oct-05	Internal	~10 gallons

[1]Weld failure in warm-up gas line which allow oil to enter the system

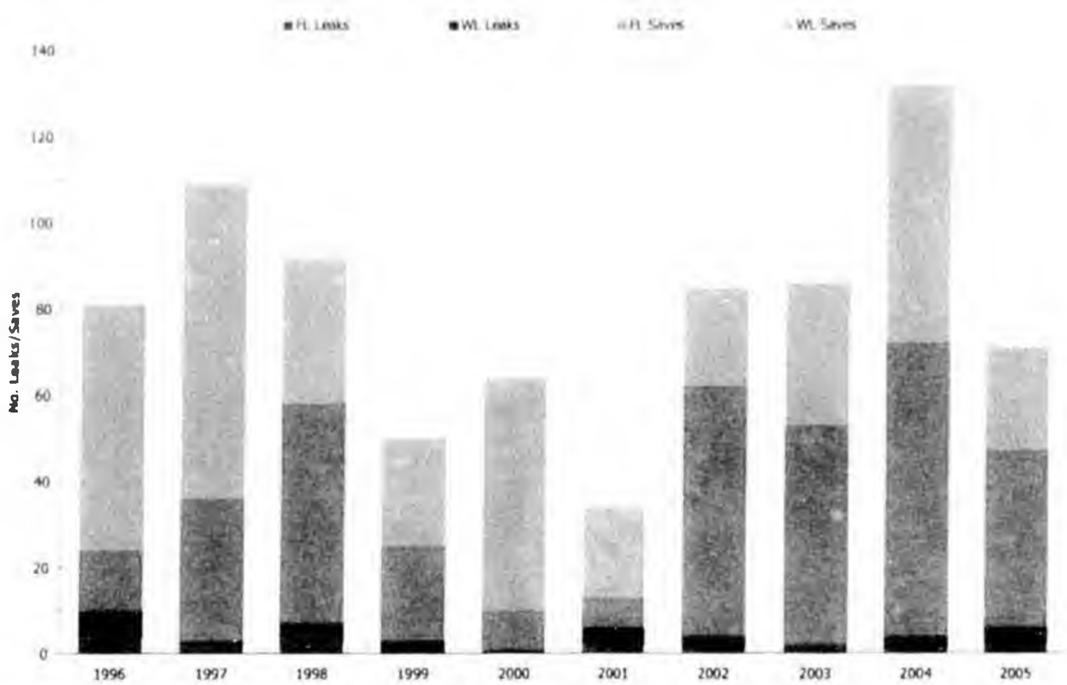
	Surface		Service				Mechanism			
	Int	Ext	OIL	SW	PW	Gas	CO_2	Int	CUI	Mech
WL	2	2		2		2		2	1	1
FL		2	1			1				2

GPB Table G.1 Leaks Due to Corrosion/Mechanical

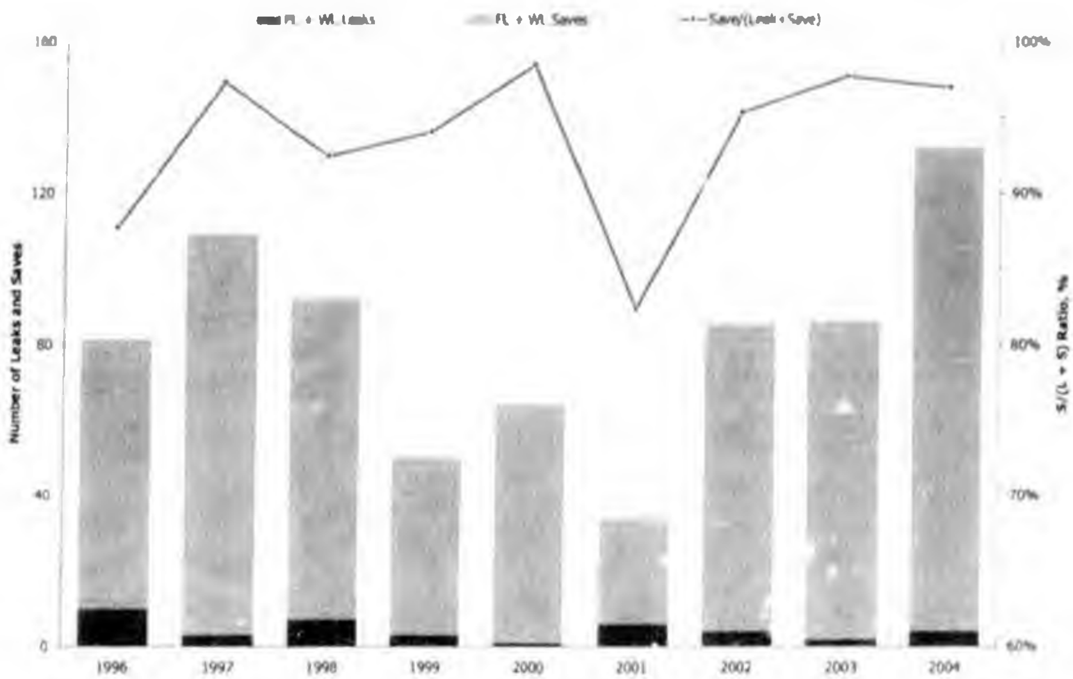
GPB Table G.2, GPB Figure G.1 and GPB Figure G.2 show the number of corrosion related leaks and saves since 1996. The ratio of leaks to saves provides a high level measure of the performance of the inspection program at detecting severe damage before it results in a failure. A 'save' is defined as a location found via the inspection program that warrants a repair, system de-rate, replacement or removal from service as the equipment no longer meets the FFS criteria defined in Appendix 3.3.5. It should be noted that items are typically scheduled for repair at 105% of MAOP, to allow time to schedule and complete the repair before the item requires removal from service.

	Flow Lines			Well Lines			Total
	Saves	Leaks	$\frac{S}{(L+S)}\%$	Saves	Leaks	$\frac{S}{(L+S)}\%$	$\frac{S}{(L+S)}\%$
1996	14	4	78%	57	6	90%	88%
1997	33	2	94%	73	1	99%	97%
1998	51	3	94%	34	4	89%	92%
1999	22	0	100%	25	3	89%	94%
2000	9	1	90%	54	0	98%	97%
2001	7	2	78%	21	4	84%	82%
2002	58	1	98%	23	3	89%	95%
2003	53	2	96%	33	0	100%	98%
2004	68	1	99%	60	3	95%	97%
2005	41	2	95%	24	4	86%	92%

GPB Table G.2 Historical Corrosion/Mechanical Leaks and Saves



GPB Figure G.1 Historical Corrosion/Mechanical Leaks and Saves by Line Type



GPB Figure G.2 Historical Corrosion/Mechanical Leaks and Saves

Section G.2 Structural Integrity Issues

There are several activities designed to observe and report structural integrity issues. Structural integrity issues are related to damage caused by structural movement: subsidence, jacking, cyclic fatigue, impact, slugging, snow loading, etc.

There were numerous structural repairs to pipeline support members during 2005. The most significant of these repairs was at A-pad, where several pipelines were refurbished and structural suppo reestablished. The remaining repairs were essentially pipeline re-leveling due to support member subsidence.

Section G.2.1 Walking Speed Survey

Where there is perambulatory access, a Walking Speed Survey (WSS) is performed. The WSS consists of a visual examination of process equipment and system components to identify mechanical integrity deficiencies. Anomalies are noted and evaluated by the Field Mechanical Piping Engineer for action as appropriate.

As the name implies the observations are made at 'walking speed' and are focused on, but not limited to,

- Piping and insulation
- Structural components
- Electrical equipment
- Instrumentation equipment
- Communication equipment

- Chemical injection tubing
- Pipe line road and animal crossings

WSS is a 5-year recurring program with the following schedule,

Year	Scheduled	Completed	Equipment Description
1	2002	✓	GPB East Cross Country Pipelines
2	2003	✓	GPB West Cross Country Pipelines
3	2004	✓	GPB East Well Pads
4	2005	✓	GPB West Well Pads
5	2006		Lisburne Cross Country Pipelines/Drill Sites

GPB Table G.3 Structural/Walking Speed Survey Schedule

A WSS of the GPB west well pads was completed in 2005.

Section G.2.2 Routine Surveillance

Field Operations and Security personnel are tasked as the primary identifiers of flow lines and well lines with potential structural integrity anomalies. Observations of wind-induced vibration, excessive pipe movement, out-of-place pipe guides, bent piping, etc. are reported.

An analysis of potential integrity anomaly is completed by a competent engineer to determine any required action. Additional analysis may be required by the Field Mechanical Piping Engineer or third party engineering experts.

For example, if excessive sagging between pipeline supports is observed, the engineer requests an NDE inspection of the affected area. The purpose of the NDE inspection is to determine if any detrimental damage (i.e. wall thinning, cracks, ovality, buckling, strain) exists. The NDE methods typically used include visual, caliper, ultrasonic, magnetic particle, radiography, and dye penetrant as appropriate. The data are analyzed to assure the pipeline is structurally sound and fit-for-service. If the pipeline is not structurally sound, an engineering design package is prepared to initiate, complete and document the work action. Management of Change and other procedures are applied as required.

Section H

Corrosion Monitoring and Inspection Goals

Section H Corrosion Monitoring and Inspection Goals

Section H.1 2005 Corrosion and Inspection Goals Reviewed

Overall, the corrosion inspection, monitoring and mitigation programs were expected to be substantially unchanged during 2005. In particular, the corrosion control target of less than 2 mpy remained in place with the inspection and monitoring activity levels the same as recent years.

Section H.1.1 Corrosion Monitoring

The weight loss coupon program frequency remained unchanged in 2005 compared to recent years and is summarized in GPB Table H.1.

Service	Flow Lines (months)	Well Lines (months)
3-phase production	3	4
Produced water	6	8
Seawater	3	3
Processed Oil	3	N/A

GPB Table H.1 Coupon Pull Frequency

As a consequence, the activity level from the weight loss coupon program was anticipated to be similar in 2005 to that seen in 2004 and indeed this was the case. There were some changes in the number of coupons reported compared to prior years. This is as a result of the following factors:

- Continued efforts to clean historical data records.
- The removal and addition of equipment associated with abandonment and installation of satellite production equipment.
- The historical data was updated to reflect the current equipment inventory.

The ER probe program was planned to be substantially the same as 2004 with probes being located on the 3-phase production lines. The 2005 result was largely as anticipated.

Section H.1.2 Inspection Programs

The fundamental elements of the Inspection Programs outlined in Appendix 3.3.3 (CRM, ERM, FIP, CIP and CUI) form the foundation for the inspection program. There were no major changes for this program anticipated in 2005 with an overall combined internal and external activity level of ~60,000 items.

There were 3 ILI runs completed on 3-phase production flow lines.

Corrosion under insulation or external corrosion inspection activity was substantially increased in 2002. This similar level of activity was scheduled in 2005 with approximately 35,000 planned items completed as expected.

In 2005, a long-term management strategy was continued for cased piping segments consisting of repeat inspections and excavation. Only 79 of the 100 planned inspections were completed due a shortage of specialized probe materials.

Section H.1.3 Chemical Optimization

There were forecast to be no large-scale changes in the corrosion mitigation program and this proved to be the case. Improvements in the small scale testing of corrosion inhibitors allows an increased number of well line tests to be completed.

Section H.1.4 Program Reviews

ADEC Review – ADEC and their third party consultant reviewed and commented on the BPXA Corrosion Monitoring Charter Agreement report and Meet and Confer sessions. In addition a field trip to GPB was organized to review the major elements of the Corrosion Management Program.

Section H.1.5 2005 Corrective Actions

This section summarizes the corrective actions taken on cross-country flow lines as a result of corrosion monitoring and inspection results exceeding the specified targets. These targets are detailed in Appendix 3.1.3.

GPB Table H.2 notes the corrective mitigation actions taken as a result of inspection information.

Equipment ID	No. of Action	Cause	Action
PTMCLS01/02	1	Increased Corrosivity	Increased CI by 10% Operational changes to flow regime

GPB Table H.2 Corrective Mitigation Actions from Inspection Data

GPB Table H.3 notes the corrective mitigation actions taken as a result of ER probe readings exceeding target.

Equipment ID	No. of Action	Cause	Action
01C	1	Increased Corrosivity	Increased CI by 50%
01D	1	Increased Corrosivity	Increased CI by 5%
05B	2	Increased Corrosivity	Increased CI by 10%
06D	1	Increased Corrosivity	Increased CI by 10%
14D	2	Increased Corrosivity	Increased CI by 10%
GHX-J	1	Increased Corrosivity	Increased CI by 10%
M-74	1	Increased Corrosivity	Increased CI by 5%
W-74	1	Increased Corrosivity	Increased CI by 10%
WZ-LDF	1	Increased Corrosivity	Increased CI by 5%

GPB Table H.3 Corrective Mitigation Actions from ER Probe Data

GPB Table H.4 notes the corrective mitigation actions taken as a result of weight loss coupons exceeding target.

Equipment ID	WLC CR mpy	Cause	Action
14D	2.66	Increased Corrosivity	Increased CI by 10%
14D	2.59		
J-47	2.26	Inhibitor Under-injection	Increase CI to existing target
J-47	2.24		
H-74	2.76	Pair average <2mpy	Review next WLC cycle
04B	2.22	Inhibitor Under-injection	Increase CI to existing target
J-45	2.71	Increased Corrosivity	Increased CI by 10%
J-45	2.26		
J-47	2.56	Increased Corrosivity	Increased CI by 10%
J-47	2.42		

Equipment ID	WLC CR mpy	Cause	Action
C-89	8.95	Line shut-in	Recommend mothball treatment
C-89	8.78		
TLFS1/FS3	2.49	Light Mechanical Damage	Review next WLC cycle
18B	2.32	Pair average <2mpy	Review next WLC cycle
02D/05E	2.22	Pair average <2mpy	Review next WLC cycle
02B	2.16	Pair average <2mpy	Review next WLC cycle
12B	2.03	Pair average <2mpy	Review next WLC cycle
14D	4.32	Inhibitor Under-injection	Increase CI to existing target
14D	4.05		

GPB Table H.4 Corrective Mitigation Actions from Coupon Data

Section H.2 2006 Corrosion Management Goals

Overall the 2006 corrosion and inspection goals will be focused on the continued delivery and optimization of the current programs.

Section H.2.1 Corrosion Monitoring

There are no plans to significantly change the corrosion weight loss coupon-monitoring program in 2006. However, a change in the WLC ill frequency is being evaluated in an effort to improve efficiencies and minimize HSE exposure. The change in frequency, if adopted, will have a small reduction (~100) in the overall number of coupons evaluated annually. Additional monitoring methods will also be investigated for the PW system in an effort to develop a more sensitive short-term monitoring tool.

Section H.2.2 Inspection Programs

The overall internal inspection program is planned to be substantially unchanged in 2006 from that implemented in 2005 The expected activity level will again be approximately 60,000 inspections items in total distributed between the field and facilities. Of the overall 60,000 inspection items approximately 45% will be associated with cross country flow line and well lines and hence be reported under the Charter Agreement Work Plan.

The external program increased substantially in 2002 with this program increase continuing through 2005 at approximately 35,000 items per year. The current schedule for 2006 is 40,000 inspection items for the full year.

2006 will see a continuation of the long-term management strategy for cased piping segments; consisting of repeat examinations and excavations as warranted. The 2006 work scope for cased piping is scheduled to be approximately 125 inspections.

The ILI program is planned to be of a similar scale to 2005 dependant upon tool and pipeline availability.

Section H.2.3 Chemical Optimization

Corrosion inhibition will continue to be the primary means of internal corrosion control at GPB. Supplemental corrosion inhibition of the PW system will be expanded to FS2 in 2006. For the 3-phase system, the emphasis will be on the optimization corrosion inhibitor and provide improved control. A similar number of rapid screen testing will be performed in 2006.

Part 2 – Alaska Consolidated Team Performance Unit

Section B-H

Section B Corrosion Monitoring Activities

Alaska Consolidated Team (ACT) Performance Unit presently consists of four producing areas: Endicott, Milne Point Unit (MPU), Northstar and Badami. Northstar was added to ACT as it came on production in the second half of 2001. Production from Badami was re-started in October, 2005 after being shut in and put into warm storage during 2003.

Each of the producing fields within ACT has its own unique set of circumstances and challenges.

Milne Point - Located approximately 25 miles west of Prudhoe Bay, the field began production in 1985. On January 1st, 1994, BPXA acquired a majority working interest and assumed operatorship. Since 1994 production and proven reserves have been increased and Milne Point production averaged approximately 49,000 bpd in 2005.

Endicott - Located north of Prudhoe Bay, Endicott consists of two islands, the main Production Island (MPI), and the satellite-drilling island (SDI) at the end of a causeway. Endicott 3-phase production piping is made largely of duplex stainless steel, which significantly reduces the environmental risks. In 2005, Endicott production averaged approximately 17,700 bpd.

Badami - Remotely located east of Prudhoe Bay, Badami had a relatively low production volume due to challenging reservoir conditions. The Badami production facilities, like other recent developments on the North Slope, are constructed using a much smaller surface footprint than GPB and do not have permanent road access, therefore having a much reduced impact on the environment. Production from Badami was re-started in October 2005 after being shut in since the third quarter of 2003. Badami production averaged approximately 1650 bpd in 2005 since start-up.

Northstar - Located offshore, Northstar is the first offshore oil field in the Beaufort Sea not connected to land by a causeway. As with Badami and other recent developments, Northstar drilling and production operations are built on a smaller footprint than the original North Slope facilities. Northstar produces a light, 42 degrees API gravity, high quality sweet crude, that is transported to shore through a pipeline with a wall thickness that is three times that required for pressure containment. Northstar production during 2005 averaged approximately 62,500 bpd.

ACT Table B.1 illustrates, on a relative basis, the unique corrosivity of each producing field within ACT along with the materials of construction and corrosion mitigation. GPB is included in the table for comparative purposes. Listed in the table are, for each field, the typical water cut in percent, average wellhead temperature, and the percent CO_2 in the produced gas.

	Prod Fluid Characteristics				Material of Construction [a]			
					Production		Injection	
Field	H_2O (%)	T (°F)	P_{CO_2}(%)	CR [b]	WL	FL	WL	FL
GPB	75	150	12	H	CS+CI	CS+CI [c]	CS+CI	CS+CI
END	92	150	18	H	DSS	DSS	CS+CI	CS+CI
MPU	52	125	1.5	L/M	CS	CS [d]	CS+CI	CS+CI
Northstar	16	160	8	M	CS+CI	N/A	N/A	N/A
Badami	~0	65	~0	L	CS	N/A	N/A	N/A

Notes
(a) CS is carbon steel, CI is corrosion inhibitor, DSS is duplex stainless steel
(b) Unmitigated relative corrosion rate, H – high, M – medium, and L - low
(c) There are a limited number of Duplex Stainless Steel flow lines in GPB
(d) Two production flow lines are inhibited at MPU
(e) Northstar CO_2 has increased from 5-6% at startup to 8% due to gas injection from GPB containing 12% CO_2.

ACT Table B.1 Relative Corrosivity of BPXA North Slope Production

Badami, MPU, and Northstar production fluids have a lower corrosivity compared to GPB. Endicott's production fluid characteristics are more corrosive than GPB and this corrosion risk is mitigated largely through the use of duplex stainless steel (DSS).

ACT Table B.2 shows the ACT fields combined are of a much smaller scale than GPB. For example, neither Northstar nor Badami have any significant non-common carrier cross-country flow lines. Also, it should be noted, that when comparing GPB and ACT facilities, these facilities vary in age from over 2[illegible] years for GPB to ~4 years for Northstar.

Metric	ACT	GPB	$\frac{ACT}{(ACT + GPB)}$ %
Number of Production Trains	4	21	16%
Approx. Number of Prod and Inj Wells	403	1,600	25%
Non-common carrier FL miles	105	1,350	7%
Total Acreage	75,000	203,000	27%

ACT Table B.2 Illustrative Comparison of Scale between ACT and GPB

Section B.1 Endicott

Endicott is a mature waterflood field. The fluid properties (high water cut, high temperatures, high CO_2 content) indicate the corrosivity of the produced fluids to be high. Due to this anticipated high corrosivity, the majority of the oil production system was fabricated from duplex stainless steel, a corrosion resistant alloy and therefore, corrosion risk is low for this system. In the oil production system, the only carbon steel is the C-Spool, connecting the wellhead to the duplex stainless steel well line. These C-

Spools are inspected regularly and replaced when no longer fit-for-service as per the criteria discussed in Appendix 3.3.5. ACT Table B.3 reflects the historical inspection activity level for Endicott from 2002 through 2005.

Service	Length, miles	Internal Inspection				External Inspection			
		2002	2003	2004	2005	2002	2003	2004	2005
Oil X country lines	3.5	4 (in vault)	14 (4 in vault)	4 (in vault)	14 (4 in vault)	4 (in vault)	4 (in vault)	4 (in vault)	4 (in vault)
Oil - Well Pads	2.5	1,327	1,531	1,990	2,637	-	-	-	
Water X-country lines	3.5	104	229	163	119	4 (in vault)	4 (in Vault)	723	30
Water - Well Pads	1.7	200	224	135	309	9 (in vault)	5	-	8
Gas X-country (GLT/MI)	7	15	45	4 (in vault)	12 (4 in vault)	4 (in vault)	774	4 (in vault)	34 (4 in vault)
Gas - Well Pads	1.2	26	29	10	61	9 (in Vault)	69		28
Fuel Line - Gasoline	N/A	5 foot excavation	-	-	-	5 foot excavation	-		
Fuel line - Diesel	N/A	5 foot excavation	-	-	-	5 foot excavation	-		
Totals		**1,686**	**2,072**	**2,216**	**3,152**	**40**	**856**	**731**	**104**

ACT Table B.3 Endicott Summary of Lines and NDE Inspections

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) carrying injection water to SDI from the MPI. Corrosion control of the water injection system relies on corrosion inhibition of the injection water, supplemented by a biocide and maintenance pigging program. Originally, this line primarily carried seawater. In the early 1990's, in an effort to increase waterflood efficiency, the line was converted to commingled PW+SW service. As produced water volumes have risen, the percentage of SW mixed in the line has dropped significantly, remaining under ten percent since 2002. As a result, changes were made to the mitigation program for the IIWL in 2004. These changes include increasing the corrosion inhibitor concentration by 50% (from 20 to 30 ppm) and reducing the biocide treatment. The effectiveness of corrosion control on the IIWL is monitored by ultrasonic inspection at 25 locations.

Section B.2 Milne Point

The primary corrosion concerns are in the water injection system and corrosion of buried piping. Corrosion inhibition, supplemented by a biocide and maintenance pigging program began in mid-2000 in the water injection system. As a result, corrosion rates, as exhibited by weight loss coupons, have dropped significantly over the past five years.

Although the low temperatures and low CO_2 content of the production fluids result in lower corrosivity for MPU, solids contribute to the corrosion mechanism of the production system. Corrosion inhibition of the K-pad production flow line was initiated in 2001 and the F-L-C Pads flow line in 2003. Additionally, corrosion inhibition of the newly developed S-Pad began late 2002.

ACT Table B.4 reflects the historical inspection activity for MPU from 2002 - 2005.

Service	Length, miles	Internal Inspection				External Inspection			
		2002	2003	2004	2005	2002	2003	2004	2005
Oil x-country lines	24	80	465	480	186		964	70	-
Oil – Well Pads	N/A[1]	754	2,754	2,049	1,990	47	N/A[2]		14
Water x-country	15	35	5	249	53		97	1,065	154
Water – Well Pads	N/A[1]	449	635	863	988	23	N/A[2]		9
Gas x-country	14		20	26			522	603	
Gas – Well Pads	N/A[1]	283	99	83	56		N/A[2]		-
Water/Alternating Gas Well Pads	N/A[1]		230	298	214				
Totals		**1,601**	**4,388**	**4,048**	**3,487**	**70**	**1,583**	**1,738**	**177**

[1] Totals not available
[2] Included with internal numbers as part of the excavations

ACT Table B.4 MPU Summary of Lines and NDE Inspections

Section B.3 Northstar

Northstar began production in November 2001. Production fluid corrosivity is moderate, but will tend to increase over time with the injection of GPB gas into the reservoir. ACT Table B.5 summarizes the inspection program for Northstar from 2002 through 2005 and shows an increase of inspection activity through time.

Service	Length, feet	Internal Inspection				External Inspection			
		2002	2003	2004	2005	2002	2003	2004	2005
Oil Pipe rack	1,200								-
Oil – Well Pad	280	106	114	204	230				-
Water Pipe rack[1]	2,400		-	-	-				-
Water – Well Pad[1]	70	17	25	46	53				-
Gas Pipe rack	600	-	-	-	-	-			
Gas – Well Pad	140	26	65	77	112			-	
Totals		**149**	**204**	**327**	**395**	-	-	-	-

[1] Disposal system, Northstar does not have an active water injection system.
Note: Line lengths are in feet as the production facility is contained in a comparatively small footprint

ACT Table B.5 Northstar Summary of Lines and NDE Inspections

Section B.4 Badami

Low productivity necessitated the shut-in of the Badami Field in the third quarter of 2003 and throughout all of 2004. Shut-in consisted of de-inventory and warm storage of major equipment. Prior to shut-in, Badami's production fluids were considered a low risk from a corrosivity standpoint, as there is little water production and low CO_2 content. Production from Badami was restarted in the fourth quarter of 2005. A startup inspection was performed on existing equipment. ACT Table B.6 summarizes this inspection program for Badami's 2005 startup.

Service	Feet	Int. Insp.	Ext. Insp.
Oil –Well Pad	840'WL , 320' HDR	29	-
Gas	240'WL, 320'HDR	7	-
Disposal Well	400'	4	-

Note Badami does not have an active water injection system.

ACT Table B.6 Badami Summary of Lines and NDE Inspections

Section B.5 Overall Inspection Activity Level

ACT Table B.7 summarizes the overall inspection activity since 2000. As can be seen, the overall activity level has remained approximately constant at ~3,400 items per year through 2002. A significant increase in inspections occurred in 2003 and 2004. This is the result of additional inspections performed at Endicott and MPU, both internal and external.

The total number of inspection decrease from 2004 to 2005 is a result of a reduction in the detailed program associated with the Milne Point Unit S-Pad start–up inspections reverting back to a more normal inspection cycle, a reduction in the number of inspections performed as a result of the approximately 5,000 feet of the K-Pad flow line replacement, and a smaller scope for external corrosion detection due to program cycle. Additionally, a buried produced water line was taken out of service and abandoned.

	Surface	2000	2001	2002	2003	2004	2005
Endicott	Int	1,346	1,480	1,686	2,072	2,216	3,152
	Ext	16	16	40	856	731	104
	Total	**1,362**	**1,496**	**1,726**	**2,928**	**2,947**	**3,256**
Milne Point	Int	1,419	629	1,601	4,388	4,048	3,487
	Ext	378	1,577	70	1,583	1,738	177
	Total	**1,797**	**2,206**	**1,671**	**5,971**	**5,786**	**3,664**
Northstar	Int	-	16	149	204	327	395
	Ext	-	-	-	-	-	-
	Total	**-**	**16**	**149**	**204**	**327**	**395**
Badami	Int	27	-	5	29	26	40
	Ext	-	-	-	-	-	-
	Total	**27**	**-**	**5**	**29**	**26**	**40**
	Grand Total	**3,186**	**3,718**	**3,551**	**9,132**	**9,086**	**7,355**

ACT Table B.7 Overall Inspection Activity Summary

Section C Weight Loss Coupons

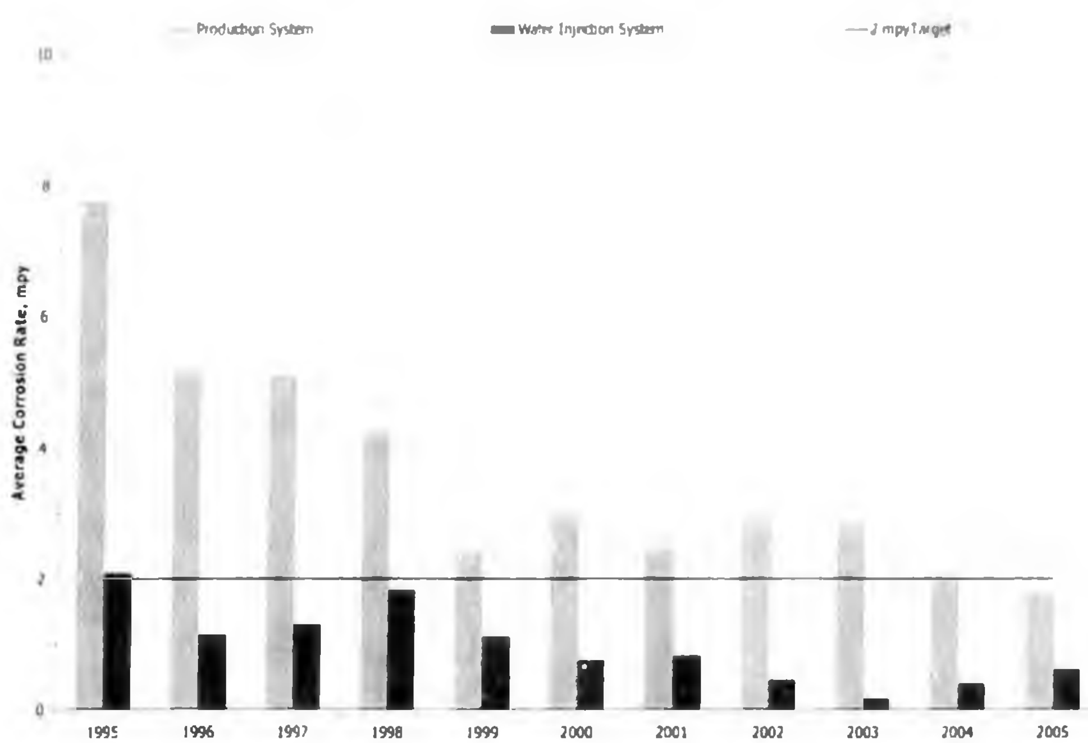
Section C.1 Endicott

ACT Table C.1 summarizes the corrosion monitoring performance for 2005 and historical data are shown in ACT Figure C.1. The average WLC corrosion rate for the production system remains near 2 mpy; however as noted previously, the major portion of the system is fabricated from duplex stainless steel and these data are used primarily for monitoring produced fluid corrosivity and erosion tendency.

The lower, relatively constant corrosion rates in the water injection system reflect the effectiveness of the corrosion mitigation program. Only two water injection WLC locations experienced corrosion rates above the 2 mpy target for 2005. On average, the corrosion rate remained below the 2 mpy target for the year.

System	Access Fittings	%WLC <2 mpy
Water Injection - Pads	17	88%
Water Injection – x-country	1	100%
Oil Production – Pads	72	47%

ACT Table C.1 Endicott Corrosion Coupon Monitoring



ACT Figure C.1 Endicott Corrosion Coupon Summary 1995-2005

Section C.2 Milne Point

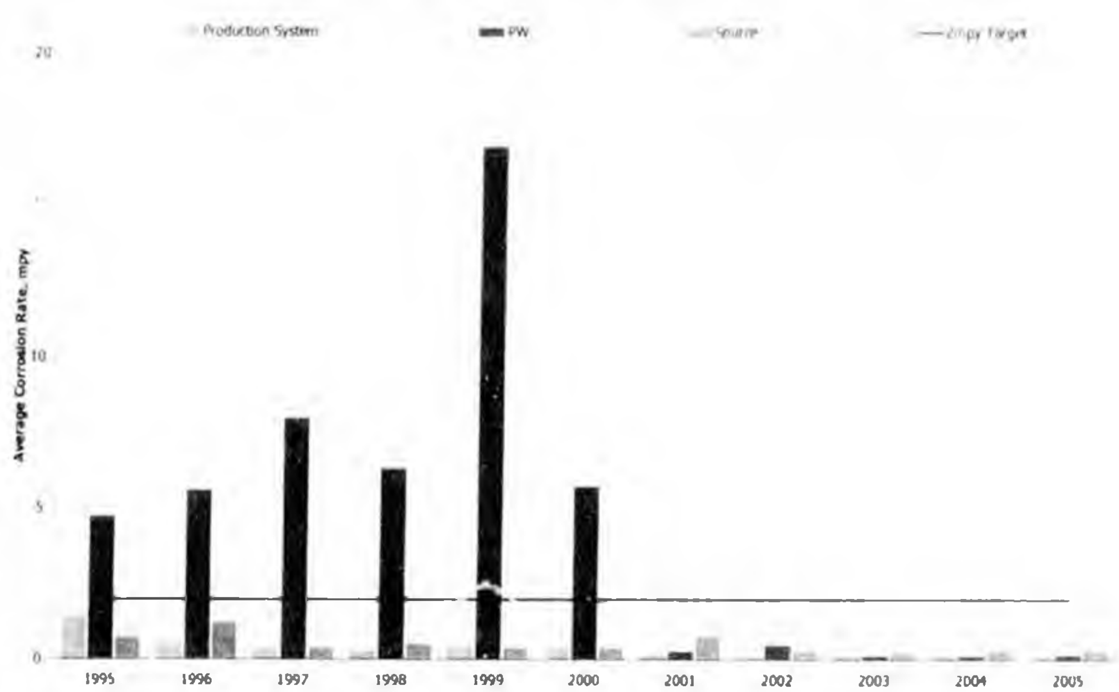
ACT Table C.2 summarizes the corrosion monitoring performance for 2005 and historical data are shown in ACT Figure C.2.

ACT Figure C.2 illustrates the low corrosion rates for the MPU production and water systems. Of concern historically were the relatively higher corrosion rates in the water injection system. These higher corrosion rates led to the initiation of corrosion inhibition in the water injection system in mid-2000. The monitoring results indicate the inhibition is having a positive effect, reducing corrosion rate as the WLC corrosion rates have consistently averaged less than 2 mpy. No WLCs exceeded the 2 mpy target in 2005.

A corrosion monitoring gap analysis was conducted in 2005 at Milne Point Unit and as a result a proposal was made to increase the amount of corrosion monitoring for more consistent coverage. Several new locations will be added to the monitoring program to include additional weight loss coupons and electrical resistance probes.

System	Access Fittings	%WLC <2 mpy
Production System	26	100%
Water Injection System	5	100%
Source Water Coupons	6	100%

ACT Table C.2 MPU Corrosion Coupon Monitoring



ACT Figure C.2 MPU Corrosion Coupon Summary

Section C.3 Northstar

ACT Table C.3 shows the results of the corrosion monitoring program at Northstar for 2004. There are no historical data prior to 2003.

System	Location	Access Fittings	%WLC <2 mpy
Oil Production			
	Upstream of CI Injection	14	29%
	Downstream of CI Injection	3	67%
Water Disposal			
	Upstream of Mud Addition	9	100%
	Downstream of Mud Addition	2	50%

ACT Table C.3 Northstar Corrosion Coupon Monitoring

The 3-phase production is currently inhibited; however monitoring data continues to indicate the corrosion rates are above the 2 mpy target. This is due to the corrosion monitoring locations being located upstream of the corrosion inhibitor injection location. Monitoring data collected from downstream locations show the inhibition program is effective in reducing corrosion rates to acceptable levels. The coupons from the upstream locations indicate the need for inhibition of the upstream section. Operations is proceeding with the recommendation to move the corrosion inhibitor injection point further upstream, to the wellhead for the producing wells. Additionally, all new wells will be equipped to inject corrosion inhibitor at the well head. As of the end of 2005, seven wells (41%) have been equipped with wellhead inhibition. However, a significant portion of the coupon data still reflect uninhibited conditions as these changes were not made until later in the year and the coupons did not see inhibitor for the full exposure period. Of interest is a new well (NST Well 05) which had received wellhead inhibitor injection from startup production. The single data point indicated the corrosion rate to be within target, at less than 0.5 mpy. The remaining wells are scheduled for conversion.

In addition to the weight loss coupon data, an electrical resistance probe was installed on the main production line to provide further corrosion rate feedback. There are no conclusions to be drawn yet as this is a relatively new installation with an incomplete data set for evaluation.

High corrosion rates in one of the water disposal wells are attributed to oxygenated mud from the grind-and-inject plant (mud). Although an oxygen scavenger has been tested in the grind-and-inject fluids, it was ineffective due to the low fluid temperatures. This system is inspected on a quarterly basis to monitor for active corrosion metal loss.

A second disposal well was added to Northstar in 2004 and the monitoring data indicate the corrosion rate to be <2 mpy, similar to the inhibited portion of the produced water piping. Operationally, this new disposal well has not seen any of the oxygenated fluids.

Section C.4 Badami

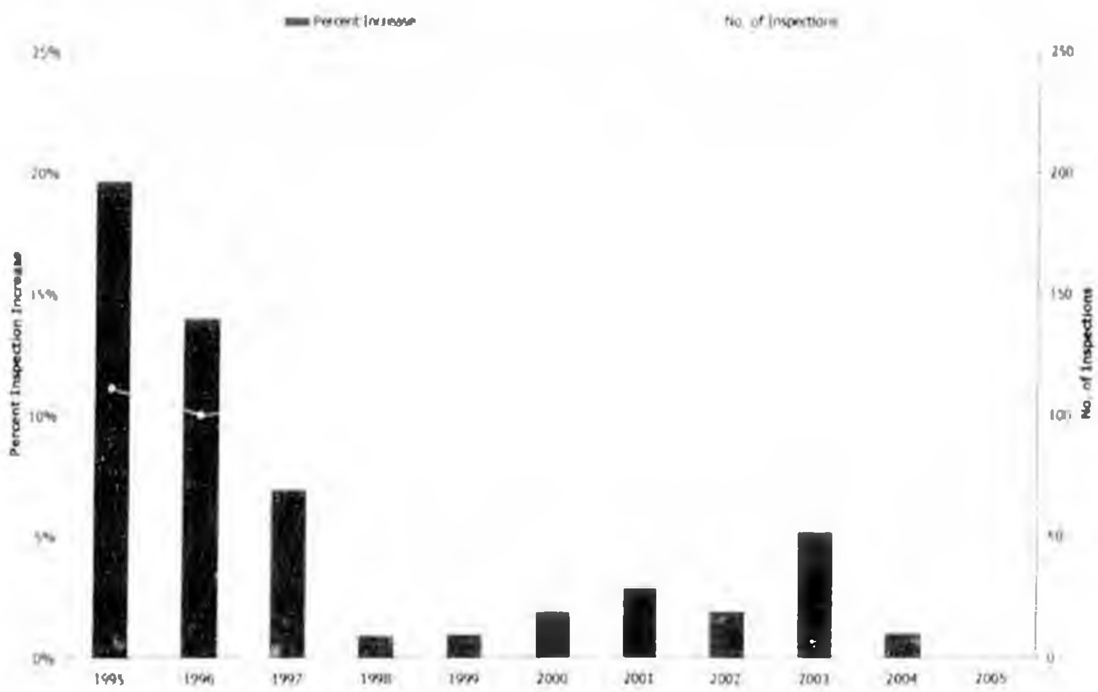
Badami currently has no WLC-monitoring program, but relies on an inspection program presented in Section E.

Section D Corrosion Mitigation Activities

Section D.1 Endicott

Corrosion mitigation for the IIWL had historically relied on maintenance pigging for line cleanliness, biocide treatments to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control. The primary monitoring tool for effectiveness of these programs is the frequent UT inspection of 25 locations along the pipeline. These UT inspections are repeated quarterly, at a minimum.

ACT Figure D.1 shows the percent inspection increases and the number of inspections from 1998 through 2005 for the IIWL. No inspection increases were identified in 2005. This is believed to be the result of the optimization program begun in October, 2004 whereby the corrosion inhibitor concentration was increased from 20 to 30 ppm and biocide program was rebalanced. Additionally, the 2005 maintenance pigging program was very successful with a total of nine maintenance pigs run out of a total ten scheduled (90%) completion rate.



ACT Figure D.1 Endicott IIWL UT Readings

In the production system, the primary damage mechanism is erosion. The erosion rate is monitored through inspection and mitigated through velocity management. Wells are risk ranked by mixture velocity once per month and the information is used to adjust the inspection frequency and fluid velocity. ACT Table D.1 is an overview of the average velocity data for 2001 to 2005. Shown are the number of wells within V/V_e[9] ratio ranges,

[9] Velocity nomenclature has been changed in 2005 from L/R to for consistency with the remainder of this report.

where V is the actual mixture velocity and V/V_e is the allowable erosion velocity as defined by API-RP-14E[10].

V/V_e Range	2001		2002		2003		2004		2005	
	# Wells	Percent	# Wells	Percent	# Wells	Percent	# Wells	Percent	# Wells	Percent
$V/V_e<1$	23	38%	12	21%	19	31%	25	38%	21	33%
$1<V/V_e<2$	25	42%	31	54%	29	47%	27	41%	28	44%
$2<V/V_e<3$	11	18%	12	21%	13	21%	13	20%	14	22%
$V/V_e>3$	1	2%	2	4%	1	2%	1	2%	0	0%
Total	**60**	**100%**	**57**	**100%**	**62**	**100%**	**66**	**100%**	**63**	**100%**

ACT Table D.1 Endicott Velocity Monitoring

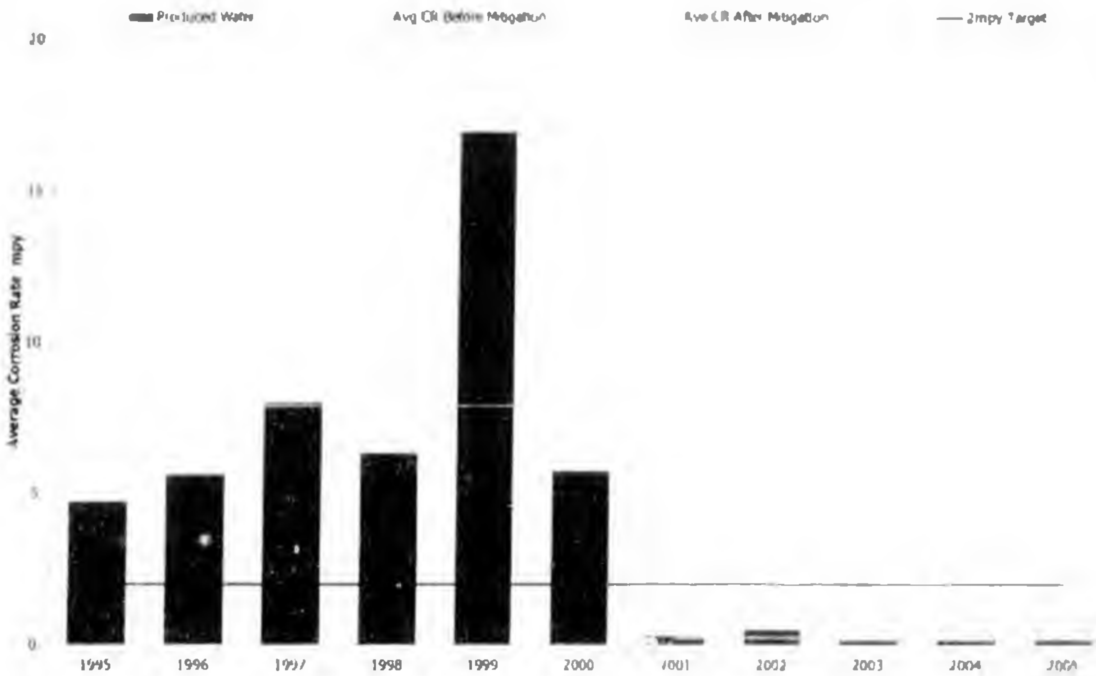
API-RP-14E defines an allowable velocity for the avoidance of erosion, based on the fluid properties (namely density) and material of construction. API-RP-14E is based on experience with steam service and is known to be conservative when applied to oil production systems, particularly where corrosion and erosion resistant materials are used. The aim is to limit actual velocities to less than 3 times the allowable velocity (V/V_e <3). This factor of 3 reflects BPXA's experience with production fluids that contain minimal amounts of entrained solids flowing through stainless steel pipelines. Equipment exhibiting high velocities is inspected at intervals ranging from weekly to bi-annually dependant upon the V/V_e Ratio, input from Well Operations, and inspection results. During 2005, no wells exhibited an average V/V_e >3, although one problem well was twinned to two well lines to reduce the effects of velocity.

Section D.2 Milne Point

Corrosion inhibition of the water injection system began in mid-2000, in addition to implementing a more rigorous maintenance pigging program. Corrosion inhibitor concentration remains at 40 ppm. Weight loss coupon data indicate the system is under control as the WLC corrosion rates have averaged less than 2 mpy since mid-2000. This represents a significant reduction from previous years as can be seen in ACT Figure D.2. For the period 1996-2000, the average corrosion rate was approximately 7 mpy. Since the enhancement of the corrosion management program in 2000, the average WLC corrosion rate for the PW system has been reduced to less than 1 mpy.

Corrosion inhibition on the K-Pad 3-phase production flow line was initiated in 2001 after inspections indicated significant under-deposit corrosion damage. The damage was associated with low fluid velocities, allowing solids to accumulate in the line. In conjunction with the inhibition program, the K-Pad flow line is cleaned with a maintenance pig on routine schedule. Inhibition levels were increased in October 2003 to 56 ppm and again in April 2004 to 100 ppm as a result of active corrosion detected through routine inspection monitoring. In 2005, approximately 5000 feet of the K-Pad line was replaced.

[10] API-RP-14E - Recommended Practice for Design and Installation of Offshore Production Platform Piping System 5th Edition.



ACT Figure D.2 Milne Point Produced Water Corrosion Rate Trend

The development at S-Pad was designed for continuous inhibition injection into the power fluid supply for the downhole hydraulic pumps. Since this water is separated and re-circulated as power fluid at the pad, a low amount (~10%) of the produced water is sent through the 3-phase flow line to the main separation facility. Additional makeup water for use in the power fluid system is treated at a rate of 20-ppm corrosion inhibitor.

The continuous inhibition of the production flow line carrying production from F, L, and C Pads remains unchanged at 56 ppm.

The remaining uninhibited production flow lines at Tract 14 and B-Pad are under review for corrosion inhibition. Inspection results from these production well lines indicate there is slight corrosion activity occurring over the long term. Recommendations were made in 2005 to provide continuous inhibition to these flow lines and the work is proceeding.

As production rates are typically low for the pipeline capacity, the fluid velocities are low and erosion is not a significant concern, therefore there is no formal velocity management program.

Section D.3 Northstar

Northstar is inhibited with continuous injection of corrosion inhibitor into the well production lines. Inhibitor concentration is set at 100 ppm based on water rates, with a minimum of 2 gallons/day regardless of the production characteristics.

As noted in Section C.3, seven of the 17 wells have had the chemical injection point relocated to the wellhead in 2005, with the remainder scheduled for conversion.

Section D.4 Badami

Corrosion inhibition was not required at the Badami field based on modeling of the corrosivity of the fluids, the low water-cut, and the results from the facility and pipeline inspection program.

With the Badami Field being brought back on-line in 2005, BPXA has reinstituted the integrity monitoring plan.

Section E External/Internal Inspection

Section E.1 External Inspection

Section E.1.1 Endicott

Cased flow lines at Endicott are inspected by electromagnetic pulse test (EMT) at the intervals noted in ACT Table E.1.

Line	Crossings	Year Surveyed	Method	Max Inspection Interval
Water - Inter-Island	1	2001	EMT	10 Years
Gas Lift - Inter-Island	1	2001	EMT	10 Years
Oil	1	N/A		N/A Duplex Stainless Steel
MI Line	1[1]	N/A		
Water – WL	2	1 line in 2000	EMT	10 Years for Carbon Steel Other line is Duplex Stainless Steel
Gas - WL	1	2000	EMT	10 Years

[1] New in 1998, inspection ports for sniffing, permanently sealed, can be inspected by excavation only

ACT Table E.1 Cased Piping Inspections

Inspection to detect external corrosion was performed on the gas line (Line 974 FH) feeding gas cap injection well(s) noted in Table E.1, and was found to have severe external corrosion throughout the line in the cased portion. This line is scheduled for replacement.

In addition, the vaults where the production, Inter-Island Water Line, and gas-lift pipelines pass are visually inspected annually. Minor external corrosion exists, but it has not increased.

Section E.1.2 Milne Point

ACT Table E.2 summarizes above-ground the external inspection program at MPU since 1997. No increase in corrosion was noted in any of the re-inspected locations. Four new locations were identified as requiring repairs.

Year	Total Insp	Repeat Insp	Increases	% I's
1997	26	-	-	n/a
1998	441	10	-	-
1999	101	65	-	-
2000	205	104	28	27
2001	179	20	5	25
2002	70	5	1	20
2003	1,583	55	1	2
2004	1,738	251	-	-
2005	131	1	-	-

ACT Table E.2 MPU External Inspection Summary for Above-Ground Piping

With regard to buried piping, 134 inspections were conducted in nine excavation sites throughout the MPU field. The reduced number of excavations is due to the extensive logistical requirements to excavate around pad pigging facilities. The excavations were primarily centered on Tract 14 piping on the well pads. Piping examined included well lines and flow lines and was focused on soil to air interface areas and deeper.

These locations were primarily at pigging launcher and receiver areas. Excavations were done on Tract 14 at I-Pad, J-Pad, I/J intersection, and H-Pads. Additionally, excavations were performed at L-Pad the Tract 14 roadway.

Of the 134 inspections:

- 45 inspections were repeat locations, of which 21 locations (47%) had increases in damage. With the exception of one moderate increase in damage the remaining locations showing damage were all slight corrosion increases.
- The repeat inspection intervals ranges from approximately two to eight years, with an average of 4.4 years
- 89 locations were baseline inspections

Section E.1.3 Badami

External inspections that have been done to date at Badami are associated with the internal inspection program where insulation was removed for ultrasonic inspection of well line elbows. No evidence of external corrosion has been noted.

Section E.1.4 Northstar

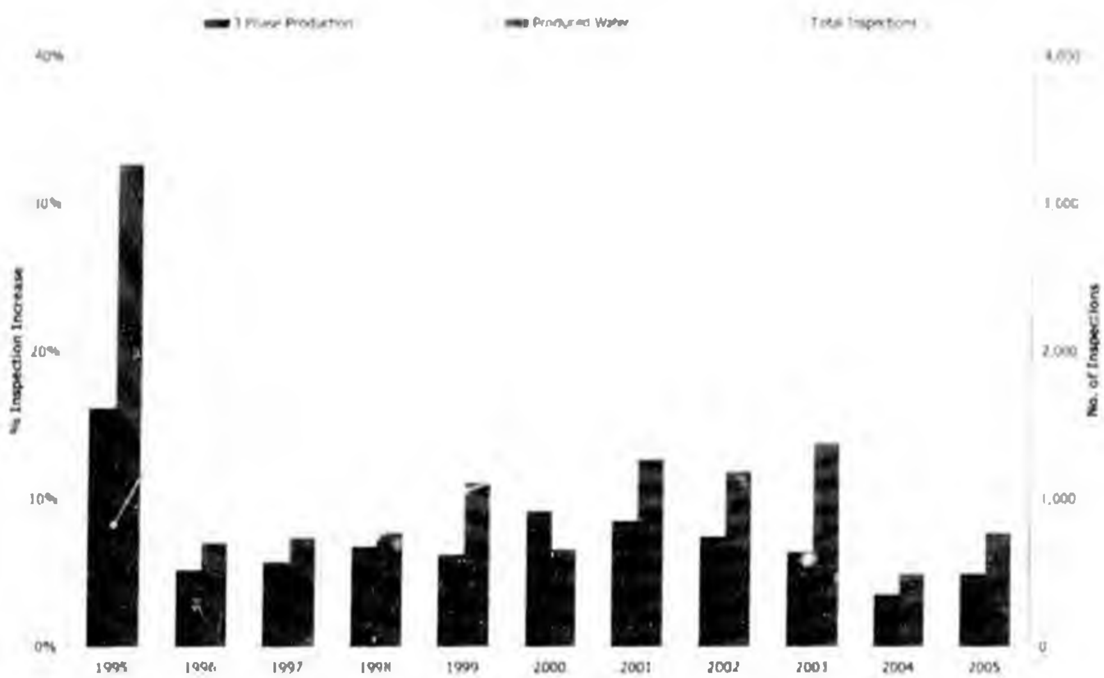
Since the facility is less than five years old, an external inspection program has not yet been established. Based on GPB experience, CUI typically takes several years to initiate. A program will be implemented within 5-years from startup (2006).

Section E.2 Internal Corrosion Inspection

Section E.2.1 Endicott

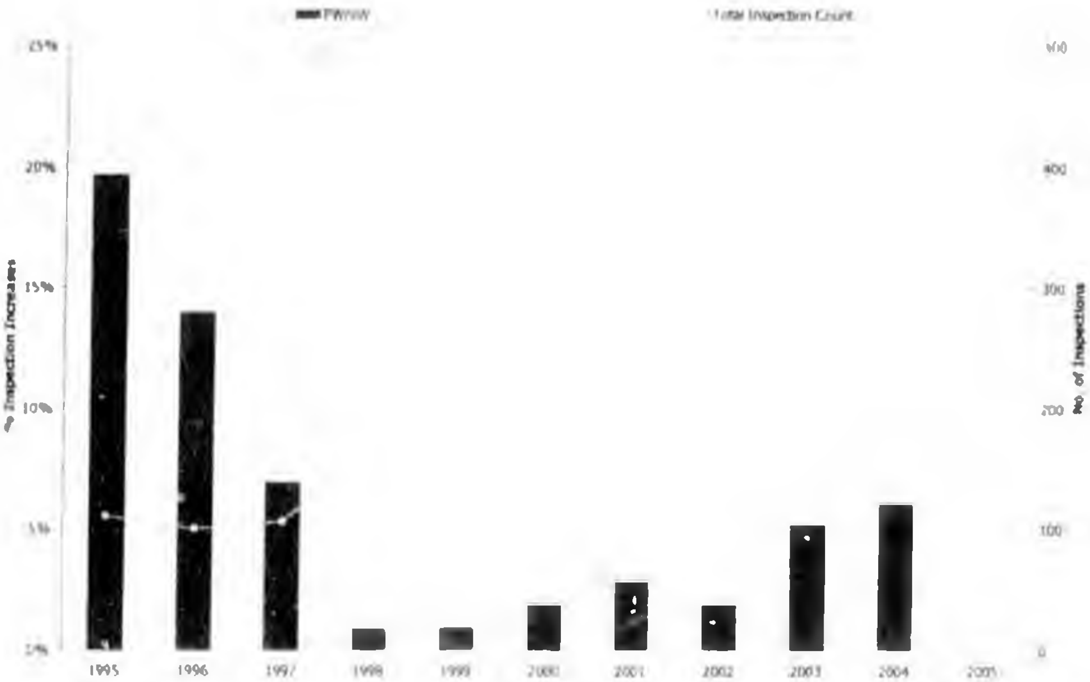
ACT Figure E.1 and E.2 indicate the percentage of inspection increases since 1995 for the well lines and flow lines at Endicott. There were no increases in the 3-phase, DSS production cross-country line. The inspection data for the 3-phase production system are used to alert Operations of potential replacements of the carbon steel C-Spools at the wellheads. The corrosion increases in carbon steel C-Spools are managed through planned replacement using the FFS criteria discussed in Appendix 3.3.5.

Corrosion activity in the water injection well lines had been increasing since 2000 and was addressed by increasing the corrosion inhibitor concentration by ~18% in 2003 and then by another 50%, to 30 ppm, in late 2004. The additional corrosion inhibitor reversed the increasing trend in 2004; however there was an increase in 2005. The majority of these increases are slight increases, whereas the increases during 2001-2003 were more significant from a corrosion standpoint. This trend is being monitored to determine what additional changes might be required to the PW inhibition program.



ACT Figure E.1 Endicott Well Line Internal Inspection Increases

Act Figure E.2 shows a significant decline of inspection increases from 1995 through 1998 for the IIWL at Endicott. There has been an increasing trend in %I's from 1998 through 2004; however these data include the addition of inspection locations that have not been inspected in several years. These additional locations confirm that corrosion was occurring in the line; however the time period between inspections makes it difficult to determine when the corrosion actually occurred. A more accurate representation of corrosion activity through time was shown previously in ACT Figure D.1 which includes only data from inspections performed on a frequent basis. The frequently monitored locations show a decrease in corrosion activity during 2004, and no increases in 2005.



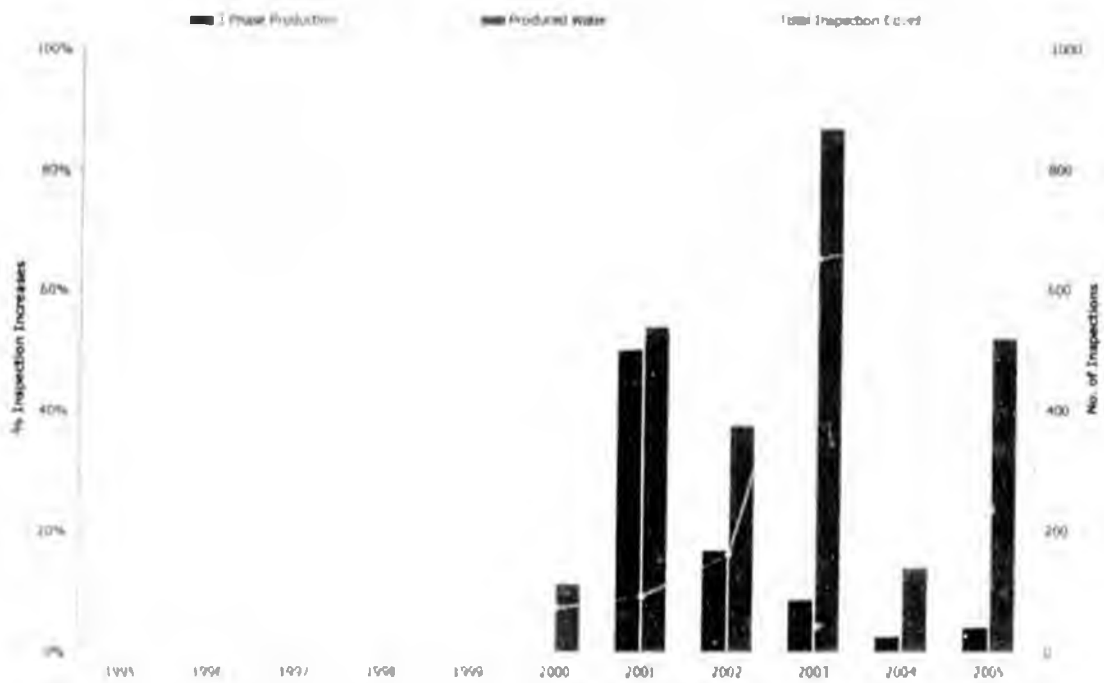
ACT Figure E.2 Endicott Flow Line Internal Inspection Increases

Section E.2.2 Milne Point

BPXA became operator at Milne Point in 1994, and from this date to 2000 the inspection program was aimed at establishing the baseline condition in the MPU systems. It is only with the 2000 data and beyond that trending of inspection increases has been possible. The results of this comparative data can be seen in ACT Figure E.3. The figure shows the total number of inspection items has been consistently increasing from 2001-2004.

Overall the 3-phase flow lines continue to show a decreasing trend of locations with corrosion activity. This is a direct result of increased inhibition of several of the 3-phase flow lines at MPU. Recommendations were made to Milne Point Unit to inhibit the remaining flow lines and this work is progressing.

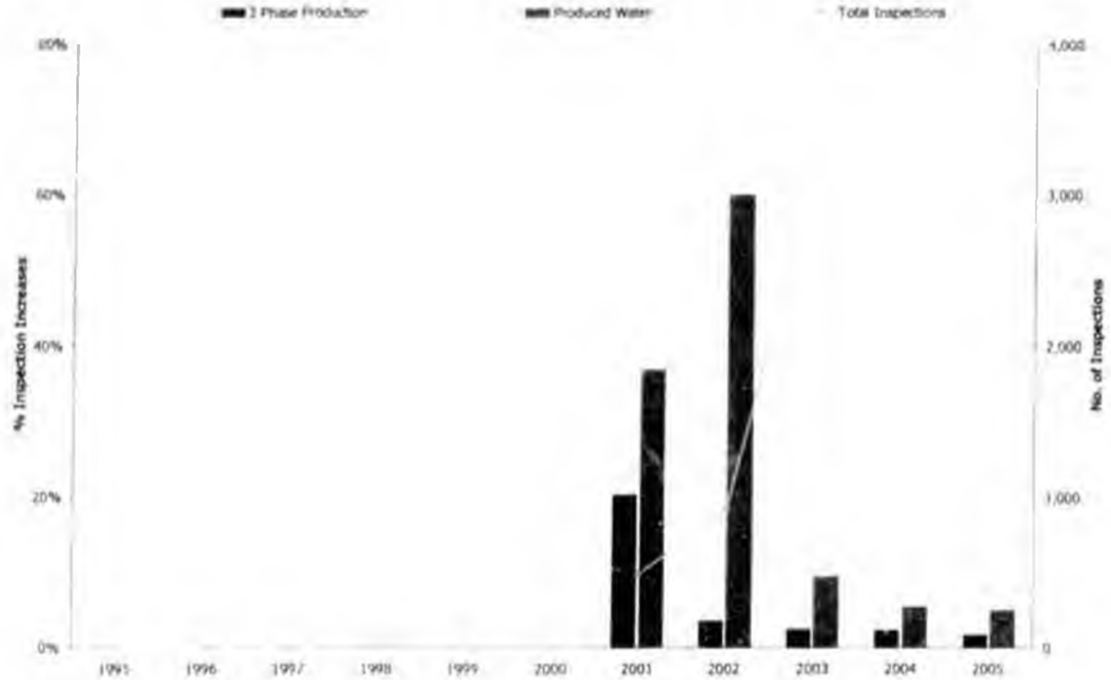
Inspection increases in the produced water dropped significantly in 2004 as compared the prior year, however an increase in inspection activity is again noted for 2005. As explained in previous reports, this is believed to be the result of the considerable time lag between inspections for the portions of flow lines that are buried. For example, the 2003 report indicated the percentage of repeat locations in produced water flow lines had shown a significant increase in 2003, up to 87% from 29% in the prior year. The level of increases were the result of inspections on buried lines which covered periods both before and after the establishment of corrosion inhibition (late-2000). The average time between inspections was ~4-5 years, indicating much of the corrosion activity reported may have occurred prior to the establishment of inhibition. Repeat inspections performed during 2004 with shorter intervals verify the improvement in corrosion control.



ACT Figure E.3 MPU Flow Line Internal Inspection Increases

In 2005, this time lag effect is again evident for inspections on the buried lines. The average time interval for inspection increases is just under five years, suggesting the corrosion occurred during the period where inhibition and maintenance pigging program was just beginning and not fully established. It should be noted all the inspection increases were categorized as slight increase, with the exception of one moderate increase location. Taking this in conjunction with the inspection data from the produced water well lines as discussed below, this is further evidence that the inhibition program is successful. These trends will be continued to be monitored.

ACT Figure E.4 shows the %I's and number of inspections on well lines. There has been a significant decrease in the number of repeat locations showing active corrosion since 2002. As noted in the discussion above, this represents a more consistent repeat inspection basis from prior years, as the majority of repeat locations were ~1-year apart, whereas in previous years the time difference between repeat inspections was several years. With regard to the produced water system, this also reflects the improvements made to corrosion control through the establishment of the inhibition program.



ACT Figure E.4 MPU Well Line Internal Inspection Increases

Section E.2.3 Badami

The Badami Field was shut in August of 2003 due to declining production. A post shutdown inspection was performed to serve as a baseline for a follow-up inspection in the third quarter of 2004 as a check to assure equipment was properly laid up in 2003. A follow up inspection performed in 2004 indicates no increase in corrosion activity from the 2003 shut-in baseline survey.

The Badami Field was re-started in October 2005 and will be put back on the integrity inspection cycle.

Although the data set is limited, inspections support the overall assertion that Badami fluids have low corrosivity. ACT Table E.3 is a summary of well line inspections for Badami. The single inspection increase appears to be related to start-up operations.

Year	Oil	Gas	Disposal	Total	Repeat Insp	Locations with Increasing Damage
1998	28	3	-	31	0	-
1999	-	-	-	-	-	-
2000	15	6	6	27	18	-
2001	-	-	-	-	-	-
2002	5	-	-	5	4	-

Year	Oil	Gas	Disposal	Total	Repeat Insp	Locations with Increasing Damage
2003	21	5	3	29	19	1
2004	18	5	3	26	26	-
2005	29	7	4	40	34	1

Note: 2004 data associated with shutdown operation; 2005 associated with restart operation

ACT Table E.3 Inspection Summary of Badami Well Lines

Section E.2.4 Northstar

During 2005, a total of 395 well line inspections were completed, up from 327 the previous year. Sixteen locations in the three phase system, one location in the disposal system and four locations in the gas system had inspection increases as compared to 25, four and three, respectively, the prior year. It has been stated in previous reports that the 3-phase locations and the gas system locations showing increasing corrosion are all in heavy wall target tees and elbows. This heavy wall piping presents a significant challenge to determining if the wall loss is due to corrosion or to the rough geometry effects of the thick walled sections. The rough geometry can skew readings by 2-3 percent or ~50 mils in a piece 1-1/2 inches thick. For this reason, these locations are monitored on a quarterly basis. Previous inspection increases in the disposal well were believed to be associated with the mud plant operation prior to having been shut down. The data appears to be confirming this as the damage is decreasing since the mud plant has been shut down. These data are summarized in ACT Table E.4.

	3-Phase	Disposal	Gas	Total
Number of. Inspections	230	53	112	395
Number of Repeat Inspections	200	45	100	345
Locations with Increasing Damage	16	1	4	21
% Inspection Increase	8%	2%	4%	6%

ACT Table E.4 Inspection Summary of Northstar

Section F Repair Activities

ACT Table F.1 summarizes the repair activity for ACT. There were 10 repairs identified for ACT. Nine repairs were at Endicott and 1 repair at Badami.

Service	Type	Internal	External	Mechanical
Oil	FL	-	-	-
	WL	9	-	-
Gas	FL	-	-	-
	WL	-	-	-
PW	FL	-	1	-
	WL	-	-	-
	Total	**9**	**1**	**-**

ACT Table F.1 ACT Repair Activity

The internal oil service well line repairs consisted of five C-Spools, two S-Spools, one repair to an existing sleeve showing communication at Endicott. The Badami oil service repair was associated with re-start operations.

The external flow line repair was at Endicott to sleeve an area of external corrosion on the IIWL.

Section G Corrosion and Structural Related Spills and Incidents

There were no structural related leaks and two corrosion related spills in ACT in 2005. ACT Table G.1, ACT Table G.2, ACT Table G.3, and ACT Table G.4 summarize leak/save and mechanical repair data for Endicott, MPU, Northstar and Badami, respectively.

Service	Leaks	Saves
Oil x-country lines	-	-
Oil Well Pads	2	6
Water x-country lines	-	1
Water Well Pads	-	-
Gas x-country GLT/MI	-	-
Gas Well Pads	-	1

ACT Table G.1 Endicott Leak/Save and Mechanical Repair Data

The two leaks were on a C-Spool (Well 1-49) and an S-Spool (Well 4-02). Four of six the saves were on C-Spools (Wells 1-55, 1-57, 22-36, and 1-27). The remaining two saves were on the IIWL (sleeved due to external corrosion) and external corrosion identified on gas injection line 974FH feeding well line 5-02.

Service	Leaks	Saves
Oil x-country	-	-
Oil Well Pads	-	-
Water x-country	-	1
Water Well Pads	-	-
Gas x-country	-	-
Gas Well Pads	-	-

ACT Table G.2 Milne Point Leak/Save and Mechanical Repair Data

There were no leaks and one save for MPU in 2005. The single save for MPU was on the B Pad water injection flow line which is scheduled for repair.

Service	Leaks	Saves
Oil – Well Pad	-	-
Gas – Well Pad	-	-
Disposal Well	-	-

ACT Table G.3 Northstar Leak/Save and Mechanical Repair Data

There were no leaks or saves for Northstar in 2005.

Service	Leaks	Saves
Oil – Well Pad	-	1
Gas – Well Pad	-	-
Disposal Well	-	-

ACT Table G.4 Badami Leak/Save and Mechanical Repair Data

The save in the Badami Well-18 was for corrosion in an elbow and was related to the re-start operation.

Section H 2006 Corrosion Monitoring and Inspection Goals

Section H.1 Endicott

The IIWL will continue to be evaluated to determine if the current decreasing trends in corrosion activity are sustainable. The IIWL will also be evaluated for additional frequent inspection locations.

A new inhibitor is being considered in the Endicott water injection system.

The well line erosion rate monitoring program will continue.

No significant changes to the corrosion-monitoring program are anticipated.

Section H.2 Milne Point

The 2006 plan will continue the inspection program to provide feedback for corrosion control and mechanical integrity.

The corrosion monitoring upgrade will be completed in 2006.

A study was made in 2004/2005 to determine the best way forward for corrosion mitigation of remaining uninhibited areas of the field. These options will be progressed further in 2006.

Piping on two of the four buried pads are expected to be brought above ground in 2006 and the remaining two in 2007.

A new inhibitor is being considered in the Milne Point Unit water injection system.

Section H.3 Northstar

Corrosion monitoring and inspection data will continue to be reviewed as the information becomes available. Changes to the inspection and mitigation activity will be dictated by these data in conjunction with process data. This is an ongoing activity that will continue for a number of years as the corrosion management programs are established at the relatively new production facility.

The recommendation to relocate the chemical injection points to the wellhead was provided, and Operations is proceeding with these modifications as materials become available. The project is expected to be completed by year end 2006. Additionally, all new wells will be equipped with capability to inject corrosion inhibitor at the wellhead.

The water disposal system will be evaluated for the effect of the effluent system carryover to assure adverse effects of dissolved oxygen are minimized. Further analysis will be performed to determine the level of corrosion activity and recommendations will be based on that evaluation.

Section H.4 Badami

Badami will be placed back on, the integrity plan for operation of the field.

Appendix 1

Glossary of Terms

Glossary of Terms

Term	Definition/Explanation
3 phase production	Unprocessed well head fluids, oil, water, gas – same as OIL
ACT	Alaska Consolidated Team
ATRT	Automated tangential radiographic testing
BAD	Badami
bpd	Barrels per day
BPXA	BP Exploration (Alaska) Inc.
CCL	Cross country line
CI	Corrosion inhibitor
CIC	Corrosion, Inspection and Chemicals
CIP	Comprehensive Inspection Program
CL	Common line – same as LDF
CMS	Corrosion management system
CPF	Central processing facility
CR	Corrosion rate, mpy
CRA	Corrosion resistant alloy
CRM	Corrosion rate monitoring inspection program
Cross Country lines	Pipelines from the manifold building to major facility
CUI	Corrosion under insulation
CW	Commingled Water
DRT	Digital radiography
END	Endicott
ER	Electrical resistance probe - see corrosion monitoring
ERM	Erosion rate monitoring inspection program
FL	Flow line – same as cross-country
FIP	Frequent inspection program
Frequency C	Continuous
Frequency D	Daily
Frequency H	Hourly
Frequency M	Monthly
Frequency Q	Quarterly
Frequency Y	Yearly/annual
FS	Flow station
G	Gas
GC	Gathering center
GLT	Gas lift transit
GPB	Greater Prudhoe Bay
IIWL	Inter Island Water Line - Endicott
ILI	In-line Inspection or Smart Pig
LDF	Large diameter flow line – same as CL
LIS	Lisburne
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic flux leakage
MI	Miscible injectant
mil	0.001 in.
MIMIR	**M**echanical **I**ntegrity **M**anagement **I**nformation **R**epository BPXA corrosion and inspection database
MPI	Main Production Island - Endicott
Mbpd	Thousands of barrels per day
mpy	Corrosion rate/degradation rate – mils per year

Glossary of Terms

Term	Definition/Explanation
MPU	Milne Point Unit
MW	Mixed water
NDE/NDT	Non-destructive examination/testing
NIA	Niakuk
NGL	Natural gas liquids
NST	Northstar
OIL	OIL service is 3-phase production service
OWG	Oil, water and gas – 3-phase production
PBU	Prudhoe Bay Unit
PO	Processed oil
ppb	Parts per billion
ppm	Parts per million
PR	Pitting rate, mpy
PTMAC	Point McIntyre
PW	Produced water
RT	Radiographic testing
SDI	Satellite drilling island
Sleeve	Mechanical repair
Slug catcher	First stage pressure vessel of OWG separation facility
STP	Seawater Treatment Plant
SW	Seawater
TRT	Tangential radiographic testing
UT	Ultrasonic testing
VSM	Vertical support member
WAG	Water alternating gas
WL/Well lines	Pipelines from the well head to manifold building
WLC	Weight loss coupon
WPM	Well pad manifold building
WSS	Walking speed survey
WTR	Combined seawater and produced water injection
X-country	Cross country

Appendix 2

Work Plan
Guide for Performance Metric Reporting

2000 Work Plan

Commitment to Corrosion Monitoring

Phillips Alaska, Inc.
BP Exploration (Alaska) Inc.

"BP and Phillips will, in consultation with ADEC, develop a performance management program for the regular review of BP's and Phillips' corrosion monitoring and related practices for non-common carrier North Slope pipelines operated by BP or Phillips. This program will include meet and confer working sessions between BP, Phillips and ADEC, scheduled on average twice per year, reports by BP and Phillips of their current and projected monitoring, maintenance and inspection practices to assess and to remedy potential or actual corrosion and other structural concerns related to these lines, and ongoing consultation with ADEC regarding environmental control technologies and management practices."

Work Plan Purpose:

The purpose of this work plan is to clearly define the purpose, scope, content, reporting requirements, roles and responsibilities, and milestones/timing for the development and implementation of the Corrosion Monitoring Performance Management Program required by Paragraph II.A.6 of the North Slope Charter Agreement.

Corrosion Monitoring Performance Management Program

Purpose: To provide for 'the regular review of BP and PAI's corrosion monitoring and related practices for non-common carrier North Slope pipelines' operated by BP or PAI.
'Corrosion Monitoring' specifically refers to the activity of monitoring pipeline corrosion rates via corrosion probes, corrosion coupons, internal pipeline inspections, and external pipeline inspections.
'Related practices' refers to the assessment of corrosion monitoring data and the associated response to the assessment, specifically chemicals, inspection, and repairs.

Scope: Non-common carrier North Slope pipelines operated by BP or Phillips Alaska, Inc.

"Non-common carrier pipelines" refer to Non-DOT-regulated pipelines. Included in this designation are cross-country and on-pad pipelines in crude, gas, and other hydrocarbon services, as well as, produced water and seawater service pipelines. In module and inter-module on pad piping are not considered part of the scope of this review program.

Content: This Corrosion Monitoring Performance Management Program consists of the following:

1. BP and PAI will "meet and confer" with ADEC twice per year, on average. These sessions will be "working sessions" where BP and PAI will inform ADEC of the following:
   A. Summary description of the inspection and maintenance practices used to assess and to remedy potential or actual corrosion, or other significant structural concerns relating to these lines, which have arisen from actual operating experience. This description will address overall areas of focus, the rationale for this focus, and the nature of monitoring and related practices used during the time since the last meeting. This description may be brief if strategies/focus areas have not changed since the last meeting.
   B. Summary overview of ongoing coupon and probe monitoring results.
   C. Summary overview of chemical optimization activities.
   D. Summary overview of ongoing internal inspection activities.
   E. Summary overview of ongoing external inspection activities.
   F. Summary overview of ongoing structural concerns.
   G. Summary of conclusions drawn and responses taken to remedy potential or actual corrosion concerns relating to these lines.
   H. Review/discussion of corrosion or structural related spills and incidents
   I. Review the actions developed by the operator to address any corrosion performance trends that significantly exceed expected parameters.
   J. Summary of program improvements and enhancements, if applicable.
   K. Review of annual monitoring report (see below) at the next scheduled semi-annual meeting.

The agenda for these meetings will also include an opportunity for open discussion and an opportunity for ADEC to ask questions, provide feedback, etc.

These meetings will be targeted for April and October of each year, although this timing can be adjusted upon the mutual agreement of BP, PAI, and ADEC. The location of the meetings will alternate between the parties.

2. BP and PAI will submit annual reports to ADEC, which will provide the status of current and projected monitoring activities. These reports will be issued on or before March 31st of each year, and reflect the prior calendar year. The following information will be provided:

   A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.

   B. A general overview of the previous year's monitoring activities.

   C. Metrics that depict coupon and probe corrosion rates.

   D. Metrics that characterize chemical optimization activities.

   E. Metrics that depict the number and type of internal/external inspections done, and, as applicable, the corrosion increases/rates and corresponding inspection intervals.

   F. Metrics that characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.

   G. Metrics that depict the numbers and types of corrosion and structural related spills and incidents.

   H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meetings described above.

   Note: These reports will be presented in, and be part of, a comprehensive North Slope Charter Agreement status report.

3. In addition to the semi-annual "meet and confer" working sessions referenced above, BP and PAI will remain accessible to provide "ongoing consultation" to ADEC regarding environmental control technologies and management practices.

   'Environmental Control Technologies' refer to those technologies specifically related to corrosion monitoring and mitigation of the subject pipelines.

   'Management practices' refer to corrosion monitoring and related practices as defined above.

4. During the semi-annual 'Meet and Confer' working meetings with BP and/or PAI, ADEC may use the services of a corrosion expert(s) (contracted from

funds under Charter Commitment paragraph II.A.7) to assist in the review of performance trends and corrosion program features.

5. BP has assigned CIC Manager, R. Woollam/564-4437, and Phillips has assigned Kuparuk Engineering and Corrosion Supervisor M. Cherry and J. Huber/659-7384, to be the contacts responsible for ensuring these commitments are met, including ADEC notification of scheduled times for the semiannual presentations. The ADEC contact for this effort is (Pipeline Integrity Section Manager/S. Colberg/269-3078) who will notify interested personnel of the presentation times, maintain the reports for distribution to the public when requested and coordinate other issues relating to this commitment.

Annual Timetable

March 31st	Annual Report
April 30th	1H Semi-Annual Review (Meet and Confer)
October 31st	2H Semi-Annual Review (Meet and Confer)

Guide for Performance Metric Reporting

General

- Different metrics show and reveal different aspects of the business and as a consequence there are rarely any 'right' or 'wrong' measures only 'right' or 'wrong' application and usage.
- Summary statistics described below may be provided as a data appendix to the annual reports with the more pertinent tables and graphics being contained in the text as appropriate. The intent is not to clutter and interrupt the flow of the text with extraneous data.
- Format of data, the order in which it is presented, etc. of each company's annual report may differ from the order presented below, depending on key messages and data context. For example, one company may choose to imbed Leak/Save data into an inspection graph as opposed to presenting the Leak/Save data in standalone tabular format.
- This is an initial document for implementation in the 2001 annual report to ADEC, it should be noted, that the guidelines provided below can and will be adjusted to improve the efficacy of the annual report and reporting mechanism.

Timescale

- Data to be presented on an aggregate annualized basis.
- Base year 1995 providing 5 year history before the start of the Charter Agreement and each year's annual report will add to time series starting in 1995.

Equipment Classification

- **Well Line** Pipe work from the well head to the Well Pad Manifold Building, generally, the flow from a single well prior to commingling before transportation to the separation plant.
- **Flow Line** Pipe work from the Well Pad Manifold Building to the Separation plant, generally, cross country and off pad pipe work which carries commingled flow to/from a well pad. Also, straight run flow from the wellhead to separation plant, without commingling, is classified at Flow Line pipe work.
- **Exceptions** Pipe work not conforming to these basic definitions will be reported by exception.

Service Definitions

- **Three Phase Production (3ø or OWG)** Basic reservoir fluids (O/W/G – oil, water and gas) produced from down hole through to the main separation plants that typically see only see changes in temperature and pressure from reservoir conditions and are therefore essentially un-separated.
- **Seawater (SW)** Water sourced typically from the Beaufort Sea that has undergone primary treatment at the Seawater Treatment Plant. Note, that the seawater treatment plants differ across the slope in the primary treatment methods, most importantly oxygen removal, with both production gas and vacuum stripping being employed.
- **Produced Water (PW)** The water produced with the primary reservoir 3 phase production after passing through the separation and treatment
- **Commingled Water (CW)** or Mixed Water (MW) Water which has been commingled and is therefore multi-sourced, this is typically a mix of SW and PW although other combinations exist in the operations on the North Slope.
- **Gas (G)** Generic term for a number of different gas systems which transport essentially dry gas between facilities including fuel gas, lift gas and miscible injectant.
- **Processed Oil (PO)** The oil/hydrocarbon produced with the primary reservoir 3 phase production after separation and treatment, this is primarily black oil but could include black oil plus NGL's.

Basic Summary Statistics

- **Distribution** The data is fundamentally of log-normal distribution, with a lower limit of zero or no-change and potentially unlimited upper extent.
- **Count** A count of the number of activities completed i.e. coupons pulled in a given year.
- **Average** The average or mean for the criteria being summarized i.e. average corrosion rate.
- **Target Value** The target value against which non-conformance, see below, is reported.
- **Number Non-conformant** The number of items not conforming to the control criteria i.e. the number of coupons exceeding the control value.
- **Percentage Non-conformance** The percentage not conforming to the control value as a percentage of the total.

Weight Loss Coupon Data

Table below summarizes the reporting of weight loss coupon data for the major fields on the North Slope

	Well Lines	CCL/FL
3 ø Production	All	All
Seawater	GPB	All
Prod. Water	GPB	GPB
Commingled Water	All	All

The data sets to be provided for both general corrosion rates and pitting rates are,

- Count of coupons,
- Average corrosion rate,
- Number non-conformant,
- % Conformant i.e. 1 minus the % non-conformant.

A corrective action list for non-conformant flow lines (FL/LDF/CCL/CLs) will also be provided.

Internal Inspection Data

Table below summarizes the reporting of internal corrosion inspection data for the major fields on the North Slope:

	Well Lines	CCL/FL
3 ø Production	All	All
Commingled Water	All	All

Note that no distinction will be made between water services across the North Slope since in many cases the service is variable making meaningful analysis and aggregation difficult.

The data sets to be provided for internal inspection are,

- Count of inspections,
- Number of increases on repeat inspection locations,
- Percentage of increases on repeat inspections.

A corrective action list for flow lines (FL/LDF/CCL/CLs) with inspection increases will also be provided.

Corrosion Inhibition

The corrosion inhibition program is to be reported as the target and actual total annual gallons and gallons per day, and as concentration, ppm, based on a field wide average.

External Corrosion Inspection

External corrosion inspection program is to be reported as an aggregate of all piping systems without distinction or differentiation of service and equipment type with a summary of the overall program status.

The data sets to be provided for external inspection are,

- Count of inspected location,
- Number of corroded locations,
- Percentage of inspection locations corroded.

Repair and Leak Statistics

The repair and leak/spill statistics to be reported for each vear plus the historical trend back to 1995 consistent with other performance metrics. The basic definitions,

Leak/Spill An agency reportable leak/spill for the pipelines covered under the Charter Agreement which was caused by corrosion and/or erosion

Save A location which required repair action as a result of corrosion and/or erosion damage but which was found through inspection prior to causing a leak/spill

The data sets to be provided for Repair/Leak statistics,

- Count of Leaks/Saves by flow line and well lines,
- Summary of leak/spill causes.

Below Grade Piping

The data sets to be provided for Below Grade Piping (BGP) program.

- Number of segments/crossings inspected broken out by inspection method,
- Number with anomalies and severity of anomaly.

Results of casing digs, visual casing inspections and casing clean-out to be reported as appropriate.

Other Programs

Reporting of ER probe, smart pigging, maintenance pigging, structural issues, and details of individual spill incidents to be reported as dictated by the current year's program activity.

Appendix 3

Corrosion Management System

Appendix 3 Corrosion Management System

This section summarizes the Corrosion Management System (CMS) in use at Greater Prudhoe Bay (GPB) Performance Unit. Figure 7 contains a schematic of a typical production facility configuration. A map and brief description of each field and the associated production facilities can be found in Figure 8 and Table 16 BPXA North Slope Operations.

Appendix 3.1 Corrosion Management System

Appendix 3.1.1 Description

The Corrosion Management System consists of a number of major program elements: Corrosion Monitoring, Erosion Monitoring, Corrosion Mitigation, Inspection and Fitness-For-Service assessment, which follow a simple management process, represented in Figure 1. The CMS elements are summarized in Table 9, Table 10 and Table 11,at the end of this section. The Corrosion, Inspection and Chemical (CIC) Group utilizes data presented in this report as part of the overall Corrosion Management System.

The overall objective of the CMS is to meet the corporate objectives of 'no accidents, no harm to people and no damage to the environment' which translates for corrosion management within BPXA to delivering a mechanical integrity program which:

- Minimizes health, safety, and environmental impacts of corrosion resulting from a loss of containment.
- Provides an infrastructure fit-for-service for the remainder of the life of the oilfield.
- Provides infrastructure of sufficient mechanical integrity capable of producing satellite fields/accumulations through existing main production facilities and infrastructure.
- Provides an infrastructure to support future major gas production and sales through current North Slope facilities.

These overall goals and objectives are achieved through a comprehensive Corrosion Management System that consists of an integrated system of strategy, processes and programs.

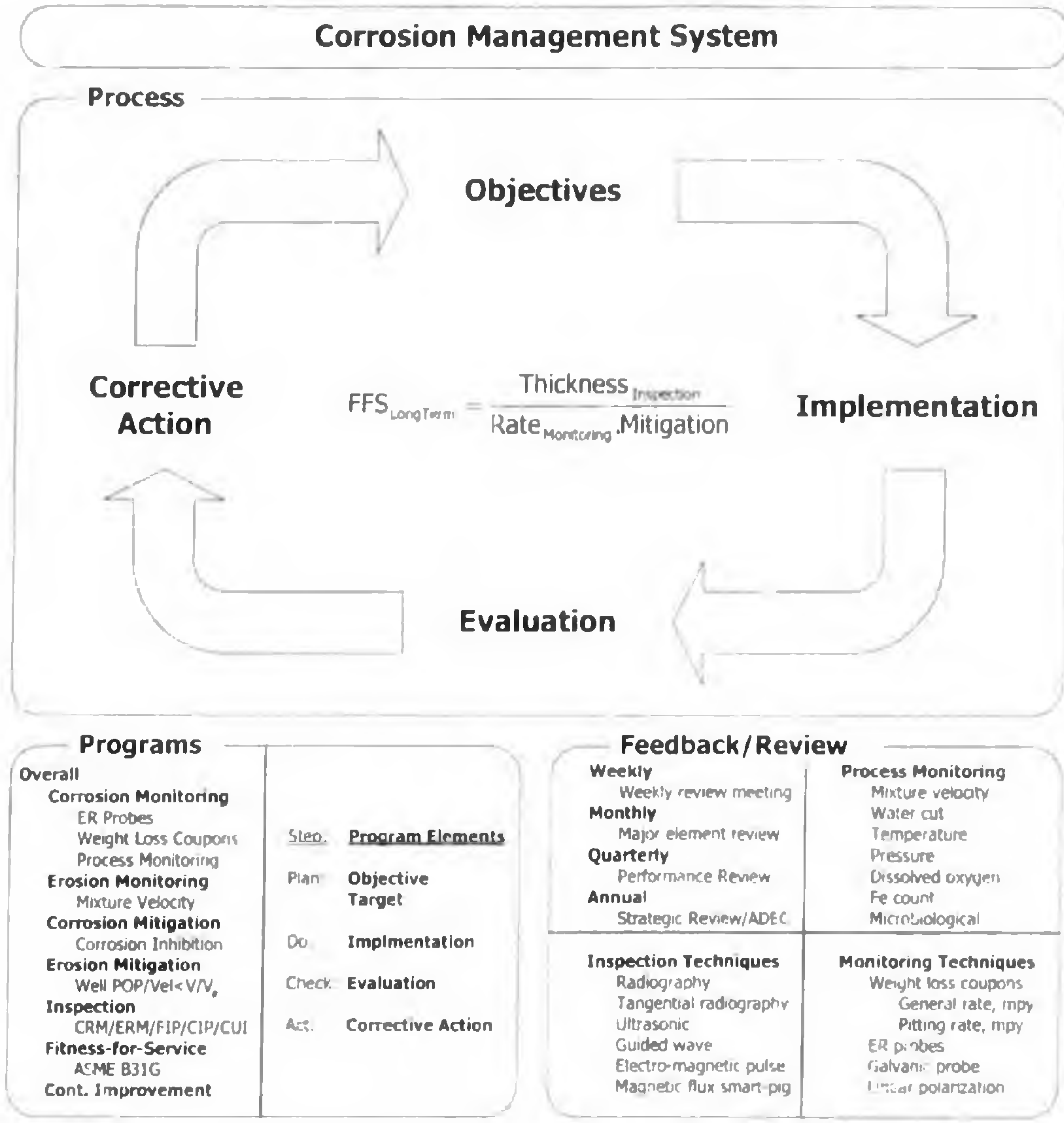


Figure 1 Overview of the Corrosion Management Process

Appendix 3.1.2 Process

Within the overall Corrosion Management System, each specific program element, i.e. Corrosion Monitoring, Mitigation, Inspection and Fitness-For-Service, follows the classic TQM (Total Quality Management) process of 'plan-do-check-act' and consists of,