Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring
Year 2007

Prepared by

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March 2008

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Part 1 – Overview

Overview

Alaska and BP have a shared history that dates back nearly 50 years. BP is proud of its history in Alaska, but we are also focused on growing our business and creating opportunities for the future. To make that future happen, we are focusing our resources on several key areas: the renewal of our North Slope infrastructure, the renewal of our workforce and the advancement of technology to develop known resources[1]. Further, managing the effects of corrosion on North Slope facilities is recognized as having an essential part in the future success of all stakeholders.

Guided by these goals, BPXA continues to invest significant effort through established corrosion monitoring and mitigation programs. We believe that the results presented in this report illustrate our longstanding commitment to continuous improvement, achievement of our corporate goals and our aspiration to create opportunities for the future.

This is the eighth annual report meeting the commitment made by BPXA to the State of Alaska to provide a regular review of BPXA's corrosion monitoring and management practices for non-common carrier pipelines on the North Slope. The contents of this report reflect the Work Plan[2] agreed jointly between BPXA, Phillips and ADEC, the Guide for Performance Metric Reporting[3], and feedback from previous ADEC reports. As requested by ADEC in 2007, the report is now divided into five main parts.

Part 1 provides an overview of BPXA's corrosion management goals.

Part 2 describes enhancements to BPXA's corrosion monitoring and management practices, and discusses significant project achievements.

Part 3 presents a summary of the results from corrosion monitoring and management activities conducted through December 2007.

Part 4 contains information regarding the BPXA operated fields within the Greater Prudhoe Bay (GPB) Business Unit. This consists principally of fluids produced from Prudhoe Bay, Lisburne, Point McIntyre and Niakuk field areas but also includes smaller volumes of fluids from satellite accumulations.

Part 5 contains information regarding the BPXA operated fields within the Alaska Consolidated Team (ACT) Business Unit. ACT principally handles fluids from the Endicott, Badami, Milne Point and Northstar field areas. As with GPB, several smaller satellite accumulations are also produced through ACT facilities.

The report provides an overview of the corrosion management process, provides data and discusses the corrosion control, monitoring, inspection and fitness-for-service programs. In concert, these individual programs form the core of the integrity/corrosion

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[1] BP in Alaska Fact Book, Message from President Doug Suttles, September, 2007.

[2] Appendix 2 (a) 2000 Work Plan

[3] Appendix 2 (b) Guide for Performance Metric Reporting

management system; designed to deliver our corporate goal of no accidents, no harm to people and no damage to the environment[4].

The corrosion management program reflects the core values of BP, demonstrating the attributes of innovation, performance-driven activity, environmental leadership and being a force for progress.

Innovation is evident in several areas, from the development of more effective corrosion inhibitors and corrosion inhibition programs, to the application of new inspection technologies. These innovations are only made possible by working closely with partners, major suppliers and the regulatory community, to bring the best available technology to Alaskan oilfields.

Performance management and the drive for improved performance are central to all aspects of the corrosion management program. This report demonstrates an on-going effort to improve corrosion management. Since 1992, average corrosion rates have been reduced by a factor of ten in the cross-country pipelines that transport a mixture of oil, water and gas (3-phase). Consistent with the pledge to openly report both good and bad performance, the report highlights areas for improvement and the plans in-place to deliver performance improvement.

Environmental protection and corrosion management are closely linked. Our improvements in corrosion management have resulted in lower corrosion rates and a lower risk of loss of containment. Opportunities to improve environmental performance will continue to be sought and the ongoing investment in pipeline inspection and repairs is but one example of the continued emphasis in this area.

Progressive evolution of the corrosion management programs is an on-going activity driven by changing field conditions and the desire to improve performance. Progress involves the continued refinement of existing programs, but also, the development and implementation of new programs and corrosion management technologies.

The current corrosion management process has delivered a significantly improved level of corrosion control for the North Slope energy infrastructure. Notwithstanding the successes, the corrosion management program will remain focused on the future in order to maintain the current level of control and where necessary, implement the actions necessary to improve performance.

[4] "Our Values", BP America Inc., http://www.bp.com/

Part 2 – Significant Enhancements to Corrosion Programs

Significant Enhancements to Corrosion Programs

BPXA's 2007 program showed some important improvements over previous years programs. All of the systems reported showed equal or improved performance compared to 2006 based on monitoring and inspection data. Some notable enhancements to BPXA's programs included:

Updated Corrosion Control Strategy

During January to April 2007 an external team of specialists from BP, our partners ExxonMobil and ConocoPhillips and industry experts joined with the BPXA corrosion team to review and update our Corrosion Control Strategy. The final document was published in September 2007 and sets out the strategic direction our corrosion programs will take going forward. Implementation of the new strategy is already underway and it is expected to take several years to achieve full conformance. Key enhancements include:

- Inclusion of all North Slope facilities & equipment.
- The recognition of "line" ownership of corrosion management.
- Evaluate the use of formalized risk based inspection (RBI) processes.
- The re-introduction of corrosion staff in all major facilities on the North Slope.
- Formal documentation of corrosion programs.
- Clearly defined roles and responsibilities
- Increased assessment and use of new technologies.

Organizational Capability

The targeted recruiting campaign continued during 2007 to increase both the capacity and competency of the corrosion teams. The Anchorage based Strategy and Planning Team increased from 18 to 28 staff (55%) and included specialists in in-line-inspection (ILI), integrity analysts and corrosion engineers. Similar growth also occurred in the North Slope CIC team.

In addition a new team was formed to implement the new Corrosion Control Strategy led by an experienced manager.

External Reviews of BPXA's Corrosion Programs

During 2007 several reviews of the BPXA corrosion program were undertaken across several areas including the condition of BPXA's pig launchers and receivers and the sea water treatment plant. Two notable ones are:

A panel of three independent corrosion experts comprising of Professors Joe Payer and Digby McDonald and John Banyard undertook a holistic review of our programs. They developed a series of recommendations which were accepted by BPXA and are currently being evaluated.

We contracted a comprehensive review of BPXA's microbial corrosion monitoring and mitigation practices. This also produced several recommendations which were accepted by BPXA and are currently being evaluated

Pipeline Replacements

Two new replacement pipelines were completed in 2007; the Milne Point 14" K-pad pipeline and the 24" Point McIntyre/Lisburne pipeline.

Construction of the new Prudhoe Bay Oil Transit pipelines continued with completion expected during 2008.

Other Significant Achievements

- The produced water chemical injection system was completed in 1Q 2007 and all PBU produced water systems are now treated with corrosion inhibitor.
- High Resolution Aerial photography of BPXA's North Slope Assets was completed in support of numerous planning programs including corrosion.
- The Milne Point buried headers at G, H, I and J-Pads were all moved to above ground locations.
- Relocation of all of the Northstar corrosion inhibitor well line injection points to the wellhead was completed. A new chemical injection skid was installed which provides increased control of inhibitor dosage to each wellhead.
- Twenty (20) pipelines were inspected using In-Line-Inspection (ILI) tools in 2007; 18 in GPB, 2 in ACT.
- Milne Point I & J pads were upgraded to allow continuous corrosion inhibitor injection into the flow lines.
- >50,000 external corrosion inspections were completed (charter related plus other equipment) – a record for BPXA.
- BP Group Technology were engaged to develop data mining and statistical analysis techniques that can be applied to BPXA monitoring and inspection data.

Part 3 – Summary of 2007 BPXA Programs

Section A GPB Corrosion Program Summary

Section A.1 GPB Corrosion Related Leaks

A measure of corrosion management program efficacy is the number of corrosion related leaks. The ultimate goal of this measure is no corrosion related leaks.

Target:	No Leaks
KPI:	Number of Leaks
Section Reference:	Part 4 - Section C - GPB Corrosion & Structural Related Repairs and Spills

1. There were six corrosion/mechanical related leaks of which;
    a. There was one internal corrosion related leak in a seawater well line.
    b. There were two internal corrosion related leaks in the 3-phase oil system.
    c. There were two external corrosion related leaks in 3-phase flow lines.
    d. There was one leak due to mechanical/freezing of a 3-phase flow line, not related to internal corrosion.
2. There were no corrosion related leaks in the processed oil transit system.
3. There were no corrosion related leaks in the produced water system.
4. There were no corrosion related leaks in the gas lift system.

Section A.2 GPB Corrosion Monitoring

A principal objective of corrosion monitoring is to measure the effectiveness of applied mitigation programs. The primary monitoring techniques employed in this program are intrusive weight loss coupons (WLC) and Electrical Resistance Probes (ER Probe) which provide the feedback for corrective action when corrosion rate targets are exceeded.

Program:	Weight Loss Coupon
Target:	<2 mils per year (mpy)
KPI:	% Conformance WLC <2 mpy
Section Reference:	Part 4 -Section A.1 - Weight Loss Coupons and Probes

1. 7,439 coupons were utilized to monitor the effectiveness of the mitigation programs.

2. 3-phase flow line WLC data showed 99% less than 2 mpy with an average corrosion rate of 0.20 mpy.
3. Water injection flow line (produced and seawater) WLC data showed 91% less than 2 mpy with an average corrosion rate of 0.91 mpy.
4. Processed oil flow line WLC data showed 100% less than 2 mpy with an average corrosion rate of 0.09 mpy.
5. 3-phase well line WLC data showed 98% less than 2 mpy with an average corrosion rate of 0.35 mpy.
6. Majority service produced water well line WLC showed 100% less than 2 mpy and average corrosion rate of 0.13 mpy.
7. 100% produced water service well line WLC showed 100% less than 2 mpy and average corrosion rate of 0.12 mpy.
8. Majority service seawater well line WLC showed 100% less than 2 mpy and average corrosion rate of 0.26 mpy.
9. 100% seawater service well line WLC showed 100% less than 2 mpy and average corrosion rate of 0.26 mpy.

Program:	Electrical Resistance Probe
Target:	<2 mils per year (mpy)
KPI:	Conformance <2 mpy
Section Reference:	Part 4 - Section A.1 - Weight Loss Coupons and Probes

1. 3-phase flow line ER Probes showed 93% of the data was <2 mpy.
2. Only two ER probes showed results that prompted mitigation actions – the lowest number since reporting initiated in 2001.

Based on the WLC and ER probe monitoring results, improved levels of corrosion control were observed in five system service types in 2007. Further, the percentages of WLC exhibiting corrosion rates within the 0 – 2 mpy target range improved in nearly every service type, with many showing 100% of the WLC at less than 2 mpy.

Section A.3 GPB Corrosion Inhibition Program

For internal corrosion control, a principal means of mitigation is through the carefully monitored application of corrosion inhibitors.

Program:	Corrosion Mitigation – Corrosion Inhibitor (CI)
Target:	Control corrosion to acceptable levels
KPI:	Target versus actual CI usage, injection volumes (ppm)
Section Reference:	Part 4 -Section A.2 - Corrosion Inhibition

1. In the 3-phase systems, the field wide average inhibitor concentration increased slightly from 155 to 160 ppm.
2. The total 3-phase corrosion inhibitor usage was 2.34 million gallons (winter equivalent) which was delivered at just above 100% of the target volume in the 3-phase flow lines and well lines.
3. The corrosion inhibitor usage in the produced water system averaged ~3,300 gpd which equates to a total of 1.25 million gallons.
4. The corrosion inhibitor usage in the processed oil system averaged ~130 gpd which equates to a total of ~48,000 gallons.

The effectiveness of corrosion mitigation, as a result of the application of corrosion inhibition, is determined from corrosion monitoring and inspection programs. Corrosion monitoring data are a leading indicator and inspection data are a lagging indicator of corrosion mitigation efforts.

Section A.4 GPB Maintenance Pigging Program

Maintenance pigging is another form of internal corrosion mitigation and management. The metrics reported here include the number of scheduled maintenance pig runs, the number of scheduled runs completed, and the percent of scheduled runs completed, by year. This is the first report year in which maintenance pigging data has been included.

Program:	Corrosion Mitigation – Maintenance Pigging
Target:	Control corrosion to target levels
KPI:	Number of maintenance pig runs planned vs. number of runs completed and percent completed.
Section Reference:	Part 4 - Section A.3 - Maintenance Pigging

1. 352 maintenance pigs were run
2. The average percent of all scheduled pig runs completed was 56% in 2006 and 63% in 2007.

Factors outside the control of the program such as weather, operations, flow conditions and launcher/receiver outages, often affect pigging schedules. Inspection and repair of pig launchers and receivers is being conducted, and a program for maintenance is under development.

Section A.5 GPB External Corrosion Inspection Program

The plan for the external corrosion program includes comprehensive inspection coverage of equipment susceptible to corrosion under insulation (CUI), minimizing loss as a result of external corrosion failures and assuring that the equipment is fit-for-service (FFS) and safe to operate.

Program:	Corrosion Under Insulation
Target:	50,000 inspections/year
KPI:	% of locations inspected with external corrosion, Leak/Save ratio
Section Reference:	Part 4 - Section B.1.1 - External Inspection Program Results

1. Of the 49,021 external corrosion inspections completed, 4% were found with corrosion degradation.
2. There were 91 mechanical repairs identified as a result of external corrosion.
3. There were 2 leaks due to external corrosion on 3-phase flow lines.
4. The Leak/Save ratio for the External Corrosion (CUI) Program was 98%.

Unlike internal corrosion where mitigation can be managed through chemical inhibition, mechanical cleaning and/or operational controls, CUI is managed through detection and repair. Once CUI has been found through inspection activities, locations are scheduled for insulation and by-product removal, fit-for-service assessment, mechanical repair if needed and rehabilitation of the insulation system.

Section A.6 GPB Cased Pipe Program

The overall plan for the cased pipe program is to employ the best inspection technology available for cased pipe segments at road and/or animal crossings where historically, the prominent threat has been external corrosion. Excavation of crossings, as required, is then performed to mitigate active corrosion and assure that the equipment is fit-for-service and safe to operate.

Program:	Cased Pipe Inspection
Target:	~200 inspections/yr
KPI:	Increases or active corrosion determined from repeat examinations.
Section Reference:	Part 4 - Section B.1.2 - Cased Piping Survey Results

1. Thirty-nine (39) cased piping segments were inspected using guided-wave inspection techniques. None of the inspections indicated active corrosion.
2. Eight (8) cased segments were excavated and inspected; 3 were found to have external corrosion and were mitigated, 4 segments showed no corrosion and one segment was part of a scheduled replacement.
3. Between guided wave, ILI and excavations, a total of 140 cased pipe segments were inspected, which is short of the targeted number of 200 cased pipe segments for 2007.

The 2007 program consisted of repeat examinations/monitoring and excavation. Cased piping inspection is recognized as an area for improvement.

Section A.7 GPB Internal Inspection Program

The objective of the internal inspection program is to provide widespread inspection coverage of equipment susceptible to internal corrosion degradation. Corrosion mechanisms and rate of metal loss are also identified to minimize failures and assure that the equipment is fit-for-service and safe to operate.

Program:	Internal Inspection Program
Target:	70,000 inspections/yr split between field piping (~31,000) and facility equipment (~39,000)
KPI:	% of locations inspected with increased metal loss, Leak/Save ratio
Section Reference:	Part 4 - Section B.2 - Internal Inspection Program Results

1. There were 28,741 inspections completed on field piping.
    a. There were 11,203 inspections on 3-phase flow lines, with 1% showing an increase.
    b. There were 8,958 inspections on 3-phase well lines, with 3% showing an increase.

c. There were 2,519 inspections on water injection flow lines, with 5% showing an increase.

d. There were 2,393 inspections on water injection well lines, with 8% showing an increase.

e. There were 2,277 inspections on processed oil transit lines, with 2% showing an increase.

2. There were 14 mechanical repairs identified as a result of internal corrosion.
3. There were 3 leaks due to internal corrosion; two in 3-phase production and one in seawater service.
4. The Leak/Save ratio for the Internal Inspection Program was 82%.

The total number of inspections and number of repeat inspections was at or above recent years. The number of inspections showing corrosion increases is lower, which indicates an overall decrease in active internal corrosion.

Section A.8 GPB Internal Corrosion Summary by Service

This section presents a summary of internal corrosion key indicators by service type for GPB. For comparative purposes, data from the current report year and the previous year are presented below.

Service	Average WLC Corrosion Rate, mpy		% WLC Corrosion Rate < 2 mpy		% WLC Pit Rate < 20 mpy		% Internal Insp. w/ Increased Cor.		Internal Cor. Related Leaks	
	2006	2007	2006	2007	2006	2007	2006	2007	2006	2007
3-phase flow lines	0.20	0.20	99%	99%	100%	100%	4%	1%	-	-
3-phase well lines	0.38	0.35	97%	98%	100%	100%	3%	3%	-	2
Water injection flow lines	1.12	0.91	87%	91%	92%	96%	9%	5%	-	-
Processed Oil flow lines	0.20	0.09	97%	100%	100%	100%	9%	2%	2	-
Maj. Service PW well lines	0.10	0.13	100%	100%	99%	99%	10% (all water WL)	8% (all water WL)	1	-
100% PW well lines	0.10	0.12	100%	100%	100%	100%				
Maj. Service SW well lines	0.45	0.26	99%	100%	96%	100%			4	1
100% SW well lines	0.45	0.26	99%	100%	98%	100%				

GPB Summary Table A.1 Internal Corrosion Summary Data by Service Type

The average corrosion rates, percentage of WLC with corrosion rates <2 mpy and percentage of WLC with pitting rates <20 mpy (threshold levels) for each service type illustrate that overall, a high level of success is being experienced by the corrosion management program.

While WLC results describe near-term corrosion management performance, leak history and internal inspection results are measures of longer-term advances in corrosion control. These data show consistent reductions in the number of internal inspections with increased corrosion between 2006 and 2007. This same trend extending over the past five years is discussed later in the report. The numbers of leaks associated with internal corrosion was lower in 2007 than in 2006. Although the internal corrosion management efforts are largely successful and show continuing improvement, optimization of mitigation and monitoring in the 3-phase, PW and SW systems continues to be a long-term goal.

Section B ACT Corrosion Program Summary

Section B.1 ACT Operating System Overview

Alaska Consolidated Team (ACT) Performance Unit consists of four producing areas: Endicott, Milne Point Unit (MPU), Northstar and Badami. Each of the producing fields within ACT has unique characteristics 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 33,600 bpd in 2007.

Endicott - Located northeast 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 fabricated largely of duplex stainless steel, which significantly reduces the environmental risks. In 2007, Endicott production averaged approximately 12,600 bpd.

Badami - Remotely located east of Prudhoe Bay, Badami has a relatively low production volume due to challenging reservoir conditions. The Badami production facilities 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 placed in warm shutdown in August of 2007. Badami production averaged approximately 600 bpd in 2007 prior to this time.

Northstar - 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 production during 2007 averaged approximately 38,000 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.

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 30 years for GPB to approximately seven years for Northstar.

Field	Prod Fluid Characteristics: H_2O (%)	T (°F)	P_{CO_2} (%)	CR [b]	Material of Construction [a]: Production WL	Production FL	Injection WL	Injection FL
GPB	76	150	12	H	CS+CI	CS+CI[c]	CS+CI	CS+CI
Endicott	94	150	18	H	DSS	DSS	CS+CI	CS+CI
Milne Point	67	125	1.5	L/M	CS	CS [d]	CS+CI	CS+CI
Northstar	27	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

Metric	ACT	GPB	$\frac{ACT}{(ACT+GPB)}$ %
Number of Production Trains	4	21	16%
Number of Prod and Inj. Wells	408	1498	21%
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.2 ACT Corrosion Related Leaks and Repairs

A measure of corrosion management program efficacy is the number of corrosion related leaks with the ultimate goal of "no leaks".

Target:	No Leaks
KPI:	Number of Leaks
Section Reference:	Part 5 - Section C - ACT Corrosion & Structural Related Repairs and Spills

1. One leak occurred at Endicott on 3-phase well line.
2. There were no leaks Milne Point.
3. There were no leaks for Northstar.
4. There were no leaks for Badami.

Section B.3 ACT Corrosion Monitoring

A principal objective of corrosion monitoring is to measure the effectiveness of mitigation programs. In ACT, the primary monitoring techniques employed in this program are intrusive weight loss coupons (WLC) which provide the feedback for corrective action when corrosion rate targets are exceeded.

Program:	Weight Loss Coupon
Target:	<2 mils per year (mpy)
KPI:	% Conformance WLC <2 mpy
Section Reference:	Part 5 - Section A - ACT Corrosion Monitoring and Mitigation

1. Endicott water injection system WLC showed 100% less than 2 mpy and an average corrosion rate of 1.66 mpy.
2. The Endicott oil production system, which is not inhibited, showed 75% WLC less than 2 mpy and an average corrosion rate of 0.22 mpy.
3. Milne Point oil production system WLC showed 100% less than 2 mpy and an average corrosion rate of 0.20 mpy.
4. Milne Point water injection system WLC showed 100% less than 2 mpy and an average corrosion rate of 0.09 mpy.
5. Northstar oil production system WLC showed 89% less than 2 mpy and an average corrosion rate of 0.72 mpy.
6. Northstar water injection system WLC showed 100% less than 2 mpy and an average corrosion rate of 0.14 mpy.
7. Badami currently has no WLC-monitoring program, and relies on the inspection program to provide corrosion control feedback.

Section B.4 ACT Corrosion Inhibition Program

For internal corrosion control, a principal means of mitigation is through the application of corrosion inhibitors. The means of corrosion mitigation used throughout the ACT assets varies with the service type, system design, operational conditions and other factors.

Program:	Corrosion Mitigation – Corrosion Inhibitor (CI)
Target:	Control corrosion to acceptable levels
KPI:	Target versus actual CI usage, injection volumes (ppm)
Section Reference:	Part 5 - Section A - ACT Corrosion Monitoring and Mitigation

Endicott

1. In October 2004 the corrosion inhibitor concentration was increased from 20 to 30 ppm and biocide program was rebalanced. Monitoring of the effectiveness of these measures continues.

Milne Point

1. The K-Pad 3-phase production flow line was replaced in 2007. The line is inhibited with continuous corrosion inhibitor and is maintenance pigged monthly.
2. Continuous inhibition of the production flow line from F, L, and C Pads was increased in 2006. The effectiveness of this inhibition change continues to be monitored.
3. The B-Pad production line had continuous corrosion inhibition facilities installed in 2006 and is currently treated at a concentration of 100 ppm.
4. Continuous inhibition of Tract 14 production flow lines at I Pad and J Pad began in mid-2007. Initial results from corrosion monitoring indicate a significant reduction in corrosion rate.

Northstar

1. Northstar is treated with continuous inhibitor into the well production lines. Based on corrosion monitoring data, the corrosion inhibitor concentration was increased in 2007.
2. As of the end of 2007, all wells have had the chemical injection location moved upstream to the wellhead, assuring all portions of the carbon steel well line are now inhibited.
3. In 2007, a new chemical injection skid was installed at Northstar. The new system allows for testing and adjusting of individual well chemical injection rates at a central location rather than by visiting each individual well.

Badami

Corrosion inhibition is currently not required at the Badami field based on modeling of fluid corrosivity, the low water-cut, and the results from the facility and pipeline inspection program. The field was shut-in August 2007 as a result of low production.

Section B.5 ACT Maintenance Pigging Program

The quarterly maintenance pigging performance for the MPU produced water lines and the 3-phase line is provided for 2006 and 2007 in this year's report.

Program:	Corrosion Mitigation – Maintenance Pigging
Target:	Control corrosion to target levels
KPI:	Number of maintenance pig runs planned vs. number of runs completed and percent completed.
Section Reference:	Part 5 - Section A - ACT Corrosion Monitoring and Mitigation

1. In 2007, 88% of the scheduled pig runs were completed for the PW lines and 76% for the 3-phase lines.
2. Maintenance pigging of the Endicott IIWL is scheduled on a five-week basis. In 2007, 91% of the scheduled pig runs were completed.

Section B.6 ACT External Inspection Program

Highlights of the external inspection program results for each ACT asset are presented below.

Program:	Corrosion Under Insulation
Target:	3,500 inspections/year
KPI:	% of locations inspected with external corrosion, Leak/Save ratio
Section Reference:	Part 4 - Section B - ACT External/Internal Inspection

Endicott

1. A total of 1,151 external inspections were performed.

2. Cased flow lines continue to be inspected at pre-established intervals.

3. The vaults where the production, Inter-Island Water Line, and gas-lift lines pass are visually inspected annually.

Milne Point

1. A total of 2,933 external inspections were performed.

    a. There were 1,398 baseline inspections on above ground pipelines were performed. One inspection increase was noted from a total of 197 above ground repeat inspections.

    b. There were 1,338 inspections performed on buried pipelines.

Northstar

1. A total of 243 external inspections were performed at Northstar in 2007, primarily on the production, gas and produced water headers; 237 locations were baseline inspections and six were repeat locations with no increase in corrosion.

Badami

No external inspections were performed at Badami during 2007.

Section B.7 ACT Internal Inspection Program

The objective of the internal inspection program is to provide widespread inspection coverage of equipment susceptible to internal corrosion degradation. Corrosion mechanisms and rate of wastage are also identified to minimize failures and assure that the equipment is fit-for-service and safe to operate.

Program:	Internal Inspection Program
Target:	Ongoing Inspection Program in ACT Assets
KPI:	% of locations inspected with increased metal loss, Leak/Save ratio
Section Reference:	Part 5 - Section B - ACT External/Internal Inspection

Endicott

1. 3,512 internal inspections were performed.

2. There were no inspection increases in the 3-phase, DSS production cross-country line.

3. Frequently monitored locations on the IIWL showed no increases during 2007.

Milne Point

1. 5,745 internal inspections were performed in 2007.

2. The 3-phase well line's damage rate has remained essentially level over the past several years at about 2% of repeat locations showing an increase in corrosion activity.

3. A total of 110 inspection increases in the produced water flow lines is noted for 2007.

4. The PW well line corrosion activity continues to show a decreasing trend over the past several years.

Northstar

1. During 2007, a total of 581 well line inspections were completed, including 502 inspections in the 3-phase and 79 in the disposal systems.

2. Both the 3-phase system and the produced water system are showing decreasing trends in inspection activity for 2007.

Badami

1. 60 inspections were performed in 2007.
2. Badami produced from October 2005 until August 2007, at which time it was placed on warm shut down. A post shut down and follow up inspection was performed to monitor ongoing status.
3. No inspection increases were noted in 2007.

Section B.8 ACT Internal Corrosion Summary by Service

This section presents a summary of internal corrosion key indicators by service type for ACT. For comparative purposes, data from the current report year and the previous year are presented here.

Service	Average WLC Corrosion Rate, mpy		% WLC Corrosion Rate < 2 mpy		% WLC Pit Rate < 20 mpy		% Internal Insp. w/ Increased Cor.		Internal Cor. Related Leaks	
	2006	2007	2006	2007	2006	2007	2006	2007	2006	2007
END Water Inj.	1.54	1.66	100%	100%	90%	96%	3%	3%	-	-
END Oil Prod.	0.51	0.22	54%	75%	89%	96%	5%	3%	-	1
MPU Oil Prod.	0.20	0.20	94%	100%	100%	100%	2%	1%	-	-
MPU Water Inj.	0.09	0.09	100%	100%	98%	100%	3%	2%	-	-
MPU Source water	0.27	0.26	100%	100%	100%	100%	-	-	-	-
NSTR Oil Prod	3.38	0.72	52%	89%	84%	100%	10%	3%	-	-
NSTR Water, upstr	0.18	0.14	100%	100%	100%	100%	12%	4%	-	-

ACT Summary Table B.1 Internal Corrosion Summary Data by Service Type

The average corrosion rates, percentage of WLC with corrosion rates ≤2 mpy and percentage of WLC with pitting rates ≤20 mpy (threshold levels) for each service type illustrate that overall, an effective corrosion control is present in the majority of service types. Whereas WLC results describe near-term corrosion management performance, leak history and internal inspection results point more toward long-term advances in corrosion control. The data also show reductions in the number of internal inspections with increased corrosion between 2006 and 2007.

Part 4 – Greater Prudhoe Bay Business Unit

GPB Section A

Corrosion Monitoring and Mitigation

Section A GPB Corrosion Monitoring and Mitigation

This section presents weight loss coupon data, ER probe results, chemical mitigation data and maintenance pigging results for 2007.

Section A.1 Weight Loss Coupons and Probes

This section summarizes the results of the weight loss coupon (WLC) and ER probe corrosion monitoring programs. In this section, the results of the programs are reviewed for each of the major service categories.

The number of corrosion monitoring locations by equipment type and service, is summarized in GPB Table A.1.

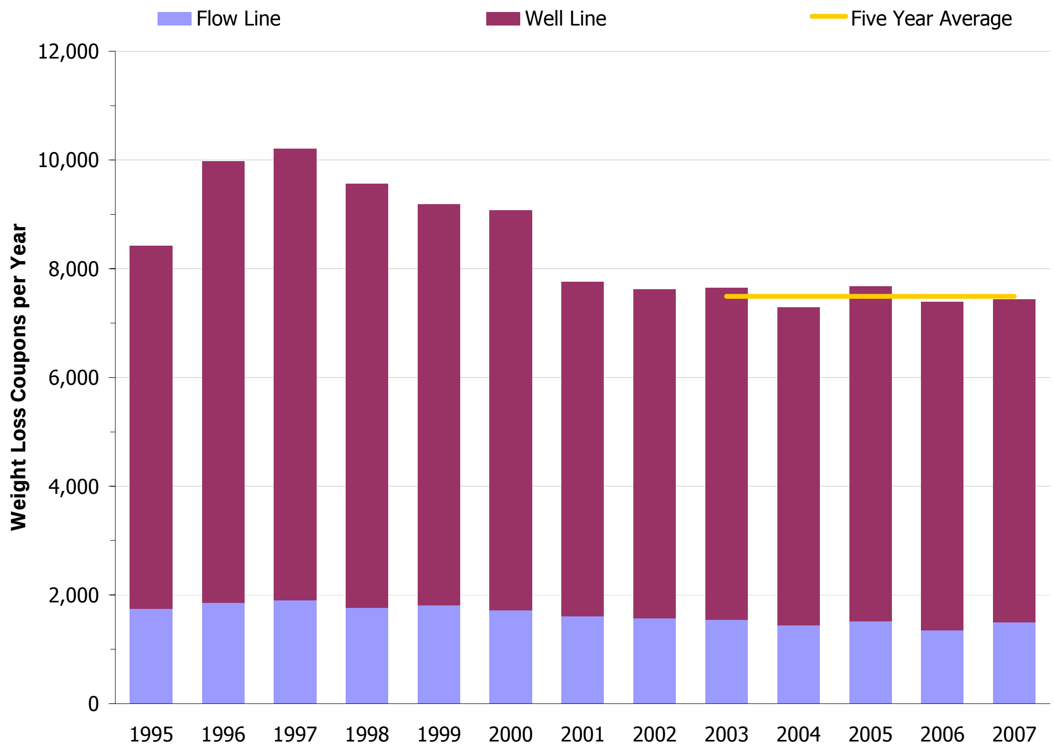
Service	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Flow Line													
3 Phase	214	308	263	266	261	249	251	252	255	242	231	178	178
Exp Oil	5	11	9	8	7	8	6	9	6	8	7	8	6
Gas	3	3	1	1	1				1				
Other	8	9	8	10	9	8	9	9	4	5	6	5	3
Water	36	37	45	43	46	45	44	44	48	38	40	38	39
Total	266	368	326	328	324	310	310	314	314	293	284	229	226
Well Line													
3 Phase	1,027	1,150	1,196	1,183	1,155	1,151	1,066	1,078	1,108	1,091	1,060	1,072	1,070
Exp Oil		3	3	3	3	3	3						
Gas	6	7	6	6	4	5	6	6	5	3	4	2	2
Other	29	28	28	25	24	21	20	25	12	13	17	15	10
Water	197	208	212	206	189	184	188	193	174	174	185	187	176
Total	1,259	1,396	1,445	1,423	1,375	1,364	1,283	1,302	1,299	1,281	1,266	1,276	1,258
Grand Total	1,525	1,764	1,771	1,751	1,699	1,674	1,593	1,616	1,613	1,574	1,550	1,505	1,484

GPB Table A.1 Corrosion Monitoring Locations by Equipment and Service

Two corrosion coupons are typically installed and recovered at each corrosion monitoring location with the exception of those lines that are regularly maintenance pigged. Lines that are pigged for maintenance typically use a single flush-mounted coupon to prevent interference with the pig. The number of coupons, coupons per monitoring location and frequency of recovery continue to be adjusted over time to optimize the value obtained from the data.

Since 2001, the number of weight loss coupons used in the program has stabilized around 7,500 coupons per year. As discussed in prior reports, there was a gradual reduction in the number of weight loss coupons being evaluated from 1997 through 2000, which reflected an on-going effort to optimize the program. The number of weight loss coupons reported for 2007 does not reflect coupons that were still in service at year-end. The number of WLC processed over time is presented in GPB Figure A.1.

Detailed data tables for each configuration of equipment type are provided in and GPB Table A.5 and GPB Table A.6.



GPB Figure A.1 Corrosion Monitoring Activity Statistics by Equipment

Section A.1.1 3-phase Production Systems

Section A.1.1.1 Introduction

The primary corrosion mechanism of concern in the 3-phase production system is CO_2 corrosion, in which CO_2 from the produced fluids dissolves and dissociates in the produced water to form an acidic environment. If the acidic conditions are left untreated, the environment can be corrosive to carbon steel[5,6]. The primary corrosion control method employed at GPB is the continuous addition of corrosion inhibitor to the flow lines and continuous or batch inhibitor additions in the well lines. For the 3-phase production system, the target corrosion rate from weight loss coupons is a general corrosion rate of 2 mpy or less (WLC ≤2 mpy) and a pitting corrosion rate of 20 mpy or less.

The 3-phase production system has benefited from consistent improvements in corrosion control since the early 1990's, with an order of magnitude reduction in the cross-country flow line corrosion rates. This reduction in corrosion rate is a direct result of the implementation of an aggressive corrosion mitigation program consisting primarily of continuous addition of corrosion inhibitor into the production fluids. Although this mitigation program was implemented at considerable capital and operating expense, the flow lines are now expected to be fit-for-service (FFS) for approximately ten times as long as was expected in the early 1990's. The correlation between corrosion inhibitor

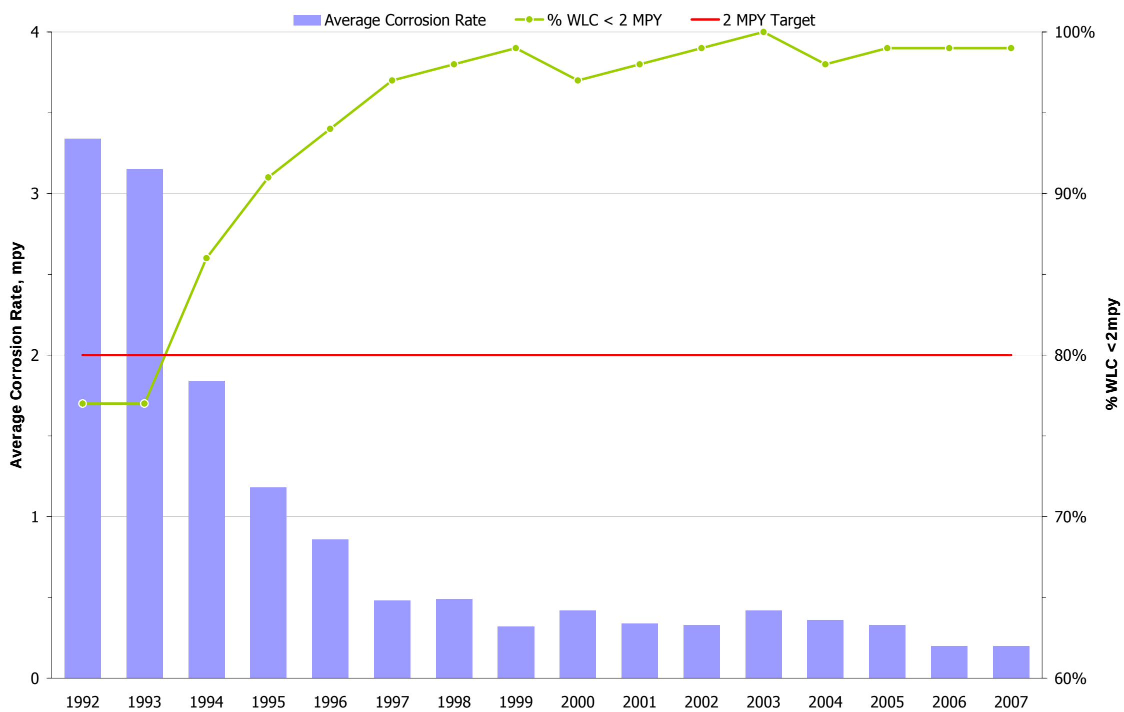
[5] Corrosion Control in Petroleum Production, Harry G Byers, NACE, 1999

[6] Corrosion Control in Oil and Gas Production, Treseder and Tuttle, NACE, 1998

concentration and corrosion rates in 3-phase flow lines is discussed in detail in Section A.2. A similar reduction of internal corrosion rates is also seen in the inspection history discussed later in Section B.

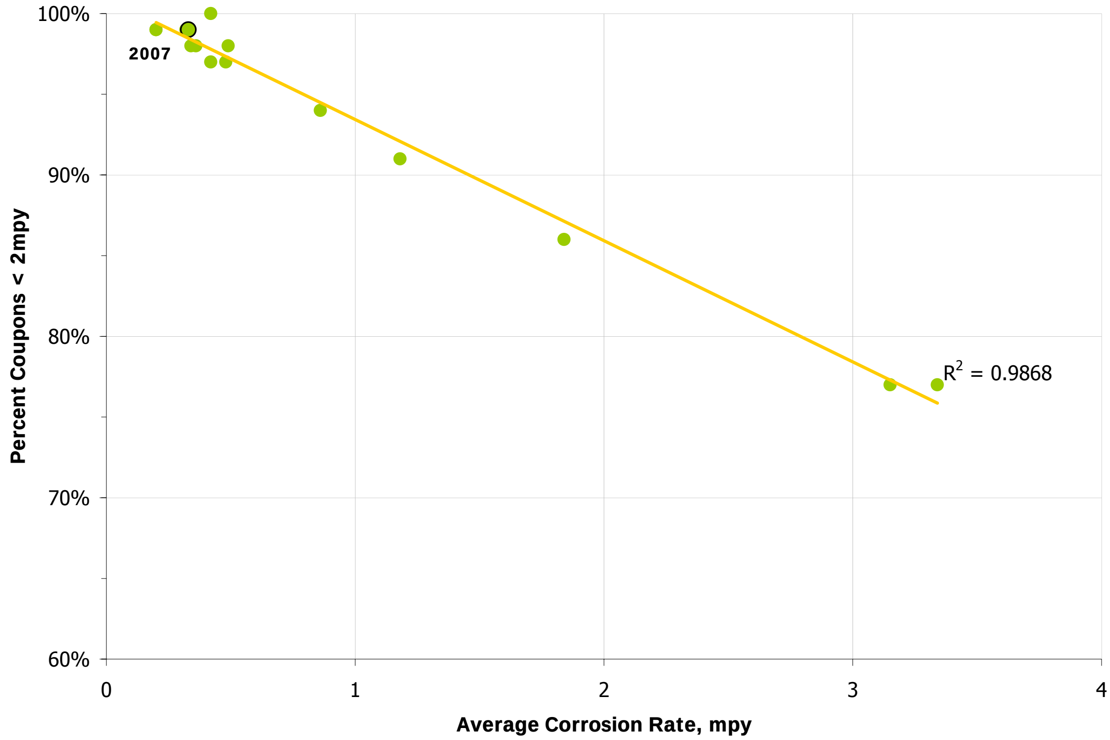
Section A.1.1.2 Cross Country Flow Line Coupons

GPB Figure A.2 shows the average corrosion rate and percentage of coupons meeting the performance standard target since 1992. The results show that the percentage of conformant flow lines has improved consistently over the last decade.



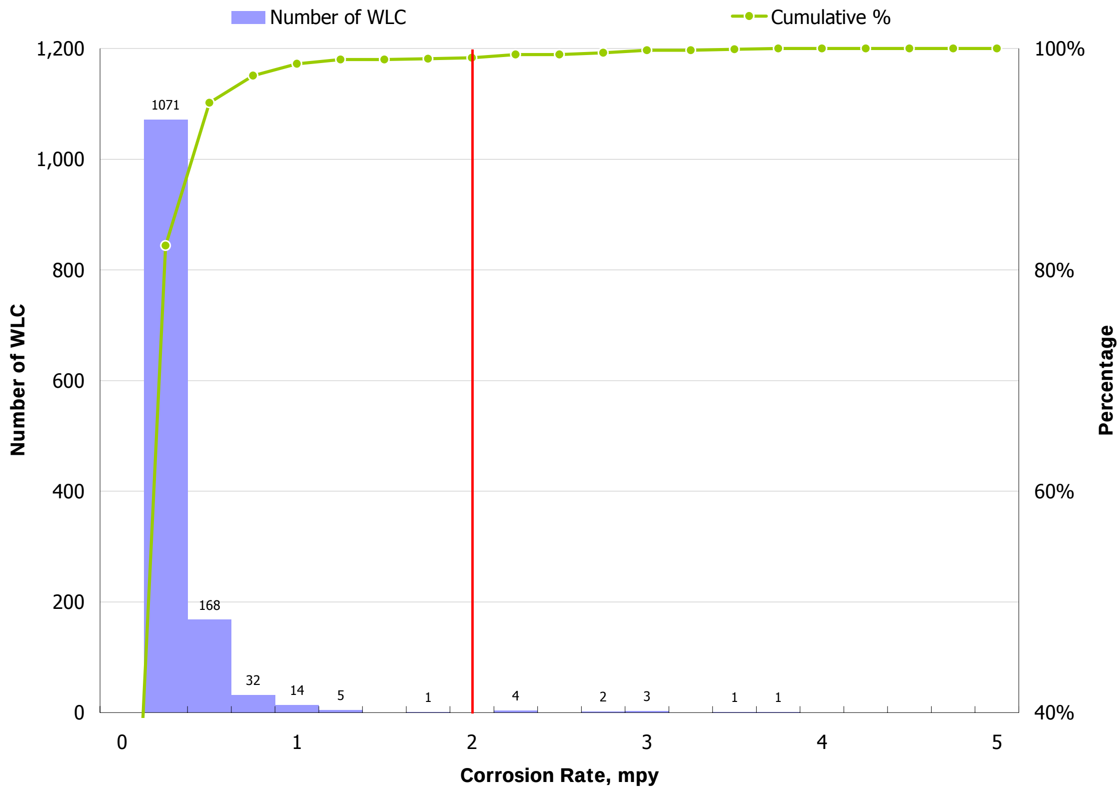
GPB Figure A.2 Flow Line Oil Service Corrosion Rate Trend

GPB Figure A.3 shows the correlation between average corrosion rate and the percentage of weight loss coupons meeting the 2 mpy target. As might be expected, there is a strong correlation between these two metrics. The average corrosion rate metric has the advantage of showing the overall performance trend for the system that would otherwise be lost when only looking at the exceptions >2 mpy. The value of exceptions is certainly not overlooked however, and all WLC corrosion rate exceptions are validated and addressed as needed.



GPB Figure A.3 Correlation between Flow Line Corrosion Rate and Percentage Conformance

GPB Figure A.4 shows the distribution of corrosion rates for WLC in flow line oil service. In 2007, eleven WLCs exhibited general corrosion rates above the 2 mpy target; however the highest rate observed was only 3.75 mpy. None of the coupons in flow line oil service exceeded the pitting rate target of 20 mpy. Refer to Section D.1.5 for details and corrective actions for WLC exceptions.

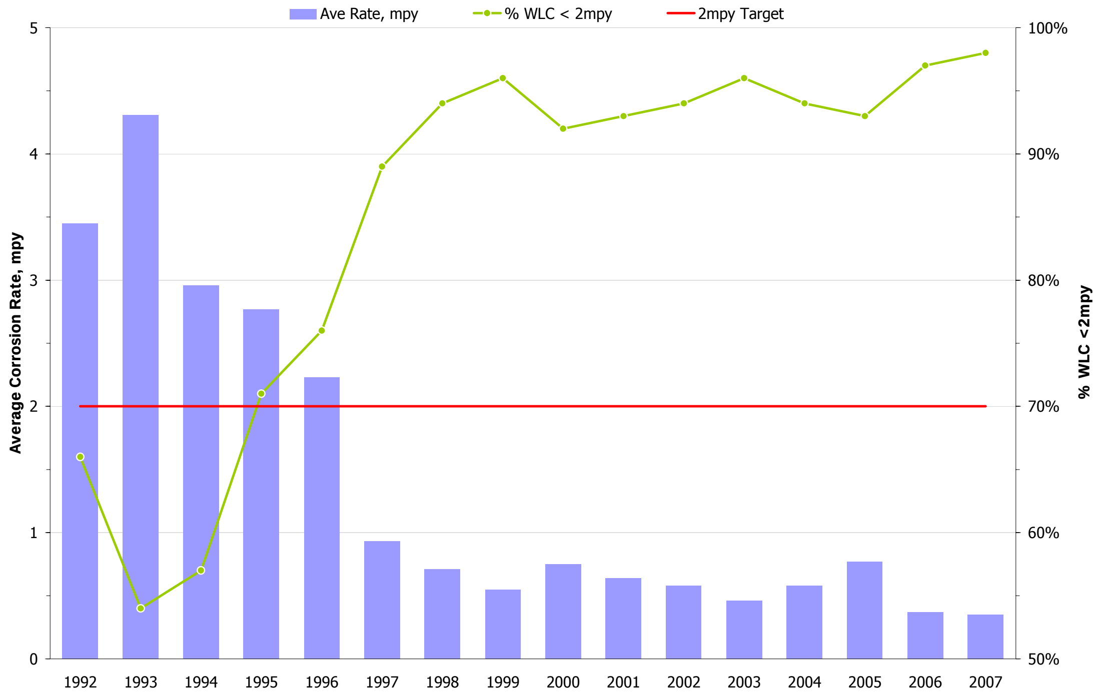


GPB Figure A.4 Flow Line Oil Service WLC Histogram

Section A.1.1.3 Well Line Coupons

GPB Figure A.5 shows the average corrosion rate and percentage of WLC ≤2 mpy since 1992. The trends in the well lines are very similar to those in the cross-country 3-phase oil flow lines, with both showing a long-term improvement in the level of control. A slight decrease in performance from 2003 to 2005 was largely due to chemical deployment problems and has been discussed in previous reports.

The long term corrosion control improvement in the well lines is of the same magnitude as that seen in the flow lines, with corrosion rates being reduced from an average >4 mpy in 1993 down to an average of ~0.5 mpy over the past six years. The average WLC corrosion rate results from 2007 represent a "best ever" performance for the well lines.



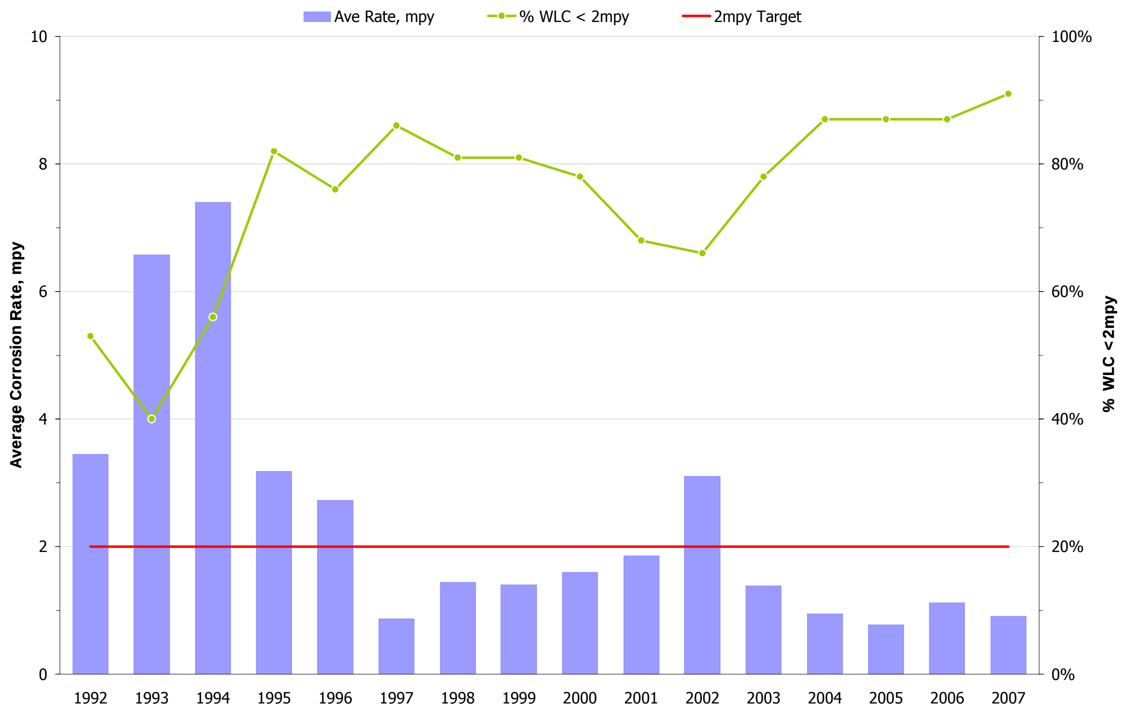
GPB Figure A.5 Well Line Oil Service Corrosion Rate Trend

Section A.1.2 Water Injection Systems

The water injection system at GPB handles produced water from the primary processing/separation facilities and seawater extracted from the Beaufort Sea and processed through the Seawater Treatment Plant (STP). During 2007, the average seawater injection volume was just over 733 Mbpd.

Section A.1.2.1 Water Injection System Flow Lines

GPB Figure A.6 is a summary of aggregate data for produced water and seawater flow lines. The 2007 WLC corrosion rate data show an improvement in performance over last year and comparable performance as in the last four years.

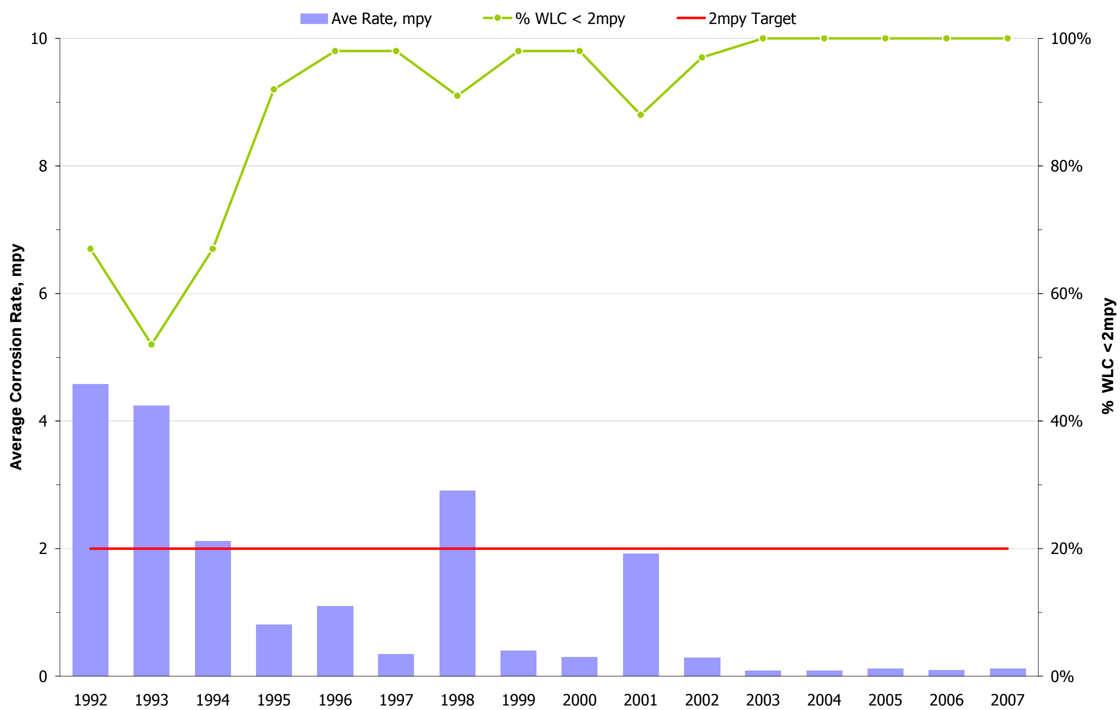


GPB Figure A.6 Flow Line PW / SW Service Corrosion Rate Trend

Section A.1.2.2 Produced Water Injection Well Lines

There are a number of corrosion mechanisms of concern in the produced water (PW) injection system. These mechanisms include CO_2 corrosion and differential concentration effects due to the high particulate content of the water, as well as microbiologically influenced corrosion (MIC). The particulates consist primarily of residual hydrocarbons remaining after the separation process, entrained production chemicals, and iron sulfides.

GPB Figure A.7 and GPB Figure A.8 summarize the historical corrosion rate data for produced water well lines. The data show general corrosion rates in the produced water system have fallen as the level of inhibition in the 3-phase system was increased and supplemental produced water corrosion inhibitor injection was initiated.

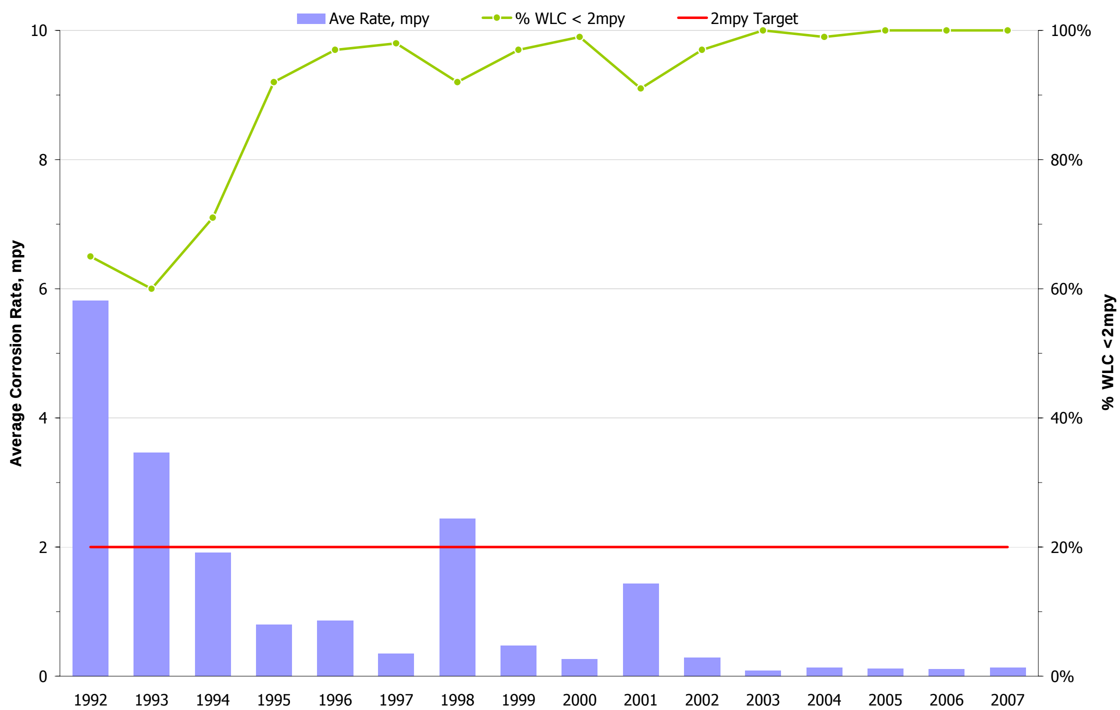


GPB Figure A.7 Corrosion Rates for 100 % PW System

GPB Figure A.7 shows the performance for 100% produced water service. The 2007 average corrosion rates maintained at ~0.1 mpy and ~100% WLC ≤2 mpy.

For coupons exposed to majority produced water service, GPB Figure A.8 shows that corrosion rate trends are similar to those for 100% produced water service. The results for 2007 continue to be encouraging for both 100% PW and majority PW service. As the data set increases and more inspection data becomes available, the results of the WLC program can be further validated.

The overall improvement in the PW monitoring data since 2001 to date can be attributed to three primary factors. First, a change in the continuous corrosion inhibitor in the 3-phase system in 2002 provided more favorable partitioning characteristics to the water phase than the prior product. This had the effect of increasing the levels of corrosion inhibitor carried from the upstream system into the produced water distribution network. The second contributor is the increase in field-wide average concentration of corrosion inhibitor over time. The third contribution is the continuation of corrosion mitigation programs specific to the PW system that started in 2002. The programs include continuous inhibitor injection in the PW system at all production facilities except LPC.



GPB Figure A.8 Corrosion Rates for Majority PW System

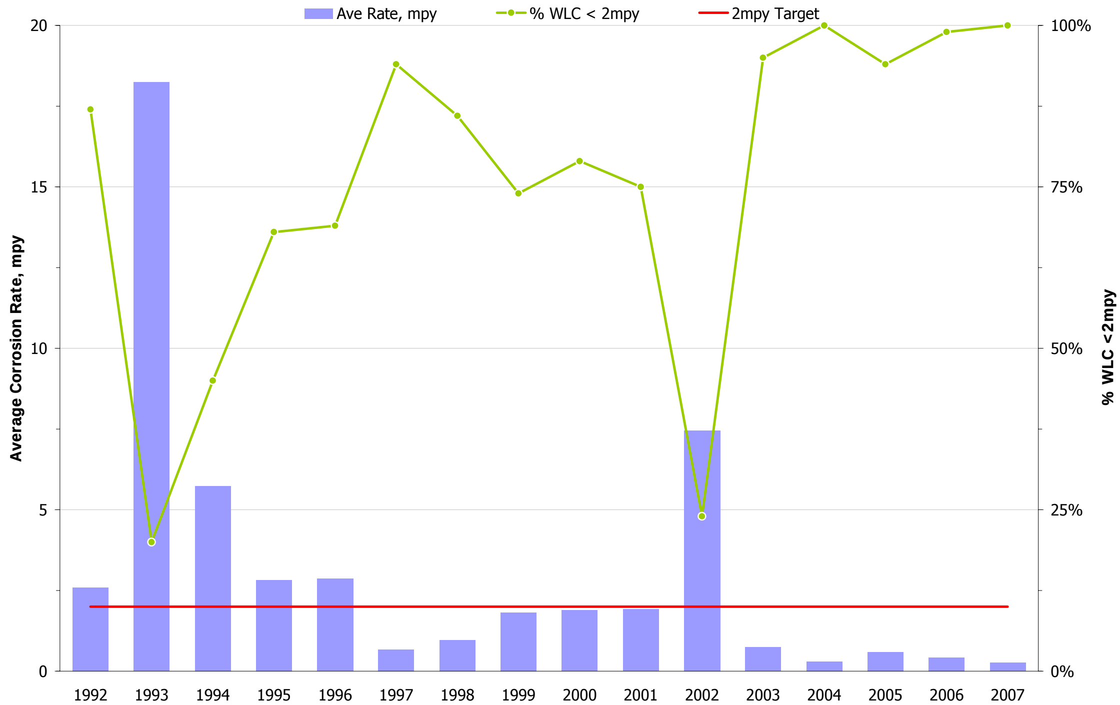
Section A.1.2.3 Seawater Injection Well Lines

The main corrosion mechanisms in the seawater (SW) injection systems are,

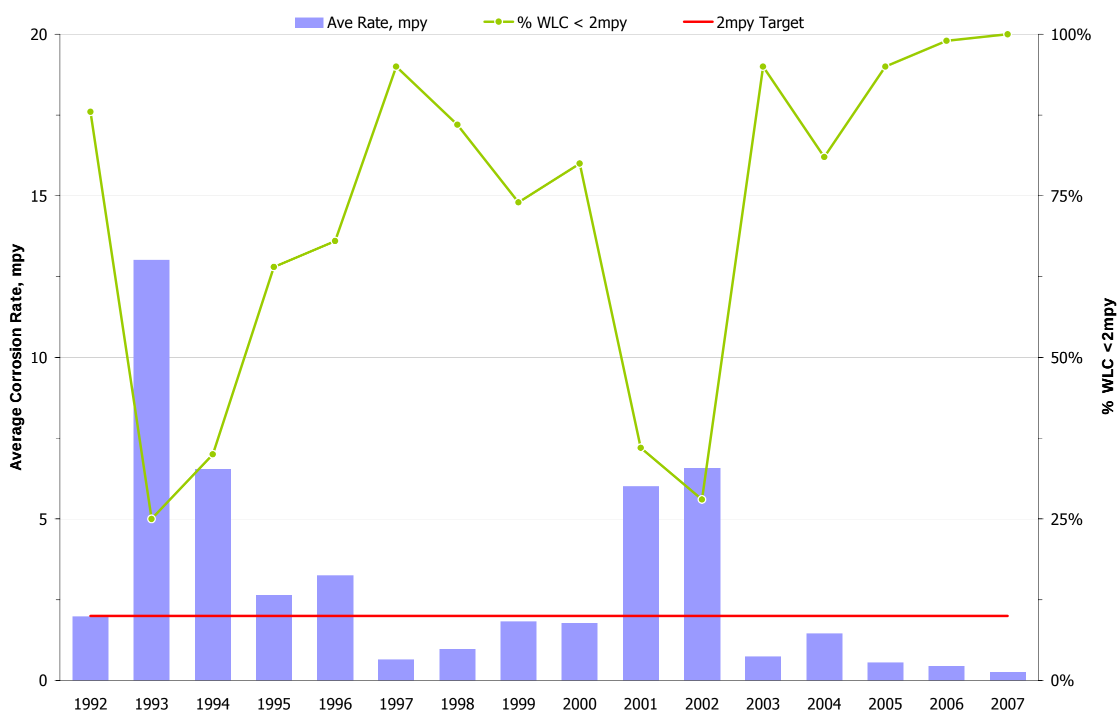
- Dissolved oxygen (DO) corrosion – This mechanism is mitigated by processing the seawater to remove the oxygen. Initial DO removal is achieved mechanically by vacuum stripping, which is then followed by chemical oxygen scavenging.
- Microbiologically Influenced Corrosion (MIC) – MIC can result from the activities of anaerobic bacteria, and is mitigated by batch treatment with biocide after the seawater is processed to remove DO, and prior to seawater transfer to the main cross country flow lines.

As with the PW system, the SW system data are presented as both 100% and majority service for the well line data, along with a comparison of general corrosion rates and pitting corrosion rates.

GPB Figure A.9 and GPB Figure A.10 show the corrosion rate trends in the SW system for both 100% SW service and majority SW service. For the 100% SW service, the improvement since 2002 is a result of implementation of the corrective actions outlined in previous reports. Due to the nature of MIC, it is recognized that weight loss coupons may not be representative of MIC mechanisms.



GPB Figure A.9 Corrosion Rate for 100% Seawater System



GPB Figure A.10 Corrosion Rates for Majority SW System

GPB Table A.2 summarizes the changes in the biocide treatment program for the SW system. Biocide dosage was increased in Mar-03 by 50% at STP to increase the effectiveness in downstream parts of the seawater system. This action decreased the downstream coupon corrosion rates. In Dec-03, the glutaraldehyde/quaternary amine biocide was replaced temporarily with glutaraldehyde. In Oct-04, the biocide was switched back to glutaraldehyde/quaternary amine.

From	To	ppm	Interval days	Product
Jan-97	Jul-97	750	7	Glutaraldehyde
Jul-97	Feb-00	750	14	Glutaraldehyde
Feb-00	Aug-01	450	14	Glutaraldehyde/quaternary amine blend
Aug-01	Jul-02	500	14	Glutaraldehyde/quaternary amine blend
Jul-02	Dec-02	500	7	Glutaraldehyde/quaternary amine blend
Dec-02	Mar-03	500	7	Glutaraldehyde/quaternary amine blend
Mar-03	Dec-03	750	7	Glutaraldehyde/quaternary amine blend
Dec-03	Oct-04	750	7	Glutaraldehyde
Oct-04	Present	750	7	Glutaraldehyde/quaternary amine blend

GPB Table A.2 Biocide Treatment Concentration and Interval

In summary, the corrosion monitoring data suggest that improvements in corrosion control continue in the seawater system. As with the produced water system, the monitoring data set continues to grow and when combined with inspection results, confidence in the data will increase.

Section A.1.3 Electrical Resistance Probes

Electrical resistance (ER) probes are installed in various locations to monitor corrosion rates in flow lines throughout GPB. ER probes measure a change in resistance due to material loss from corrosion and the measurements are converted to corrosion rates in mils per year. ER probes are equipped with remote data collectors (RDC), which measure and record the metal loss data every 4 hours. This provides an adequate number of data points to assess corrosion rates while maximizing battery life in the units.

The typical ER probe used is a model T-10 that has 5 mils (0.005") of usable metal thickness. All flow line ER probes are replaced based on a 1-year service life, or when one half the usable metal thickness has been consumed. This practice reduces false negative and false positive readings as a result of damaged or unresponsive probes.

ER probes are located on both the upstream (well pad) end and downstream (gathering center) end of flow lines located on the west side of GPB. On the east side, probes are only located on the downstream (flow station) end of flow lines.

For the electrical resistance (ER) probes, the number of active locations in the flow lines is given in GPB Table A.3.

Year	Total Probe Locations
2001	83
2002	82
2003	85
2004	87
2005	87
2006	87
2007	87

GPB Table A.3 Active ER Probe Locations

ER probe data is collected in the field and uploaded to the corrosion and inspection database once per week. The target for ER probe corrosion rate is ≤2 mpy. Each week any ER probe with a seven day average corrosion rate greater than 2 mpy is evaluated to determine data validity. If an increase in corrosion rates is verified based on the probe data analysis and other supporting operational data, an action is determined and the probe is considered 'actioned'. The action may be a corrosion inhibitor increase, however other types of mitigation may also be recommended.

GPB Table A.4 shows the number of ER probes with corrosion rates greater than target as compared to the number of probes on which action was taken, dating back to 2001.

Year	Average % <2 mpy	No. ER Probe > 2	No. ER Probes 'Actioned'
2001	97%	193	6
2002	97%	137	6
2003	96%[7]	138	21
2004	92%	316	59
2005	88%	241	11
2006	87%	232	7
2007	93%	248	2

GPB Table A.4 Number of ER Probes >2 mpy and 'Actioned'

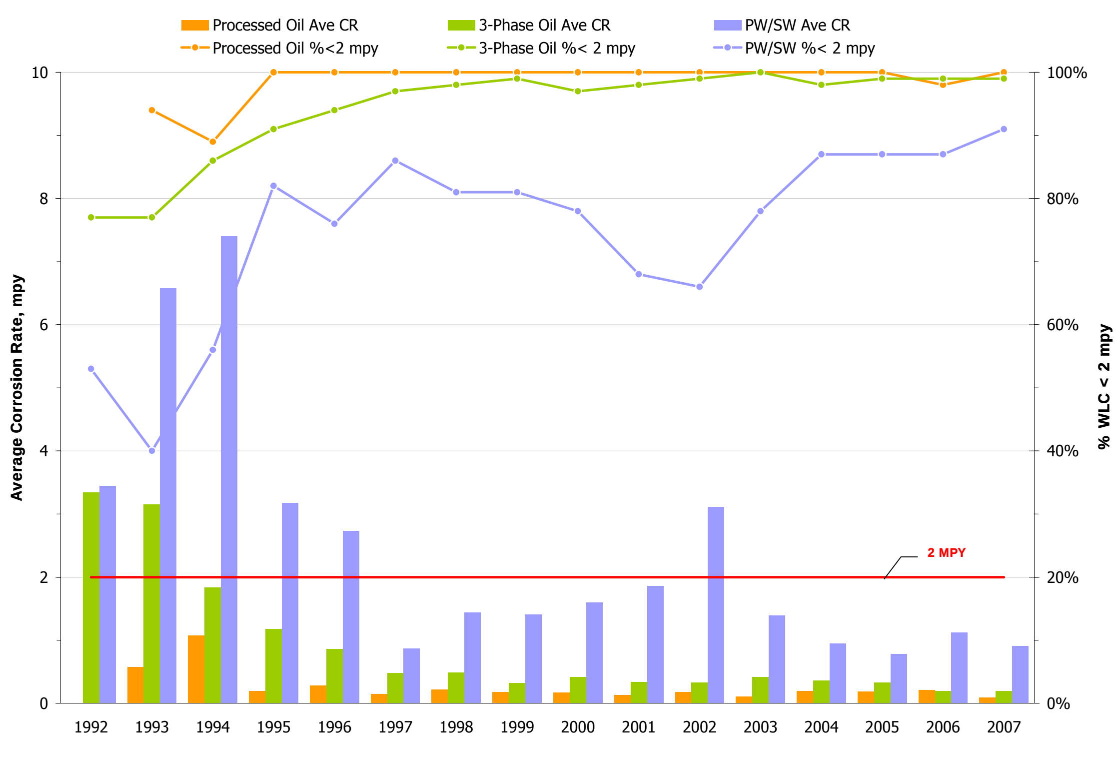
[7] Incorrectly reported as 93% in 2003 Report

The two occurrences greater than 2 mpy in 2007 were corrected with corrosion inhibitor rate increases. The percentage of ER probes 'actioned' in 2007 is substantially lower than last year. Each year there are a number of probes that report suspect metal loss data as a result of fluid flow and/or temperature fluctuations. These fluctuations are regularly investigated to validate whether the corrosion rate for the ER probe actually exceeds the 2 mpy target.

Section D.1.5 shows the corrective mitigation actions taken as a result of ER probe readings exceeding target and Appendix 3.3.1 describes by example, the methodology by which corrosion inhibitor concentration is increased as a result of ER probe monitoring.

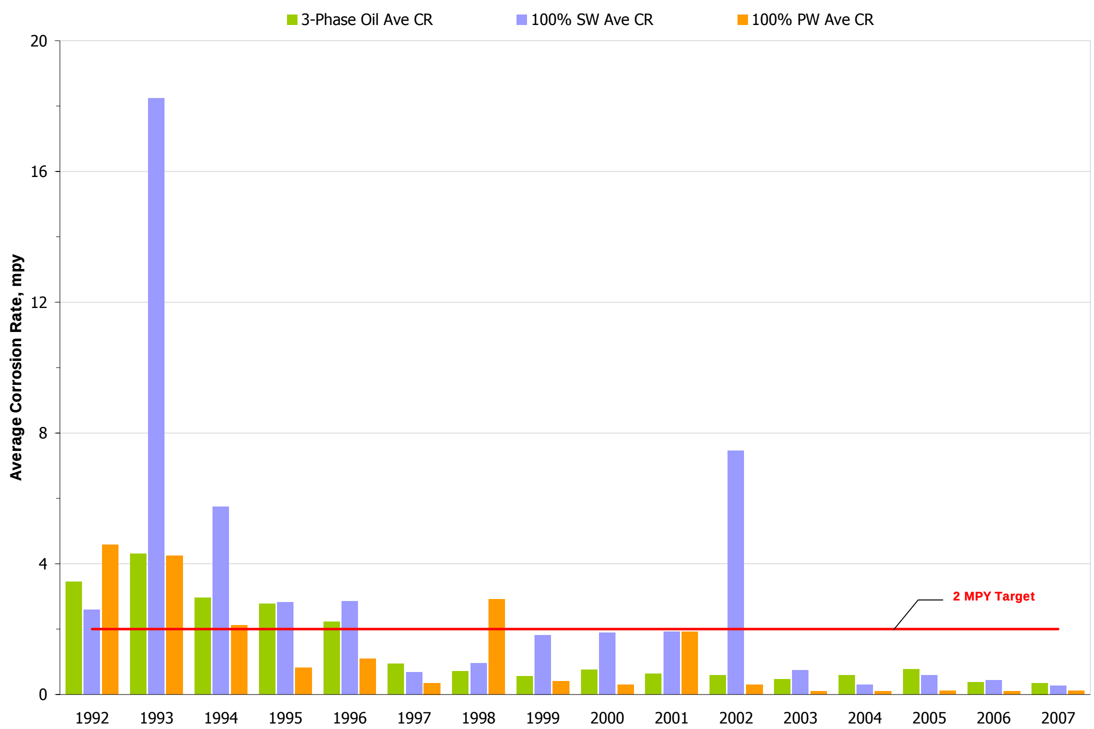
Section A.1.4 1992 to Date Summary by System

This section provides a comparative summary of WLC data collected since 1992 for the major systems at GPB. GPB Figure A.11 shows the WLC corrosion rate and corrosion target conformance since 1992. The average corrosion rate in the 3-phase production system has remained low since 2002 and illustrates a high level of corrosion control. The reasons for improvement in the water injection system performance were provided in Section A.1.2.

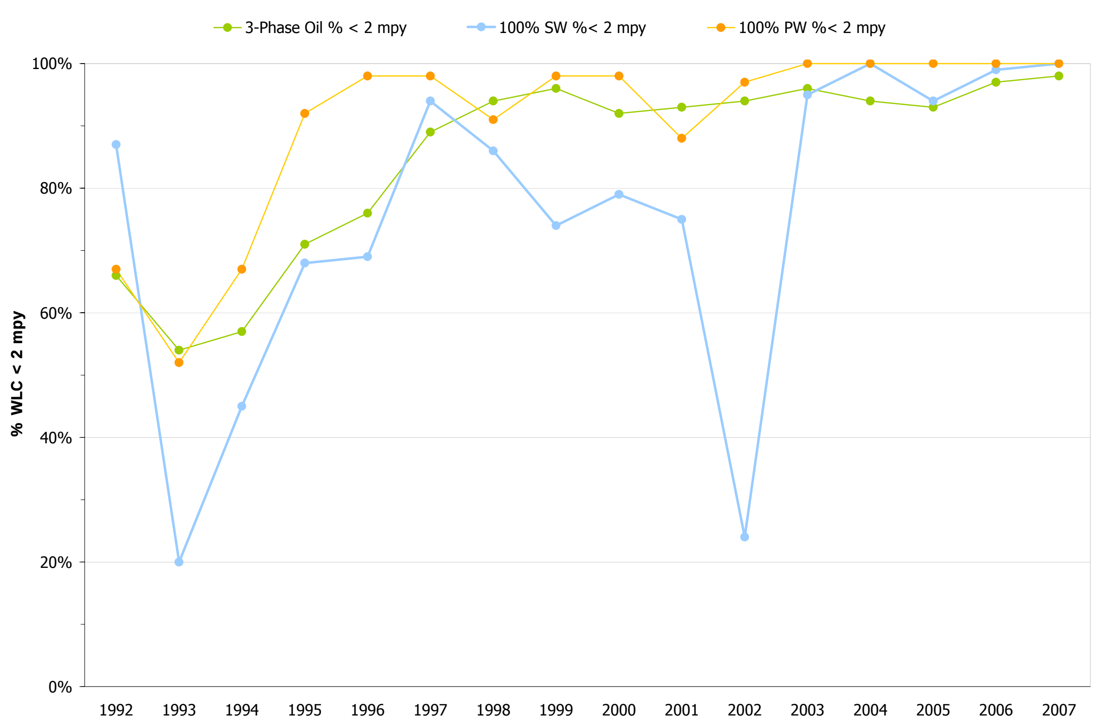


GPB Figure A.11 Flow Line Corrosion Coupon Summary by Equipment and Service

GPB Figure A.12 shows the corrosion rate and GPB Figure A.13 shows WLC corrosion conformance for well lines. The well line 3-phase system performance has remained low since 2000. The produced water and seawater well lines' corrosion performance has shown gradual improvement since 2002.



GPB Figure A.12 Well Line WLC Average Corrosion Rate Summary by Equipment and Service

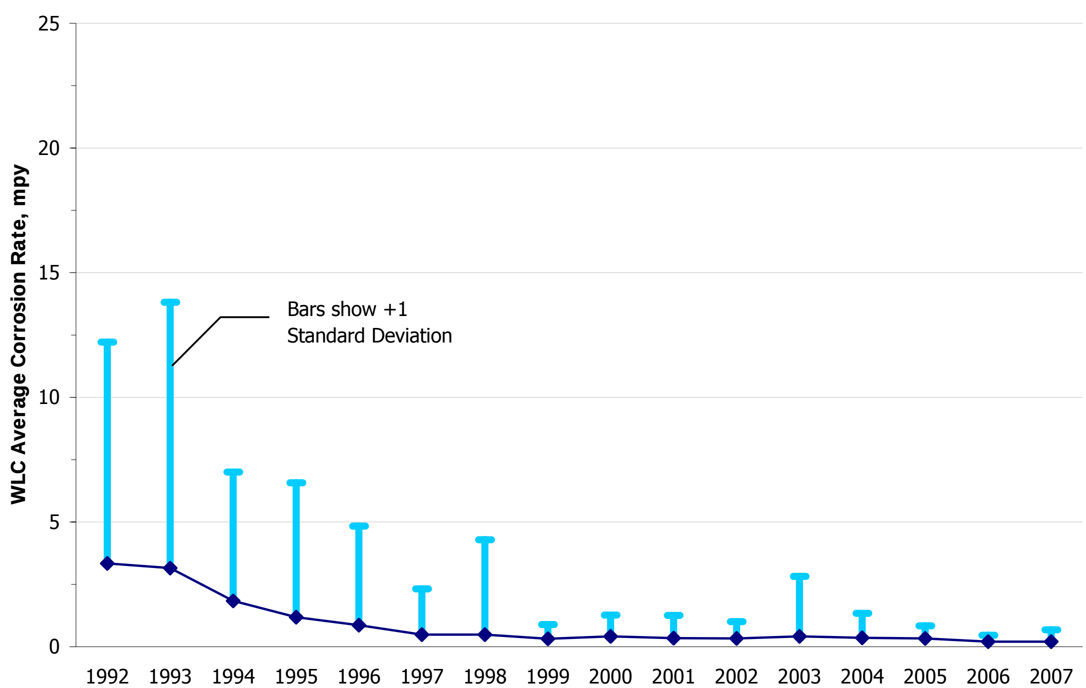


GPB Figure A.13 Well line WLC % <2 mpy Summary by Equipment and Service

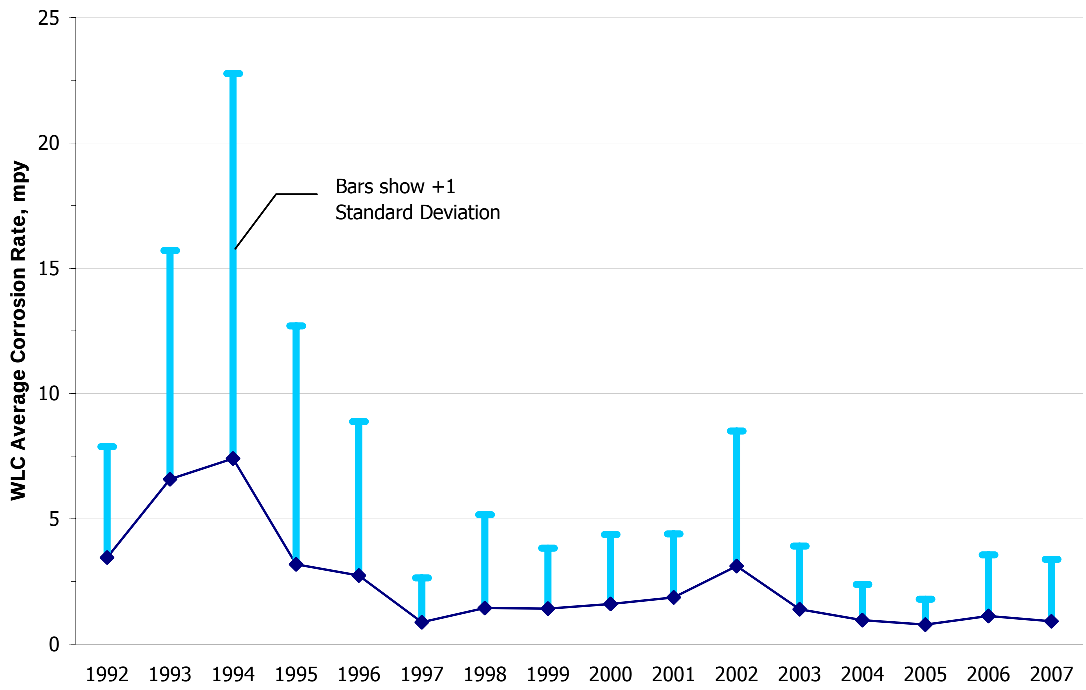
While the average WLC corrosion rate is important to consider for each system, another factor is the range of corrosion rate values observed. In the course of each year and through thousands of WLC analyses, corrosion rates ranging from zero to some maximum are observed. One way of comparing the relative range of corrosion rates to the average is to calculate a standard deviation for the data set. GPB Figure A.14 through GPB Figure A.19 illustrate the difference between standard deviation from the average corrosion rate, and average corrosion rate since 1992, for each of the major service types. Most significantly, the trend observed in all systems is a declining standard deviation (concurrent with the declining average CR) since the early days of the program. This observation increases confidence in the declining CR values which show that corrosion control is being optimized.

Another metric of corrosion management performance identified through the WLC program is pitting rate. In 2007, 100% of the WLCs in the processed oil, majority produced water, 100% produced water, majority seawater and 100% seawater systems measured pitting rates below the target maximum of 20 mpy. Additionally, 98% and 99% of the pitting rates in the 3-phase oil flow lines and well lines, respectively, were below the target maximum. In the combined PW/SW lines, 91% of the 107 coupons analyzed were below the target maximum pitting rate.

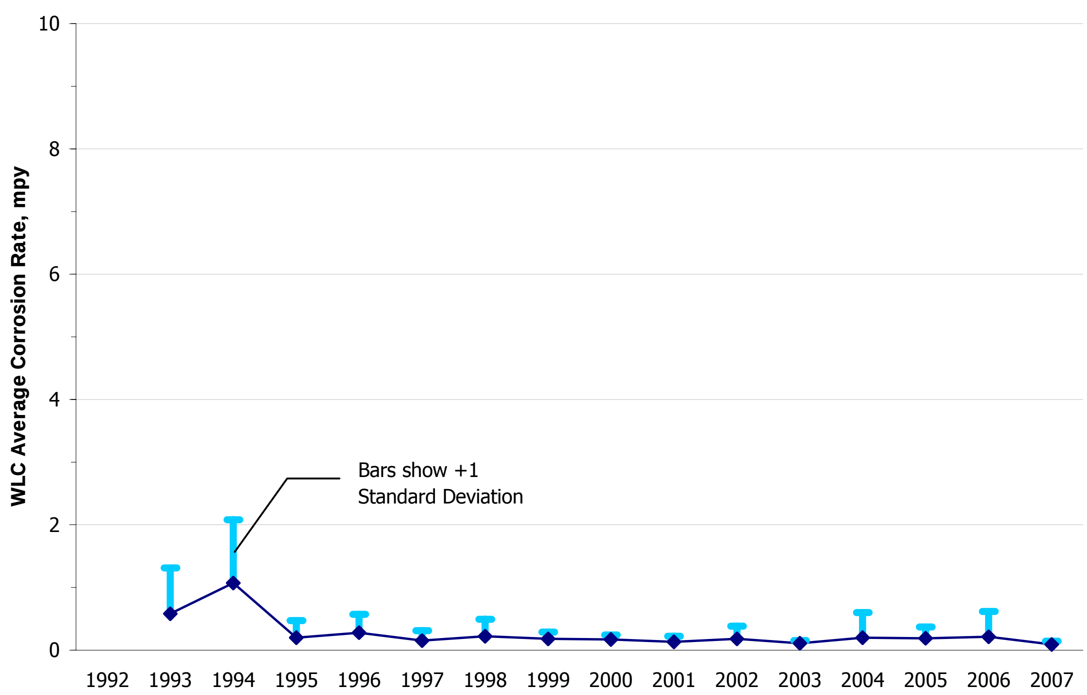
This comparative summary illustrates the successes of the program today in comparison to the ~15-year corrosion history. GPB Table A.5 presents historical WLC corrosion rate data for the major GPB services since 1992. Pitting rate data for the same services and time period is shown in GPB Table A.6.



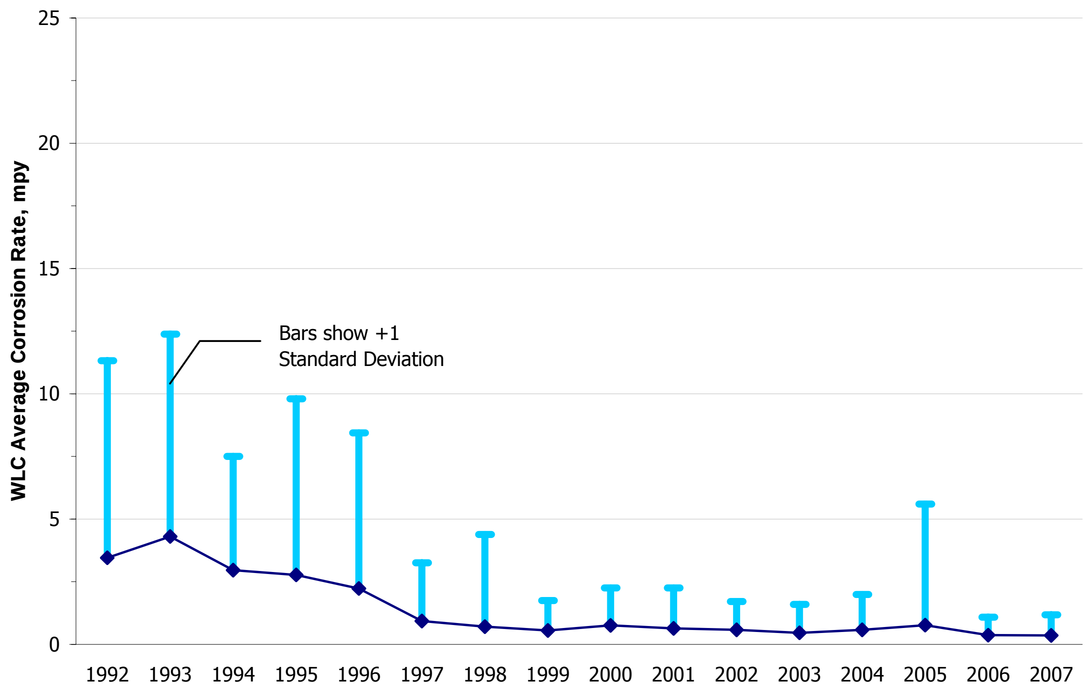
GPB Figure A.14 WLC Corrosion Rate and Standard Deviation for 3 Phase Oil Flow Lines.



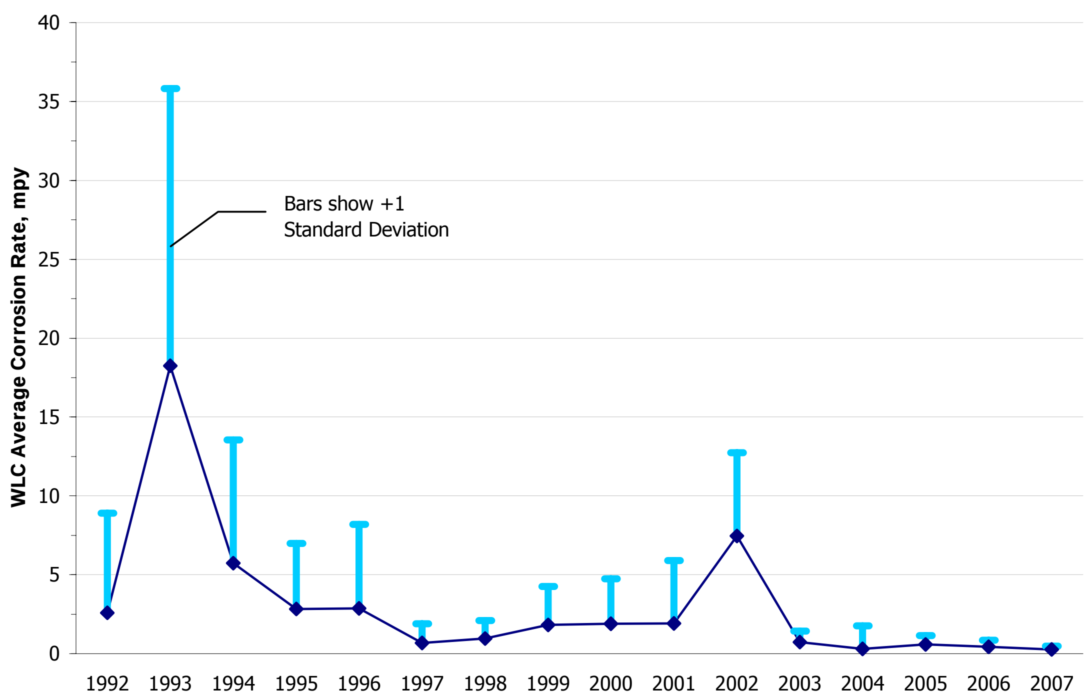
GPB Figure A.15 WLC Corrosion Rate and Standard Deviation for PW/SW Flow Lines.



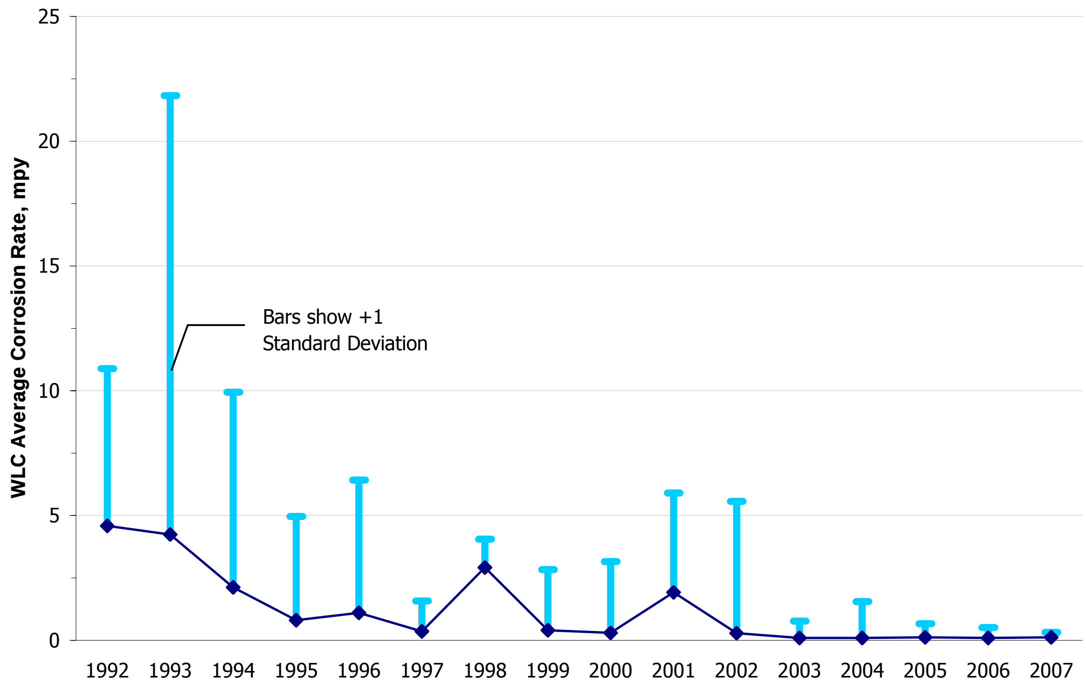
GPB Figure A.16 WLC Corrosion Rate and Standard Deviation, for Processed Oil Flow Lines.



GPB Figure A.17 WLC Corrosion Rate and Standard Deviation, for 3 Phase Oil Well Lines.



GPB Figure A.18 WLC Corrosion Rate and Standard Deviation, for 100% SW Well Lines.



GPB Figure A.19 WLC Corrosion Rate and Standard Deviation, for 100 % PW Well lines.

BU	Equip	Service	Metric	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
GPB	FL	OIL	WLC	767	933	962	1,402	1,521	1,567	1,459	1,483	1,415	1,262	1,312	1,316	1,238	1,289	1,119	1,154
GPB	FL	OIL	Ave CR	3.34	3.15	1.84	1.18	0.86	0.48	0.49	0.32	0.42	0.34	0.33	0.42	0.36	0.33	0.20	0.20
GPB	FL	OIL	SD CR	8.87	10.66	5.16	5.40	3.98	1.84	3.80	0.57	0.85	0.92	0.68	2.40	0.98	0.51	0.26	0.48
GPB	FL	OIL	WLC < 2	591	715	832	1,275	1,437	1,522	1,430	1,469	1,375	1,241	1,299	1,310	1,218	1,270	1,113	1,143
GPB	FL	OIL	% WLC < 2mpy	77%	77%	86%	91%	94%	97%	98%	99%	97%	98%	99%	100%	98%	99%	99%	99%
GPB	FL	PW/SW	WLC	81	106	154	198	184	195	171	181	160	131	137	144	119	117	122	107
GPB	FL	PW/SW	Ave CR	3.45	6.58	7.40	3.18	2.73	0.87	1.44	1.41	1.60	1.86	3.11	1.39	0.95	0.78	1.12	0.91
GPB	FL	PW/SW	SD CR	4.43	9.13	15.37	9.52	6.15	1.77	3.72	2.42	2.78	2.54	5.39	2.52	1.43	1.01	2.44	2.48
GPB	FL	PW/SW	WLC < 2	43	42	86	162	140	168	139	147	124	89	90	113	104	102	106	97
GPB	FL	PW/SW	%<2mpy	53%	40%	56%	82%	76%	86%	81%	81%	78%	68%	66%	78%	87%	87%	87%	91%
GPB	FL	PO	WLC		17	35	33	47	60	44	48	50	36	40	46	42	54	43	34
GPB	FL	PO	Ave CR		0.58	1.07	0.20	0.28	0.15	0.22	0.18	0.17	0.13	0.18	0.11	0.20	0.19	0.21	0.09
GPB	FL	PO	SD CR		0.73	1.01	0.27	0.29	0.16	0.27	0.11	0.07	0.09	0.20	0.04	0.40	0.18	0.41	0.05
GPB	FL	PO	WLC < 2		16	31	33	47	60	44	48	50	36	40	46	42	54	42	34
GPB	FL	PO	% WLC < 2mpy		94%	89%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	98%	100%
GPB	WL	OIL	WLC	6,696	5,564	4,915	5,188	6,523	6,735	6,382	6,185	6,243	4,846	5,261	5,570	5,225	5,413	5,359	5,054
GPB	WL	OIL	Ave CR	3.45	4.31	2.96	2.77	2.23	0.93	0.71	0.55	0.75	0.64	0.58	0.46	0.58	0.77	0.37	0.35
GPB	WL	OIL	SD CR	7.87	8.07	4.54	7.03	6.21	2.33	3.68	1.20	1.50	1.61	1.13	1.13	1.41	4.83	0.72	0.83
GPB	WL	OIL	WLC < 2	4,445	2,994	2,807	3,681	4,972	5,981	6,002	5,944	5,757	4,520	4,923	5,353	4,910	5,008	5,203	4,940
GPB	WL	OIL	% WLC < 2mpy	66%	54%	57%	71%	76%	89%	94%	96%	92%	93%	94%	96%	94%	93%	97%	98%
GPB	WL	Majority PW	WLC	531	514	662	829	976	1,073	964	740	699	659	464	426	458	434	408	292
GPB	WL	Majority PW	Ave CR	5.82	3.46	1.91	0.80	0.86	0.35	2.44	0.47	0.27	1.43	0.29	0.09	0.13	0.12	0.11	0.13
GPB	WL	Majority PW	SD CR	12.84	4.81	1.92	1.19	8.68	2.26	12.06	1.64	0.43	8.55	0.88	0.13	0.31	0.14	0.11	0.17
GPB	WL	Majority PW	WLC < 2	345	307	467	760	947	1,047	884	716	690	598	449	426	453	434	408	292
GPB	WL	Majority PW	% WLC < 2mpy	65%	60%	71%	92%	97%	98%	92%	97%	99%	91%	97%	100%	99%	100%	100%	100%
GPB	WL	100% PW	WLC	282	304	286	485	604	717	719	524	459	473	330	354	370	378	368	276
GPB	WL	100% PW	Ave CR	4.58	4.24	2.12	0.81	1.10	0.35	2.91	0.40	0.30	1.92	0.29	0.09	0.09	0.12	0.10	0.12
GPB	WL	100% PW	SD CR	9.25	5.34	2.05	1.19	10.98	2.62	13.66	1.50	0.51	10.05	0.97	0.13	0.08	0.14	0.11	0.17
GPB	WL	100% PW	WLC < 2	190	158	192	447	589	703	656	512	450	416	321	354	370	378	368	276
GPB	WL	100% PW	% WLC < 2mpy	67%	52%	67%	92%	98%	98%	91%	98%	98%	88%	97%	100%	100%	100%	100%	100%
GPB	WL	Majority SW	WLC	434	410	382	315	162	56	44	82	98	44	25	19	36	94	123	116
GPB	WL	Majority SW	Ave CR	1.97	13.02	6.55	2.64	3.25	0.65	0.96	1.82	1.78	6.01	6.58	0.74	1.45	0.56	0.44	0.26
GPB	WL	Majority SW	SD CR	5.48	16.14	7.56	3.87	5.26	1.20	1.14	2.36	2.77	6.88	5.27	0.68	2.65	0.54	0.42	0.20
GPB	WL	Majority SW	WLC < 2	382	103	133	201	110	53	38	61	78	16	7	18	29	89	122	116
GPB	WL	Majority SW	% WLC < 2mpy	88%	25%	35%	64%	68%	95%	86%	74%	80%	36%	28%	95%	81%	95%	99%	100%
GPB	WL	100% SW	WLC	184	194	174	187	78	52	44	70	86	16	21	19	12	88	115	106
GPB	WL	100% SW	Ave CR	2.59	18.24	5.74	2.82	2.86	0.68	0.96	1.82	1.89	1.92	7.46	0.74	0.30	0.59	0.43	0.26
GPB	WL	100% SW	SD CR	7.13	19.04	8.07	4.45	5.39	1.24	1.14	2.50	2.93	1.07	5.28	0.68	0.27	0.55	0.41	0.20
GPB	WL	100% SW	WLC < 2	160	38	79	128	54	49	38	52	68	12	5	18	12	83	114	106
GPB	WL	100% SW	% WLC < 2mpy	87%	20%	45%	68%	69%	94%	86%	74%	79%	75%	24%	95%	100%	94%	99%	100%

GPB Table A.5 Flow and Well Line General Corrosion Rate Data Summary

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BU	Equip	Service	Metric	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
GPB	FL	OIL	WLC	767	933	962	1,402	1,521	1,567	1,459	1,483	1,415	1,262	1,312	1,316	1,238	1,289	1,119	1,154
GPB	FL	OIL	Ave P CR	6.78	5.71	4.15	8.96	7.71	6.71	2.93	1.68	1.92	1.29	0.75	0.65	1.24	0.41	0.04	0.07
GPB	FL	OIL	SD P CR	21.14	15.60	13.50	22.93	14.99	13.69	6.71	6.23	7.79	10.71	3.97	8.34	5.91	2.58	0.74	0.95
GPB	FL	OIL	P WLC < 20	678	851	912	1,284	1,427	1,514	1,433	1,460	1,382	1,247	1,291	1,314	1,223	1,285	1,119	1,154
GPB	FL	OIL	% P WLC <20mpy	88%	91%	95%	92%	94%	97%	98%	98%	98%	99%	98%	100%	99%	100%	100%	100%
GPB	FL	PW/SW	WLC	81	106	154	198	184	195	171	181	160	131	137	144	119	117	122	107
GPB	FL	PW/SW	Ave P CR	8.53	15.83	17.28	17.03	14.40	15.26	11.36	5.31	6.36	9.37	13.12	7.07	3.04	2.57	4.54	1.54
GPB	FL	PW/SW	SD P CR	8.49	5.40	8.61	6.60	5.40	4.10	3.01	2.53	2.33	0.91	0.01	0.01	0.00	0.00	0.00	0.00
GPB	FL	PW/SW	P WLC < 20	66	83	111	150	147	172	156	168	153	112	106	125	119	114	112	103
GPB	FL	PW/SW	% P WLC <20mpy	81%	78%	72%	76%	80%	88%	91%	93%	96%	85%	77%	87%	100%	97%	92%	96%
GPB	FL	PO	WLC		17	35	33	47	60	44	48	50	36	40	46	42	54	43	34
GPB	FL	PO	Ave P CR		1	2	6	4	5	3	1	1	1	1	0	1	0	1	0
GPB	FL	PO	SD P CR		1	4	12	5	5	6	2	4	3	3	2	3	2	3	0
GPB	FL	PO	P WLC < 20		17	35	31	47	60	43	48	50	36	38	46	42	54	43	34
GPB	FL	PO	% P WLC <20mpy		100%	100%	94%	100%	100%	98%	100%	100%	100%	95%	100%	100%	100%	100%	100%
GPB	WL	OIL	WLC	6,696	5,564	4,915	5,188	6,523	6,735	6,382	6,185	6,243	4,846	5,261	5,570	5,225	5,413	5,359	5,054
GPB	WL	OIL	Ave P CR	7.32	9.36	5.22	11.66	11.89	5.25	3.14	2.78	3.30	1.96	1.72	1.66	1.95	1.69	0.53	0.49
GPB	WL	OIL	SD P CR	22.59	24.27	14.36	32.60	29.36	14.72	9.06	7.83	10.14	6.43	5.63	5.33	5.78	5.73	2.64	4.09
GPB	WL	OIL	P WLC < 20	5,778	4,914	4,581	4,531	5,644	6,461	6,228	6,061	6,056	4,743	5,186	5,520	5,130	5,319	5,346	5,045
GPB	WL	OIL	% P WLC <20mpy	86%	88%	93%	87%	87%	96%	98%	98%	97%	98%	99%	99%	98%	98%	100%	100%
GPB	WL	Majority PW	WLC	531	514	662	829	976	1,073	964	740	699	659	464	426	458	434	408	292
GPB	WL	Majority PW	Ave P CR	34.12	24.67	15.84	20.18	15.02	9.65	20.69	8.87	4.65	6.69	2.95	1.03	1.88	1.25	1.21	1.36
GPB	WL	Majority PW	SD P CR	41.07	31.95	27.13	29.05	29.64	28.96	58.60	26.07	9.75	17.52	8.97	2.93	7.70	3.87	4.18	4.28
GPB	WL	Majority PW	P WLC < 20	258	294	499	574	802	968	805	674	670	579	452	425	455	432	402	288
GPB	WL	Majority PW	% P WLC <20mpy	49%	57%	75%	69%	82%	90%	84%	91%	96%	88%	97%	100%	99%	100%	99%	99%
GPB	WL	100% PW	WLC	282	304	286	485	604	717	719	524	459	473	330	354	370	378	368	276
GPB	WL	100% PW	Ave P CR	4.58	4.24	2.12	0.81	1.10	0.35	2.91	0.40	0.30	1.92	0.29	0.09	0.09	0.12	0.10	0.12
GPB	WL	100% PW	SD P CR	9.25	5.34	2.05	1.19	10.98	2.62	13.66	1.50	0.51	10.05	0.97	0.13	0.08	0.14	0.11	0.17
GPB	WL	100% PW	P WLC < 20	190	158	192	447	589	703	656	512	450	416	321	354	370	378	368	276
GPB	WL	100% PW	% WLC < 2mpy	67%	52%	67%	92%	98%	98%	91%	98%	98%	88%	97%	100%	100%	100%	100%	100%
GPB	WL	Majority SW	WLC	434	410	382	315	162	56	44	82	98	44	25	19	36	94	123	116
GPB	WL	Majority SW	Ave P CR	4.74	17.32	9.50	11.43	16.88	1.50	1.55	5.62	6.61	18.80	29.33	9.11	12.86	2.11	2.94	0.72
GPB	WL	Majority SW	SD P CR	15.65	44.26	14.23	15.45	23.11	4.52	2.31	8.16	10.40	18.59	27.35	20.21	30.17	4.03	8.56	2.58
GPB	WL	Majority SW	P WLC < 20	404	320	329	261	115	55	44	80	92	24	15	16	32	94	119	116
GPB	WL	Majority SW	% P WLC < 20mpy	93%	78%	86%	83%	71%	98%	100%	98%	94%	55%	60%	84%	89%	100%	97%	100%
GPB	WL	100% SW	WLC	184	194	174	187	78	52	44	70	86	16	21	19	12	88	115	106
GPB	WL	100% SW	Ave P CR	5.19	13.31	7.88	9.19	10.10	0.54	1.55	5.24	5.57	9.13	31.62	9.11	9.17	2.01	2.11	0.51
GPB	WL	100% SW	SD P CR	18.94	18.79	12.18	13.45	19.87	2.18	2.31	8.49	6.38	7.30	29.49	20.21	21.36	4.03	6.29	2.17
GPB	WL	100% SW	P WLC < 20	172	157	154	160	62	52	44	68	82	14	12	16	10	88	113	106
GPB	WL	100% SW	% P WLC < 20mpy	93%	81%	89%	86%	79%	100%	100%	97%	95%	88%	57%	84%	83%	100%	98%	100%

GPB Table A.6 Flow and Well Line Pitting Rate Data Summary

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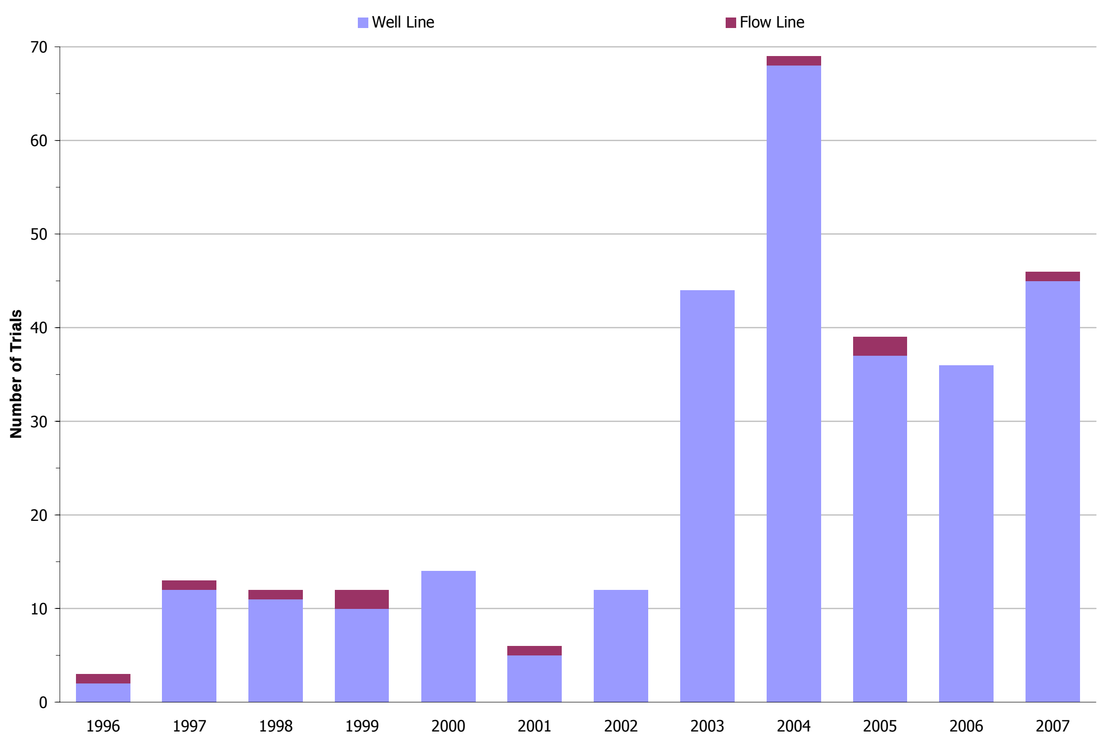
Section A.2 Corrosion Inhibition

Corrosion inhibition is an on-going process that encompasses a broad range of activities, from developing new corrosion inhibitors for improved performance, to the allocation of extra chemical for additional corrosion control. The following sections provide an update on chemical development, field wide chemical deployment, chemical usage and finally corrosion control.

Section A.2.1 3-Phase Corrosion Inhibitor Testing

GPB Figure A.20 summarizes the number of well line and flow line tests which have been completed since 1996. The level of well line test activity increased beginning in 2003 due to a change in the screening protocol, which reduced the time required per test. The combined number of well line and flow line tests has increased from ~10-14 per year[8] to more than 45 during 2007. This level of activity represents a substantial investment of resources towards the development of new and more effective corrosion inhibitors.



GPB Figure A.20 Number of Well Line and Flow line Tests

Section A.2.2 3-Phase Corrosion Inhibitor Deployment

The chemical development and testing program has been highly successful with 16 new products being developed for use in the continuous wellhead inhibition program since

[8] The data prior to 2000 are incomplete and represents the test work completed on the heritage WOA only.

1995. All these changes represent a significant improvement in overall corrosion control performance.

GPB Table A.7 summarizes the changes in corrosion inhibitor products since 1995. The table does not include test products which did not make it to field wide usage. In addition, the summary table does not include summer versions of products that differ only in pour point from the winter version shown in the table.

Supplier	Chemical	95	96	97	98	99	00	01	02	03	04	05	06	07
Nalco Exxon	EC1110A	■	■											
Nalco Exxon	EC1259			■	■									
Nalco Exxon	97VD129				■	■	■							
Nalco Exxon	98VD118				■	■	■	■						
ONDEO Nalco	99VD049					■	■	■						
ONDEO Nalco	01VD017							■						
ONDEO Nalco	01VD121							■	■	■	■		■	■
Nalco	DVE4D002											■		
Champion	RU205	■												
Champion	RU210	■	■	■										
Champion	RU223	■	■	■	■									
Champion	RU258			■										
Champion	RU271				■	■	■							
Champion	RU126A						■							
Champion	RU256[1]			■	■	■	■	■	■	■	■			
Champion	Cortron 2004-15[1]										■	■	■	■

[1] Used for the batch treatment of well lines while the remaining chemicals are all used for continuous application

GPB Table A.7 Summary of the Chemical Deployment History

Section A.2.3 3-Phase Corrosion Inhibitor Usage and Concentration

Another measure of chemical optimization is the amount of corrosion inhibitor used relative to the volume of water produced from the reservoir. GPB Table A.8 summarizes the annual water production, corrosion inhibitor volumes, and concentrations since 1995. The inhibitor volumes are expressed as a 'winter product equivalent', i.e. the lower volumes of highly concentrated chemical used during the summer have been normalized to the winter equivalent.

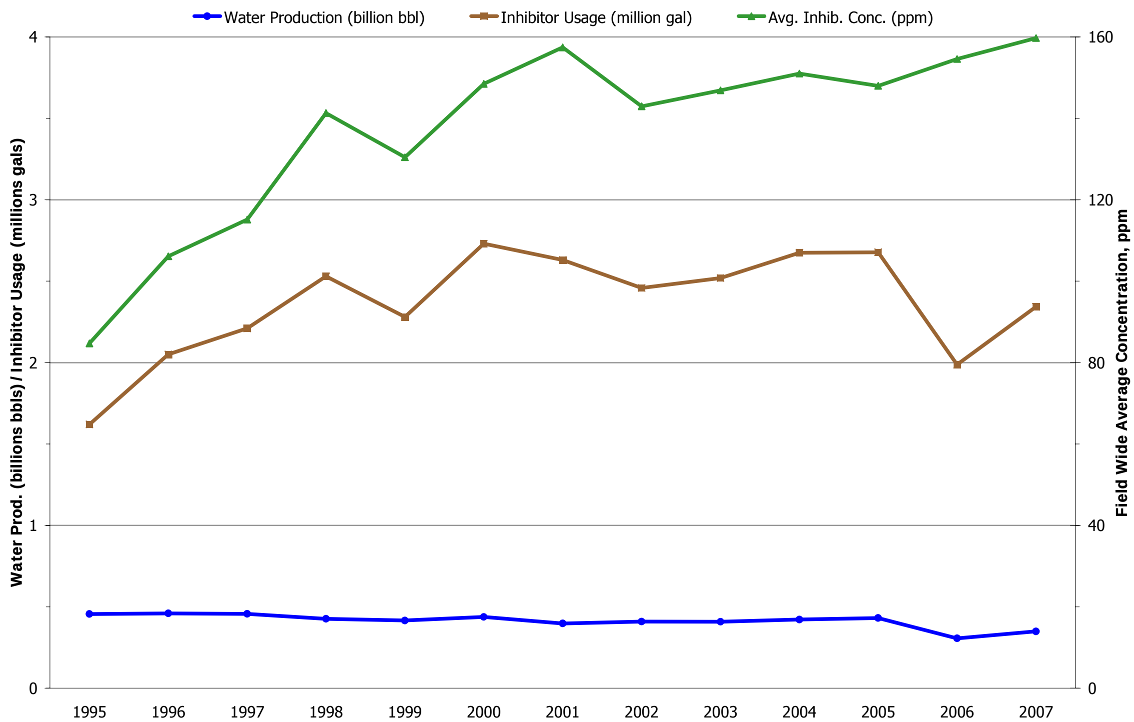
The concentration of inhibitor in the water phase provides a relative measure of the effectiveness of the chemical used to control corrosion. However, such data can be misleading as the types of corrosion inhibitors used can vary from year to year (GPB Table A.7). As more effective chemicals are developed, 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
2006	306	74	1.99	155
2007	349	76	2.34	160

GPB Table A.8 Summary of the Chemical Usage History

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 A.21 shows, the volume of corrosion inhibitor has increased since 1995 while the water volumes have remained relatively constant.

The metrics in GPB Figure A.21 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 2007 the target chemical usage was 2.31 million gallons as compared to actual usage of 2.34 million gallons; or just over 100% of the target volume.



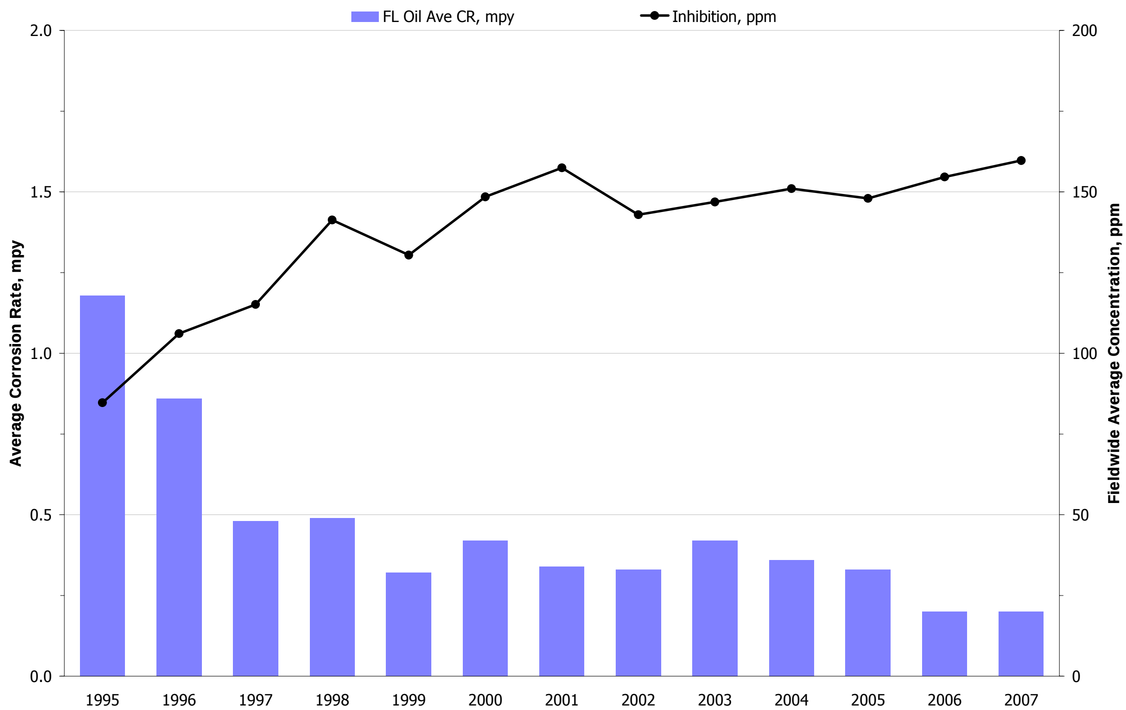
GPB Figure A.21 Field Wide Chemical Usage

Section A.2.4 3-Phase Corrosion Inhibition and Corrosion Rate Correlation

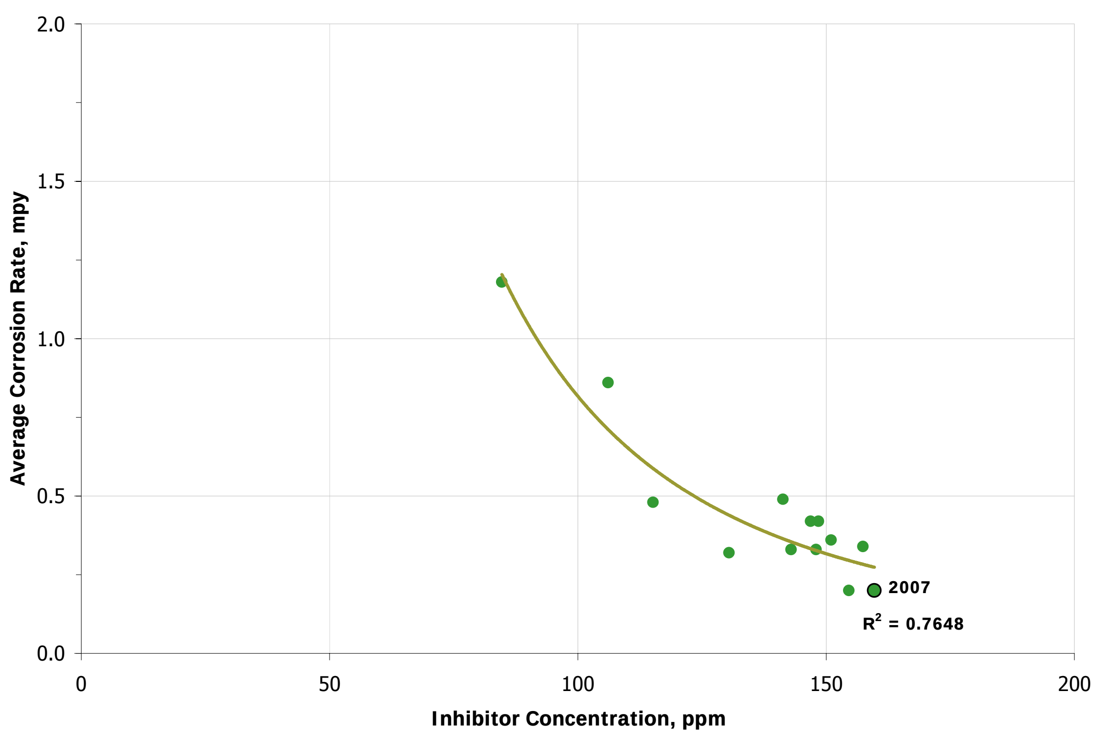
As discussed in Section A.1.1, the reduction in corrosion rates in the 3-phase production system flow lines and well lines are largely attributable to the implementation of an aggressive corrosion inhibition program across GPB.

GPB Figure A.22 shows the correlation between the increased level of corrosion inhibitor and the reduction in average WLC corrosion rate from 1995. As might be expected, the decline in average WLC corrosion rate correlates with the increase in corrosion inhibition levels over time. The figure also shows how additional corrosion inhibitor has reduced the average WLC corrosion rate through time.

GPB Figure A.23 shows the annual field-wide average corrosion inhibitor concentrations versus annual average WLC corrosion rates for 3-phase production flow lines. The figure shows how additional corrosion inhibitor has reduced the average WLC corrosion rate through time, but also shows a potential limitation of corrosion inhibition as the minimum corrosion rate (or maximum corrosion inhibitor efficiency) is approaching an asymptote of ~0.25 mpy.



GPB Figure A.22 WLC Average Corrosion Rate versus Inhibitor Concentration



GPB Figure A.23 Corrosion Inhibitor Concentration vs. Average Corrosion Rate

Section A.2.5 Produced Water Inhibitor

Significant upgrades to the produced water chemical injection systems were completed in 2007. These upgrades allowed supplemental injection of corrosion inhibitor at all the processing facilities with the exception of LPC. The chemical type and concentration should aid corrosion mitigation of the produced water system by helping to remove deposits and controlling MIC. Usage rates through 2007 averaged ~3,300 gallons per day for a total of 1.25 million gallons for the year.

Section A.2.6 Produced Oil Inhibitor

Supplemental injection of corrosion inhibitor was initiated in 3Q06 at the five major facilities that produce processed crude into the GPB oil transit pipeline system. The rate on injection is based on total fluid production since significant water volumes are not typically present. The supplemental chemical injection continued through 2007. Usage rates through 2007 averaged 130 gallons per day for a total of ~47,000 gallons year.

Section A.2.7 Corrosion Inhibition Summary

In summary, corrosion inhibition 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. This activity is ultimately directed toward one end which is the reduction in corrosion rate. The effectiveness of the chemical optimization program in delivering improved corrosion rates is demonstrated in the monitoring and inspection results.

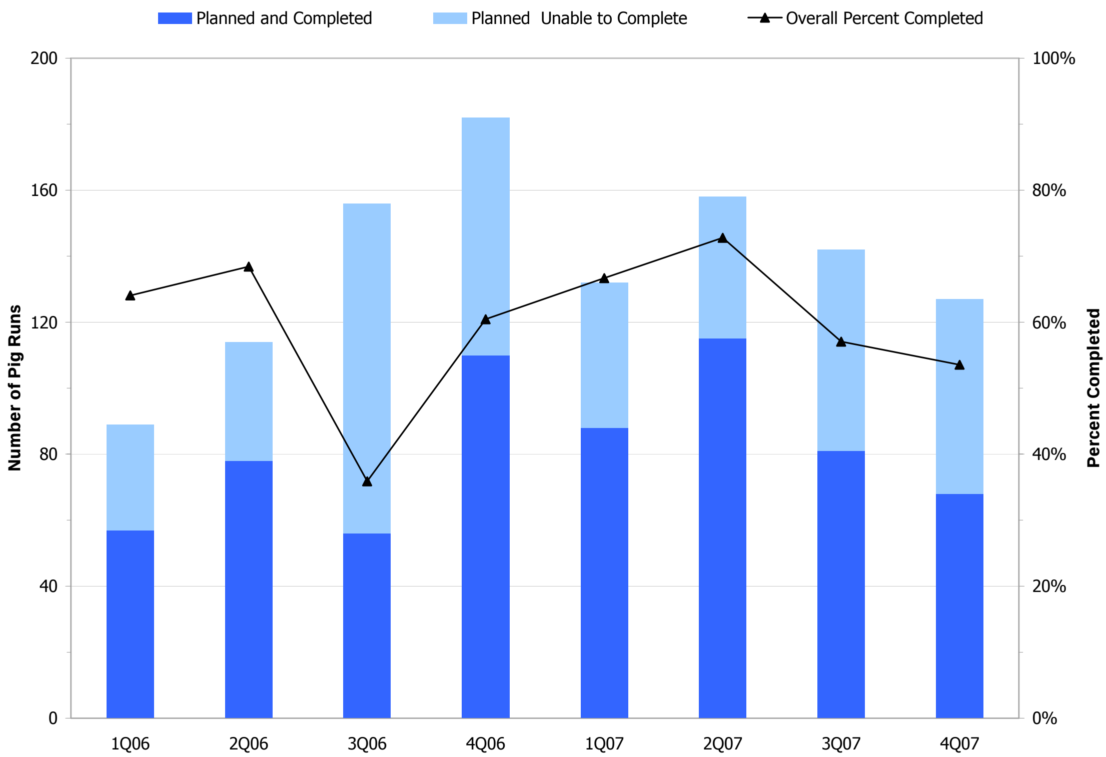
Section A.3 Maintenance Pigging

Maintenance (or cleaning) pigging is another form of internal corrosion mitigation and management. A maintenance pig is a device inserted at the upstream end of a pipeline that is then pushed downstream by pressure and flow in the system. The pig is then removed at the downstream end of the line. Maintenance pigs are manufactured in a wide range of designs and materials, based on their intended purpose, e.g. sealing, scraping, brushing, etc.

The operational characteristics of some lines may be such that continuous injection of corrosion inhibitor is not the sole approach to controlling corrosion. Maintenance pigging can be used to augment the corrosion management of these pipelines by improving contact between the chemical treatment and the pipe surface, and promoting better chemical distribution over the length and circumference of the pipe. Maintenance pigs are also used to remove solids (e.g. biomass, sand, scale) and water from the pipe and reduce the likelihood of under-deposit corrosion.

While the use of maintenance pigging can be an important tool for managing internal corrosion, there are practical issues that affect the maintenance pigging program. Limitations to wholesale application of pigging include the inability to launch or remove pigs, design restrictions in the pipe that prevent passage of the pig, and operating conditions where insufficient flow or pressure is available to move the pig.

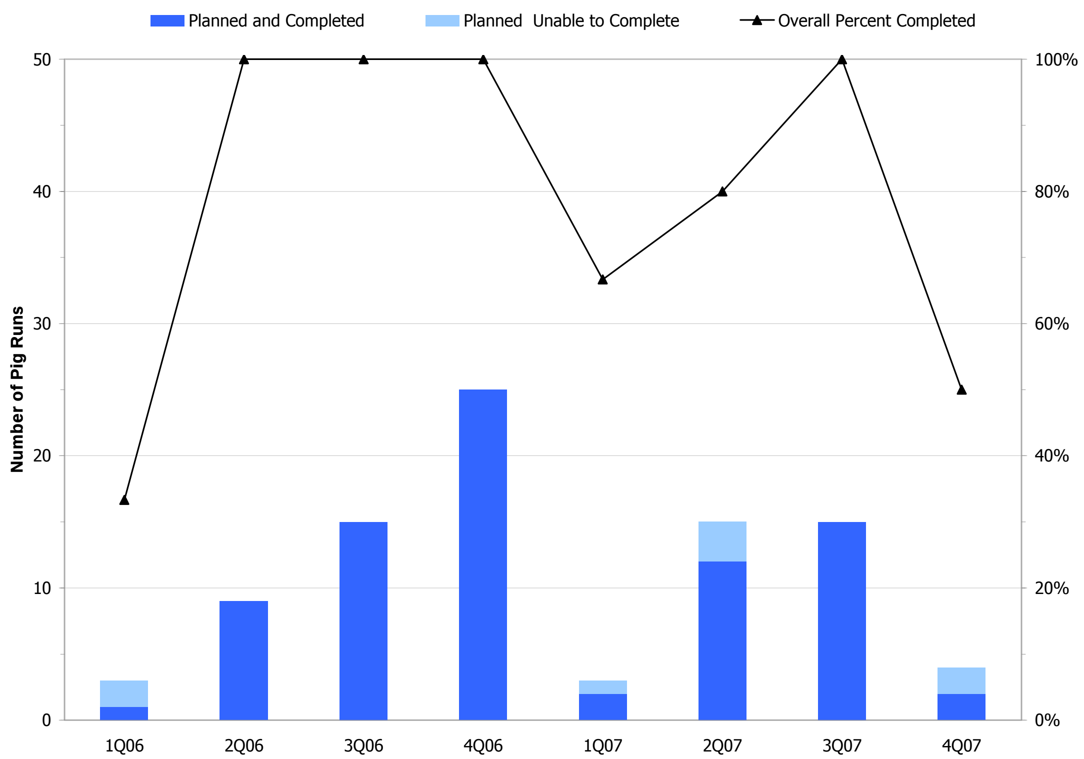
This is the first year in which maintenance pigging performance metrics have been included in this report. Data have been compiled from the 2006 and 2007 maintenance pigging programs at GPB, based on lines that are piggable. The metrics include the number of scheduled maintenance pig runs, the number of scheduled runs completed and the percent of scheduled runs completed, by year. GPB Figure A.24 shows the overall performance of the program for all scheduled pig runs in 2006 and 2007, for all service types. The average percent of scheduled pig runs completed was 56% in 2006 and 63% in 2007.



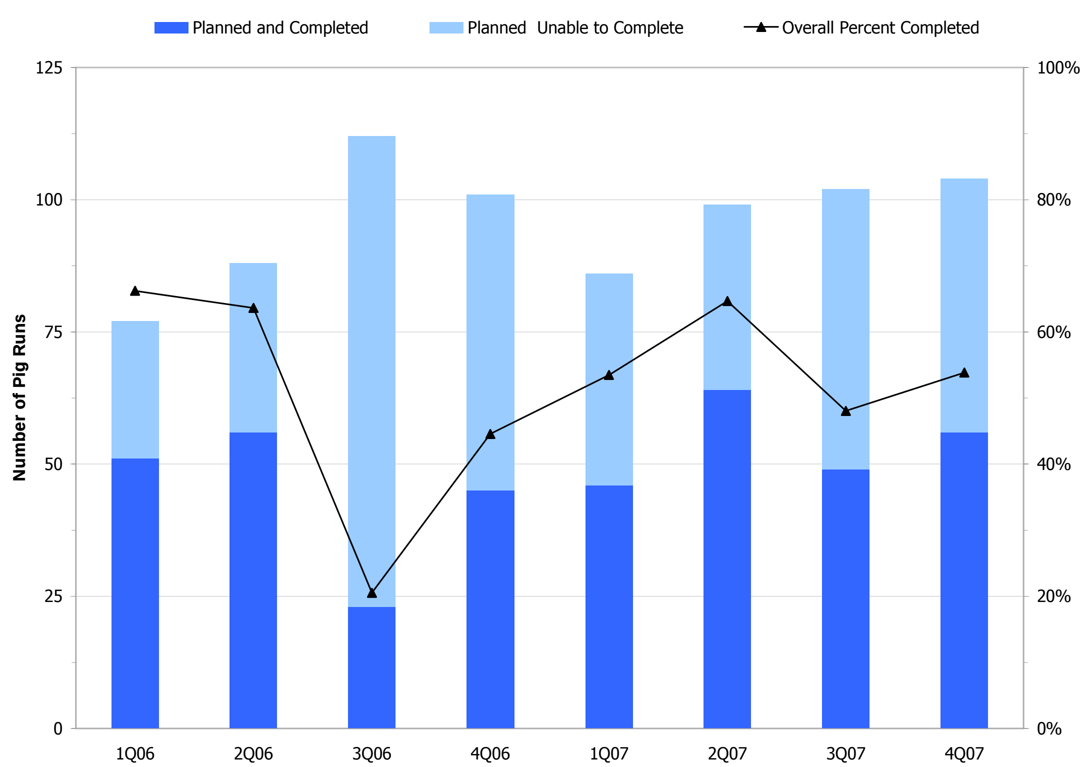
GPB Figure A.24 Maintenance Pig Runs Scheduled and Completed, All Service Types

Maintenance pigging schedules are established on an annual basis so that operations personnel can coordinate pigging activities with operations demands. Over the course of the year, a number of situations can arise associated with weather conditions, equipment outages, and operations can occur where it is not possible to complete or reschedule maintenance pig runs. The majority of uncompleted runs in 2006 and 2007 were due to launchers or receivers being out of service for repair and/or replacement.

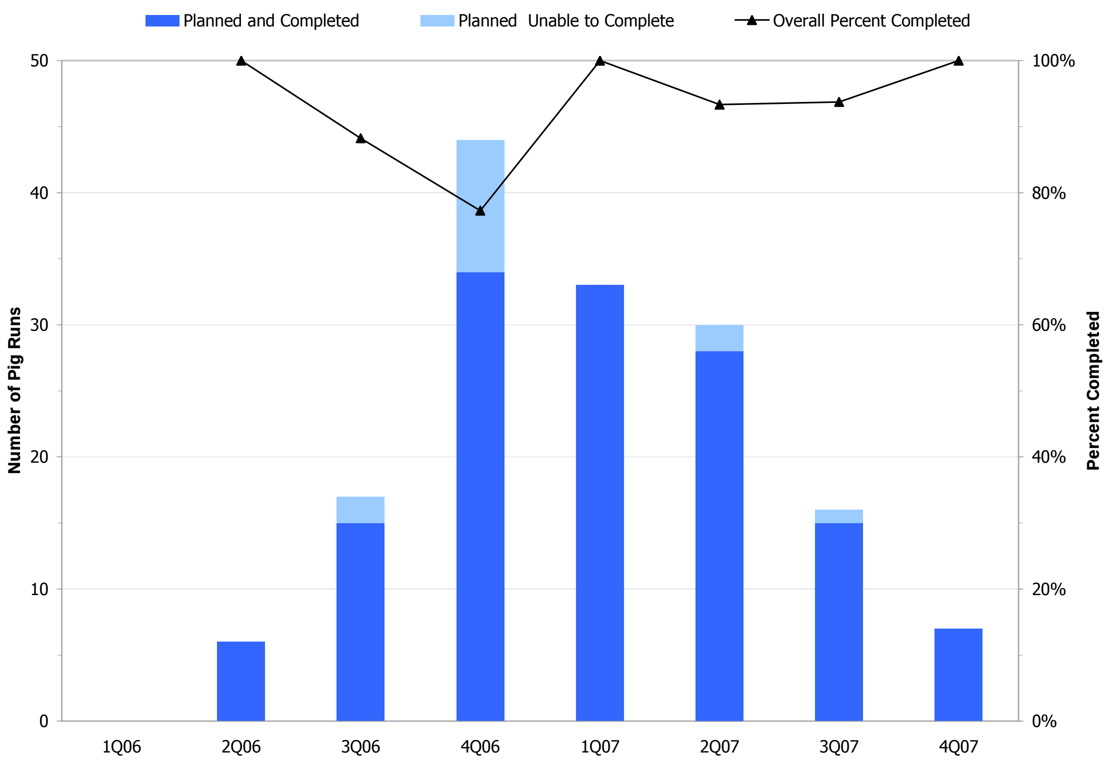
The following figures illustrate the maintenance pigging program metrics for the four major service types. GPB Figure A.25 presents the results of the maintenance pigging program for 3-phase oil lines. GPB Figure A.26 and GPB Figure A.27 present results for the produced water lines and processed oil lines. The maintenance pigging metrics for seawater service lines are shown in GPB Figure A.28. The pigging decline observed in some services in 3Q06 was the result of lines being shut-in for work on the processed oil lines. Maintenance pigging in the SW and PW systems in 3Q and 4Q of 2007 was challenged by equipment service outages, i.e. repairs being performed on pig launcher doors and barrels.



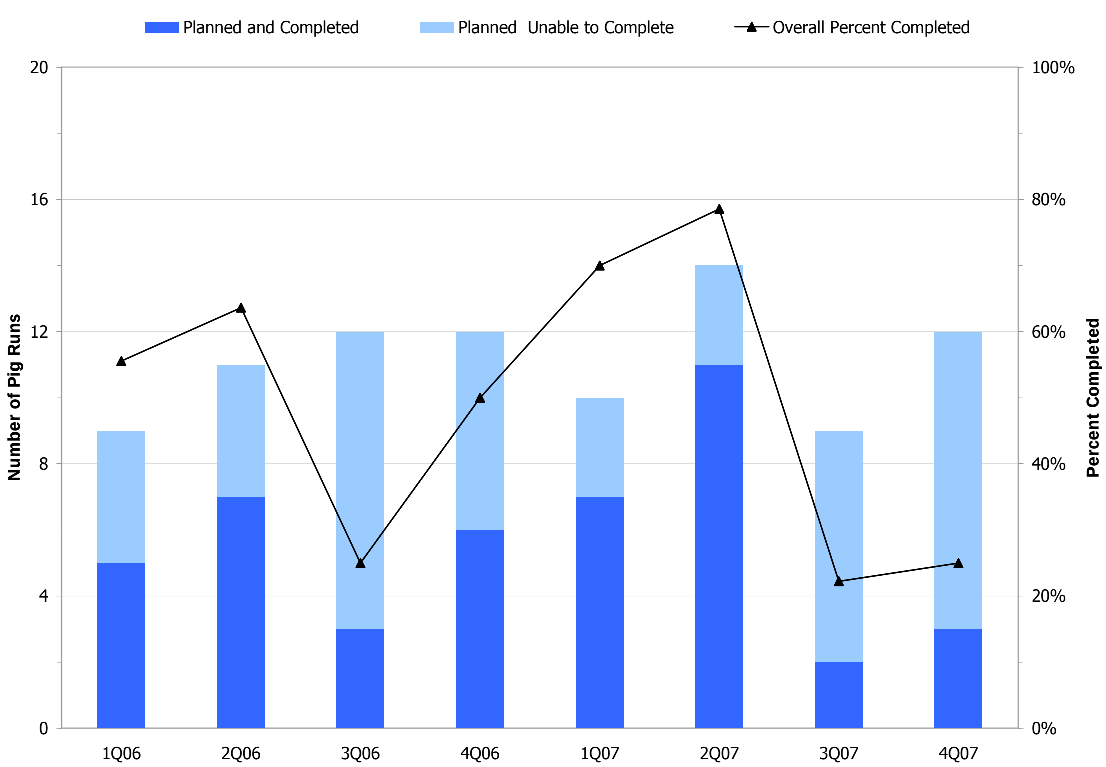
GPB Figure A.25 Maintenance Pig Runs Scheduled and Completed, 3 Phase Oil Service



GPB Figure A.26 Maintenance Pig Runs Scheduled and Completed, Produced Water Service



GPB Figure A.27 Maintenance Pig Runs Scheduled and Completed, Processed Oil Service



GPB Figure A.28 Maintenance Pig Runs Scheduled and Completed, Seawater Service

GPB Section B

External/Internal Inspection

Section B GPB 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. There are also specialized techniques for specific applications. The details for these techniques are shown in Appendix 3.3.3 and Appendix 3.3.4.

A number of factors contribute to the selection and allocation of inspection resources including, but not limited to, current equipment condition, current known corrosion 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 B.1 External Inspection

This section summarizes the inspections performed to detect external corrosion and the results of those inspections. GPB Table B.1 summarizes the CUI inspection program for the period 1995 to 2007 separated by service and equipment type and the aggregate data. These aggregate data include both baseline and repeat inspections

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 of insulated pipe susceptible to CUI based on the location and orientation. 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	60,731	4,803	8%	80,757	2,453	3%	141,488	7,256	5%
Processed Oil	7,079	407	6%	-	-	-	7,079	407	6%
Gas	75,150	4,766	6%	39,962	334	1%	115,112	5,100	4%
Other	72	3	4%	1,664	42	3%	1,736	45	3%
Water	30,063	2,197	7%	13,438	384	3%	43,501	2,581	6%
Total	**173,095**	**12,176**	**7%**	**135,821**	**3,213**	**2%**	**308,916**	**15,389**	**5%**

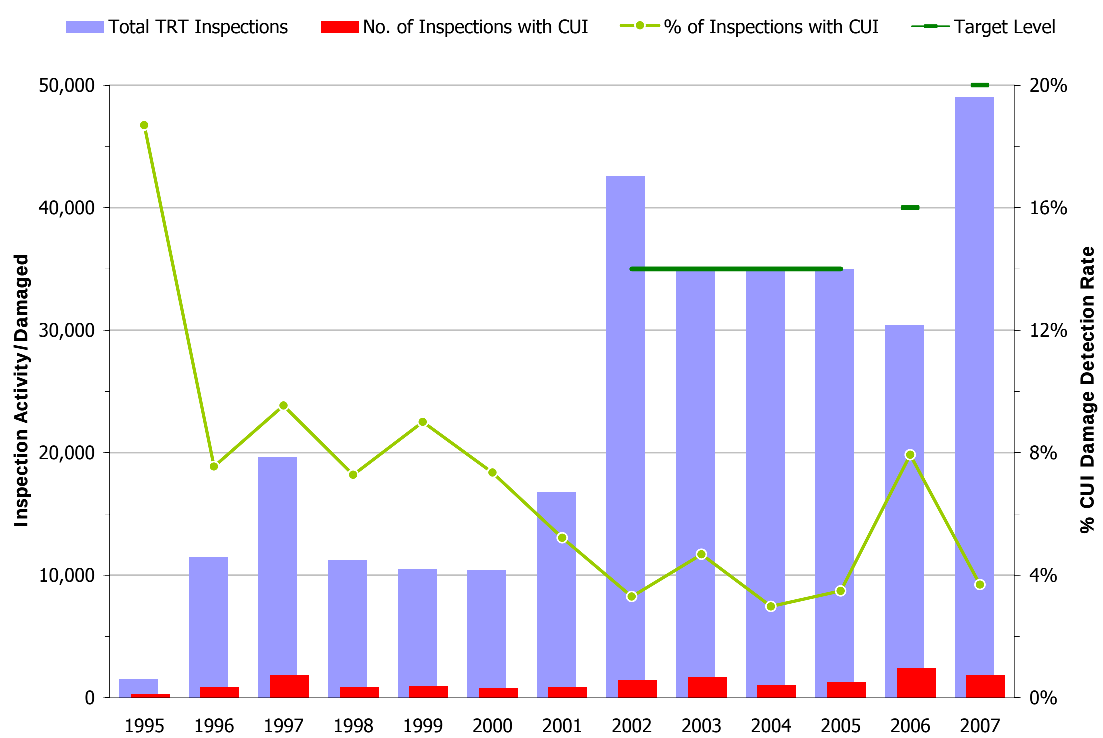
GPB Table B.1 CUI Inspections by Service Type, 1995-2007

Section B.1.1 External Inspection Program Results

GPB Table B.2 and GPB Figure B.1 show the number and results of the external corrosion inspections performed since 1995. 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	2006	2007
Well Line													
Activity Level	-	36	1,676	934	2,377	5,235	12,841	23,670	10,833	13,949	21,325	15,899	26,929
Corrosion Detected	-	6	232	65	80	246	722	357	140	370	440	567	455
% Corroded	-	17%	14%	7%	3%	5%	6%	2%	1%	3%	2%	4%	2%
Transit & Flow Line													
Activity Level	1,498	11,455	17,934	10,291	8,132	5,169	3,966	18,923	24,293	21,155	13,668	14,519	22,092
Corrosion Detected	280	861	1,638	752	866	519	156	1,049	1,505	677	781	1,845	1,354
% Corroded	19%	8%	9%	7%	11%	10%	4%	6%	6%	3%	6%	13%	6%
GPB Overall													
Activity Level	1,498	11,491	19,610	11,225	10,509	10,404	16,807	42,593	35,126	35,104	34,993	30,418	49,021
Corrosion Detected	280	867	1,870	817	946	765	878	1,406	1,645	1,047	1,221	2,412	1,809
% Corroded	19%	8%	10%	7%	9%	7%	5%	3%	5%	3%	3%	8%	4%

GPB Table B.2 External Corrosion Activity and Detection Summary



GPB Figure B.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 2007 the number of inspections planned was increased to 50,000 and the number completed was 49,021.

As compared to the inspection results from last year, there was a decrease in CUI damage detected, even though the number of inspections increased by almost 19,000.

Overall, the percentage of locations found with damage has fallen from an initial high of >15% to a recent field-wide average of 4%.

Section B.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.

The 2007 program consisted of repeat examinations/monitoring and excavation at 140 segments. GPB Table B.3 shows the inspection activity for cased pipe segments.

Service	Guided Wave	ILI	Excavation
Gas	14	-	6
3-Phase oil	17	81	1
Processed oil	3	12	-
PW/SW	5	-	1
Total	**39**	**93**	**8**

GPB Table B.3 Cased Pipe Survey Activity by Technique

There were 39 cased segments evaluated using guided wave. None of the casings tested had any increased metal loss features reported and 5 cased segments reported slight anomalies. Follow up activities will include monitoring of these casing with guided wave (magnetostrictive, MsS), validation with another type of long range guided wave technology (G3), evaluation for in-line inspection (ILI) and/or excavation.

Ninety-three (93) cased crossing were surveyed with ILI. Four crossings were reported with >40% wall loss with the severest reported at 49%. These are all internal in nature and have been identified in prior in-line inspections. The 2007 examinations have shown little or no change in corrosion peak depth since previous inspection.

The cased pipe survey program has identified 43 segments that are under evaluation for excavation and/or additional testing.

Section B.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 2007, eight cased segments were excavated and the subsequent inspections were used to verify monitoring results. There were three segments with external corrosion that was mitigated, four segments with no corrosion damage and one segment that was replaced as part of scheduled activity. None of the inspected segments showed internal corrosion.

Since 1992, there have been 79 cased pipeline segments at road and/or animal crossings excavated in GPB. Three of these excavations were as a result of loss of containment; two attributed to external corrosion and one attributed to internal corrosion. The remaining 76 excavations were verification of inspection results. GPB Table B.9, at the end of this section, shows 53 locations were found with external corrosion damage, 6 locations were found with internal corrosion damage, one location was found with coincidental internal and external corrosion, one location was a scheduled upgrade and fifteen locations had no corrosion damage.

In summary, the strategy and execution of the cased pipe assessment (survey and excavation) will continue to develop as the program is refined and more information and/or experience with emerging long-range inspection technologies are gained. Effort to increase cased pipe program activity and/or improve technology is recognized as an area for continuous improvement.

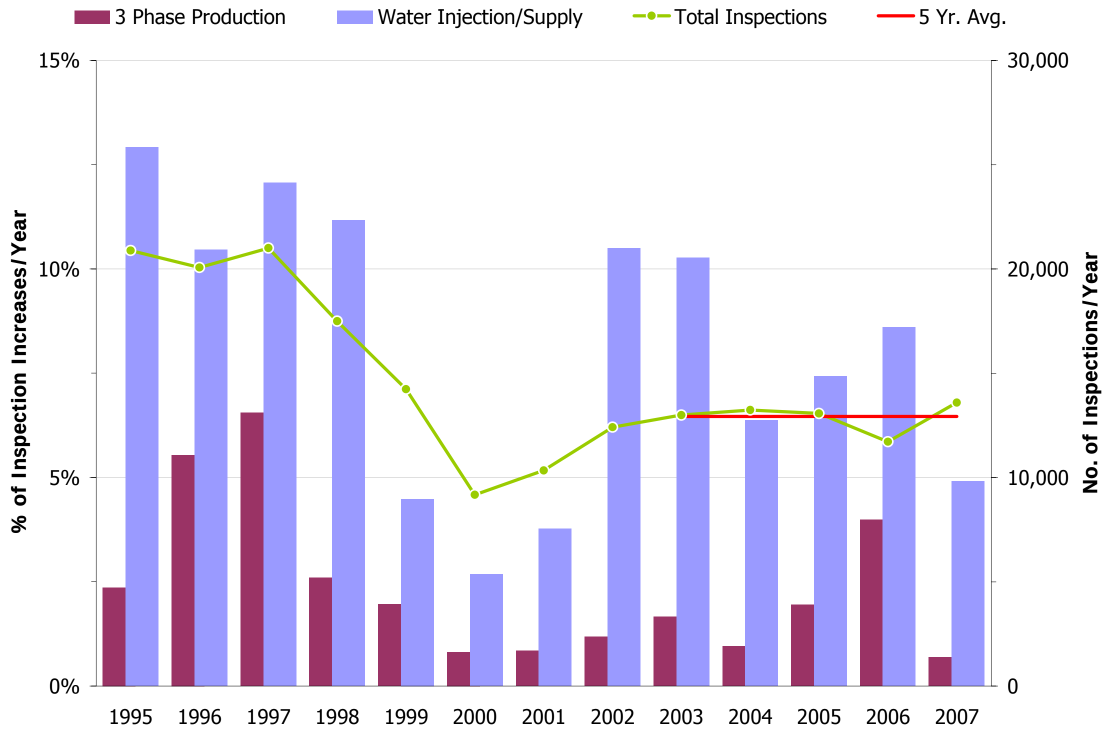
Section B.2 Internal Inspection Program Results

The results presented in this section are aggregate data obtained from flow line, oil transit 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.

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

The percentage of reinspected locations showing increased corrosion (inspection increases) can be considered a high level indicator of active corrosion in a given system.

GPB Figure B.2 shows the percentage of inspection increases and the number of inspections per year for the flow lines segregated by 3-phase production and water injection (seawater and produced water) service. The number of flow line inspections increased by 14% over the number of inspections last year; higher than the five year average.



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

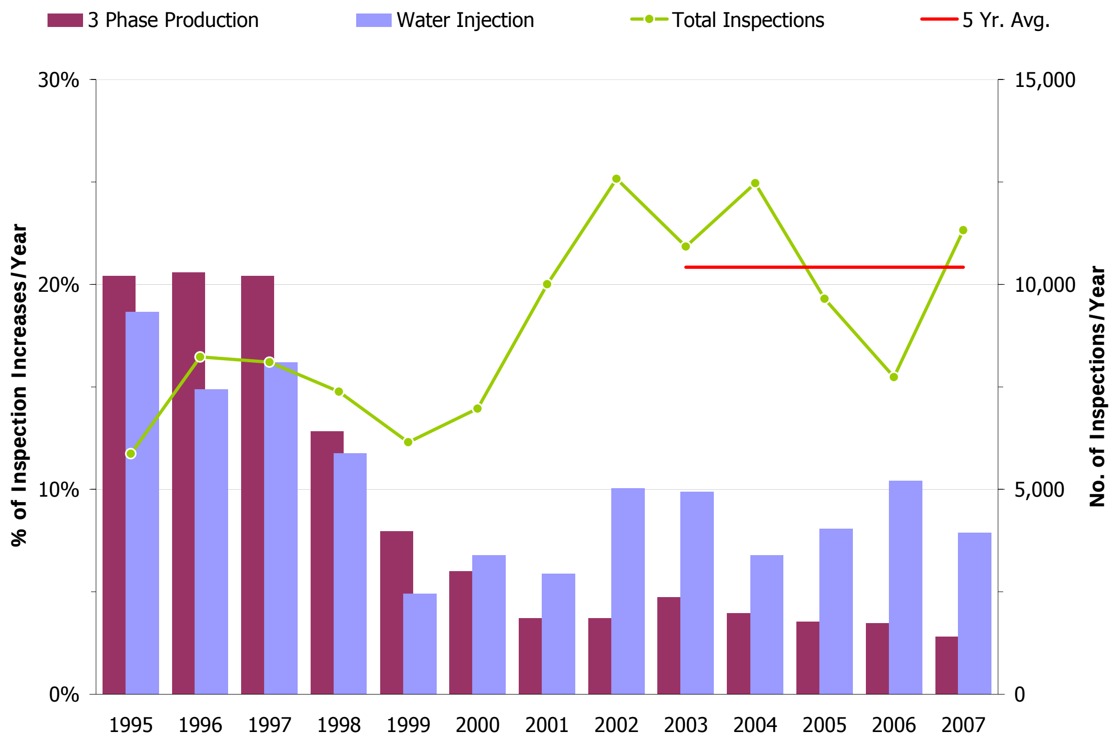
The percentage of inspection increases in the 3-phase flow lines declined considerably from 1997 to a historical low in 2000-2001. Since that time, there has been a generally increasing trend in locations showing active corrosion. In 2007 however, the number of inspection increases for both the 3-phase and water flow lines reached the lowest point since 2002, while the total number of inspections stayed nearly the same. These values demonstrate improvement of corrosion control in the flow lines.

For the water flow line, the inspection data show significant improvement in corrosion control where the percent inspection increases has declined for the first time in four years. While the data are encouraging, the water injection system continues to be an area for improvement.

GPB Figure B.3 shows the percent inspection increases trend and the number of inspections per year for the well lines. The total number of inspections achieved on the well lines is similar to the pre-2006 average.

For 3-phase well lines the percentage of inspection increases has shown a downward trend over the last five years.

For the water system, the trends for well lines are similar to flow lines; declining for the first time in four years. As with the flow lines, improvements in the chemical mitigation program are expected to continue, adding to the level of corrosion control.



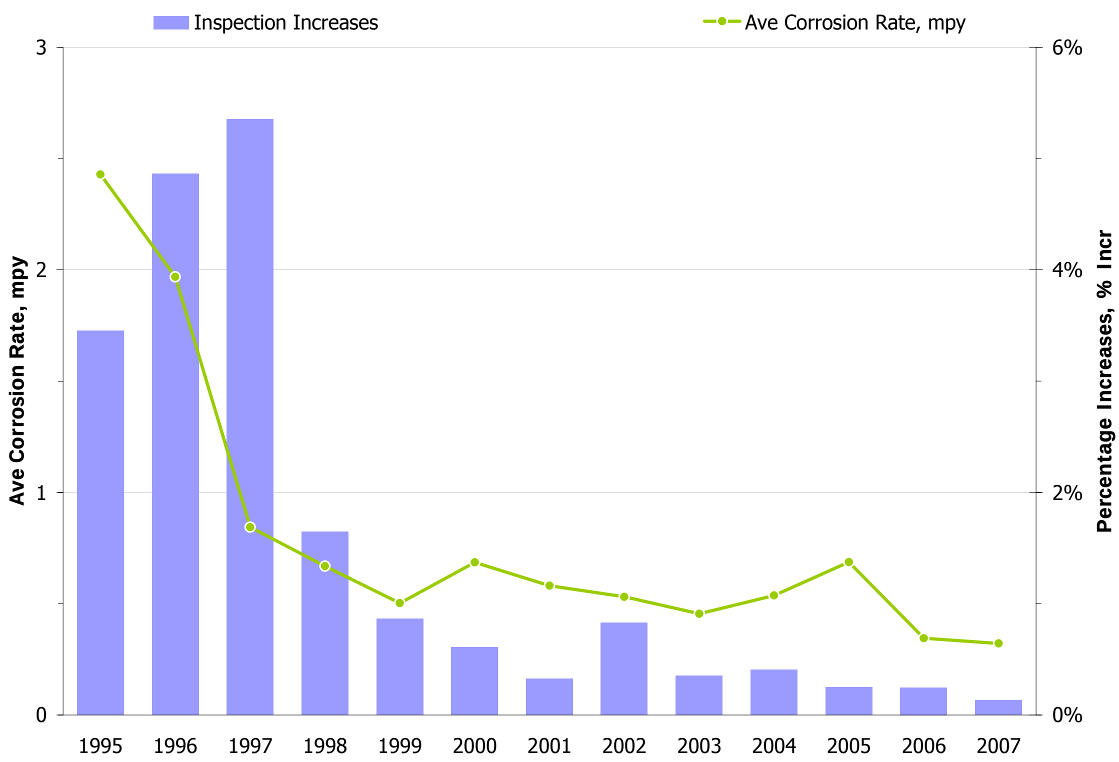
GPB Figure B.3 Well Line Internal Inspection Increase by Service

Section B.3 Correlation between Inspection and Corrosion Monitoring[9]

The following section describes the correlation between the inspection and monitoring programs for the 3-phase production system. Inspection and corrosion monitoring have different characteristics; in particular, inspection techniques are comparatively insensitive to short-term corrosion conditions, but are the most accurate as they measure actual wall loss of the pipe. In contrast, corrosion monitoring is more sensitive to short-term conditions but less accurate as a measure of corrosion rate, as the weight loss coupon is not an integral part of the pipe wall. Therefore, in order to have confidence in the results from the corrosion monitoring program, it is also necessary to show that a correlation exists between the monitoring program and the results of the inspection program. Refer to Table 12, Appendix 3 for additional information regarding these inspection and monitoring techniques.

GPB Figure B.4 shows the trend for WLC average corrosion rate and the trend for percentage of inspections increases for the 3-phase well lines and flow lines. The trends for WLC and inspection results are consistent with each other and show a positive correlation. Also, the WLC trend precedes the inspection trend, as would be expected since coupons are a leading indicator.

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



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

The inspection results included in this analysis only include data which has an inspection interval (time since last inspection) of less than two years. The indicated reporting year has been changed to reflect the mid-point of the inspection interval, rather than the time of inspection as used in other figures in this report. This shift in time reporting compensates for the fact that corrosion can occur over the entire interval between inspections. Similarly, the weight loss coupon corrosion rates are reported as the mid-point of the exposure period, not the WLC removal date.

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, further program optimization can be driven by the corrosion monitoring program, rather than by the inspection 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.

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 responsive manner.

Section B.4 In-line Inspection

In-line inspection (ILI) tools, i.e. 'smart pigs', are important for managing the long-term integrity of pipeline systems and at GPB in particular, the flow lines. ILI is not however, the most appropriate or applicable inspection technology in all situations due to limitations imposed by operating parameters, environmental conditions, system design and accessibility of the pipelines.

Magnetic flux leakage (MFL) type ILI 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.

In 2007, ILI was performed on sixteen 3-phase production flow lines and two processed oil transit lines. This is the highest number of lines inspected using ILI by BPXA to date and illustrates the commitment to continuous improvement of the Inspection Program.

The following table summarizes equipment service, diameter, and length of lines that were inspected using ILI in 2007.

Equipment	Service	Diameter (Inches)	Previous ILI	From	To	Length (miles)
04C	3-Phase	24	1992	Drill Site 4	FS-2	1.4
16-D	3-Phase	16	1994	Drill Site 16	FS-2	4.9
17-D	3-Phase	16	1992	Drill Site 17	FS-2	4.9
A-74	3-Phase	24	1999	Well Pad A	GC-3	2.6
B-36	3-Phase	24	1997	Well Pad B	GC-3	1.5
D-36	3-Phase	24	2004	Well Pad D	GC-1	1.3
H-74	3-Phase	24	2000	Well Pad H	GC-2	1.7
J-74	3-Phase	24	1999	Well Pad J	GC-2	1.8
M-74	3-Phase	24	1999	Well Pad M	GC-2	3.6
N-74	3-Phase	24	1999	Well Pad N	GC-2	1.7
S-36	3-Phase	24	2003	Well Pad S	GC-2	6.1
STP-36	3-Phase	36	2004	Pt. Mac	GC-1	9.7
U-384	3-Phase	16	2000	Well Pad U	GC-2	2.4
W-74	3-Phase	24	2005	Well Pad W	EWE Jct.	0.9
XF-21	3-Phase	24	2006	GC-2	GC-1	4.3
Y-36	3-Phase	24	2003	Well Pad Y	GC-1	6.4
FS1/ALPS-34	PO	34	2006	FS1	PS1 (Skid 50)	4.9
OT-31/13	PO	34	2006	GC1	PS1 (Skid 50)	4.9

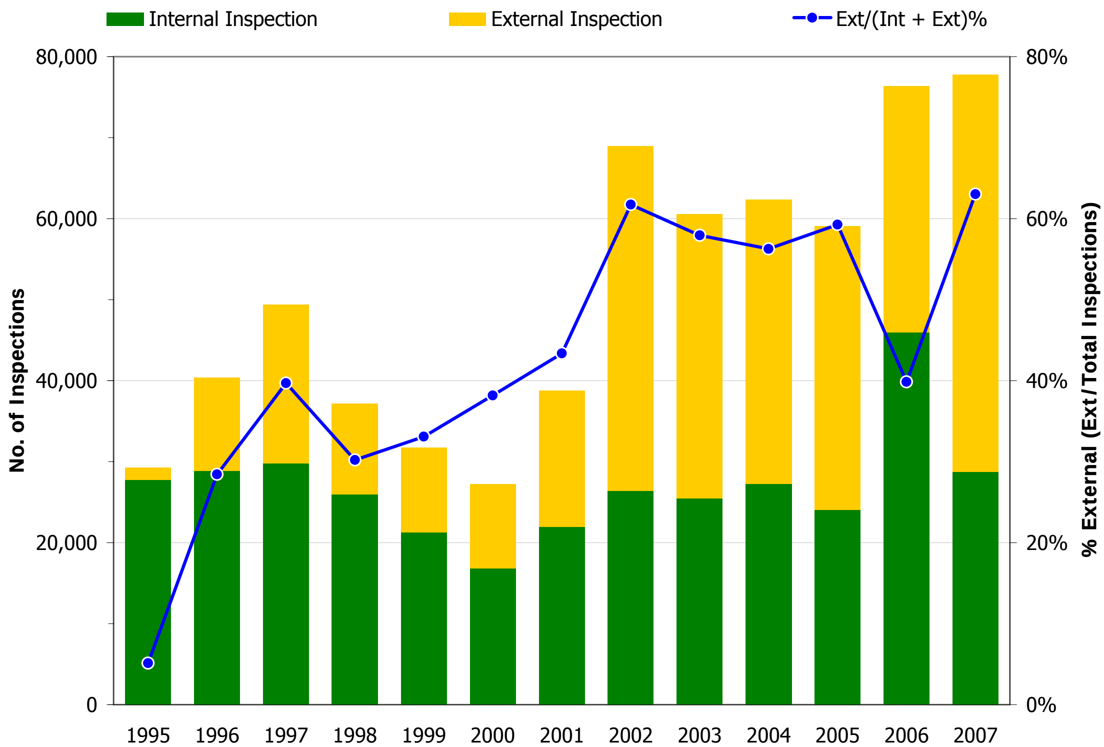
GPB Table B.4 Completed Smart Pig (ILI) Assessments

The metal loss features reported by ILI have been prioritized for verification by radiographic and/or ultrasonic inspection. The verification results through 2007 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 B.5 Internal/External Inspection Comparison

GPB Figure B.5 and GPB Table B.5 summarize the level of internal and external inspection activity across GPB since 1995. Due to the events involving processed oil transit lines, the level of internal corrosion inspection during 2006 increased significantly when compared to other years. The number of inspections in 2007 returned to a more typical level, balanced with activity in other areas of the system.



GPB Figure B.5 Internal and External Inspection Activity for Transit, Flow and Well Lines

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
External	1,498	11,491	19,609	11,225	10,509	10,403	16,807	42,593	35,109	35,110	34,994	30,419	49,021
Internal	27,737	28,909	29,771	25,937	21,253	16,841	21,946	26,403	25,490	27,277	24,047	45,924	28,741
Total	29,235	40,400	49,380	37,162	31,762	27,244	38,753	68,996	60,599	62,387	59,041	76,343	77,762
$\frac{Ext}{(Ext + Int)}$%	5%	28%	40%	30%	33%	38%	43%	62%	58%	56%	59%	40%	63%

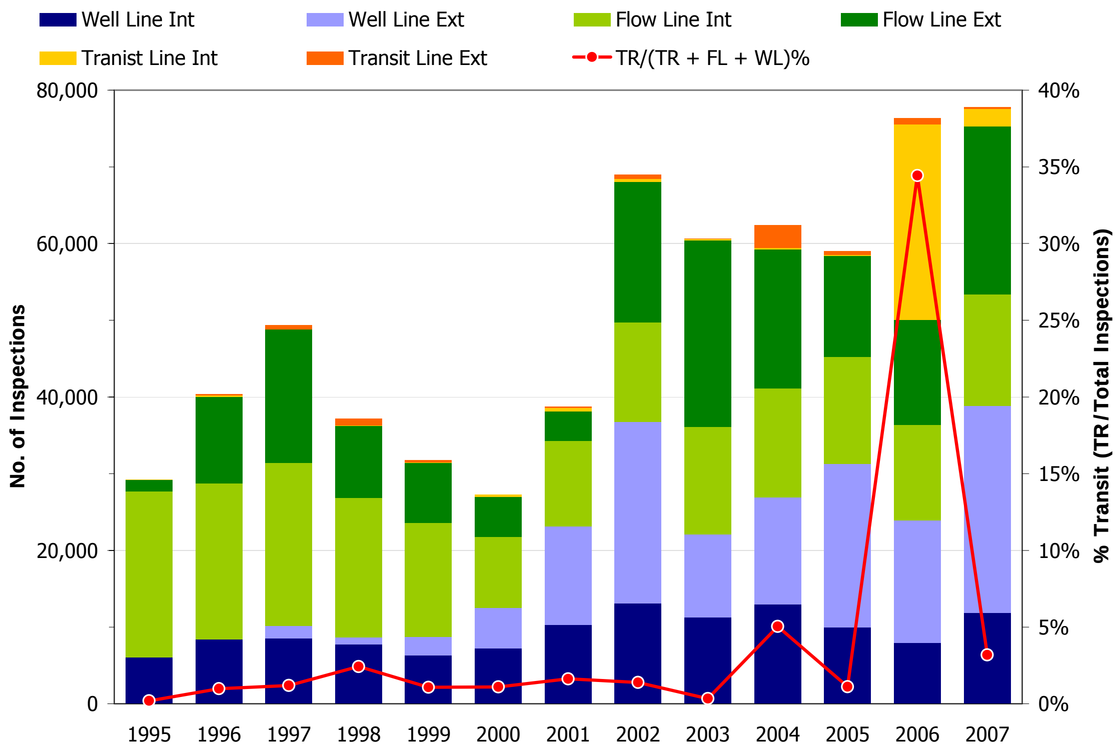
GPB Table B.5 Internal and External Inspection Activity

GPB Table B.6 and GPB Figure B.6 show the split between transit line, flow line and well line inspections for both the internal and external programs. A summary of the internal program results is shown in GPB Table B.8 at the end of this section.

The overall inspection activity level increased to over 77,000 inspections in 2007, the highest number of inspections since the program began, with increased emphasis on CUI this year.

	Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Transit Line	External	0	173	541	871	282	0	133	567	4	2,996	498	807	207
	Internal	56	226	52	32	62	302	500	392	201	151	160	25,474	2,277
	Total	56	399	593	903	344	302	633	959	205	3,147	658	26,281	2,484
	Ext / (Ext + Int) %	0%	43%	91%	96%	82%	0%	21%	59%	2%	95%	76%	3%	8%
Flow Line	External	1,498	11,282	17,393	9,420	7,850	5,169	3,833	18,356	24,289	18,159	13,170	13,712	21,885
	Internal	21,630	20,285	21,213	18,178	14,850	9,305	11,141	12,915	14,016	14,146	13,942	12,451	14,601
	Total	23,128	31,567	38,606	27,598	22,700	14,474	14,974	31,271	38,305	32,305	27,112	26,163	36,486
	Ext / (Ext + Int) %	6%	36%	45%	34%	35%	36%	26%	59%	63%	56%	49%	52%	60%
Well Line	External	0	36	1,675	934	2,377	5,234	12,841	23,670	10,816	13,955	21,326	15,900	26,929
	Internal	6,051	8,398	8,506	7,727	6,341	7,234	10,305	13,096	11,273	12,980	9,945	7,999	11,863
	Total	6,051	8,434	10,181	8,661	8,718	12,468	23,146	36,766	22,089	26,935	31,271	23,899	38,792
	Ext / (Ext + Int) %	0%	0%	16%	11%	27%	42%	55%	64%	49%	52%	68%	67%	69%
	Grand Total	29,235	40,400	49,380	37,162	31,762	27,244	38,753	68,996	60,599	62,387	59,041	76,343	77,762
Transit Line	TR / (TR + FL + WL) %	0.2%	1.0%	1.2%	2.4%	1.1%	1.1%	1.6%	1.4%	0.3%	5.0%	1.1%	34.4%	3.2%
Flow Line	FL / (TR + FL + WL) %	79%	78%	78%	74%	71%	53%	39%	45%	63%	52%	46%	34%	47%
Well Line	WL / (TR + FL + WL) %	21%	21%	21%	23%	27%	46%	60%	53%	36%	43%	53%	31%	50%

GPB Table B.6 Internal and External Inspection Activity Summary by Transit, Flow & Well Line



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

Section B.6 Inspection Summary

In summary, the main observations from the inspection section are as follows;

External Program

- In 2007, ninety-eight percent of external inspections planned were completed, as compared to seventy-five percent completion the previous year.
- There was a decrease in the amount of CUI damage detected in 2006, even though the number of inspections in 2007 increased by almost 19,000 over last year. The 2007 survey showed 4% of the inspected locations had CUI damage present, consistent with recent field wide average.

Cased Piping

- Between guided wave, ILI and excavations, a total of 140 cased pipe segments were inspected, which is short of the targeted number of 200 cased pipe segments for 2007.

Internal Program

- The internal inspection results show continued improvement over corrosion control in the 3-phase flow lines, while the percentage of inspections with increased corrosion was constant for the 3-phase well lines. The percentage of inspection increases in the water injection flow lines, water injection well lines and the oil transit lines was lower this year than in 2006. Refer to the following table.

Equipment	2006		2007	
	No. Inspections	% Increase	No. Inspections	% Increase
3-phase FL	9,922	4%	11,203	1%
3-phase WL	5,978	3%	8,958	3%
Water Inj. FL	2,079	9%	2,519	5%
Water Inj. WL	1,775	10%	2,393	8%
Oil Transit	25,296	9%	2,277	2%

GPB Table B.7 Internal Inspection Activity Summary by Transit, Flow and Well Line

- 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 is 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	2006	2007
GPB	FL	OIL	I	367	921	1,154	394	240	68	60	103	151	101	179	251	63
			NC	15,219	15,806	16,576	14,956	12,075	8,209	7,108	8,707	9,112	10,640	9,063	6,155	9,213
			NL	3,607	2,116	1,968	455	368	145	1,783	2,030	1,940	810	1,700	3,343	1,927
			Total	**19,193**	**18,843**	**19,698**	**15,805**	**12,683**	**8,422**	**8,951**	**10,840**	**11,203**	**11,551**	**10,942**	**9,749**	**11,203**
		WTR	I	171	126	154	197	73	20	43	138	176	107	141	147	112
			NC	1,156	1,080	1,128	1,569	1,569	727	1,109	1,178	1,544	1,582	1,789	1,564	2,176
			NL	423	116	134	89	75	61	353	378	218	218	280	369	231
			Total	**1,750**	**1,322**	**1,416**	**1,855**	**1,717**	**808**	**1,505**	**1,694**	**1,938**	**1,907**	**2,210**	**2,080**	**2,519**
		Total	**Total**	**20,943**	**20,165**	**21,114**	**17,660**	**14,400**	**9,230**	**10,456**	**12,534**	**13,141**	**13,458**	**13,152**	**11,829**	**13,722**
GPB	TR	PO	I	12	12	4		10	161	81	7	3	12	10	114	23
			NC	34	81	46	20	26	59	191	338	92	110	90	1,325	1,177
			NL	10	133	2	12	26	82	228	47	106	29	60	24,035	1,077
			Total	**56**	**226**	**52**	**32**	**62**	**302**	**500**	**392**	**201**	**151**	**160**	**25,474**	**2,277**
		Total	**Total**	**56**	**226**	**52**	**32**	**62**	**302**	**500**	**392**	**201**	**151**	**160**	**25,474**	**2,277**
GPB	WL	OIL	I	630	904	876	600	312	264	213	276	324	290	232	157	197
			NC	2,459	3,491	3,424	4,083	3,635	4,135	5,531	7,164	6,577	7,115	6,337	4,392	6,867
			NL	960	1,740	1,953	698	574	512	2,447	3,386	2,245	2,388	1,238	1,426	1,894
			Total	**4,049**	**6,135**	**6,253**	**5,381**	**4,521**	**4,911**	**8,191**	**10,826**	**9,146**	**9,793**	**7,807**	**5,975**	**8,958**
		WTR	I	225	261	201	211	73	124	79	125	146	152	108	130	130
			NC	1,024	1,534	1,080	1,622	1,419	1,747	1,288	1,141	1,346	2,137	1,232	1,126	1,532
			NL	615	357	621	218	174	254	491	534	359	520	535	518	731
			Total	**1,864**	**2,152**	**1,902**	**2,051**	**1,666**	**2,125**	**1,858**	**1,800**	**1,851**	**2,809**	**1,875**	**1,774**	**2,393**
		Total	**Total**	**5,913**	**8,287**	**8,155**	**7,432**	**6,187**	**7,036**	**10,049**	**12,626**	**10,997**	**12,602**	**9,682**	**7,749**	**11,351**
GPB	**Total**	**Total**	**Total**	**26,912**	**28,678**	**29,321**	**25,124**	**20,649**	**16,568**	**21,005**	**25,552**	**24,339**	**26,211**	**22,994**	**45,052**	**27,350**

Note: I = Increased Degradation from Previous Inspection
NC = No Change from Previous Inspection
NL = New Location 1st Inspection

GPB Table B.8 Transit, Flow and Well Line Internal 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 S Pad 14" Produced Water S Pad 10" Gas Lift S Pad 8" Miscible Injection	61% external wall loss 36% internal/ext wall loss 34% external Wall Loss 41% external wall loss	Sleeve/insulation/coat repair Sleeve/insulation/coat repair Insulation/coating repair Replaced segment/FBE
	GC1 Main Entrance	Distribution 24" Gas Lift Y Pad 24" 3 Phase Production	29% external wall loss 24% external wall loss	Insulation/coating repair Insulation/coating repair
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift Y Pad 24" 3 Phase Production	42% external wall loss 26% external wall loss	Sleeve/insulation/coat repair Insulation/coating repair
1996	GC-1 Spine Road	Distribution 24" Gas Lift D Pad 24" 3 Phase Production Y Pad 24" 3 Phase Production Distribution 20" Produced Wtr.	53% external wall loss 33% external wall loss 18% external wall loss 8% external wall loss	Sleeve/insulation/coat repair Insulation/coating repair Insulation/coating repair 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" Sales Oil 30" Distribution 24" Gas Lift Distribution 32" Sea Water	11% external wall loss 14% external wall loss No corrosion damage No corrosion damage	Insulation/coating/tape repair Insulation/coating/tape repair None 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 B.9 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 loss 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 B.9 (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 B.9 (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
2006	F-Pad to GC1 Caribou Crossing	F Pad 24” 3 Phase Production	43% external wall loss	insulation tape repair
	F-Pad to GC-1 Frontier Road Crossing	F Pad 24” 3 Phase Production	55% external wall loss	insulation tape repair
	X-Pad to GC-3 Caribou Crossing	X Pad 24” 3 Phase Production	19% external wall loss	insulation tape repair
		X Pad 6” Miscible Injection	24% external wall loss	insulation tape repair
	S-Pad West Road Crossing	S Pad 14" Produced Water	37% internal wall loss	insulation tape repair
	GC3 Pad Road Crossing	X Pad 24” 3 Phase Production	49% external wall loss	insulation tape repair
	B Pad Main Entrance Road Crossing	B Pad 6" Miscible Injection	no corrosion damage	none
	GC2 to GC-1 Caribou Crossing 1	Oil Transit 34” Processed Oil	leak - internal wall loss	demolished – removed piping
	GC2 to GC-1 Caribou Crossing 3	Oil Transit 34” Processed Oil	79% internal wall loss	demolished – removed piping
	GC2 to GC-1 Caribou Crossing 4	Oil Transit 34” Processed Oil	87% internal wall loss	demolished – removed piping
	C-Pad to GC-3 Access Road Crossing	Oil Transit 34” Processed Oil	31% internal wall loss	temporary insulation – planned replacement

GPB Table B.9 (Continued) Cased Piping Excavation History

2006	GC3 to Sk-50 Caribou Crossing 1	Oil Transit 34" Processed Oil	17% internal wall loss	temporary insulation – planned replacement
	GC3 to Sk-50 Caribou Crossing 2	Oil Transit 34" Processed Oil	18% internal wall loss	temporary insulation – planned replacement
	GC3 to Sk-50 Caribou Crossing 3	Oil Transit 34" Processed Oil	13% external wall loss	temporary insulation – planned replacement
	GC3 to Sk-50 Caribou Crossing 4	Oil Transit 34" Processed Oil	no damage	temporary insulation – planned replacement
2007	GC3/GC2MI at casing CI136	Distribution 12" Miscible Injection	no damage	none
	GLT-24 at casing CI124	Distribution 24" Gas Lift	23% external wall loss	tape wrap & insulation repair
	GLT-24 at casing CI136	Distribution 24" Gas Lift	5% external metal loss	tape wrap & insulation repair
	GLT-24 at casing CI221	Distribution 24" Gas Lift	no damage	none
	S-804 at casing CI111	S Pad 8" Miscible Injection	8% external wall loss	tape wrap & insulation repair
	W-69 at casing CI180	W Pad 8" Produced Water	no damage	none
	W-74 at casing CI180	W Pad 24" 3 Phase Production	no inspection	planned replacement
	W-79 at casing CI180	W Pad 10" Gas Lift	no damage	none

GPB Table B.9 (Continued) Cased Piping Excavation History

GPB Section C

Corrosion & Structural Related Repairs and Spills

Section C GPB Corrosion & Structural Related Repairs and Spills

Section C.1 Repair Activities

The repair activities for 2007 are summarized in GPB Table 1. A total of 168 piping repairs were performed in 2007.

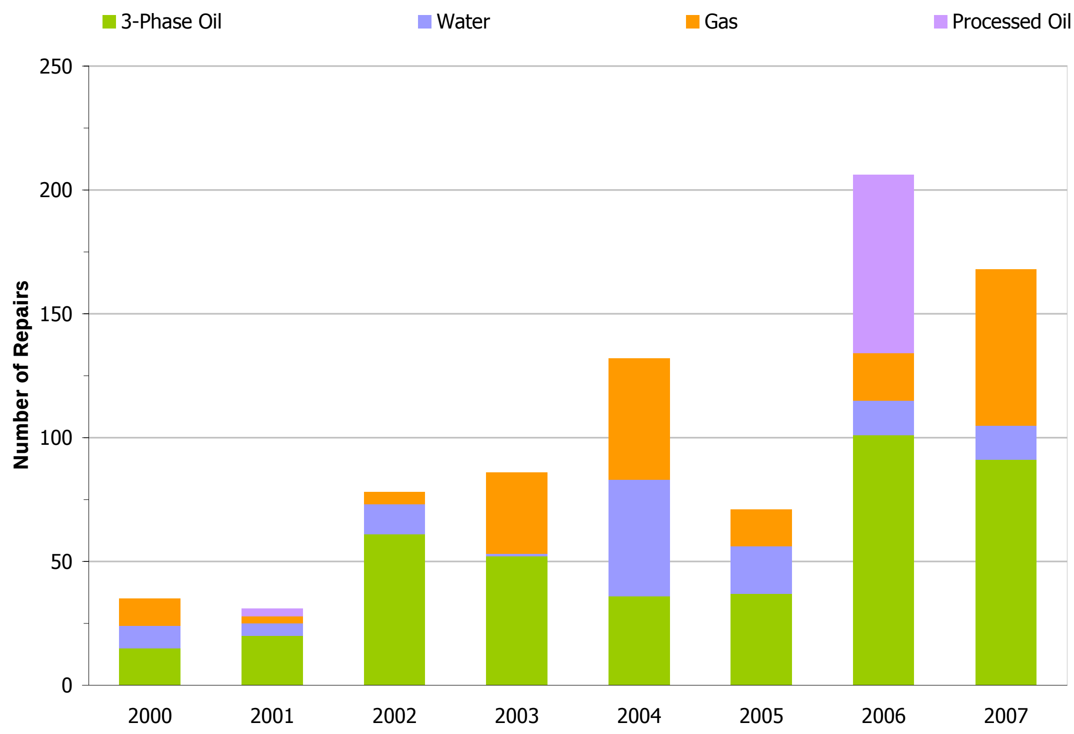
Service	Type	Internal	External	Mechanical	Total
3-Phase Oil	FL	3	50	20	73
	WL	4	13	1	18
Water	FL	-	-	4	4
	WL	7	2	1	10
Gas	FL	-	19	32	51
	WL	-	7	5	12
Processed Oil	TR	-	-	-	-
Total		14	91	63	168

GPB Table C.1 Repair Activity

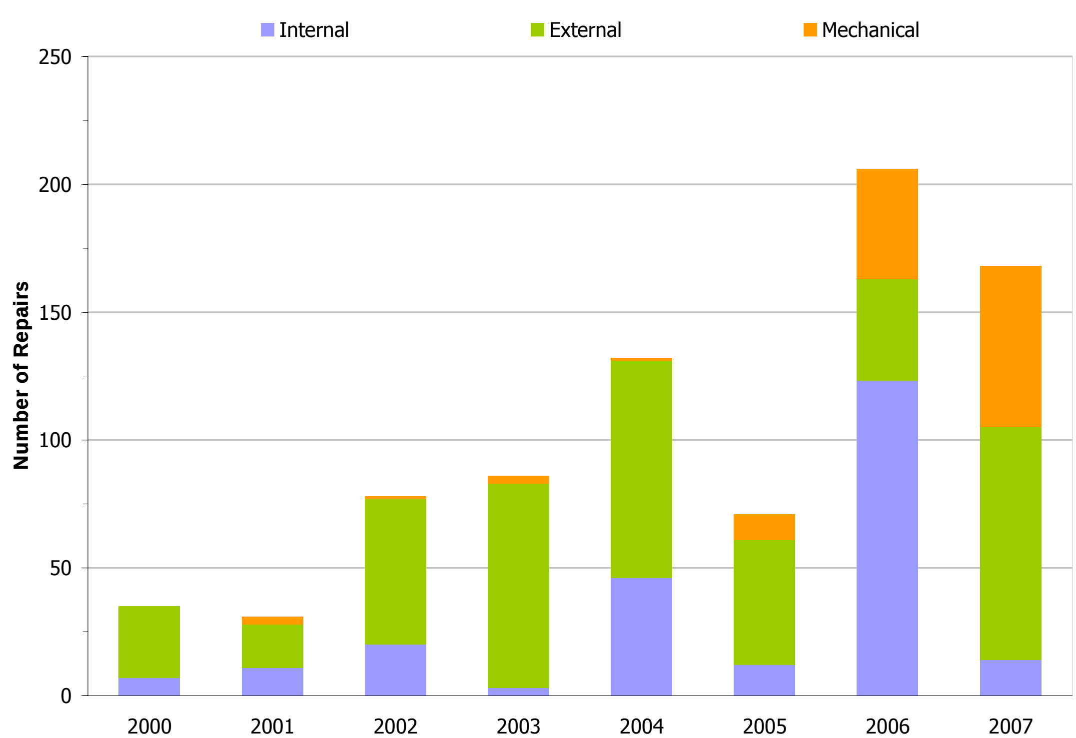
There were 91 repairs attributed to external corrosion in 2007; the highest number of external repairs since 2000. There were 63 repairs attributed to mechanical damage which is an increase from historic figures. The mechanical repairs are largely the result of manufacturing discontinuities in the pipe steel, or gouges and scratches that occurred during pipeline construction and were later found while inspecting for CUI.

There were 14 repairs attributed to internal corrosion, of which three were located on 3-phase oil flow lines, four were located on 3-phase oil well lines and seven were located on water well lines. Of the total number of internal corrosion repairs, five were planned repairs, three were leak repairs and six were identified during inspection before a leak occurred, and were repaired.

GPB Figure C.1, GPB Figure C.2, GPB Figure C.3, and GPB Table C.2 show the 8-year trend in repairs grouped by service, damage mechanism, and equipment, respectively.



GPB Figure C.1 Repairs by Service



GPB Figure C.2 Repairs by Damage Mechanism

GPB Figure C.3 Repairs by Equipment

		3 Phase Oil		Water		Gas		Processed Oil	Total
		Flow Line	Well Line	Flow Line	Well Line	Flow Line	Well Line	Transit Line	
2000	Internal	2	5	-	-	-	-	-	7
	External	1	7	2	7	8	3	-	28
	Mechanical	-	-	-	-	-	-	-	0
	Total	3	12	2	7	8	3	0	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	0	78
2003	Internal	-	3	-	-	-	-	-	3
	External	28	20	-	1	23	8	-	80
	Mechanical	1	-	-	-	1	1	-	3
	Total	29	23	0	1	24	9	0	86
2004	Internal	5	5	23	13			-	46
	External	13	13	9	1	12	37	-	85
	Mechanical	2	-	1				-	3
	Total	20	18	33	14	12	37	0	134
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	0	71
2006	Internal	64	2	2	10	-	-	45	123
	External	20	5	-	1	2	11	1	40
	Mechanical	8	2	1	-	1	5	26	43
	Total	92	9	3	11	3	16	72	206
2007	Internal	3	4	-	7	-	-	-	14
	External	50	13	-	2	19	7	-	91
	Mechanical	20	1	4	1	32	5	-	63
	Total	73	18	4	10	51	12	0	168
Grand Total		**298**	**117**	**59**	**62**	**113**	**85**	**75**	**809**

GPB Table C.2 Historical Repairs by Service

Section C.2 Corrosion Related Leaks

This section summarizes the corrosion and structural related incidents that occurred in 2007 and provides a historical perspective on leaks (loss of containment) and saves (repairs before leak of non-FFS equipment).

GPB Table C.1 summarizes the equipment, failure mechanism and volume of leaks that occurred in 2007. Of the 6 leaks that occurred, two were due to external corrosion, three were attributed to internal corrosion and one was a frozen flow line that ruptured.

Service	Location	Type	Date	Mechanism	Volume
3 phase	Drill Site 15	WL	5/25/07	Internal	< 1 gal.
3 phase	W Pad to GC2	FL	6/17/07	External	< 1 gal.
3 phase	Drill Site 04 to FS2	FL	8/24/07	External	Contained
3 phase	Drill Site 15	WL	9/7/07	Internal	< 1 gal.
3 phase	Drill Site 16 to FS2	FL	10/15/07	Mechanical/Froze	~1,932 gal.
Seawater	Drill Site 04	WL	11/28/07	Internal	~500 gal.

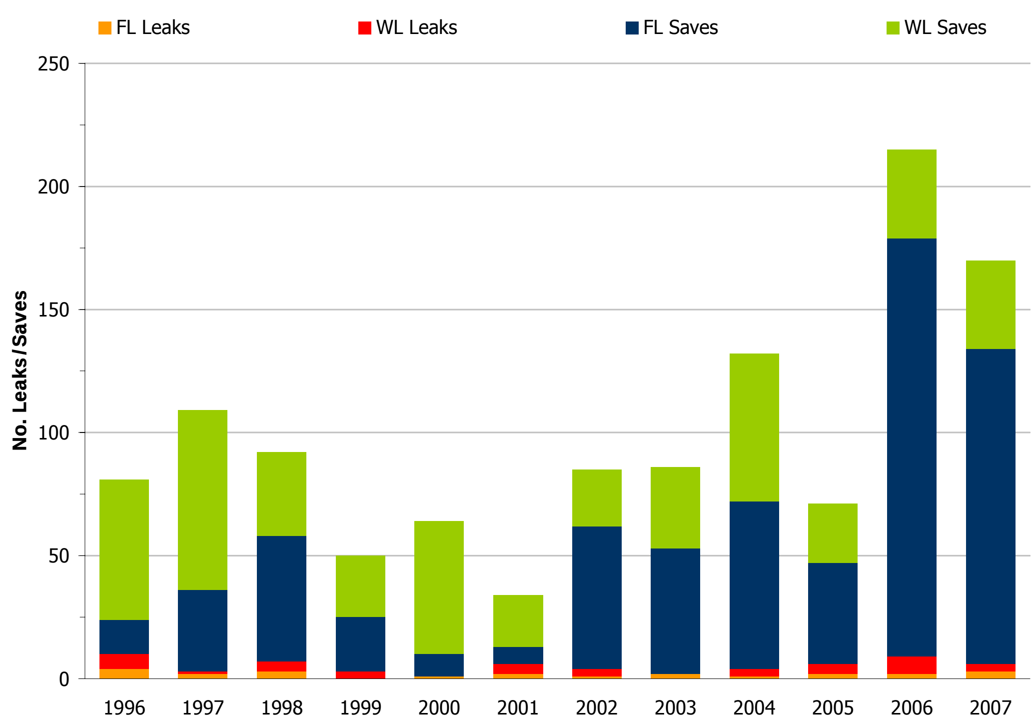
	Surface		Service				Mechanism			
	Int	Ext	OIL	SW	PW	Gas	CO_2	Int	CUI	Mech
WL	3	-	2	1	-	-	-	3	-	-
FL	1	2	3	-	-	-	-	-	2	1
TR	-	-	-	-	-	-	-	-	-	-

GPB Table C.1 Leaks Due to Corrosion / Mechanical

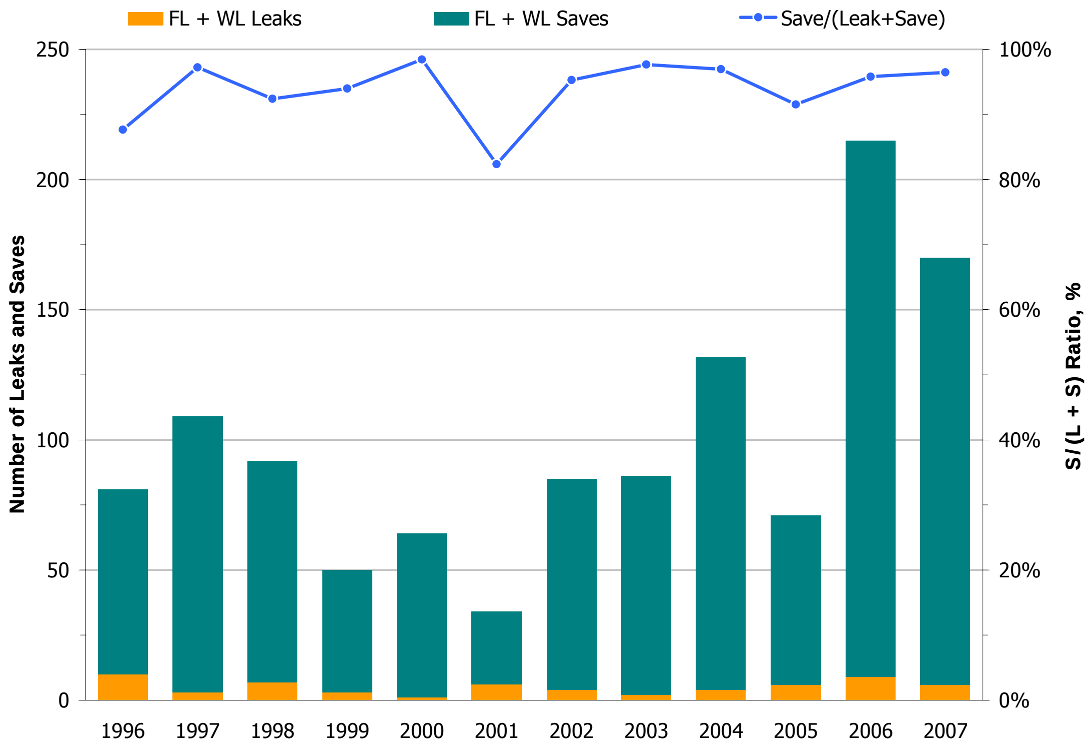
GPB Table C.2, GPB Figure C.4 and GPB Figure C.5 show the number of corrosion related leaks and saves since 1996. The ratio of leaks to saves provides a high level measure of the performance of the inspection program at detecting severe damage before it results in a failure. A 'save' is defined as a 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.

	Transit & 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%
2006	170	2	99%	36	7	84%	96%
2007	128	3	98%	36	3	92%	96%

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



GPB Figure C.4 Historical Corrosion / Mechanical Leaks and Saves by Line Type



GPB Figure C.5 Historical Corrosion / Mechanical Leaks and Saves

Section C.3 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: i.e. subsidence, jacking, cyclic fatigue, impact, slugging, snow loading, etc.

There were numerous structural repairs to pipeline support members during 2007. The repairs were primarily pipeline re-leveling due to support member subsidence or jacking.

Section C.3.1 Walking Speed Survey

Where there is perambulatory access to facilities, 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
- Pipeline road and animal crossings

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

Previous Completion	Next Scheduled	Equipment Description
2007	2012	GPB East Cross Country Pipelines
2003	2008	GPB West Cross Country Pipelines
2004	2009	GPB East Well Pads
2005	2010	GPB West Well Pads
2006	2011	Lisburne Cross Country Pipelines/Drill Sites

GPB Table C.3 Structural / Walking Speed Survey Schedule

A WSS of the GPB East (EOA) Cross Country Pipelines was completed in 2007. In addition to the EOA Pipelines, a WSS for the GPB Processed Oil Transit Pipelines - EOA, WOA, and LPC; and the GPB NGL System were completed.

Section C.3.2 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 condition (i.e. wall thinning, cracks, ovality, buckling, and 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.

GPB Section D

Corrosion Monitoring and Inspection Goals

Section D GPB Corrosion Monitoring and Inspection Goals

Section D.1 2007 Corrosion and Inspection Goals Reviewed

The corrosion inspection, monitoring and mitigation programs were expected to be substantially unchanged from the previous year during 2007. In particular, the corrosion control target of less than 2 mpy remained in place with monitoring activity levels the same as recent years.

Section D.1.1 Corrosion Monitoring

The weight loss coupon install/remove frequency remained unchanged in 2007 compared to recent years and is summarized in GPB Table D.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 D.1 Coupon Pull Frequency

The activity level from the weight loss coupon program was anticipated to be similar in 2007 as that in 2006, and indeed this was the case.

The ER probe program was planned to be substantially the same as in 2006 with probes being located on the 3-phase production lines. The 2007 result was largely as anticipated.

Section D.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.

ILI was performed on sixteen 3-phase production flow lines and two processed oil transit lines.

External corrosion inspection activity was substantially increased starting in 2002, from ~13,000 up to 35,000 per year in 2006. An increased level of 50,000 inspections was planned in 2007, 98% of which were completed. A total of 29,741 internal inspections were performed in 2007.

The long-term management strategy was continued for cased piping segments consisting of repeat inspections and excavation. The 2007 target was 200 cased segments, and 140 were completed using a combination of techniques.

Section D.1.3 Chemical Optimization

There were no large-scale changes forecast for the corrosion mitigation program in 2007 and this proved to be the case.

Section D.1.4 Program Reviews

As a result of oil transit line events in 2006, there continued to be numerous opportunities to explain and review the corrosion program with stakeholders (e.g. State, Federal, and Working Interest Owners) over the past year. The substantial volume of input received as a result of these stakeholder discussions and reviews is currently being analyzed and integrated.

Section D.1.5 2007 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 D.2 notes the corrective mitigation actions taken as a result of inspection information.

Equipment ID	No. of Action	Cause	Action
16D	1	Increased Corrosivity	Increase CI by 10%
J-74	1	Increased Corrosivity	Increased CI by 10%

GPB Table D.2 Corrective Mitigation Actions from Inspection Data

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

Equipment ID	No. of Action	Cause	Action
14D	1	Increased Corrosivity	Increased CI at 2 wells
14D	1	Increased Corrosivity	Increased CI by 5% at 3 wells

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

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

Equipment ID	WLC CR mpy	Cause	Action
14D	2.76	Inhibitor Under-injection / Excursions of High Gas Velocity	Increase CI to existing target / Field Investigation Conducted – probe location noisy due to flow
	2.73		
	3.52		
	3.41		
	2.25		
	2.22		
04B	2.25	Inhibitor Under-injection	Increase CI to existing target
	2.22		
05D	2.79	Increased Corrosivity	Increase CI target
	2.79		
	2.65		

GPB Table D.4 Corrective Mitigation Actions from Coupon Data

Section D.2 2008 Corrosion Management Goals

Overall, the 2008 corrosion and inspection goals will be focused on the continued delivery and optimization of current programs.

Section D.2.1 Corrosion Monitoring

The weight loss coupon program will be evaluated for schedule optimization. Additional monitoring methods will continue to be investigated for the PW system in an effort to develop a more sensitive short-term monitoring tool.

Section D.2.2 Chemical Optimization and Maintenance Pigging

Corrosion inhibition will continue to be the primary means of internal corrosion control at GPB. Supplemental corrosion inhibition of the PW system will continue. For the 3-phase system, the emphasis will be on the optimization corrosion inhibitor and providing improved control. Corrosion inhibitor evaluation using rapid screen tests will continue to be performed throughout the year as products become available.

Continuous improvement of maintenance pigging programs will continue in 2008, and the pigging frequency and efficacy are being optimized. Management of the maintenance pigging schedule and the operations reporting mechanism is also undergoing review and improvement.

Section D.2.3 Inspection Programs

The internal inspection program for cross country flow line and well lines will be ~29,000; which represents ~45% of the complete internal inspection program. The complete internal inspection program consisting of forward planning and execution will be approximately 65,000 inspections.

The external program target is 50,000 inspections for the full year.

The long-term management strategy for cased piping segments will continue; consisting of repeat examinations and excavations as warranted. The work scope for cased piping is scheduled to be approximately 200 inspections.

The ILI program target is 20 pipelines but delivery will be dependant upon tool and pipeline availability.

The Walking Speed Survey program will continue as scheduled, with GPB West Cross Country Pipelines.

Part 5 – Alaska Consolidated Team Business Unit

ACT Section A

Corrosion Monitoring and Mitigation

Section A ACT Corrosion Monitoring and Mitigation

Section A.1 Endicott

Section A.1.1 Monitoring

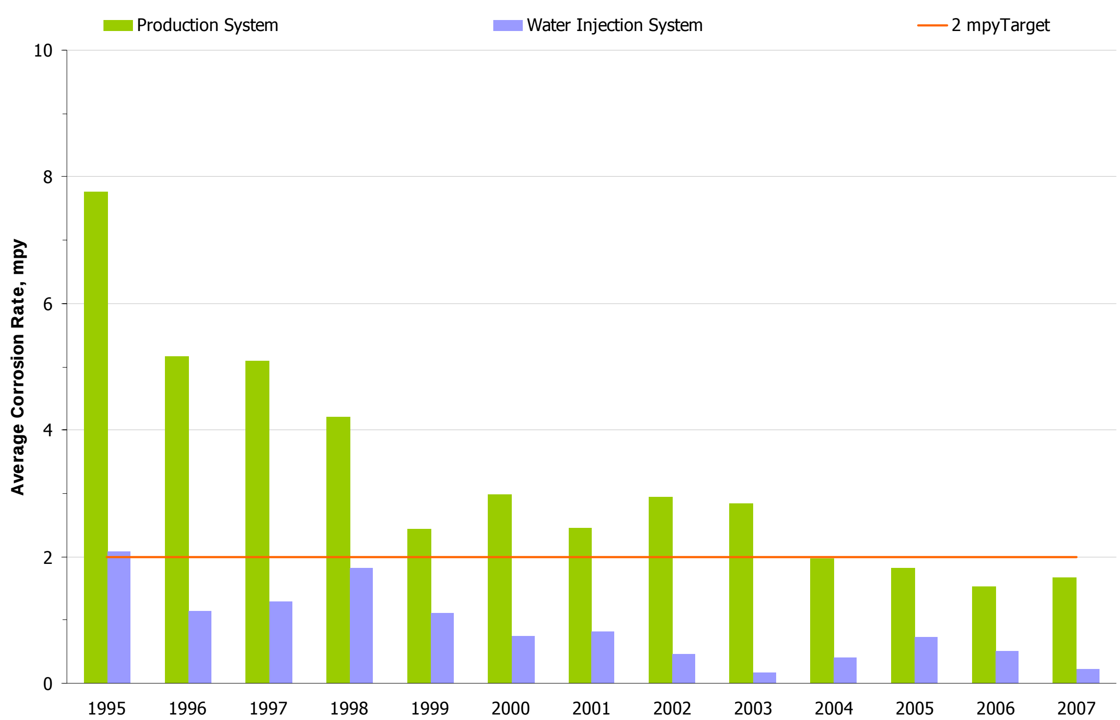
ACT Table A.1 summarizes the Endicott corrosion monitoring performance for 2007 and historical data are shown in ACT Figure A.1.

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. They also assist in determining the corrosion susceptibility of the carbon steel C-Spools connecting the wellhead to the well line.

The lower, relatively constant corrosion rates in the water injection system reflect the effectiveness of the corrosion mitigation program. No water injection WLC experienced corrosion rates above the 2 mpy target for 2007.

System	Access Fittings	% WLC < 2 mpy
Water Injection - Pads	19	100%
Water Injection – x-country	1	100%
Oil Production – Pads	71	75% (DSS)

ACT Table A.1 Endicott Corrosion Coupon Monitoring



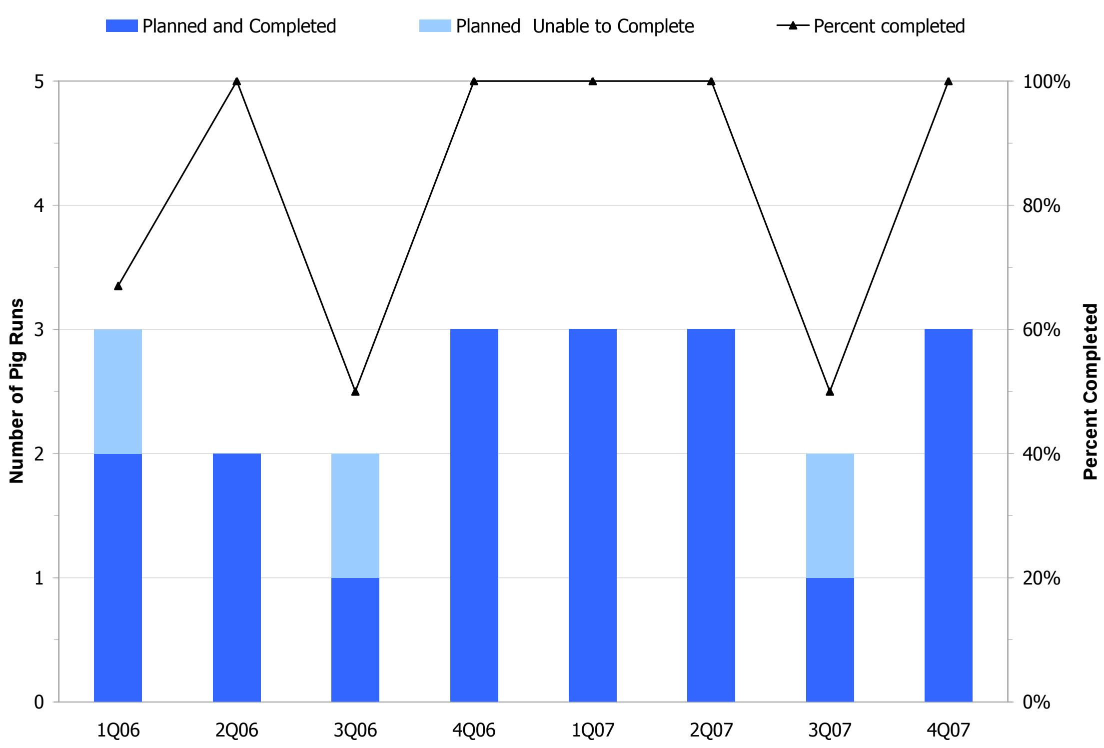
ACT Figure A.1 Endicott Corrosion Coupon Summary

Section A.1.2 Mitigation

The primary internal 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 periodic biocide treatment and maintenance pigging program. Originally, this line 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, SW usage has diminished and is no longer used for injection purposes.

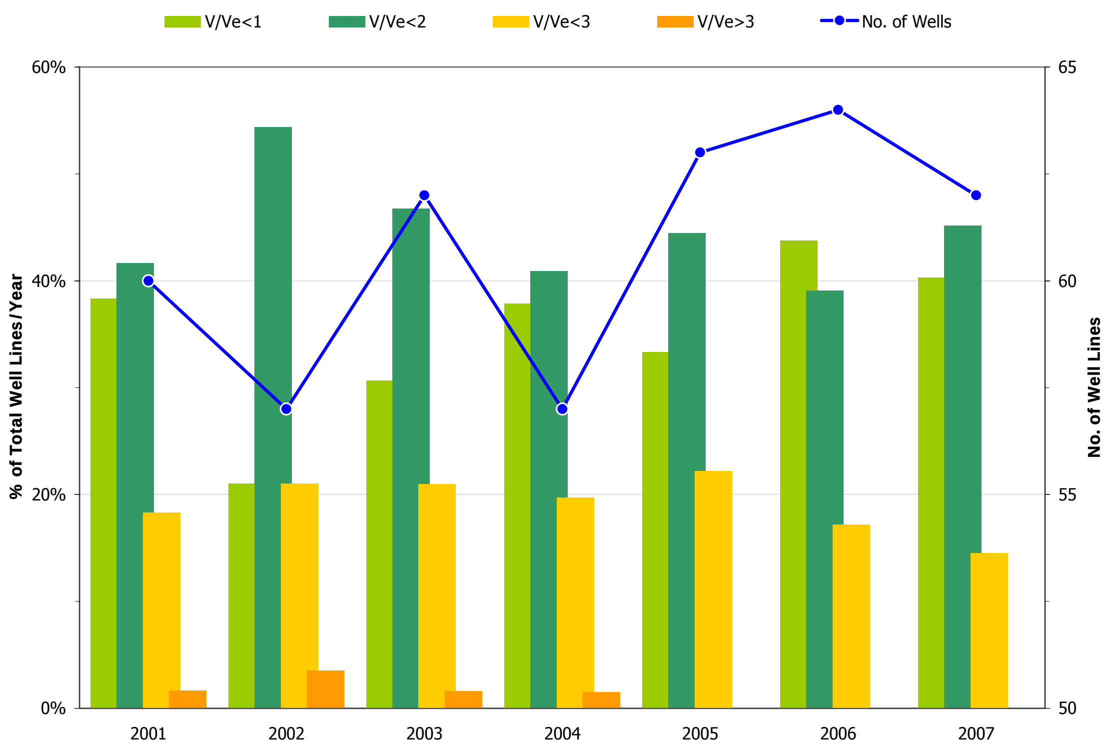
Corrosion mitigation for the IIWL had historically relied on maintenance pigging for line cleanliness, biocide treatments to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control. The principle monitoring tool to determine effectiveness of these programs is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

Maintenance pigging of the Endicott IIWL is scheduled on a five-week interval. ACT Figure A.2 shows performance for the IIWL pigging by quarter for the years 2006-2007. The missed cycle in the third quarter of 2007 is due to the plant just coming back on line after a planned shutdown. Prior to the shutdown, the line was cleaned multiple times for evacuation and replacement of the below grade section at the "Y" intersection.



ACT Figure A.2 Endicott IIWL Maintenance Pigging Performance

In the production system, the primary damage mechanism is erosion in the duplex stainless steel sections and corrosion in the carbon steel C-Spool sections. 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 A.2 is an overview of the average velocity data since 2001. Shown are the percent of wells within V/V_e ratio ranges, where V is the actual mixture velocity, V_e is the velocity at which erosion becomes a concern and V/V_e is the allowable erosion velocity ratio as defined by API-RP-14E[10].



ACT Table A.2 Endicott Velocity Monitoring

API-RP-14E defines an allowable velocity for the avoidance of erosion, based on the fluid properties including 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) which reflects BPXA’s experience with production fluids that contain minimal amounts of entrained solids flowing through stainless steel lines. 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 2007, no wells exceeded an average V/V_e >3.0.

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

Section A.2 Milne Point

Section A.2.1 Monitoring

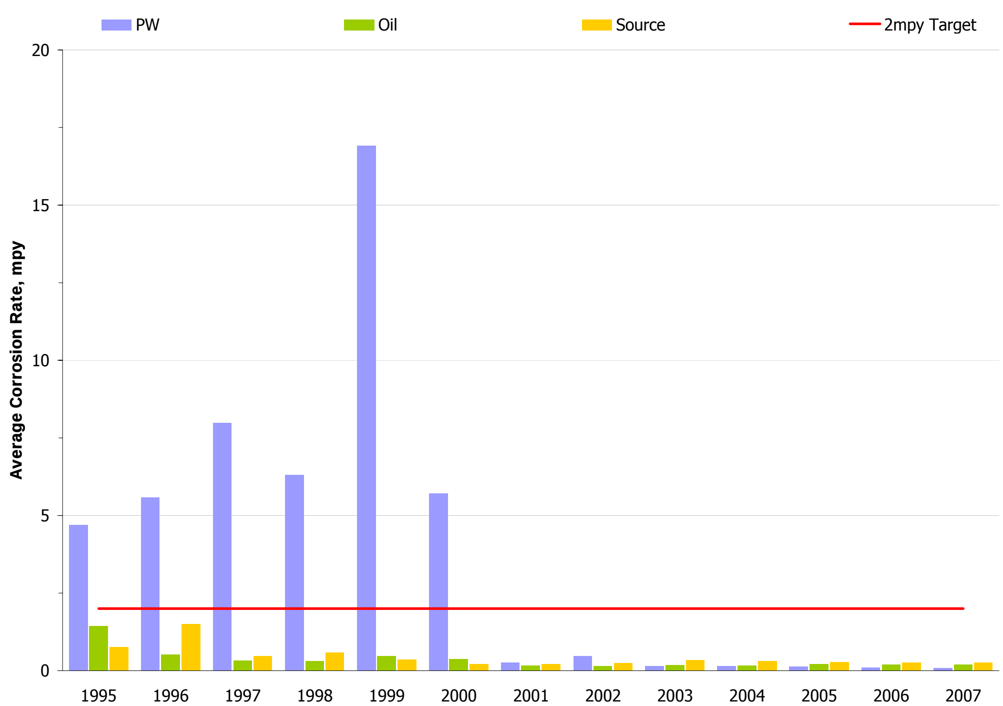
ACT Table A.3 summarizes the Milne Point Unit corrosion monitoring performance for 2007 and historical data are shown in ACT Figure A.3.

ACT Figure A.3 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 has had 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 2007.

A corrosion monitoring gap analysis was conducted in 2005 and as a result a proposal was made to increase the number of corrosion monitoring locations for more consistent coverage. Several new locations were added to the monitoring program to include additional weight loss coupons and electrical resistance probes. This work was completed in 2006.

System	Access Fittings	% WLC < 2 mpy
Production System	28	100%
Water Injection System	6	100%
Source Water Coupons	6	100%

ACT Table A.3 MPU Corrosion Coupon Monitoring

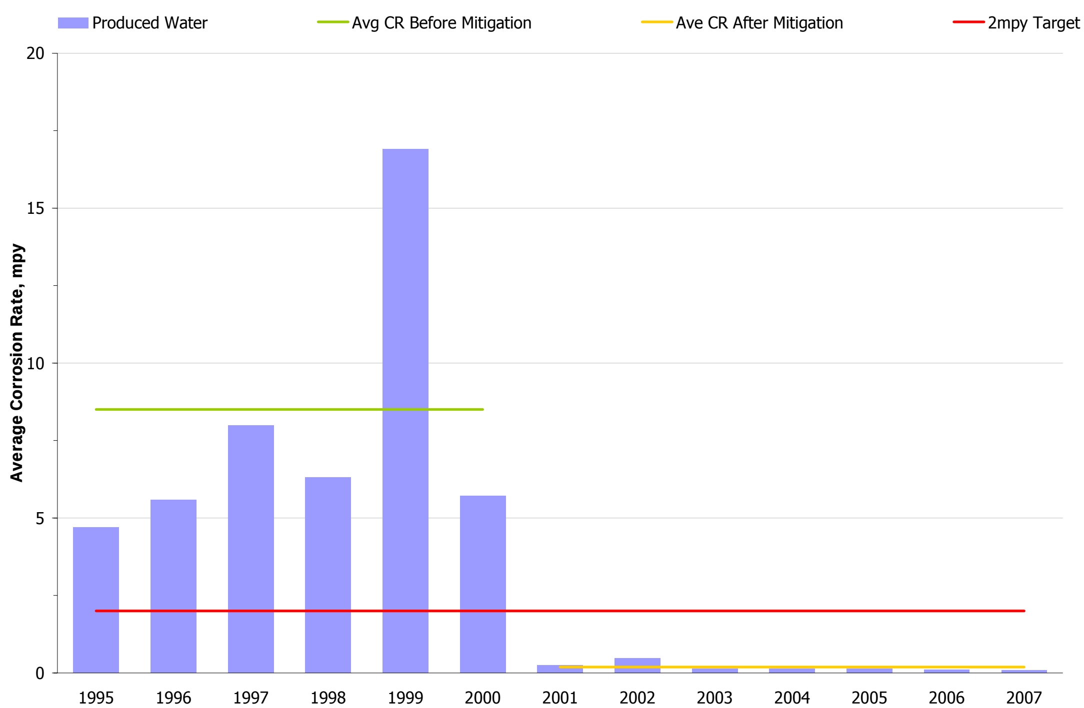


ACT Figure A.3 MPU Corrosion Coupon Summary

Section A.2.2 Mitigation

The primary corrosion concerns are in the water injection system and corrosion of buried piping. Corrosion inhibition, supplemented by periodic biocide treatments 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.

Corrosion inhibition of the water injection system began in mid-2000. In addition, a more rigorous maintenance pigging program was implemented. 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 A.4. 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. Although the corrosion rate monitoring data indicates good performance, the inspection data are indicating better control is needed in the PW service lines. As a result of a trial of a new corrosion inhibitor, the inhibitor concentration was increased from 40 ppm to 55 ppm as well as eliminating the biocide regime. This trial is still under investigation awaiting follow up inspection to confirm the effectiveness.



ACT Figure A.4 Milne Point Produced Water Corrosion Rate Trend

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

Corrosion inhibition of the K-pad production flow line was initiated in 2001 and the trunk system carrying the F-L-C Pads flow line in 2003. The K-Pad flow line was shut-in during 2006 and was replaced in 2007. Corrosion inhibition of the newer S-Pad began late 2002, close to startup of the pad. The Tract 14 production flow line trunk system had continuous chemical inhibition initiated in 2007.

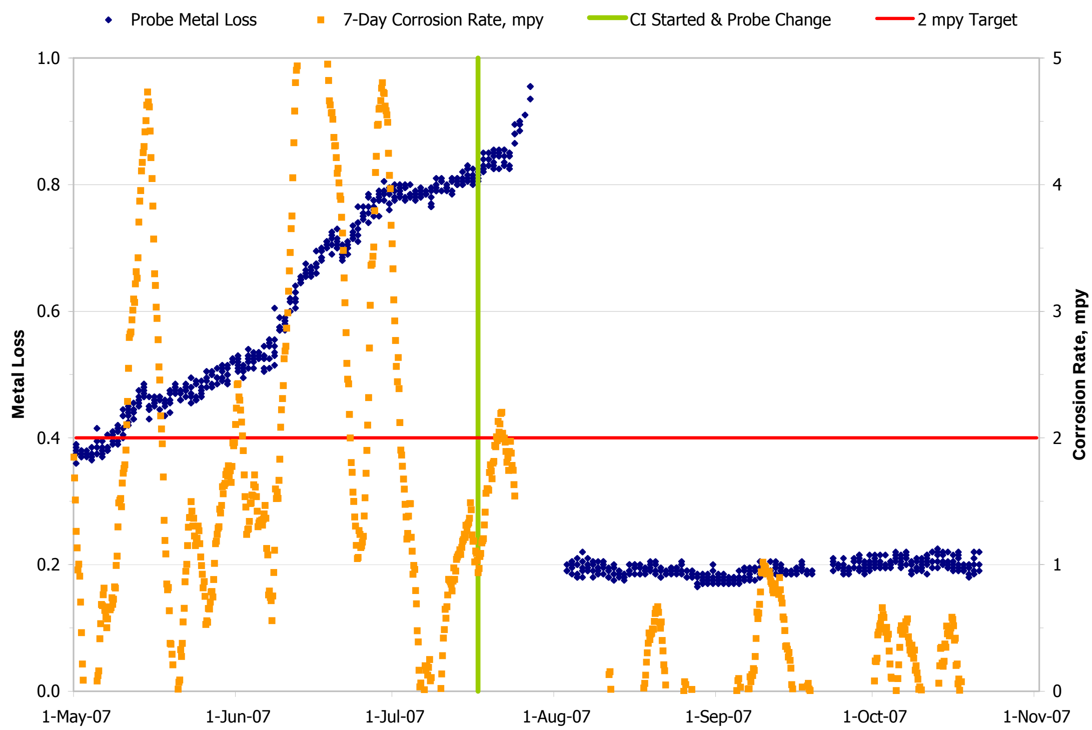
In 2005, approximately 5,000 feet of the K-Pad line was replaced. The damage was associated with low fluid velocities, allowing solids to accumulate in the line. Although the corrosion mechanism appeared to be under control, a decision was made in 2006 to replace the K Pad flow line. The line was mothballed and shut-in during May, 2006 and was replaced in 2007. The line is inhibited with continuous corrosion inhibitor and is maintenance pigged monthly.

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 with corrosion inhibitor. Since the production from S-Pad feeds into the K Pad flow line, it was also mothballed and shut-in during 2006 until the K Pad flow line could be replaced. The flow line is maintenance pigged monthly.

In 2006, the continuous inhibition of the production flow line carrying production from F, L, and C Pads was increased due to corrosion activity determined via the inspection program. The effectiveness of this inhibition change continues to be monitored.

The B-Pad production line had continuous corrosion inhibition facilities installed in 2006 and is currently treated at a concentration of 100 ppm.

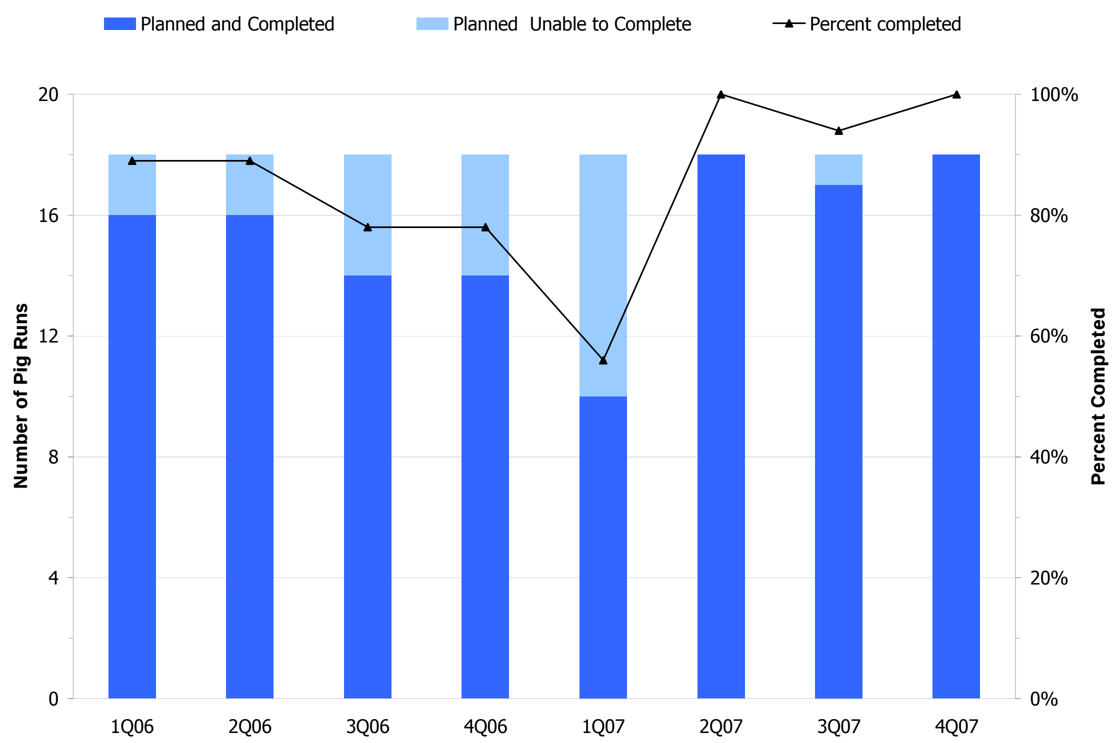
The Tract 14 production flow lines at I-Pad and J-Pad were fitted with continuous corrosion inhibition facilities. Continuous inhibition in these lines began in July, 2007. Initial results from corrosion monitoring indicate a significant reduction in corrosion rate as shown in ACT Figure A.5.



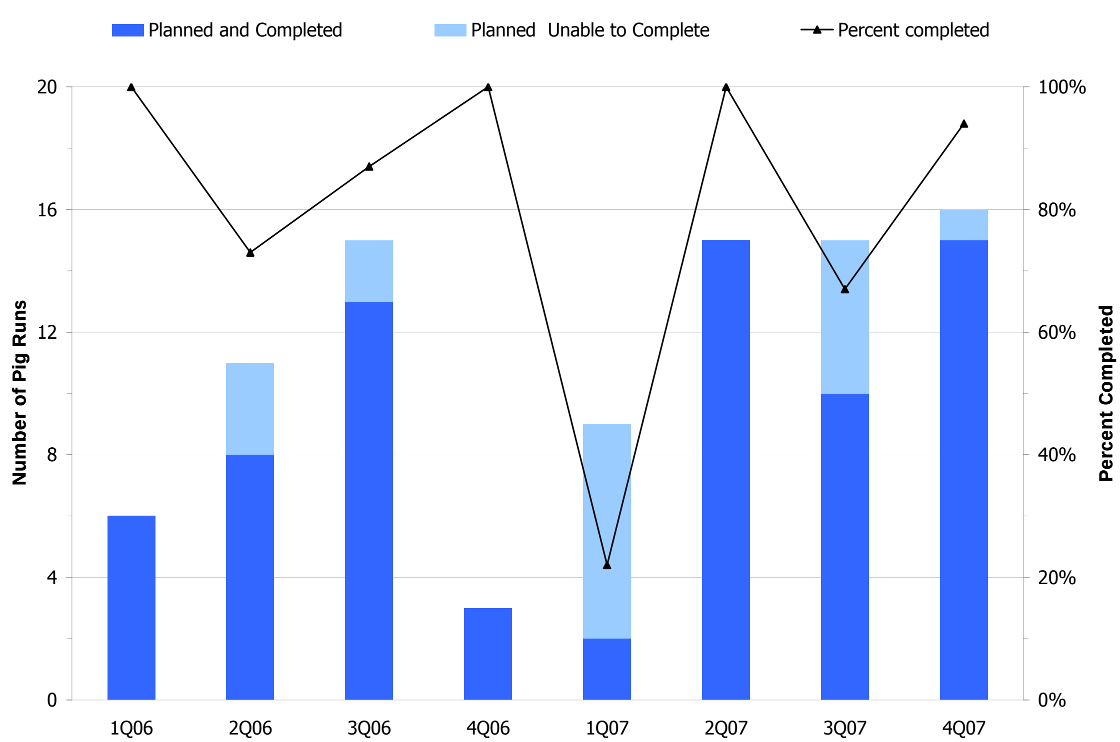
ACT Figure A.5 ER Probe Response, MPU Flow Line, CI Injection

In addition, Milne Point relocated all of the Tract 14 (Pads G, H, I and J) buried well pad piping above ground in 2006.

The quarterly maintenance pigging performance for the MPU produced water lines and the 3-phase lines are shown in ACT Figure A.6 and ACT Figure A.7, for the years 2006-2007. The decrease in pigging runs performed in the first quarter of 2007 is the result of addition and training of a new pigging crew for the MPU field operations. The decrease in activity in 3-phase system during the third quarter of 2007 was the result of tying in new pigging facilities for the K Pad line replacement.



ACT Figure A.6 MPU PW Maintenance Pigging Performance



ACT Figure A.7 MPU 3-phase Maintenance Pigging Performance

Section A.3 Northstar

Section A.3.1 Monitoring

ACT Table A.4 shows the results of the corrosion monitoring program at Northstar for 2007. ACT Figure A.8 shows the historical WLC performance for the three phase system.

System	Location	Access Fittings	% WLC <2 mpy
Oil Production		19	89%
Water Disposal			
	Upstream of Disposal Facility	9	100%
	Downstream Disposal Facility	2	50%

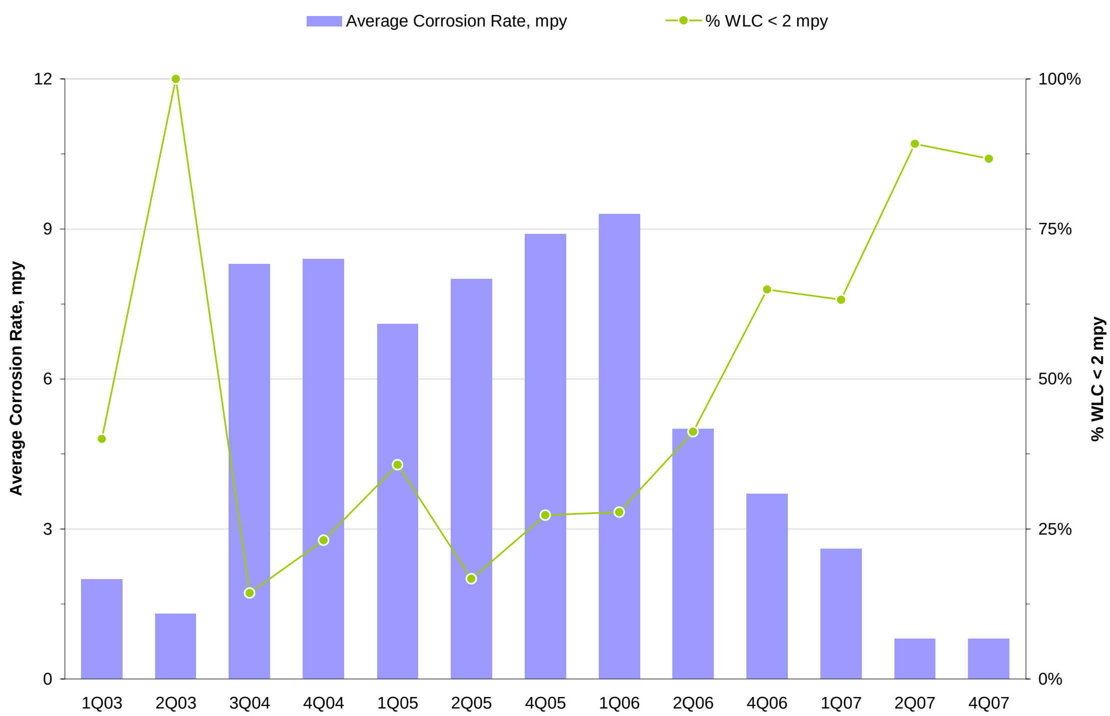
ACT Table A.4 Northstar Corrosion Coupon Monitoring, 2007

The 3-phase production is currently inhibited; however, monitoring data previously indicated that the uninhibited well line corrosion rates were above the 2 mpy target. This was 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 higher corrosion rates seen on weight loss coupons from the upstream locations indicated the need for inhibition of the upstream section. The relocation of the corrosion inhibitor injection point further upstream was completed in 2007. Additionally, all new wells will be equipped to inject corrosion inhibitor at the well head. A significant portion of the coupon data still reflect uninhibited conditions as these changes were made throughout the year and many of the coupons did not see inhibitor for the full exposure period. The two wells exhibiting corrosion rates above 2 mpy in 2007 have both been mitigated with corrosion inhibitor increases.

In addition to the weight loss coupon data, an electrical resistance probe was installed on the main production line in Jul-06 to provide additional corrosion rate feedback. This probe data has been useful in correlating the corrosion rate excursions to periods when the corrosion inhibitor was being under-injected. Occasional excursions above 2 mpy have been attributed in general to noise in the system, however all excursions are analyzed to determine if the wells are receiving the proper amount of inhibitor.

The higher corrosion rates experienced in one of the water disposal wells can be attributed to oxygenated mud from the grind-and-inject plant (mud) and the addition of oxygenated fluids from the sewage treatment facility. Although an oxygen scavenger was tested in the grind-and-inject fluids, it was found to be ineffective due to the low fluid temperatures. This system is being inspected on a quarterly basis to monitor for active 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 mud from the drilling operation plant.



ACT Figure A.8 Northstar 3-Phase Oil Corrosion Rate Trend

Section A.3.2 Mitigation

Northstar began production in November 2001. Production fluid corrosivity is moderate, but has been increasing over time with the injection of higher CO_2 GPB gas into the reservoir for pressure maintenance purposes.

Northstar is inhibited with continuous injection of corrosion inhibitor into the well production lines. As of the end of 2007, all wells have had the chemical injection location moved upstream to the wellhead assuring all portions of the carbon steel well line are now inhibited. A new chemical injection skid was also installed at Northstar during 2007. The new system allows for testing and adjusting of individual well chemical injection rates at a central location rather than by visiting each individual well. The advantage is that all wells can now be spot checked on a routine basis to confirm proper chemical injection.

Although the corrosion activity in the disposal system appears to be decreasing, options for reducing the dissolved oxygen content of the fluids introduced into the disposal system from the effluent are under review.

Section A.4 Badami

Section A.4.1 Monitoring

Badami currently has no WLC-monitoring program, and relies on the inspection program presented in Section B.4 to provide corrosion control feedback.

Section A.4.2 Mitigation

Production from the Badami field began in 1998, however low production necessitated periods of shut-in of the field from the third quarter of 2003 and throughout all of 2004 and again in the summer of 2007. Shut-ins consist of de-inventory and warm storage of major equipment. During production periods, Badami's production fluids are considered a low risk from a corrosivity standpoint, as there is little water production and very low CO_2 content. Startup and periodic inspections were performed on existing equipment during the shut in periods.

Corrosion inhibition is currently not required at the Badami field based on modeling of fluid corrosivity, the low water-cut, and the results from the facility and pipeline inspection program. In 2007 the field was again placed in warm shutdown.

ACT Section B

External/Internal Inspection

Section B ACT External/Internal Inspection

Section B.1 Endicott

The duplex stainless steel well lines are subject to erosion and are monitored through a velocity monitoring and inspection program. 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. Beginning in late 2007, carbon steel C-spools are being replaced with duplex stainless steel on an as-needed-to-replace basis. ACT Table B.1 reflects the historical inspection activity level for Endicott since 2002.

Service	Length, miles	Internal Inspection						External Inspection					
		2002	2003	2004	2005	2006	2007	2002	2003	2004	2005	2006	2007
Oil X-country lines	3.5	4 (in vault)	14 (4 in vault)	4 (in vault)	14 (4 in vault)	92 (4 in vault)	-	4 (in vault)	4 (in vault)	4 (in vault)	4 (in vault)	19 (in vault)	-
Oil - Well Pads	2.5	1,327	1,531	1,990	2,637	2,925	3,045	-	-	-	-	-	-
Water X-country lines	3.5	104	229	163	119	136	216	4 (in vault)	4 (in vault)	723	30	22	8
Water - Well Pads	1.7	200	224	135	309	319	207	9 (in vault)	5	-	8	-	-
Gas X-country (GLT/MI)	7	15	45	4 (in vault)	12 (4 in vault)	53 (4 in vault)	-	4 (in vault)	774	4 (in vault)	34 (4 in vault)	21 (4 in vault)	184
Gas - Well Pads	1.2	26	29	10	61	41	44	9 (in Vault)	69	-	28	-	959
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**	**3,566**	**3,512**	**40**	**856**	**731**	**104**	**62**	**1,151**

ACT Table B.1 Endicott Summary of Lines and NDE Inspections

Section B.1.1 External Inspection

Cased flow lines at Endicott are inspected at the intervals noted in ACT Table B.2. In addition, the vaults where the production, Inter-Island Water Line, and gas-lift pipelines pass are visually inspected annually. Both below grade sections of the Inter-Island Water Line and the Inter-Island Gas Line were replaced with carbon steel in 2007 at the "Y" road intersection. In addition, the casings for these road crossings were extended above grade and the ends sealed to minimize water infiltration into the vaults.

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

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

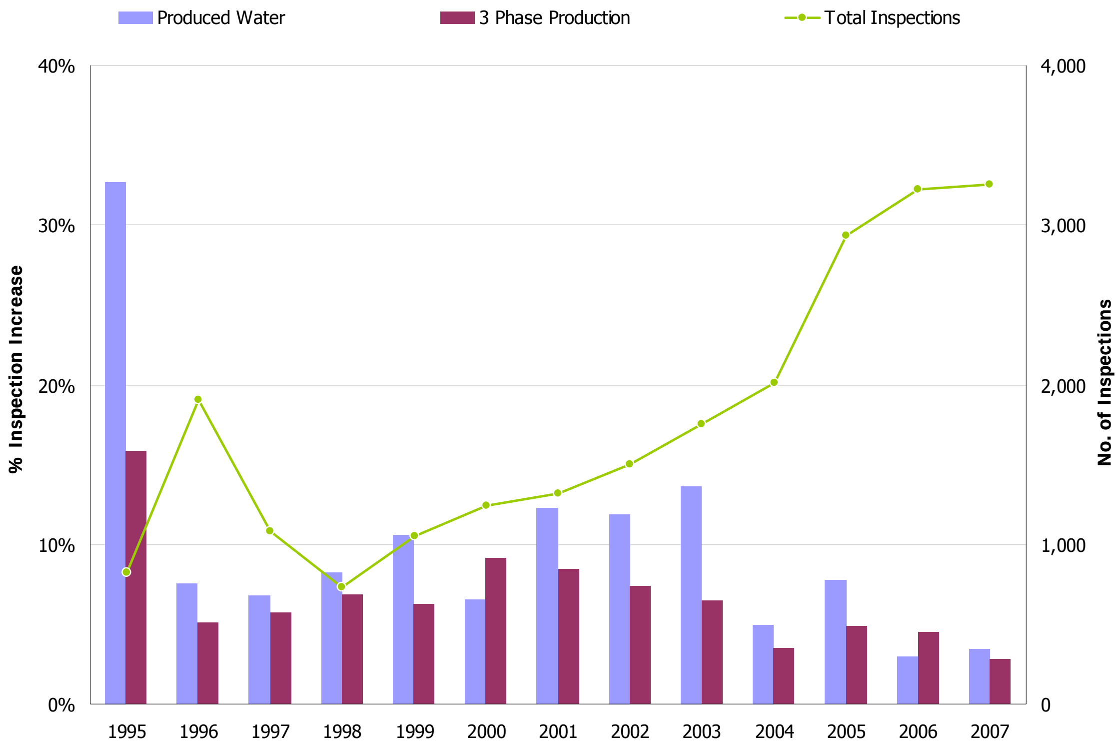
ACT Table B.2 Cased Piping Inspections

Section B.1.2 Internal Inspection

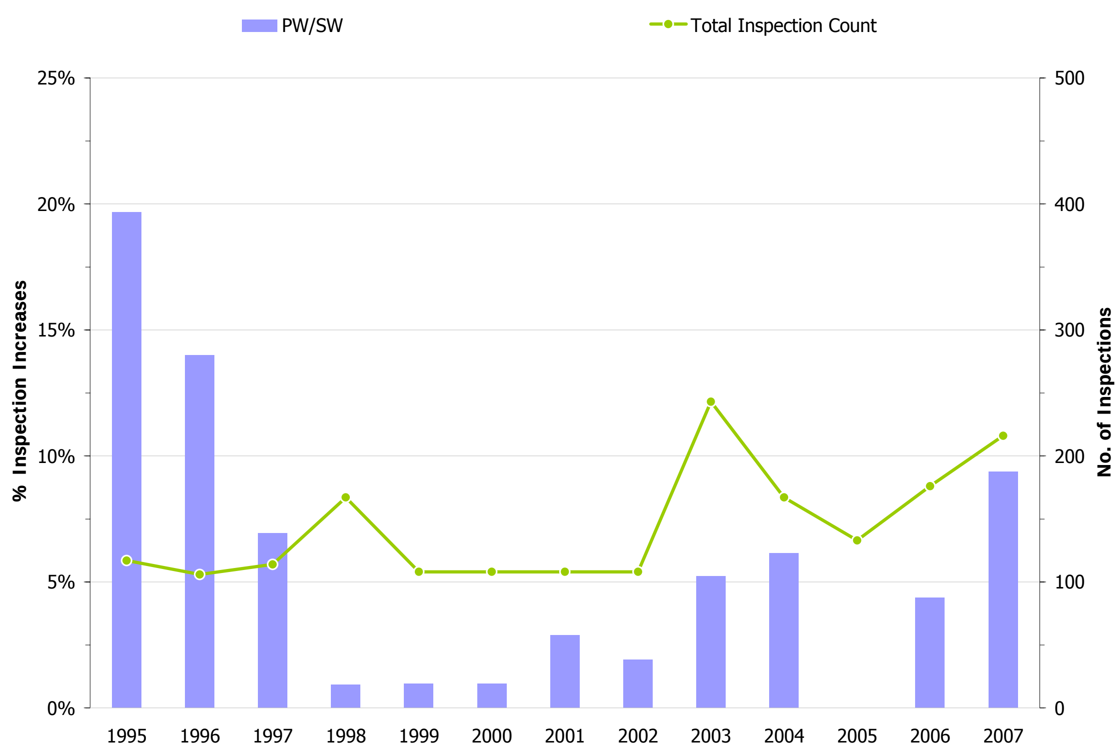
ACT Figure B.1 and ACT Figure B.2 indicate the percentage of inspection increases since 1995 for the well lines and flow lines at Endicott. There were no increases in the 3-phase, DSS production cross-country line. The inspection data for the 3-phase production system are used to alert Operations of potential replacements of the carbon steel C-Spools at the wellheads. Beginning in 2007, the carbon steel C-Spools are being replaced with duplex stainless steel spools on as-needed basis.

Corrosion activity in the water injection well lines had been increasing since 2000 and was addressed by increasing the corrosion inhibitor concentration in 2003 and again in 2004. The additional corrosion inhibitor reversed the increasing trend in 2004; however there was an increase in 2005. This trend has reduced in 2006 and 2007. All of the 2007 increases are slight, whereas the increases during 2001-2003 were more significant.

ACT Figure B.2 shows a significant decline of inspection increases from 1995 through 1998 for the IIWL at Endicott. There has been an increasing trend in inspection increases from 1998 through 2004, and again in 2006-2007; 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 is shown in ACT Figure B.3 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 during 2005-2007. Adding additional inspection locations are being evaluated for the IIWL frequent monitoring program as a result of the 2006 smart pig run.

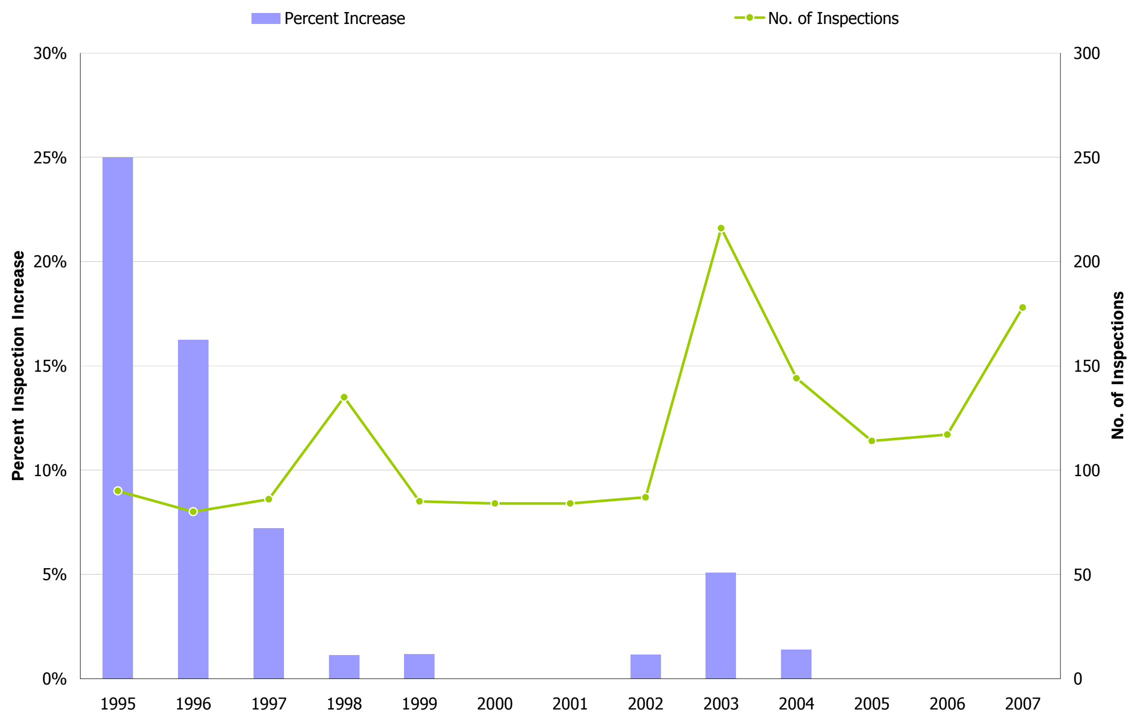


ACT Figure B.1 Endicott Well Line Internal Inspection Increases



ACT Figure B.2 Endicott IIWL Internal Inspection Increases

ACT Figure B.3 shows the percent inspection increases and the number of inspections since 1995 for the IIWL that are monitored on a frequent basis. No inspection increases were identified in 2007, the third year in a row.



ACT Figure B.3 Endicott IIWL Frequent Inspection Results

Section B.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. ACT Table B.3 reflects the historical inspection activity for MPU since 2002. The S-Pad pipeline was inspected using ILI.

Service	Length, miles	Internal Inspection						External Inspection					
		2002	2003	2004	2005	2006	2007	2002	2003	2004	2005	2006	2007
Oil x-country lines	24	80	465	480	186	817	1,450	-	964	70	-	101	1,255
Oil – Well Pads	N/A[1]	754	2,754	2,049	1,990	1,900	1,452	47	N/A[2]	-	14	6	65
Water x-country	15	35	185	249	53	119	1,437	-	97	1,065	154	83	162
Water – Well Pads	N/A[1]	449	635	863	988	1,088	1,055	23	N/A[2]	-	9	10	49
Gas x-country	14	-	20	26	-	4	61	-	522	603	-	4	480
Gas – Well Pads	N/A[1]	283	99	83	56	82	131	-	N/A[2]	-		-	922
Water/Alternating Gas Well Pads	N/A[1]	-	230	298	214	173	159	-	-	-		-	-
Totals		**1,601**	**4,388**	**4,048**	**3,487**	**4,183**	**5,745**	**70**	**1,583**	**1,738**	**177**	**204**	**2,933**

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

The Tract 14 (G, H I, and J Pads) below ground pad piping has been removed from service and new piping was installed above ground in 2006. With respect to the remaining below grade piping, excavations were conducted on Tract 14 flow lines and L-Pad and C-Pad piping. A total 5,246 inspections were conducted in 111 excavation sites throughout the MPU field. This significant increase was performed to expand the coverage of existing piping and to develop a better understanding of line condition.

Of the 5,246 inspections:

- 513 inspections were repeat locations, of which 105 locations (20%) had increases in damage. Of these 105 locations showing increases in corrosion activity, 57 were slight increases in damage, 39 moderate and nine were large. All increases greater than slight were in produced water service.
- The repeat inspection intervals range from approximately 6 months to ten years, with an average of 2.6 years.
- 4,733 locations were baseline inspections.

Section B.2.1 External Inspection

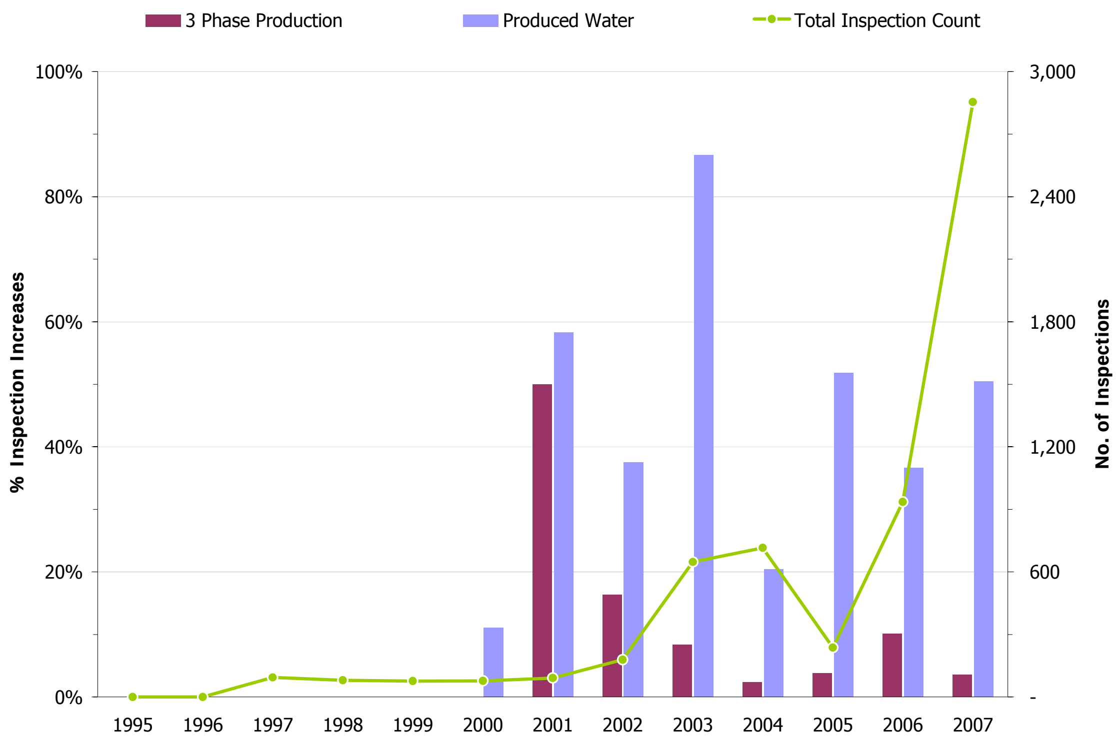
ACT Table B.4 summarizes the above-ground external inspection program at MPU since 1997. Only one inspection increase was noted from a total 197 repeat inspections. A total of 1,398 locations were baseline inspections.

Year	Total Insp.	Repeat Insp.	Increases	% Increases
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	-	-
2006	190	30	3	10
2007	1,595	197	1	0.5

ACT Table B.4 MPU External Inspection Summary for Above-Ground Piping

Section B.2.2 Internal Inspection

The results of internal inspection program can be seen in ACT Figure B.4. The figure shows the total number of flow line inspection items has been, in general, increasing since 2001.



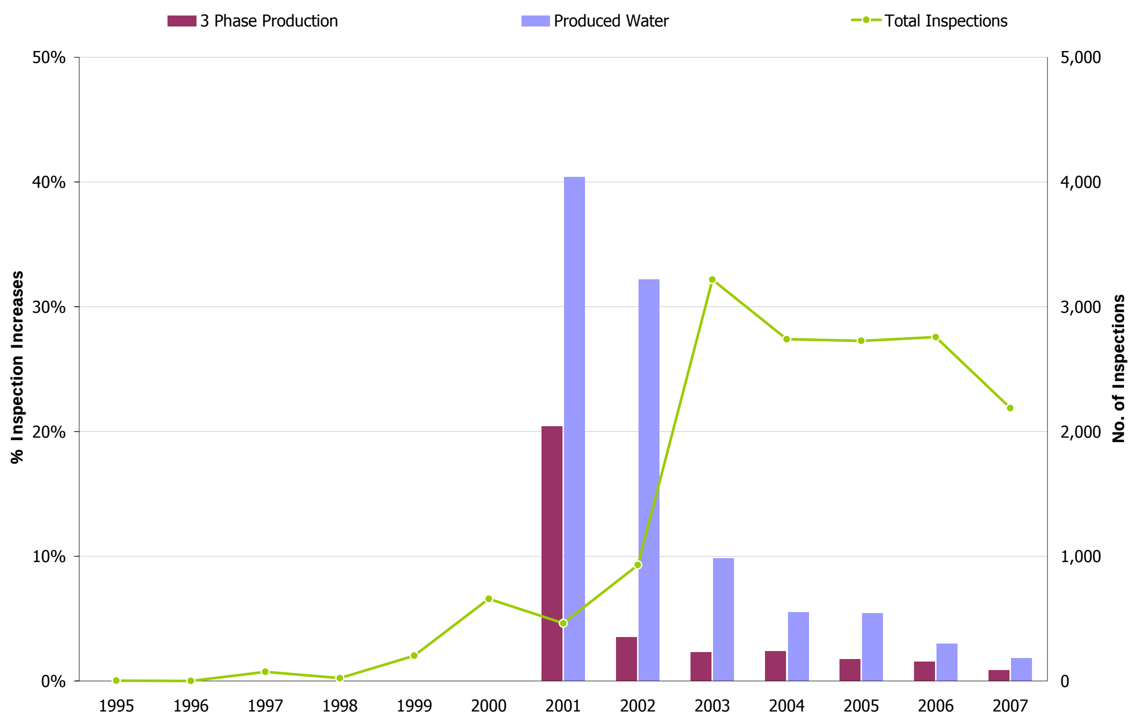
ACT Figure B.4 MPU Flow Line Internal Inspection Increases

Overall the 3-phase flow lines are continuing to show a decreasing trend of locations with corrosion activity as additional inhibition locations are established. In 2007, the Tract 14 main trunk line was placed on continuous inhibition.

A total of 110 inspection increases in the produced water flow lines were noted for 2007. Whereas the corrosion monitoring indicates this system is under better control as compared to pre-inhibition, the inspection data suggests further intervention is required.

ACT Figure B.5 shows the percentage of inspection increases and number of inspections on well lines. Inspection activity has remained constant at approximately 2,600 items per year since 2004. The reduction in internal inspection activity for 2007 is due to the significantly increased excavation activity in 2007. The PW well line corrosion activity continues to show a decreasing trend over the past several years.

The 3-phase well line damage rate has remained essentially level over the past several years, at about 2% of the repeat locations showing an increase in corrosion activity. There is currently no corrosion inhibition program for the production well lines.



ACT Figure B.5 MPU Well Line Internal Inspection Increases

Section B.3 Northstar

ACT Table B.5 shows the historical inspection activity for Northstar since 2002.

Service	Length, feet	Internal Inspection						External Inspection					
		2002	2003	2004	2005	2006	2007	2002	2003	2004	2005	2006	2007
Oil Pipe rack	1,200	-	-	-	-	-	-	-	-	-	-	-	166
Oil – Well Pad	280	106	114	204	230	215	502	-	-	-	-	-	-
Water Pipe rack[1]	2,400	-	-	-	-	-	-	-	-	-	-	-	34
Water – Well Pad[1]	70	17	25	46	53	34	79	-	-	-	-	-	-
Gas Pipe rack	600	-	-	-	-	-	-	-	-	-	-	-	43
Gas – Well Pad	140	26	65	77	112	67	-	-	-	-	-	-	-
Totals		**149**	**204**	**327**	**395**	**316**	**581**	**-**	**-**	**-**	**-**	**-**	**243**

[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.

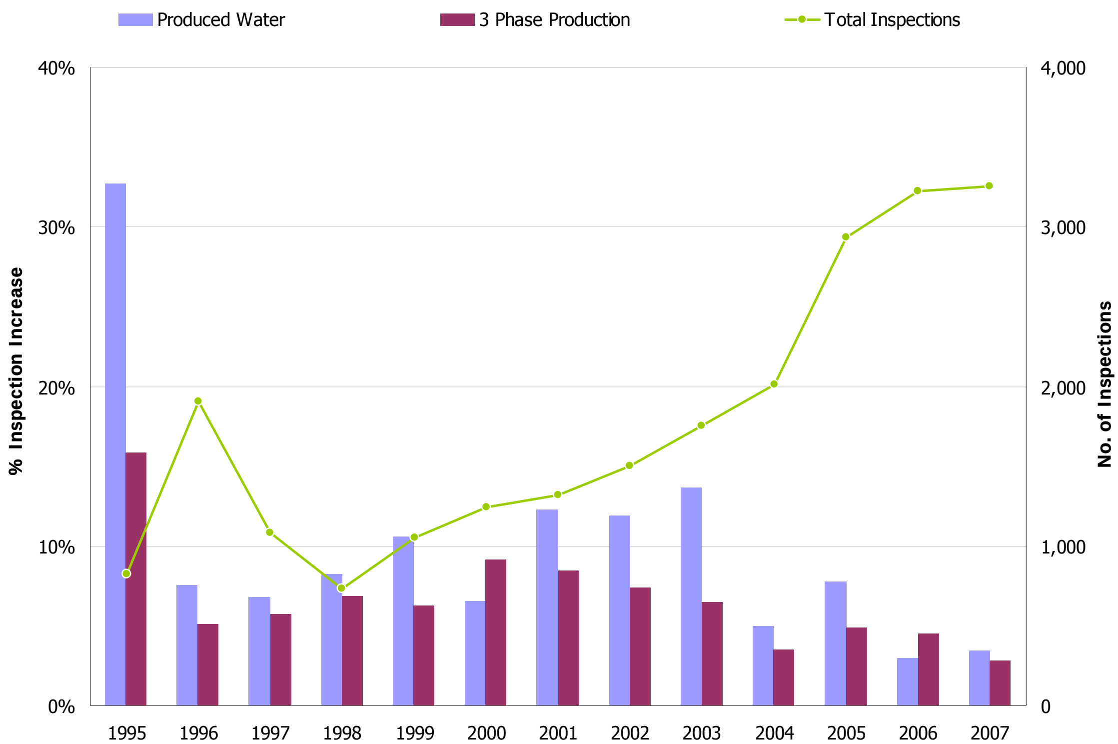
ACT Table B.5 Northstar Summary of Lines and NDE Inspections

Section B.3.1 External Inspection

A total of 243 external inspections were performed at Northstar in 2007. These were primarily on the production, gas and produced water headers. A total of 237 locations were baseline TRT inspections and six were UT locations as follow up to the TRT as part of a mitigation effort. Pipe condition was rated good for the locations inspected (primarily A and B rank, with one C rank).

Section B.3.2 Internal Inspection

Both the 3-phase system and the produced water system are showing decreasing trends in inspection increases for 2007 (refer to ACT Figure B.6). By the end of 2007, all 3-phase well lines had the corrosion inhibitor injection locations moved further upstream to the well head, assuring the entire well line was inhibited. Inspection increases in the disposal well are believed to be associated with oxygenated fluids from the drilling mud plant and also oxygenated fluids introduced from the effluent system. The disposal system is inspected on a quarterly basis.



ACT Figure B.6 Northstar Well Line Internal Inspection Increases

During 2007, a total of 581 well line inspections were completed including 502 inspections in the 3-phase and 79 inspections in the disposal systems. It has been stated in previous reports that the 3-phase and gas system locations that were showing increasing corrosion were all in heavy wall target tees and elbows. This heavy wall piping presents a significant challenge to determining whether the wall loss is due to corrosion or results from 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.

Section B.4 Badami

ACT Table B.6 summarizes this inspection program for Badami during 2007.

Service	Feet	Int. Insp.	Ext. Insp.
Oil –Well Pad	840'WL , 320' HDR	45	-
Gas	240'WL, 320'HDR	7	-
Disposal Well	400'	8	-

Note Badami does not have an active water injection system.

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

Section B.4.1 External Inspection

No external inspections were performed at Badami during 2007.

Section B.4.2 Internal Inspection

The Badami Field was in warm shutdown from August of 2003 to October of 2005. Badami produced again until August of 2007, at which time it was placed back into warm shutdown. A post shutdown and follow up inspection was performed to monitor shut in status. Although the data set is limited, inspections support the overall assertion that Badami fluids have low corrosivity. ACT Table B.7 is a summary of well line inspections for Badami. No inspection increases were noted in 2007.

Year	Oil	Gas	Disposal	Total	Repeat Inspections	Locations with Increased Damage
1998	28	3	-	31	0	-
1999	-	-	-	-	-	-
2000	15	6	6	27	18	-
2001	-	-	-	-	-	-
2002	5	-	-	5	4	-
2003	21	5	3	29	19	1
2004	18	5	3	26	26	-
2005	29	7	4	40	34	1
2006	66	14	18	98	96	4
2007	45	7	8	60	60	-

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

ACT Table B.7 Inspection Summary of Badami Well Lines

Section B.5 ACT Inspection Summary

ACT Table B.8 summarizes the overall ACT inspection activity since 2000. As can be seen, the activity level has remained approximately constant at ~3,400 items per year through 2002. A significant increase in inspections occurred in 2003. The significant increase in inspection count in 2007 is accounted for primarily by additional dig locations at MPU on flow lines, extended external inspections at MPU, and an increase in inspection activity at Northstar.

	Surface	2000	2001	2002	2003	2004	2005	2006	2007
Endicott	Int	1,346	1,480	1,686	2,072	2,216	3,152	3,566	3,512
	Ext	16	16	40	856	731	104	62	1,151
	Total	**1,362**	**1,496**	**1,726**	**2,928**	**2,947**	**3,256**	**3,628**	**4,663**
Milne Point	Int	1,419	629	1,601	4,388	4,048	3,487	4,109	5,745
	Ext	378	1,577	70	1,583	1,738	177	204	2,933
	Total	**1,797**	**2,206**	**1,671**	**5,971**	**5,786**	**3,664**	**4,313**	**8,678**
Northstar	Int	-	16	149	204	327	395	316	581
	Ext	-	-	-	-	-	-	-	243
	Total	**-**	**16**	**149**	**204**	**327**	**395**	**316**	**824**
Badami	Int	27	-	5	29	26	40	98	60
	Ext	-	-	-	-	-	-	-	-
	Total	**27**	**-**	**5**	**29**	**26**	**40**	**98**	**60**
	Grand Total	**3,186**	**3,718**	**3,551**	**9,132**	**9,086**	**7,355**	**8,355**	**14,225**

ACT Table B.8 Overall Inspection Activity Summary

ACT Section C

Corrosion and Structural Related Repair Activities and Spills/Incidents

Section C ACT Corrosion & Structural Related Repairs and Spills

Section C.1 Repair Activities

ACT Table C.1 summarizes the repair activity for ACT. There were 6 repair locations identified for ACT. Two were external repairs at Milne Point; one due to mechanical damage by a saw blade on the K-Pad flow line and a sleeve repair for external corrosion on the B-Pad 3-phase line. There were two repairs for external corrosion at Endicott on the Inter-Island Water Line and two repairs at Endicott for an internal corrosion/erosion on 1-19 and well line leak on 1-63. There were no repairs at Northstar or Badami.

Service	Type	Internal	External	Mechanical
Oil	FL	-	1	1
	WL	2	-	-
Gas	FL	-	-	-
	WL	-	-	-
PW	FL	-	2	-
	WL	-	-	-
	Total	**2**	**3**	**1**

ACT Table C.1 ACT Repair Activity

Section C.2 ACT Corrosion and Structural Related Spills and Incidents

There was one corrosion related leak in ACT in 2007. ACT Table C.2, ACT Table C.3, ACT Table C.4, and ACT Table C.5 summarize leak/save and mechanical repair data for Endicott, MPU, Northstar and Badami, respectively.

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

ACT Table C.2 Endicott Leak/Save and Mechanical Repair Data

One internal leak occurred at Endicott in 2007. The leak occurred on 3-phase well line 1-63 and the mechanism was corrosion/erosion that occurred during a backflow event. One save was recorded on the 1-19 well line as noted above.

Service	Leaks	Saves
Oil x-country	-	14
Oil Well Pads	-	-
Water x-country	-	-
Water Well Pads	-	-
Gas x-country	-	-
Gas Well Pads	-	-

ACT Table C.3 Milne Point Leak / Save and Mechanical Repair Data

There were no leaks and 2 saves for MPU in 2007. These saves were associated with the K-Pad and B-Pad 3-phase lines.

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

ACT Table C.4 Northstar Leak / Save and Mechanical Repair Data

There were no leaks or saves for Northstar in 2007.

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

ACT Table C.5 Badami Leak / Save and Mechanical Repair Data

There were no leaks or saves for Badami in 2007.

ACT Section D

2008 Corrosion Monitoring and Inspection Goals

Section D ACT 2008 Corrosion Monitoring and Inspection Goals

Section D.1 Endicott

The IIWL corrosion inhibition and monitoring program will continue, in order to maintain the current decreased trends in corrosion activity.

A new inhibitor will be considered in the Endicott water injection system pending the trail at Milne Point Unit.

The well line erosion rate monitoring program will continue.

Carbon steel C-Spools will continue to be replaced on an as-needed basis with duplex stainless steel.

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

Section D.2 Milne Point

The 2008 plan will continue the inspection program to provide feedback for corrosion control and mechanical integrity.

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 2008.

Monitoring and reporting results of the new inhibitor trial in the Milne Point Unit water injection system will continue, incorporating feedback from the inspection program.

With the recent upgrade to the corrosion monitoring program, the new data will be incorporated into the control program.

Two VSMs were identified for leveling in 2007 and are planned to be leveled in 2008.

Section D.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 evolves.

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.

The gas injection system corrosion will continue to be monitored through inspection.

Section D.4 Badami

While on warm shut down, Badami will continue to be evaluated through the integrity plan to ensure that the plant is maintained properly.

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
TR	Transit line
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

Charter Agreement – Corrosion Related Commitments
Work Plan
Guide for Performance Metric Reporting

Charter Agreement – Corrosion Related Commitments

The BPXA contact for all corrosion matters relating to the Charter Agreement is,

Bill Hedges, Corrosion Strategy and Planning Manager

E-mail:bill.hedges@bp.com

Phone: (907) 564-4466

Project Achievements

Oct-Nov 2000	Work Plan agreed between BPXA/PAI and ADEC (Appendix 2a)
March 2001	1st Annual Report submitted to ADEC
April 2001	1st 2001 Meet and Confer session held
Oct-Dec 2001	Consultations with ADEC and ADEC's consultant
November 2001	2nd 2001 Meet and Confer session held
Dec 01-Jan 02	Developed and agreed corrosion management metrics
February 2002	BPXA/PAI and ADEC agreed on performance metrics (Appendix 2b)
March 2002	2nd Annual Report submitted to ADEC
April 2002	1st 2002 Meet and Confer session held
November 2002	2nd 2002 Meet and Confer session held
March 2003	3rd Annual Report submitted to ADEC
May 2003	1st 2003 Meet and Confer session held
October 2003	2nd 2003 Meet and Confer session held
March 2004	4th Annual Report submitted to ADEC
April 2004	1st 2004 Meet and Confer session held
August 2004	North Slope Field Trip
March 2005	5th Annual Report submitted to ADEC
May 2005	1st 2005 Meet and Confer session held
August 2005	North Slope Field Trip
March 2006	6th Annual Report submitted to ADEC
May 2006	1st 2006 Meet and Confer session held

November 2006	2nd 2006 Meet and Confer session held
March 2007	7th Annual Report submitted to ADEC
April 2007	1st 2007 Meet and Confer session held
November 2007	2nd 2007 Meet and Confer session held
March 2008	8th Annual Report submitted to ADEC

Annual Charter Timetable

March 31st	Annual Report submitted
April 30th	1st Semi-Annual Review/Meet and Confer
October 31st	2nd Semi-Annual Review/Meet and Confer

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

- **3-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.
- S**eawater (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 year 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 will 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.

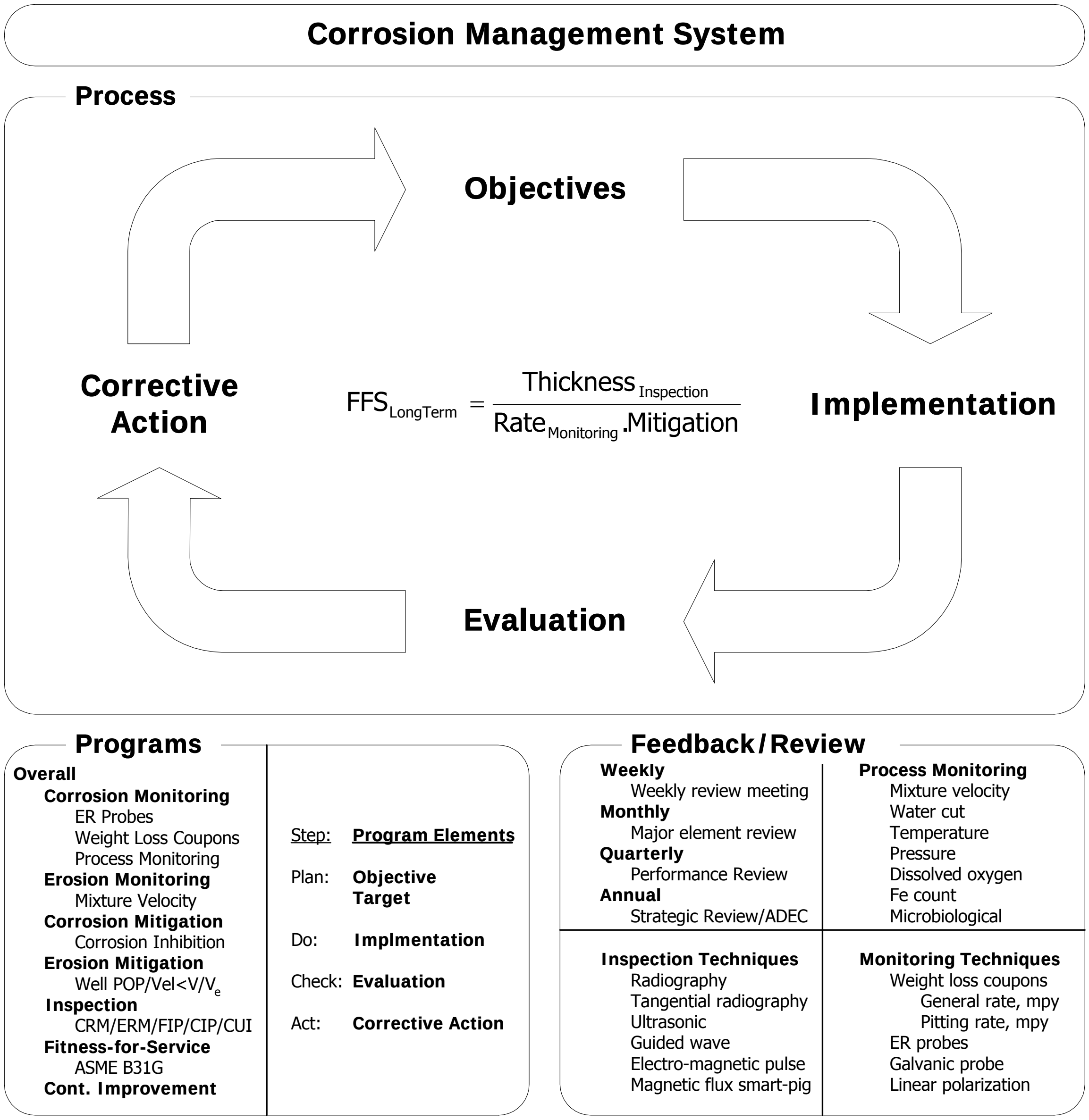


Figure 1 Overview of the Corrosion Management Process

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,

Step	Activity	Description
Plan	**Objective**	The program objective and purpose
	Target	The metric against which performance is assessed
Do	**Implementation**	Implementation plan to achieve objective
Check	**Evaluation**	Method to evaluate performance of plan against target
Act	**Corrective Action**	The action required to correct deviation from target

Table 1 Corrosion Management Process

Appendix 3.1.3 Objectives and Targets

The objectives[11] for the CMS are set in order to support the delivery of the corporate objective and BPXA objectives described in Part 1 – Overview. For the purposes of the CMS these can be translated into the corrosion management objectives of;

- Eliminate corrosion and erosion related failures,
- Provide Fit-For-Service infrastructure to the end of field life.

Based on these objectives, individual targets are set for the corrosion, erosion, mitigation and inspection programs, which in combination are designed to deliver the objectives. The overall business objectives and individual program objectives and targets are described in detail in Table 9, Table 10 and Table 11.

For example, the weight loss coupons (WLC) in the 3-phase production system have a corrosion rate target of 2 mils per year (mpy). The monitoring program objective is to meet or beat this target, which means an actual WLC corrosion rate of 2 mpy or less (WLC ≤2 mpy).

Appendix 3.1.4 Implementation

There are a number of different corrosion monitoring and inspection techniques, each of which has both advantages and disadvantages. The advantages and disadvantages, or strengths and weaknesses, make the results from an individual technique more or less applicable depending on the application circumstances.

Table 12, Table 13, and Table 14 summarize the main categories of corrosion monitoring, process monitoring, inspection techniques and briefly summarize relative strengths and weaknesses for different applications.

Appendix 3.1.5 Evaluation

The elements of the CMS have to be applied to each system at GPB to reflect their applicability and efficacy. The corrosion and erosion monitoring, inspection and mitigation practices for the major services and equipment type are summarized in Table 15.

[11] In addition to Charter Work Plan, some information is supplied to provide additional context and help in understanding BPXA corrosion management activities

The results from each of the corrosion management programs are reviewed on a regular basis to provide feedback and to take any necessary corrective action based on deviation from target performance. In general, the major review cycles within the CMS are presented in Table 2.

Review	Description
Weekly	A weekly internal review meeting at which the latest corrosion monitoring, mitigation, inspection and process data are analyzed and reviewed, and any tactical changes implemented
Monthly	Monthly summary of the major elements of the program are reviewed for the need for longer term corrective action
Quarterly	Quarterly strategic performance review held in order to ensure that the implementation plan is delivering the strategic objectives
Annual	Annual program and strategy review designed to review the strategic direction of the program and review effectiveness of the current programs in delivering the strategic direction, e.g. Annual Report to ADEC

Table 2 Corrosion Management Feedback Cycles

Based on the results of the evaluation process, corrective action plans are developed and the overall management program and strategic direction are reviewed.

Appendix 3.1.6 Corrective Action

Corrective actions provide feedback to the adjustment and setting of Objectives and Targets. Corrective actions can be broken down into five basic categories;

- Chemical Mitigation,
- Operational Intervention,
- Reduce Maximum Operating Pressure (Derate),
- Repair/Replacement,
- Abandon or Remove from Service.

Chemical mitigation is discussed in detail in Section A. Operational intervention centers on the GPB Velocity Management Program that is designed to control internal mixture velocity below target values dependent on equipment type, water cut and line size. Repair/replacement programs are driven by the inspection findings and include mechanical sleeves, pipe work refurbishment, and pipeline replacement.

Appendix 3.2 Corrosion and Inspection Data Management

In order to deliver a comprehensive corrosion management program and manage the extensive corrosion monitoring and inspection activity, it is necessary to have an active and structured electronic database.

With the introduction of single-operatorship at Greater Prudhoe Bay one of the major problems faced by the CIC Group was the integration of two historical data sets for inspection, corrosion monitoring and corrosion mitigation information.

There has been a significant investment in resources in order to bring together these two different histories from incompatible databases based on early 1990's technology.

Appendix 3.2.1 MIMIR Database

The database development effort has involved a dedicated team of software developers and also significant resources from within the CIC Group. The program is currently a “work in progress” and in 2005 BP/CIC will continue work on the development of chemical management, electronic data recording, tank and vessel, and standard reporting modules.

Users of the system are provided two primary methods for accessing data stored in the database. The first is a custom user interface written in Microsoft Visual Basic©, and the second is through ad-hoc data query tools such as BrioQuery© and BusinessObjects© which allow free-form SQL© access to the data.

Checks for data integrity are provided at a number of different levels including error checking at the point of data capture and data entry, regular reviews of data quality, and data entry rules within the database.

The data is continuously monitored for integrity, quality and consistency; as a consequence any errors detected are corrected as they are found. In addition, as better analysis tools become available through further integration then records are amended to reflect the improved level of analysis.

As a result of the ongoing quality effort and the tracking of production/service changes, this is a 'live' database and therefore as the system changes then the records returned will change. The following are some of reasons why returned values change through time,

Quality Control and Audit A fundamental design philosophy for the database was that errors should be corrected through time as they are discovered. Therefore as the database is used and the quality control rules and procedures applied, data-entry, translation and record-keeping errors are eliminated.

Equipment Service Changes The database tracks active, in or out-of-use equipment, and equipment service changes. As a piece of equipment moves through different services and different status, then the data in the database tracks the equipment status.

Transition Issues As noted above, the two historical databases, heritage East and heritage West, were incompatible with very different structures and data fields. Therefore these have had to be translated to the new system. As the quality control and audit tools are applied to the translated data, error and mistranslations are removed.

Time The database is in active use with data being added everyday, given that there is sometimes a time delay between the reporting date and entry date then the data totals can and do change.

Table 3 gives an illustration of the number of records and the rate at which those records are accumulated on an annual basis in the database. The table clearly shows the level of complexity and volume of data involved in managing the corrosion programs at GPB.

In addition, the table also shows that the range and types of information being gathered is being improved through time to enable better overall corrosion management at the GPB. The most notable examples of this increasing range of coverage of the corrosion and inspection database is the inclusion of the production and injection data, the introduction of chemical usage data and the long term storage of ER probe data.

Data Record	Unit	Records	# / year	History
Weight loss coupons	10^6	0.2	0.01	20+ years
ER probes readings	10^6	1.7	0.4	2½ years
Equipment	10^3	28	-	-
Inspection locations	10^6	0.6	.07	-
Inspection records	10^6	1.2	0.1	~13 years
Chemical injection	10^3	52	22	2½ years
Production rates	10^6	8.3	0.5	~15 years
Injection rates	10^6	2.0	0.2	~12 years

Table 3 Database Record Accumulation Rate

Appendix 3.2.2 Historical Data

The small differences in data between Annual Reports reflect the movement of lines into and out of service, the addition or abandonment of equipment, and the addition or removal of corrosion access fittings to the program. The historical data for prior years has been updated to reflect the current equipment inventory.

Appendix 3.3 Corrosion Management Context

The following sections are provided to lend context to the current year results.

Appendix 3.3.1 ER Probe and Corrosion Inhibitor Response

This section describes, by example, the methodology by which corrosion inhibitor concentration is increased as a result of corrosion monitoring through the use of ER probes. ER probes are in use across GPB on the large diameter 3-phase production flow lines.

Figure 2 and Table 4 illustrate the use of ER probes in managing changing corrosion conditions in a large diameter flow lines. Figure 2 shows the ER probe readings and derived corrosion rates, over a period of approximately 10 months in 2003. For the first 10 weeks the measured corrosion rate is bordering on 2 mpy and a 5% increase in CI is implemented. In early February the existing ER probe was replaced due to data quality issues. In mid March another increase of CI was implemented based on ER probe corrosion rate. During April and part of May, the CR still exceeded the target and two additional CI increases were implemented. Finally in mid-May, the CR falls below the 2 mpy target and the CI remains at the increased concentration.

Time Period	Comments
14-Jan	Probe placed on watch list
14-Jan to Feb 11	Probe at or near 2 mpy, 5% increase in pad CI target
14-Feb	Poor data quality, ER probe replaced.
18-Feb to 21-Mar	Probe continues to show rate >2mpy, 10% increase in pad CI target
21-Mar to 30 Apr	Probe continues to show rate >2mpy, 10% increase in pad CI target
01-May to 01-Oct	Probe shows rate <2mpy, No adjustments to CI target

Table 4 Corrosion Inhibitor Concentration vs. Corrosion Rate

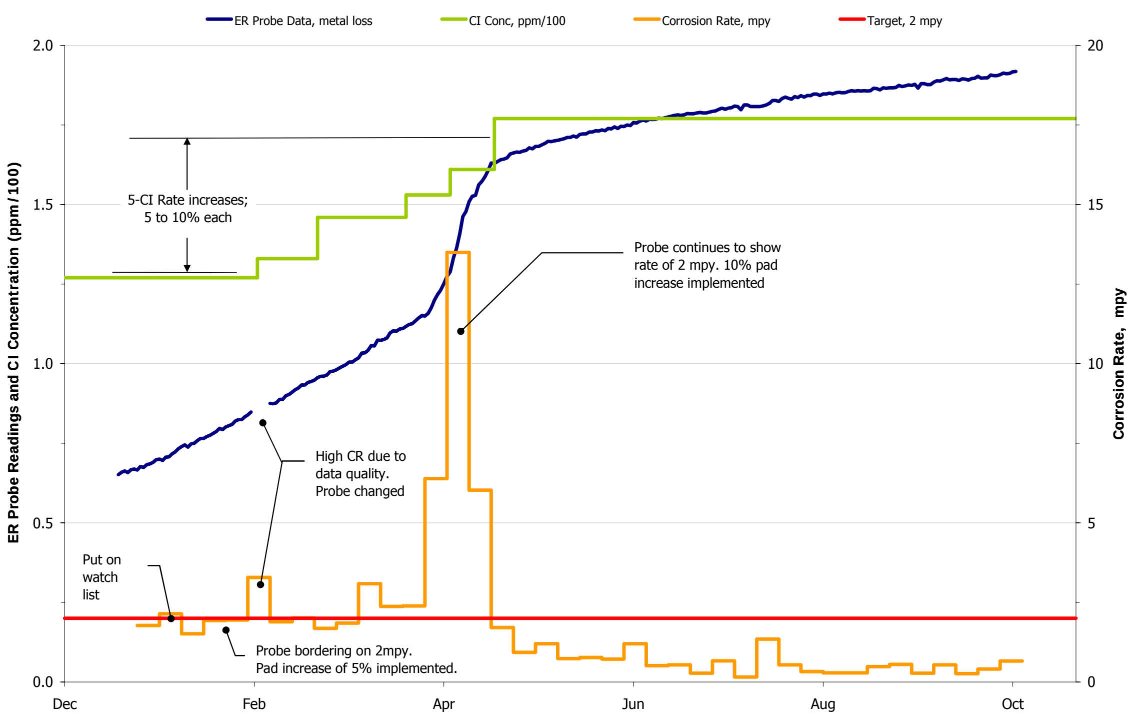


Figure 2 Corrosion Inhibitor Concentration vs. Corrosion Rate

Appendix 3.3.2 Corrosion Inhibitor Development

The development of new corrosion inhibitors starts in the research and development laboratories of the chemical suppliers where potential products are tested for effectiveness under a range of conditions designed to simulate production fluids. Once these preliminary test chemistries have passed the laboratory screening process, the promising products are tested under field conditions using dedicated test facilities at GPB. The test process is summarized in Table 5.

In 2003, a new standardized protocol for well line testing was developed. Approximately ten new products are tested each quarter on a small scale test using an individual well line with each test lasting ~2 days and using approximately 5 gallons of the corrosion inhibitor under evaluation. Products that successfully pass the well line test program are then considered for a large-scale field trial.

The large-scale field trial involves converting between one and three well pads to the test product for 90 days and using 20-40,000 gallons of test chemical. This enables corrosion probe, coupon, and inspection data to be generated to verify the test product's effectiveness as a corrosion inhibitor. The large-scale field trial also allows assessment of the impact of the product on oil separation and stabilization process. Progress is being made in developing a new, standardized protocol for more rapid verification of a product’s effectiveness as a corrosion inhibitor.

Location	Test	Description
Laboratory	Wheel-box Test	Performance of new potential corrosion inhibitor actives is compared to high performing actives. The test conditions simulate GPB and the test is run for 24 hours. Performance is determined by coupon weight loss.
	Kettle Test	This investigates the ability of an inhibitor formulation to partition from an oil phase into a brine phase under stagnant conditions. Test duration is 16 hours and corrosion rate is determined by linear polarization resistance (LPR) probes.
	HP Autoclave	This method determines the performance of inhibitors under high pressure and high temperature conditions. Monitoring method is by either coupon weight loss measurements or LPR. Test duration varies from 1 to 7 days.
	Jet Impingement	A once-through jet impingement configuration evaluates the performance of an inhibitor formulation under extremely high shear conditions. The persistency of the inhibitor film can also be determined. Test duration is one hour and corrosion rate is determined by LPR measurements.

Location	Test	Description
	Flow Loop Test	The ultimate laboratory scale test that simulates temperature, pressure and flow conditions including velocity and water cut. Typical test duration is 24 hours and corrosion rate is determined by LPR measurements.
Field	Well Line Test	Dedicated test well lines are used at GPB as the first step in the field-testing process. Typically 5 gals of chemical used with a test duration of 2 days.
	Large Scale Test	1 to 3 well pads using 20-40,000 gallons of corrosion inhibitor with a test duration of 90+ days. Allows the evaluation of corrosion inhibitor performance by ER, WLC, and inspection, as well as impact of product on separation plant performance.
	Evaluation	Products are evaluated against both technical performance and cost effectiveness criteria in order to assess if there is an overall improvement in performance.
GPB	Implementation	Once a decision has been made to convert the field to a new product, additional precautions are taken with additional corrosion monitoring and plant performance evaluations in order to assure product efficacy.

Table 5 Summary Description of the Typical Test Program Components

As an example, the ER probe results from a typical cross-country flow line test are shown in Table 6 and are summarized in Figure 3. Based on these data, the test chemical in this example was not cost effective and therefore was not utilized across the field.

Status	Chemical	Conc. ppm	CR, mpy	Notes/Comments
Baseline	Incumbent	130	0.2	
Stage 1	Test	150	8.1	Even at a higher dose rate the test chemical was unable to inhibit corrosion to the same level as the incumbent.
Stage 2	Test	170	2.0	Reduces corrosion rate.
Stage 3	Test	190	0.8	Dose rate was increased in order to achieve the same level of corrosion control as the incumbent. At this increased level of corrosion inhibition the test product was uneconomic and the test was terminated.
Return	Incumbent	130	0.1	Re-inject the incumbent product and corrosion rates return to the same level as those prior to the test.

Table 6 Flow line Test Program Result Summary

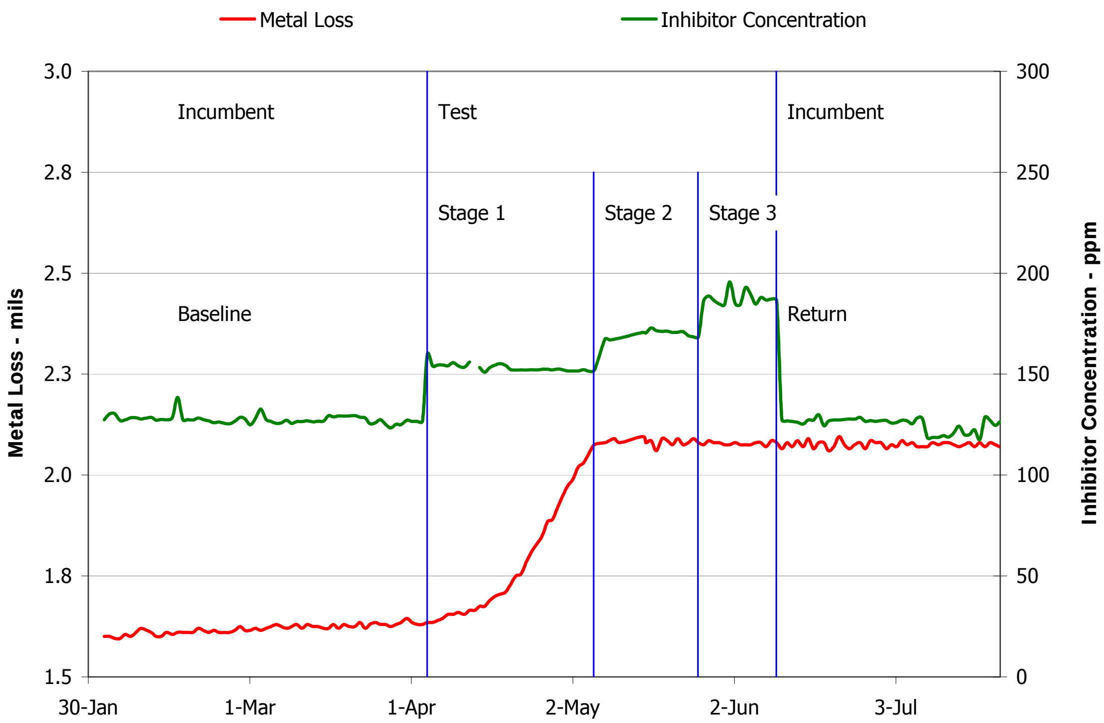


Figure 3 ER Probe Chemical Optimization Test

A second example, utilizes the output from the weight loss coupon program. This example from a test performed in 2001, demonstrates the need/value of multiple monitoring techniques when evaluating corrosion inhibitor performance. The trial product was tested for a 90-day period with no negative response observed by the ER probes. However, after the 90-day test period the corrosion coupons were pulled and showed relatively high general corrosion and pitting rates - see Figure 4. The product evaluated was a failure and the incumbent product was re-instated based on the coupon results. Corrosion inhibitor tests use all the monitoring tools available such as corrosion probes, coupons, and inspection data to determine corrosion control performance. In addition, the corrosion inhibitor is evaluated for plant production performance to show compatibility with the separation process.

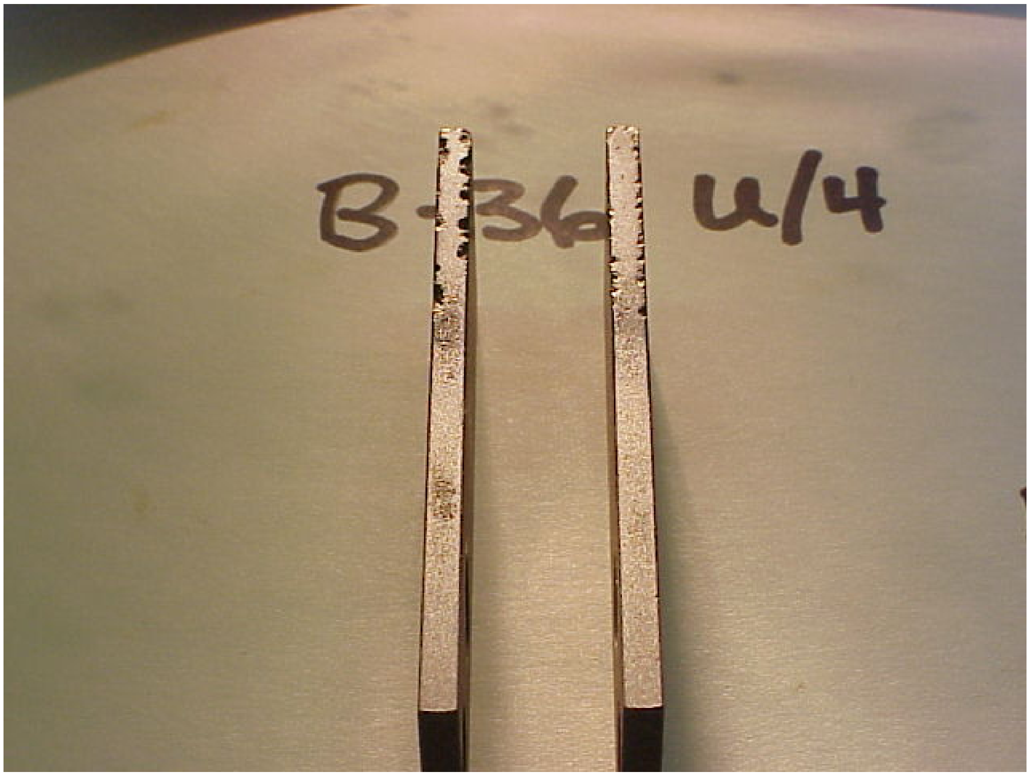


Figure 4 Corrosion coupons pulled after an 'unsuccessful' chemical trial

Appendix 3.3.3 Internal Inspection Program – Scope

This section summarizes the scope and criteria used to determine the frequency of inspection for the internal corrosion inspection program. The over-riding factor in determining inspection intervals is the purpose of inspection based on a combination of equipment condition, corrosion rate, and operating environment. The internal inspection program is sub-divided into four elements, each with a separate purpose and therefore frequency of inspection:

CRM – Corrosion Rate Monitoring: The goal of this program is to detect active corrosion in support of corrosion control activities, primarily the chemical inhibition program. The data are complimentary to other monitoring data, such as corrosion probes and corrosion coupons. As the primary aim is to determine when corrosion occurs, this program is of fixed scope at fixed inspection intervals. For a typical cross-country pipeline, the CRM program includes up to 40 inspection locations which include examples of all locations susceptible to corrosion, such as elbows, girth welds, long seam welds, bottom of lines sections, etc. These locations are each inspected twice per year. The inspections are staggered, with half the set being completed in the 1st calendar quarter and half in the 2nd. These are repeated in the 3rd and 4th quarters, respectively. Therefore, information regarding the level of active corrosion (or lack of) in a pipeline is generated every 3 months. The CRM program covers all cross-country pipelines in corrosive service.

ERM – Erosion Rate Monitoring: The purpose of this program is similar to the CRM but is aimed at monitoring erosion activity. As this damage mechanism is driven by production variables, i.e. production rates and solids loading, it is driven by 'triggers', such as velocity limits, well work, etc. If such triggers are exceeded, inspections are performed on a monthly to quarterly basis until confidence is gained that erosion is not occurring.

FIP – Frequent Inspection Program: The aim of this program is to manage mechanical integrity at locations where significant corrosion damage is detected. Locations are added to the FIP if they are approaching repair or derate criteria or if unusually high corrosion or erosion rates are detected. As the name implies, inspections are performed frequently until the item is repaired, replaced, derated, taken out of service, or corrosion/erosion rates reduced. The inspection interval varies, depending on how close the location is to repair/derate and the rate of corrosion but does not exceed 1 year. All equipment is covered by the FIP.

CIP – Comprehensive Integrity Program: This is an annual program and is aimed at detecting new corrosion mechanisms and new locations of corrosion as well as monitoring damage at known locations. The CIP therefore provides an assessment of the extent of degradation and the fitness-for-service. All equipment is covered by the CIP, although not all equipment is inspected annually.

The scope of the internal inspection program is relatively constant at approximately 60,000 inspection items per year. This includes both field and facility inspections.

Appendix 3.3.4 Corrosion Under Insulation

Corrosion under insulation is primarily associated with water ingress into the pipeline thermal insulation; in particular, at the field-applied insulation joints (weld packs).

The pipelines are generally uncoated carbon steel and are therefore vulnerable to external corrosion under the insulation (CUI) if water comes into contact with the pipe surface. The pipelines are constructed from either single or double joints (40 - 80 ft. long) with a shop-applied polyurethane insulation protected with a galvanized wrapping. The area around the girth welds are insulated with 'weld packs.' The detailed design of weld packs varies but all are prone to water ingress.

Table 7 shows the distribution of insulation joint types based on a sample of ~50,000 locations. For each specified joint type, there is an associated CUI incident rate. These data show there is as much variability in the CUI incident rate between the insulation joint configurations as there is associated with the service type. This suggests that the joint configuration and insulation joint location, along with age, have as much influence on the occurrence of external corrosion at weld-packs compared to the service type and operating temperature.

GPB Joint Design	Joint Type Freq	CUI Incident Rate
Anchor Joint	4.4%	2.8%
Damaged Insul	8.4%	2.0%
Damaged Weld Pack Insul	0.1%	2.4%
Ell Anchor Joint	0.1%	6.8%
Ell Bottom Elev	3.6%	6.3%
Ell Bottom Elev Saddle	0.5%	9.9%
Ell Horiz Saddle	1.0%	8.4%
Ell Horizontal	10.1%	3.8%
Ell Top Elev	2.6%	1.3%
Ell Top Elev Saddle	0.3%	4.5%
Mid-Span Weld Pack	56.4%	1.8%
Saddle Joint	11.1%	3.6%
Vertical Joint	0.1%	5.3%
Wall Penetration	1.2%	1.4%
Average CUI Incident Rate		**2.5%**

Table 7 CUI Incident Rate by Joint Type

The main challenge in managing CUI is the detection of the external corrosion damage. Water ingress into the weld packs is a random process and therefore it is difficult to apply highly specific rules to target the inspection program.

Appendix 3.3.5 Fitness for Service Assessment

The basic fitness-for-service criterion used by BPXA is ANSI/ASME B31G. The base document is the modified B31G, PRC 3-805, which is augmented with additional requirements defined in BP specification SPC-PP-00090, "Evaluation and Repair of Corroded Piping Systems".

Application of fitness-for-service is best illustrated by the following example and discussion using a typical 24" diameter, 375-mil wall thickness cross-country low-pressure (LP) flow line. The average depth of damage for this example is approximately 24% or 90 mils and average corrosion network length of 8.9". In calculating the corrosion rate to achieve this depth of damage, it was assumed that the corrosion rate is linear since the beginning of field life in 1977.

Figure 5 summarizes the dependence of Maximum Allowable Operating Pressure (MAOP) with the remaining wall thickness of a section of flow line based on ANSI/ASME B31G and is intended to show the multiple-layers of protection to the environment provided by the current fitness-for-service criteria. At the original wall thickness of 375 mils, the example flow line has a B31G calculated MAOP of ~1400 psi. As the wall thickness is reduced by corrosion, this pressure containment capacity is also reduced.

Table 8 shows the MAOP for various wall thicknesses starting from the original wall thickness of 375 mils. It can be seen that the repair criterion used provide a significant level of conservatism over the minimum wall thickness required to retain the maximum operating pressure. In addition, high-level over-pressure protection provides additional protection over the normal operating pressure.

In addition to the depth of damage discussed, there are a number of other considerations that have to be accounted for when assessing fitness-for-service. Some of the concerns are,

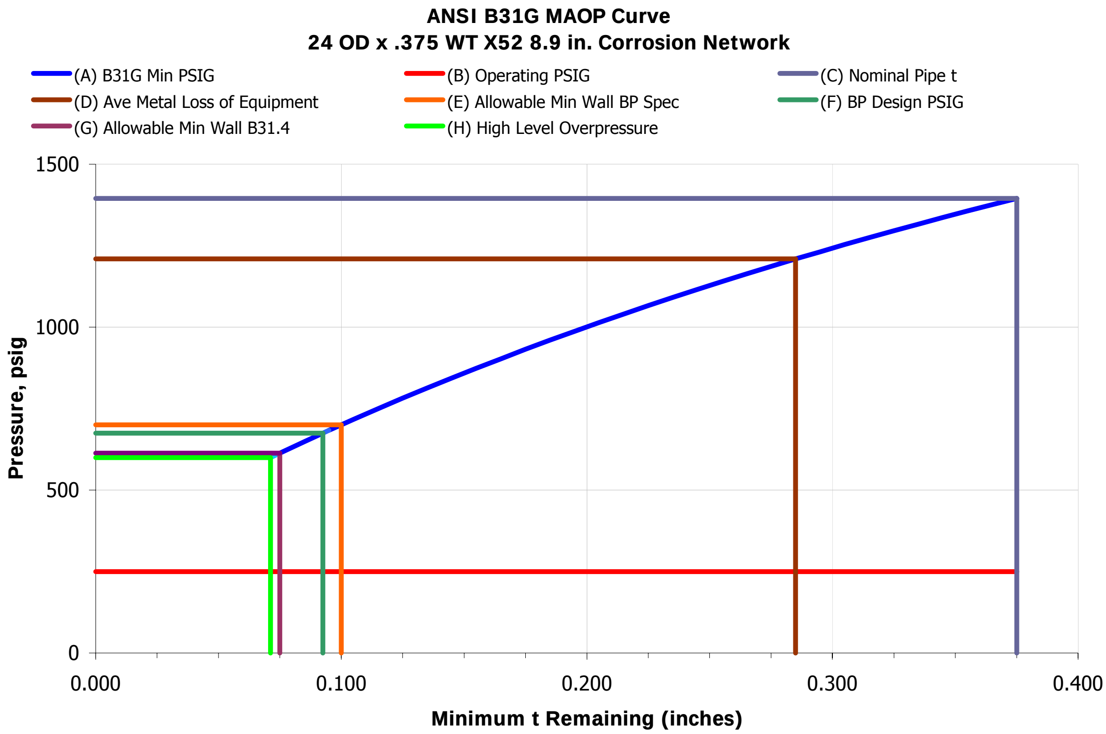
Localized/Pitting Corrosion Localized/pitting corrosion consisting of clearly defined relatively isolated regions of metal loss. The axial and circumferential extent of such regions needs to be determined and any potential areas of interaction where there is axial overlap between pitting regions.

General/Uniform Corrosion General corrosion consisting of widespread corrosion between islands of original material, again, as with pitting corrosion, the axial and circumferential extent of such regions need to be determined. The extent of damage is determined by the boundaries of good or non-corroded material surrounding the damaged area.

Interaction If more than one areas of metal loss exist in close proximity, the possible interaction between these corroded areas needs to be considered. The worst case for interaction of several corroded areas is that a composite of all the profiles within a given metal-loss area needs to be considered.

Critical Dimensions The critical dimensions of metal loss, whether internal or external corrosion damage, need to be determined depending on the corrosion damage morphology described above. The most important dimensions are the axial or longitudinal length, and the maximum depth of damage.

Evaluation of Corroded Pipe The evaluation of corroded pipe involves determining the remaining strength and safe operating pressure on the basis of the overall axial length, circumferential extent, and maximum depth of the corroded area.



	Legend	Description/Comments
(A)	B31G Min PSIG	The relationship between maximum allowable operating pressure, MAOP, as given by B31G and the remaining wall thickness
(B)	Operating PSIG	The normal operating pressure for a typical low pressure common line or flow line (CL/LDF)
(C)	Nominal Pipe t	The original nominal pipe wall thickness which for this example is 0.375" (375 mils) as is the case for many of the flow lines at GPB
(D)	Ave metal loss	From the inspection data an average pit depth or depth of damage across the field for the 24" LP OIL flow lines
(E)	Min Wall BP Spec	The minimum wall thickness, 0.100", which is permitted under BP specification SPC-PP-00090 for the management of corroded pipe-work. Any location at or below this level is actioned regardless of the calculated MAOP
(F)	BPXA Design PSIG	The original design pressure that the pipe wall thickness was designed to retain
(G)	Allowable Min Wall	Allowable minimum wall thickness under B31 below which a repair is mandated by code
(H)	High level P protection	High level over-pressure protection for the LP systems as either a pressure switch or the PSV's on the separator/slug-catcher

Figure 5 MAOP versus Remaining Wall Thickness

Step	t, mils	MAOP	Curve	Description
1	375	1395	(C)	As constructed pipe condition with no corrosion or degradation of wall thickness
2	285	1209	(D)	After 25+ years of service the average wall loss for the flow line system is 24% or 90 mils and has a MAOP of 1209 psi. This is an equivalent corrosion rate of ~4 mpy. At the average corrosion rate seen to date, in approximately 50 years the wall loss will be such that it reaches the repair criteria in Step 3. Note that the target corrosion rate is 2 mpy to provide additional protection and scope for extended field life.
3	100	700	(E)	The BP repair criterion from BP Specification SPC-PP-00090 is 100 mils with an MAOP of 700 psi. This repair criterion is 25 psi above the design pressure and 25 mils or 33% above minimum wall thickness defined by code B31G giving significant level of additional protection
4	95	675	(F)	The original system design pressure
5	75	614	(G)	The minimum wall thickness allowed under B31G for this application which is 80% wall loss regardless of pressure
6	71	600	(H)	High level over-pressure protection for the low pressure production system at Greater Prudhoe Bay
7		250	(B)	The normal operating pressure for the system

Table 8 Thickness, MAOP Correlation

Figure 6 illustrates the FFS envelop for a combination of depth and length of defect as defined in BP Specification SPC-PP-00090. As can be seen from the curve, the criteria for allowable operating service condition is more conservative than the industry standard at the low end of the remaining wall thickness. This conservatism reflects two issues, (a) the need to provide a margin for error in the determination of wall thickness and corrosion rate, and hence remaining life, and (b) the decreased accuracy of the NDE techniques in use at a wall thickness of less 100 mils.

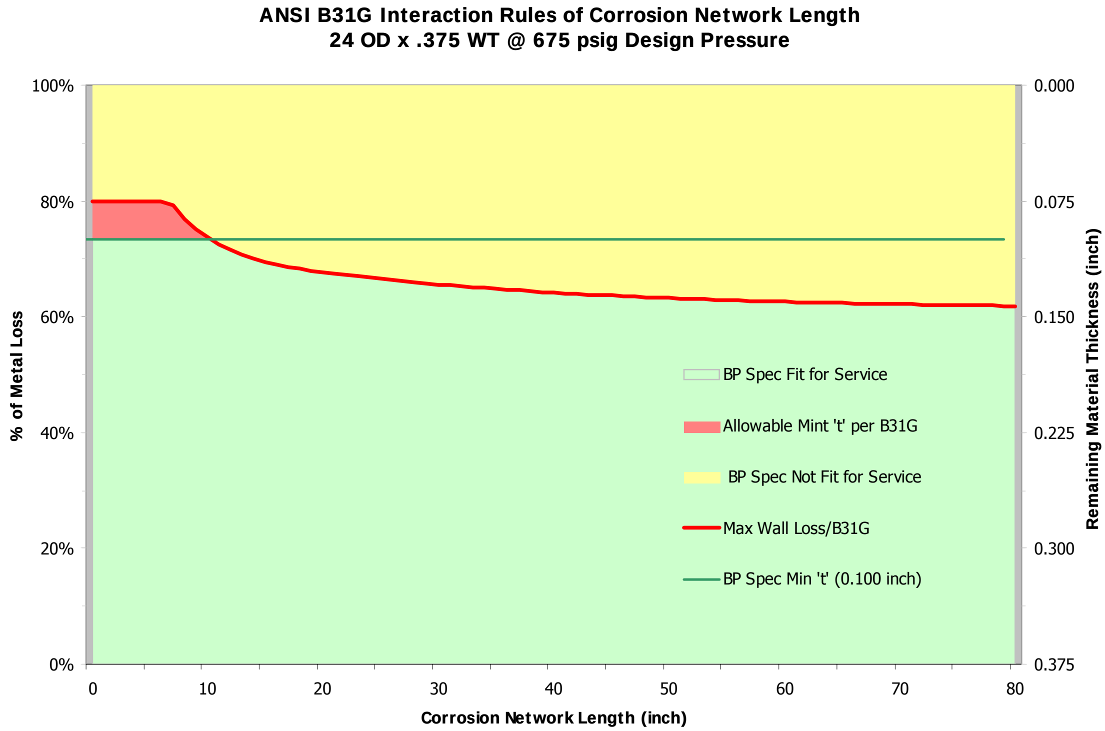


Figure 6 Fitness-for-Service Envelope Based on BP SPC-PP-00090

In addition, repairs are typically scheduled when the corrosion damage has reached 105% of the repair criteria. This additional conservatism is in order to allow repairs to be planned rather than requiring an immediate plant shutdown.

In summary, the current equipment FFS assessment for piping accounts for two major elements, whichever is the greater remaining wall thickness of the assessment criteria.

- Remaining strength of material is sufficient to contain internal pressure as calculated by ANSI/ASME B31G/modified B31G methodology,
- Minimum thickness, regardless of pressure retaining calculation, is equal to the greater of 0.100 inch or 20% remaining wall thickness.

These same criteria are applied to remaining flow and well lines with the appropriate characteristics and parameters.

Appendix 3.3.6 In-line Inspection

In-line inspection (ILI) tools, or smart pigs, are used at GPB where pigging facilities and process environment allow for technical and cost effective performance within the capabilities of the instruments. Magnetic flux leakage (MFL) type tools are the most commonly used by BPXA.

It is important to note that because the vast majority of the cross-country flow lines are above ground, the value of ILI data are considerably lessened compared to buried or underground systems. The primary value for GPB is in the initial identification and location of damaged locations within a pipeline system. Having initially identified the location of damaged areas, the long-term integrity, pipeline condition and current corrosion rate, of the flow line can be more effectively managed through the use of targeted manual NDE techniques.

Having established the condition and location of damaged sections of line the locations are then added to the routine NDE program where the condition and fitness-for-service is determined and where the on-going corrosion rate and level of corrosion mitigation can be monitored.

There are limitations with the ILI technology currently used at GPB. A typical high resolution[12] MFL smart pig gives wall thickness measurements that are ±10% of the nominal wall thickness and sizing resolution of 3 times wall thickness for length and width assessment. In addition, there are temperature and pressure limitations that prevent or make difficult the use of MFL tools in many lines at GPB. The typical upper operating temperature for the MFL tools is 122°F/50°C compared with a typical separator fluids temperature of 150-160°F/65-71°C.

While the ILI program is an important element in the overall corrosion and integrity management program, it should be considered like any other inspection or monitoring technique as simply another tool to be applied where it delivers the most value.

When used, smart pig inspections are performed to gain a relative understanding of pipeline condition and rate of deterioration and/or to provide confidence that the internal and external conventional inspection programs have identified locations where mechanical integrity is at risk. Because MFL tools do not directly measure pipeline condition, results from in-line inspections are not reported in as received from the smart pig service company but are reported as part of the overall NDE summary.

Areas identified by ILI and interpreted as being a risk to future operation of equipment, are verified through visual, radiographic and/or ultrasonic inspection techniques and the results are reported as part of routine inspection programs.

[12] MFL manufacturer technical data sheet

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.0 Overall program goals	Eliminate corrosion/erosion related failures	No harm to people No accidents No damage to environment Regulatory compliance Compliance with industry standards	Integrated program with monitoring, inspection, operational controls, and corrosion inhibitor	Key performance indicators Leading and lagging indicators	Adjust mitigation, monitoring, and operational targets to meet objective Defect elimination - repair/replace/abandon
	Provide equipment availability to end of Field life	2050	Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibition	Key Performance Indicators Leading and Lagging Indicators	Adjust Mitigation, Monitoring, and Operational Targets to Meet Objective
	Cost effective Corrosion Management	Budget	Alliance Partnerships Technical Incentive Contracts Continuous Improvement	Key Performance Indicators Leading and Lagging Indicators	Develop more Cost Effective Methods For Delivering the Program Best in Class Technology Investment for the Future

Table 9 Corrosion Management System

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1 Corrosion Monitoring	Monitor for changes in corrosion rates	System dependant targets Corrosion rate to meet overall objectives Regulatory compliance Compliance with industry standards	Short term corrosion rate determination Medium term corrosion rate determination	ER probes Weight loss coupon rate Pitting Rates	Adjust Mitigating action to achieve corrosion rate target
	Monitor effectiveness of the chemical mitigation programs	Optimize Corrosion Inhibitor Rates and Distribution Optimize chemical mitigation programs e.g. Oxygen scavenger Biocide Drag reducing agent Scale	See above	See above	Provide feedback to Chemical treatment Operations Inspection activities Adjust Mitigation Effort Production Chemistry
	Monitor changes in the process conditions	Field-wide Velocity Management targets	Weekly Review of Operational Controls by CIC Group Operations review of fluid velocities Velocity alarms in Distributive Control System (DCS)	Mixture Velocities, Water Cuts, and Water Rates	Adjust production rates to meet velocity management targets
	Corrosion mechanism changes with time	Mitigation action in place prior to threat to mechanical integrity	Data availability and access Ease of 'data mining' and evaluation Single data storage Comprehensive data management and reporting process	Long-Term Process Change	Develop mitigation program Mechanism management as part of routine business
1.2 Erosion Monitoring	Monitor the effectiveness of the erosion mitigation programs	V/Ve <2.5 Max mixture Velocity and water cut matrix Well Put-On-Production (POP) process Regulatory compliance Compliance with industry standards	Unified velocity management standard across the North Slope Monthly compilation Of High Risk Wells Inspection of High Risk Wells Mixture velocity calculation in DCS	Mixture Velocities Inspection results	Additional inspection and monitoring at high risk sites Adjust Process Conditions Well shut-in Production reduction Design/debottleneck facilities

Table 10 Corrosion Management System Element – Monitoring

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.3 Corrosion Mitigation	Mitigate Corrosion Through Application of Corrosion Inhibitors	Control Corrosion Rates to Acceptable Levels (See Overall Program Goals) Regulatory compliance Compliance with industry standards	Continuous Injection into individual wells as far upstream as possible - currently at Wellhead Protect all equipment between injection point and separation plant	ER Probes WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort
		Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	Batch Treatments on a routine schedule with injection at the Wellhead	WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort Through Reviews
	Mitigate Corrosion through Operational Controls	Operational Guidelines	Weekly Reviews by CIC Group	Mixture Velocities	Adjust Process Conditions
	Mitigate Corrosion through Maintenance Pigging	Achieve Scheduled Frequency	Maintenance Pigging	Inspection Pigging Returns	Adjust Maintenance Pigging Schedule
1.4 Erosion Mitigation	Mitigate Erosion Through Operational Controls and Design	Control Erosion Rates to Acceptable Levels (See Overall Program Goals) V/Ve < 2.5 Regulatory compliance Compliance with industry standards	Well POP process V/Ve Guidelines	V/Ve Inspection (ERM)	Adjust Process Conditions

Table 10 (continued) Corrosion Management System Element – Mitigation

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.5 Inspection	Integrated inspection program to provide a overall assessment of plant condition and corrosion rates	Inspection activity level Leak/save target Inspection increases Plant condition Regulatory compliance	Corrosion rate monitoring program (CRM) Erosion rate monitoring program (ERM) Comprehensive inspection program (CIP) Frequent inspection program (FIP) Corrosion under insulation program (CUI)	NDE technique sheets and procedures Standardized assessment of piping condition, degradation rate and mechanism	Provide feedback to chemical mitigation program Erosion management program Fitness for service assessment Equipment life assessment Proactive repair scheduling
	Assessment of Current Damage Mechanisms	Zero Increases	Internal and external programs	See above	Repair/replace/monitor
	Search for New Damage Mechanisms	Mitigation action in place prior to threat to FFS	Baseline new equipment Apply lessons learnt from industry practice else where in the world Apply lessons learned for other BP operations Apply learnings across the field for similar equipment/process conditions Communications with Operations and Reservoir Engineers	See above	Develop mitigation program Mechanism management as part of routine business
1.6 Fitness for Service	Fitness for service assurance	Regulatory compliance Compliance with industry standard	See above inspection programs	Battelle Modified B31G fitness-for-service criteria (note piping only) BP internal specification for the assessment of damaged pipe	Repair equipment Replace equipment Derate equipment Abandon equipment
	Structural integrity	Regulatory compliance Compliance with industry standard	Walking speed survey every 5 years	Piping design code BP Spec, B31.4 and B31.8 Piping stress analysis Nondestructive testing as required	Repair/replace Correct support defect Monitor for further degradation

Table 10 (continued) Corrosion Management System Element – Inspection

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.7 Continuous Improvement	Provide Feedback to Monitoring, Mitigation, and Inspection Programs	Continuous Improvement	Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibitor Provides Feedback Control Loop for Program Improvements Consolidated data store, MIMIR	Weekly program review Quarterly program review Annual program reviews and strategy assessment Annual equipment life/availability review Key Performance Indicators	Strategic adjustment Budget/funding level changes Mitigation process change and review Technical/R&D requirements and programs

Table 10 (continued) Corrosion Management System Element – Inspection

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1.1 Monitoring – Electrical Resistance Probes (ER)	Monitor the Effectiveness of the Mitigation Programs	< 2mpy Regulatory compliance Compliance with industry standard	ER Probes - Upstream and/or Downstream Ends of Flow lines	Investigate Cause for Corrosion Rate Increase	Mitigation Adjustments ER Probe Maintenance
1.1.2 Monitoring – Weight Loss Coupons (WLC)	Monitor the Effectiveness of the Mitigation Programs	Gen CR: < 2mpy Pit CR: < 20mpy Regulatory compliance Compliance with industry standard	WLC – Installed Flow lines, Well lines, Headers, and Piping	Investigate Cause for Corrosion Rate Increase	Mitigation Adjustments Inspection Program Adjustments
1.1.3 Monitoring – Process Conditions	Monitor changes in the Process Conditions	(See Mixture Velocity and Erosion Sections Below) Regulatory compliance Compliance with industry standard		Investigate Cause for Process Upset Long-Term Process Change Monitor Impact	Mitigation Adjustments
1.1.4 Monitoring – Mixture Velocity Management Program	Monitor the Effectiveness of the Mitigation Programs	Operational Guidelines Mix Vel Limits Regulatory compliance Compliance with industry standard	Operations Acceptance of Mixture Velocity Guidelines SETCIM	Review Alarm List to Determine True Offenders	Adjust Process Conditions
1.1.5 Monitoring – Erosion Management Program	Monitor the Effectiveness of the Erosion Mitigation Programs	Operational Guidelines Well Put on Production (POP) $V/V_e < 2.5$ Regulatory compliance Compliance with industry standard	Operations Acceptance of Erosion Guidelines High Risk Well Inspection Program (ERM)	Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	Adjust Process Conditions

Table 11 Monitoring Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.2.1 Mitigation – Corrosion Inhibitor	Mitigate Corrosion Through Application of Corrosion Inhibitors	Control Corrosion Rates to Acceptable Levels (See Overall Program Goals) Regulatory compliance Compliance with industry standard	Continuous Injection Into Individual Wells as Far Upstream As Possible – Currently at Wellhead Protect All Equipment Between Injection Point and Separation Plant	ER Probes WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort
		Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	Batch Treatments on a Routine Schedule with Injection at the Wellhead	WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort through Reviews
1.2.2 Mitigation – Operational Control, Maintenance, and Material Selection	Mitigate Corrosion Through Operational Controls	Operational Guidelines Mixture Velocity Limits Regulatory compliance Compliance with industry standard	Operations Acceptance of Mixture Velocity Guidelines	Mixture Velocities Review Alarm List to determine true offenders	Adjust Process Conditions
	Mitigate Erosion through Operational Controls	Operational Guidelines Well POP V/Ve < 2.5	Operations Acceptance of Erosion Guidelines High Risk Well Inspection Program (ERM)	Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	Adjust Process Conditions
	Mitigate Corrosion through Maintenance Pigging	Achieve Scheduled Frequency	Maintenance Pigging	Inspection Pigging Returns	Adjust Maintenance Pigging Schedule
	Corrosion Resistant Alloys	Zero Increases (I's)	Selected Facilities & Equipment	Inspection Applicability For Service Requirements	Replace as Necessary
1.2.3 Mitigation – Structural Integrity	Mitigate structural damage caused by subsidence, jacking, vibration, impact, snow loading, etc. through inspections	No failures due to structural damage Regulatory compliance Compliance with industry standard	Operational procedures for visual surveillance of pipelines Piping stress analysis as required NDE inspections as required	Review Pipeline Design Code/BP Specification	Repair, replace and correct deficiencies as required Add Pipeline Vibration Dampeners (PVDs) as required

Table 11 (continued) Mitigation Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.3.1 Corrosion Rate Monitoring (CRM)	Assessment of current corrosion mechanisms Monitor for new corrosion mechanisms	No measurable active corrosion -Zero increases (I's) Regulatory compliance Compliance with industry standard	CRM Program – Fixed locations on approximately bi-annual frequency	Inspections Condition of Equipment Rate of degradation	Mitigation Adjustments Repair/Replace Preventative Maintenance
1.3.2 Erosion Rate Monitoring (ERM)	Monitor high risk wells Assessment of current erosion locations	Manageable rate of degradation Regulatory compliance Compliance with industry standard	ERM Program – monthly to quarterly	Inspections Condition of Equipment Rate of degradation	Mitigation Adjustments Repair/Replace Preventative Maintenance
1.3.3 Frequent Inspection Program (FIP)	Assessment of High Corrosion Rates Monitor locations near repair	Fitness-for-Service Regulatory compliance Compliance with industry standard	FIP Program – monthly to bi-annual	Inspections Condition of Equipment Rate of degradation	Mitigation Adjustments Repair/Replace Preventative Maintenance
1.3.4 Comprehensive Integrity Program (CIP)	Comprehensive Coverage of equipment Fitness-for-Service review	Fitness-for-Service Regulatory compliance Compliance with industry standard	CIP – Condition and rate based half-life recurring frequency Extend coverage through new locations	Inspections Condition of Equipment Rate of degradation	Mitigation Adjustments Repair/Replace Preventative Maintenance
1.3.5 Corrosion Under Insulation (CUI)	Comprehensive Coverage of equipment	Inspection of Locations susceptible to CUI Fitness For Service Regulatory compliance Compliance with industry standard	CUI – Risk based annual program Management of location inventory through recurring examinations	Detect Damage Areas Analysis of occurrence	Repair/Replace Preventative Maintenance

Table 11 (continued) Mitigation Program Techniques

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Corrosion Monitoring	Electrical Resistance (ER) Probes	Measurement of corrosion rate by monitoring changes in electrical resistance of a metal probe due to volume loss	High	Low	H/D	Correlate poorly to actual pipewall corrosion rates
	Weight Loss Coupons Corrosion Rate	Exposure of metal samples to corrosive fluid and calculation of volume loss rates based on weight	Medium	Medium	M	Limited benefit in determining short-term effects, such as flow regime changes on corrosion rates
	Weight Loss Coupons Pitting Rate	Exposure of metal samples and assessment of pitting rate via measurement of pit depths	Medium	Medium	M	Not a very sensitive measure for GPB 3phase but more effective in the PW system
	Galvanic Probe	Detects changes in corrosivity as a function of current flow between two dissimilar metals.	High	Low	C	Not a reliable measurement of mild steel corrosion rate. Very suitable to monitor oxygen and chlorine changes in seawater
	Linear Polarization Resistance (LPR)	Electrochemical technique for assessing corrosion rate by application of controlled voltage and measuring current response	High	Low	H/D	Not used at GPB due to the interference of hydrocarbon films on measurement

Table 12 Corrosion Monitoring Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Process Monitoring	Mixture velocity	Mixture velocity of fluids in pipe-work	Medium	Medium	D	Accuracy dependent upon production information (T, P, Oil, Water, Gas)
	Water cut	Percent water in liquid fluids	Medium	Medium	D	Accuracy dependent upon production information (Oil, Water)
	Temperature and pressure	Measured temperature and pressure in process equipment	Medium	Medium	D	
	Dissolved Oxygen	Amount of oxygen dissolved in Sea Water	High	Medium	D	In-line accuracy problematic. Chemet method more accurate
	Iron (Fe) counts	Amount of Iron (Fe) dissolved in process water	High	Low	M	
	Microbiological activity	Amount of microbiological life forms in process fluids	Medium	Low	M	

Table 13 Process Monitoring techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Inspection/NDE	Radiographic Testing (RT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on conventional lead screen/film. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. Currently being phased out in lieu of 'greener' process of DRT – see below
	Digital Radiographic Testing (DRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on phosphor screen/imaging plate. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. DRT provides additional benefits in waste reduction associated with conventional film and processing chemicals
	Tangential Radiography Testing (TRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through insulation at the tangent of the specimen and projecting an image on screen/film, phosphor screen/imaging plate, or detector array.	High	Low	Y	Utilized for detection of corrosion under insulation (CUI). Deployed where potential moisture ingress is suspected on thermally insulated piping
	Ultrasonic Testing (UT)	Assessment of pipe wall thickness by sending/receiving ultrasound through a specimen. Echoes returning indicate remaining thickness of the specimen.	Medium	High	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation
	Guided Wave Ultrasonic Testing (GUT)	Volumetric assessment of pipe wall by sending/receiving ultrasound through a specimen in the form of cylinder Lamb Waves. Monitoring changes in these waves indicate potential changes in pipe thickness. Alternatively, echoes returning to the source transducer may also indicate interruptions or pitting in the pipe segment.	Low	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method is capable of semi-quantifying metal loss but cannot discriminate between internal and external corrosion
	Electromagnetic Pulse Testing (EMT)	Assessment of pipe wall by propagating broadband electromagnetic waves on the exterior surface of the specimen. When waves traveling down steel pipe encounter corrosion on the pipe surface, the waves are distorted. Distortions in waveform may indicate rust by-product on the surface of the steel and subsequent metal loss.	High	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method cannot quantify metal loss and has a tendency to report false positive results but seldom overlooks surface atmospheric corrosion

Table 14 Inspection/Non-Destructive Examination Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Inspection/NDE (Cont)	In-line Inspection – Smart Pig Magnetic Flux (MFL) Technique	Assessment of pipelines for the detection and measurement of metal loss. These pigs carry high strength magnets, which apply a strong magnetic field into the pipe wall. The magnetic field saturates the pipe steel with magnetic flux. As a result, areas of metal loss cause the flux to leak out of the pipe wall. The flux leakage data are recorded and used to infer the size and depth of any metal loss defects in the pipe.	High	Medium	N/A	Utilized where design and process operation permit in-line pigging. Metal loss MFL In-line Inspection provides complete evaluation of pipeline integrity within the limitations of the MFL technique.

Table 14 (continued) Inspection/Non-Destructive Examination Techniques – Benefits and Limitations

Service	Equipment Type	Monitoring Technique	Inspection Program	Mitigation Program*
Oil	Flow line	ER Probes WLC Process Monitoring	CRM FIP CIP CUI	CI Injection Mixture Velocities Periodic Maintenance Pigging Operational Controls
	Well line	WLC Process Monitoring	CRM ERM FIP CIP CUI	CI Injection Mixture Velocities Mixture Velocities Operational Controls
Produced Water	Flow line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Periodic Maintenance Pigging Mixture Velocities Operational Controls
	Well line	WLC	CRM FIP CIP CUI	CI Injection** CI Carry Over Mixture Velocities Operational Controls
Seawater	Flow line	WLC Galvanic Probes Dissolved 0_2 Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment 0_2 Scavenger Periodic Maintenance Pigging Operational Controls
	Well line	WLC Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment Periodic Maintenance Pigging Operational Controls
Export oil	Flow line	WLC ER Probes	CRM FIP CIP CUI	CI Carry Over Mixture Velocities Operational Controls Periodic Maintenance Pigging

*Applicable to all inspection programs noted
**No CI injection for FS-2 PW

Table 15 Corrosion Management System Implementation by Equip Type and Service

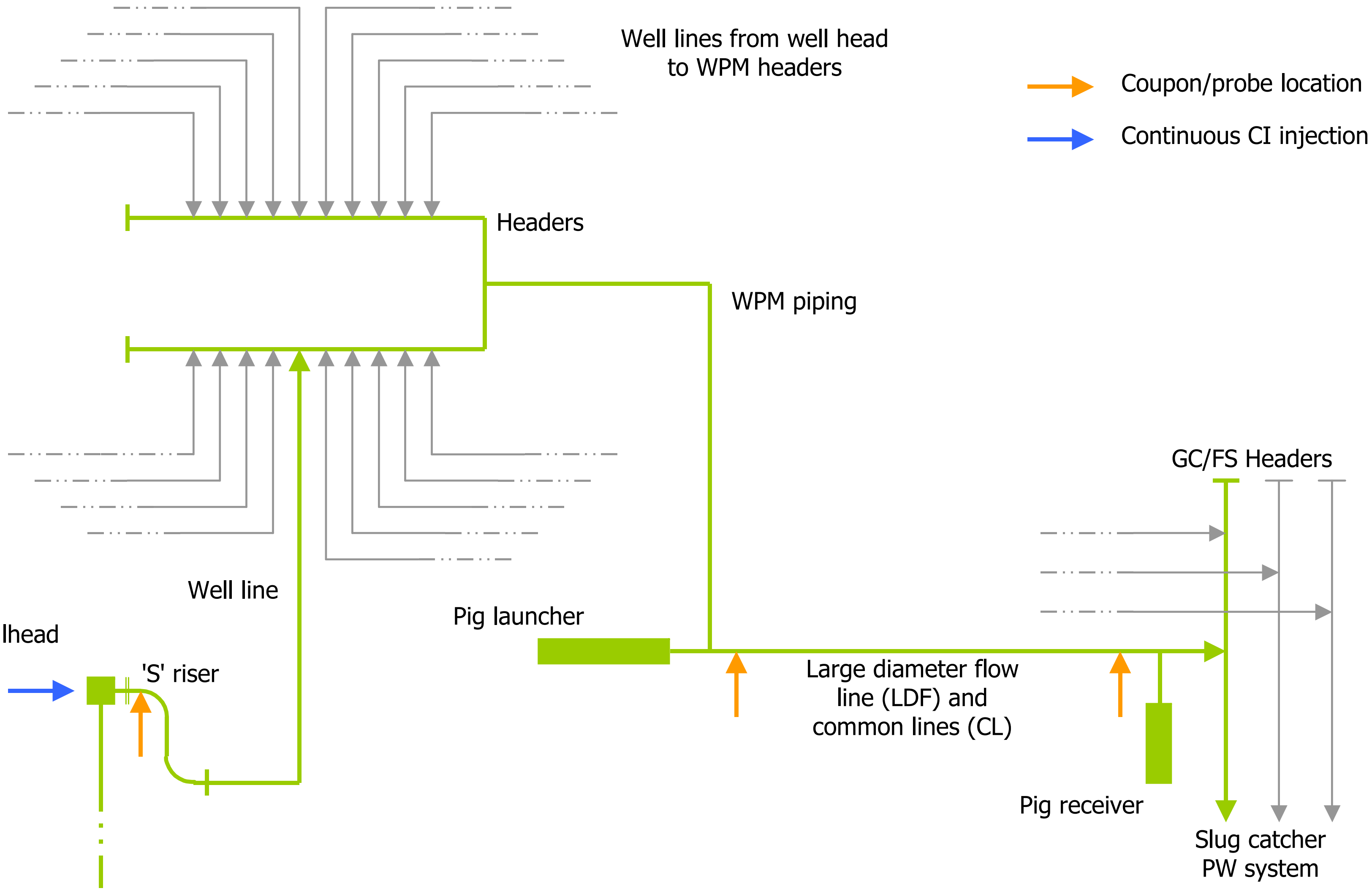


Figure 7 Facility Schematic

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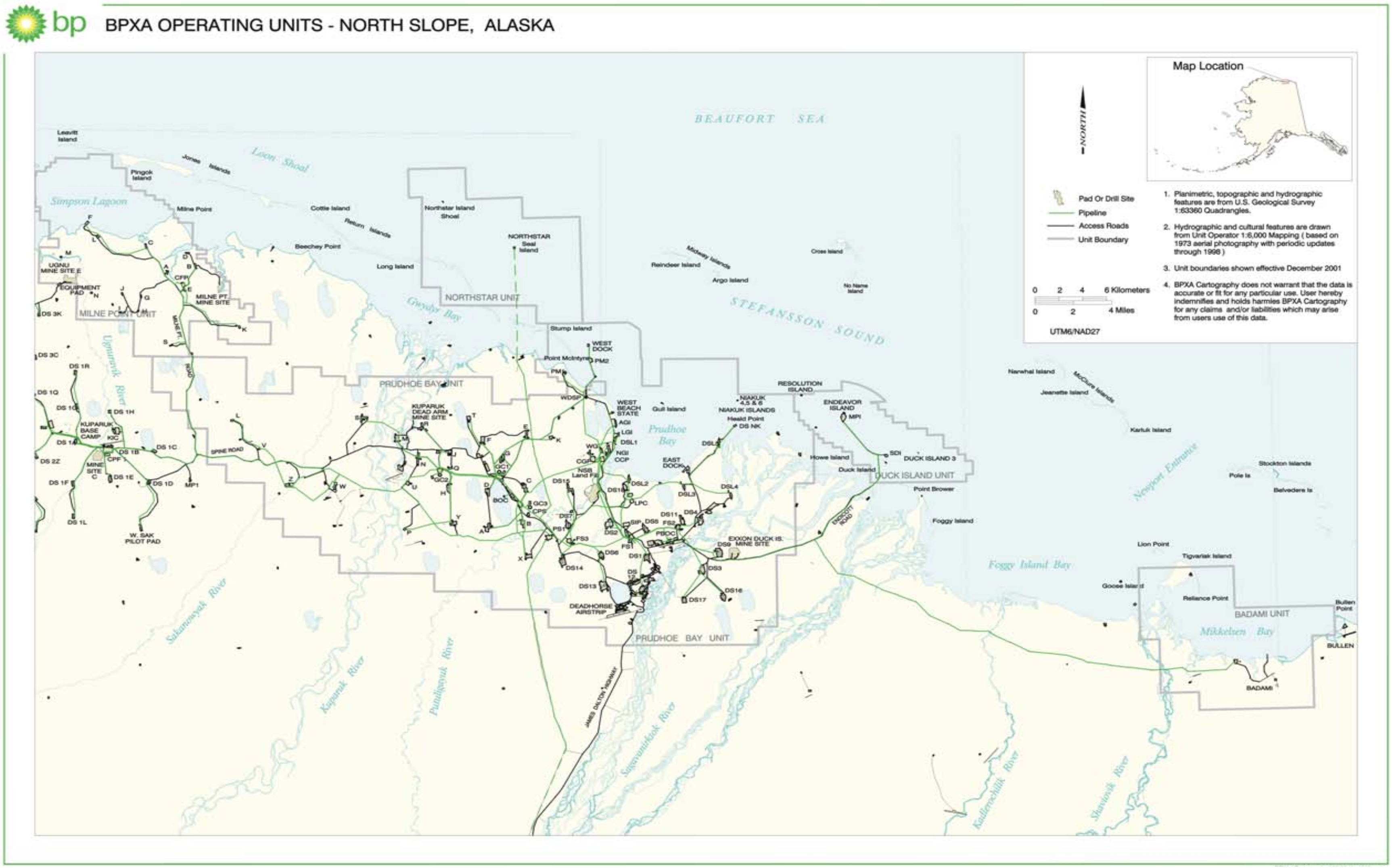

Figure 8 Map of North Slope

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BP North Slope Operations	**Field Data (current 1/01)**	
Greater Prudhoe Bay	Field Area	150,000 acres
	Original Oil in Place (Gross)	25 billion barrels
	Original Gas in Place (Gross)	47 trillion Std. Cu Ft
	Oil Production Wells	1,080
	Gas Injection Wells	36
	Water Injection Wells	174
	Major Separation Plants	6
	Major Gas Handling Plants	2
	Major Water Handling Plants	3
	Miles of Pipelines (approximate)	1,300
Midnight Sun	Field Area	3,000 acres
	Original Oil in Place (Gross)	0.06 billion barrels
	Original Gas in Place (Gross)	trillion Std Cu Ft
	Oil Production Wells	2
	Water Injection Wells	1
	Miles of Pipelines (approximate)	4
Aurora	Field Area	10,000 acres
	Original Oil in Place (Gross)	billion barrels
	Original Gas in Place (Gross)	trillion Std Cu Ft
	Oil Production Wells	5
	Miles of Pipelines (approximate)	1
Pt. McIntyre	Field Area	8,000 acres
	Original Oil in Place (Gross)	0.8 billion barrels
	Original Gas in Place (Gross)	0.9 trillion Std Cu Ft
	Oil Production Wells	59
	Gas Injection Wells	1
	Water Injection Wells	15
	Miles of Pipelines (approximate)	6
Lisburne	Field Area	30,000 acres
	Original Oil in Place (Gross)	1.8 billion barrels
	Original Gas in Place (Gross)	trillion Std Cu ft
	Oil Production Wells	74
	Gas Injection Wells	4
	Major Separation Plants	1
	Miles of Pipelines (approximate)	27
Niakuk & Western Niakuk	Field Area	1,900 acres
	Original Oil in Place (Gross)	billion barrels
	Original Gas in Place (Gross)	trillion Std Cu Ft
	Oil Production Wells	18
	Water Injection Wells	7
	Miles of Pipelines (approximate)	6

BP North Slope Operations	**Field Data (current 1/01)**	
Milne Point	Field Area	36,454 acres
	Original Oil in Place (Gross)	0.92 billion barrels
	Oil Production Wells	107
	Gas/Water Injection Wells	59
	Source Water Wells	8
	Major Separation Plants	1
	Miles of Pipelines (approximate)	55
Schrader Bluff	Field Area	28,000 acres
	Original Oil in Place (Gross)	1.97 billion barrels
	Oil Production Wells	49
	Gas\Water Injection Wells	14
	Source Water Wells	3
	Miles of Pipelines (approximate)	15
Eider	Field Area	300 acres
	Original Oil in Place (Gross)	0.013 billion barrels
	Original Gas in Place (Gross)	0.052 trillion Std Cu Ft
	Oil Production Wells	1
	Gas Injection Wells	1
	Miles of Pipelines (approximate)	.5
Endicott	Field Area	8,800 acres
	Original Oil in Place (Gross)	billion barrels
	Original Gas in Place (Gross)	1.4 trillion Std Cu Ft
	Oil Production Wells	47
	Gas Injection Wells	5
	Water Injection Wells	21
	Major Separation Plants	1
	Miles of Pipelines (approximate)	52
Sag Delta North	Field Area	380 acres
	Original Oil in Place (Gross)	0.014 billion barrels
	Oil Production Wells	2
	Gas Injection Wells	2
	Miles of Pipelines (approximate)	.5
Badami	Original Oil in Place (Gross)	0.160 billion barrels
	Oil Production Wells	6
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	50
Northstar (current 3/02)	Field Area	38,000 acres
	Original Oil in Place (Gross)	.176 billion barrels
	Oil Production Wells	4
	Disposal Injection Wells	1
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	30

Table 16 BPXA North Slope Operations

BP Exploration (Alaska) Inc.
Corrosion, Inspection and Chemical (CIC) Group
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Anchorage, Alaska 99519