

ALASKA LEGISLATION, 2000-2001

11972 SENATE RESOURCES

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 objectives¹¹ for the CMS are set in order to support the delivery of the corporate objective and BPXA objectives described in the Foreword. 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 ($WLC \leq 2$ 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

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

mitigation practices for the major services and equipment type are summarized in Table 15.

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 in 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 D. 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 BusinessObject[™] 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 probe 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
13-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

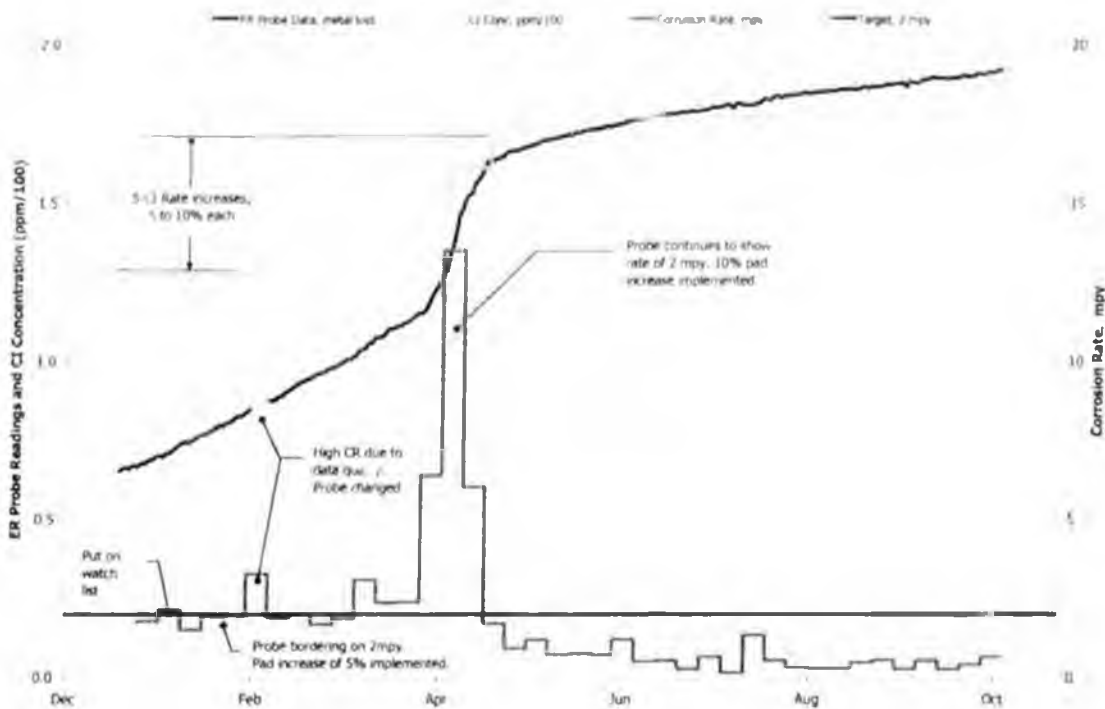


Figure 2 Corrosion Inhibitor Concentration vs. Corrosion Rate

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	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

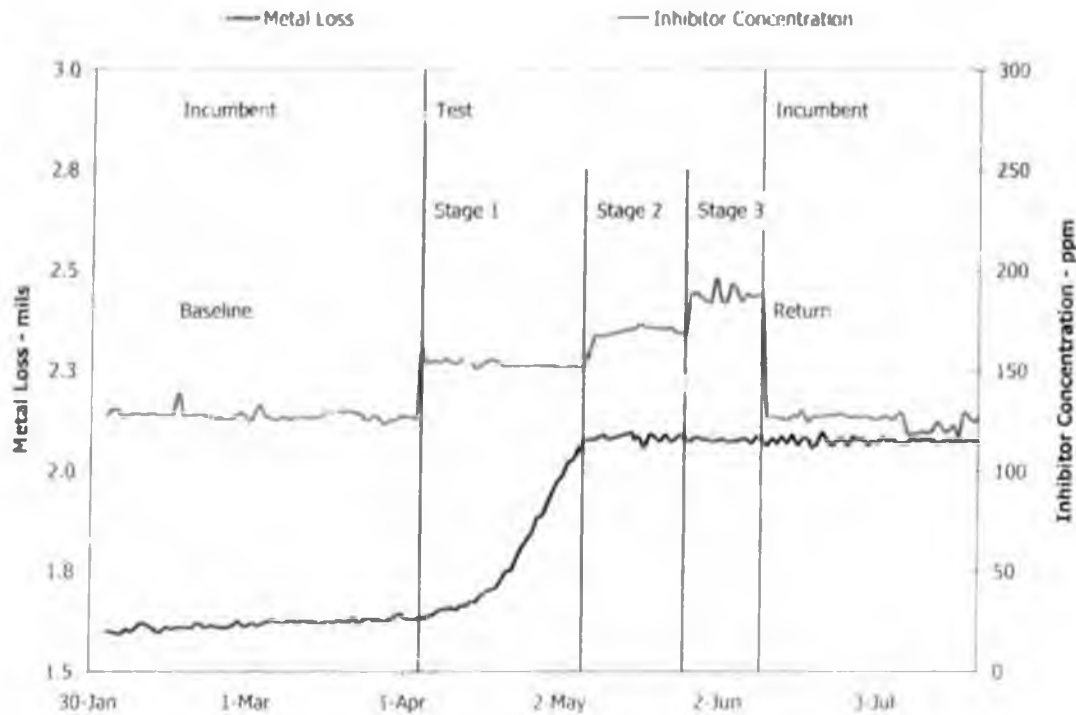


Figure 3 ER Probe Chemical Optimization Test

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.

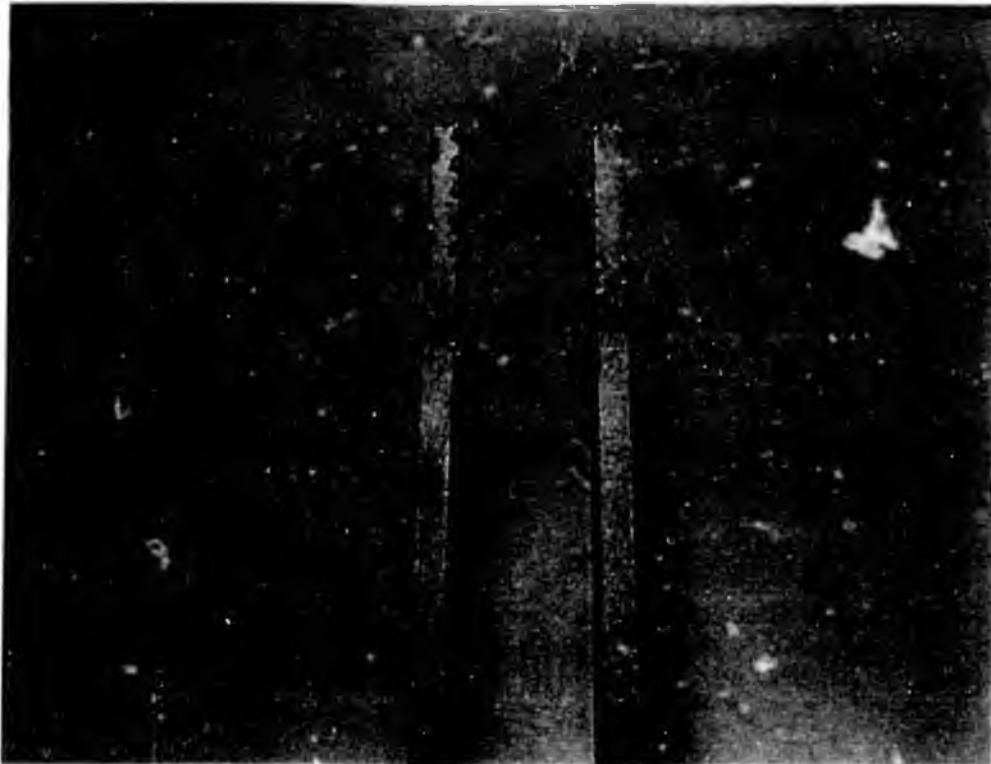


Figure 4 Corrosion coupons pulled after an 'unsuccessful' chemical trial

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%
EII Anchor Joint	0.1%	6.8%
EII Bottom Elev	3.6%	6.3%
EII Bottom Elev Saddle	0.5%	9.9%
EII Horiz Saddle	1.0%	8.4%
EII Horizontal	10.1%	3.8%
EII Top Elev	2.6%	1.3%
EII 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,

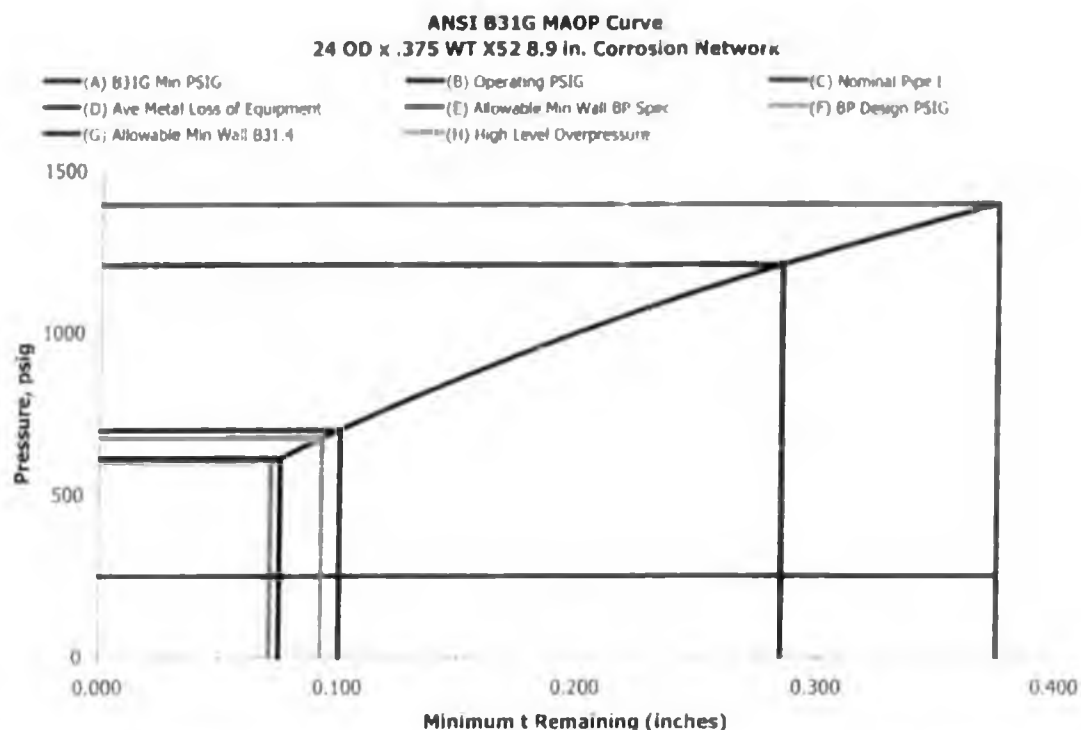
Localized/Pitting Corrosion Localized/pitting corrosion consisting of clearly defined relatively isolated regions of metal loss. The axial and circumferential extent of such regions needs to be determined and any potential areas of interaction where there is axial overlap between pitting regions.

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 being, 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

Appendix 3 – Corrosion Management System

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 2.4% 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.

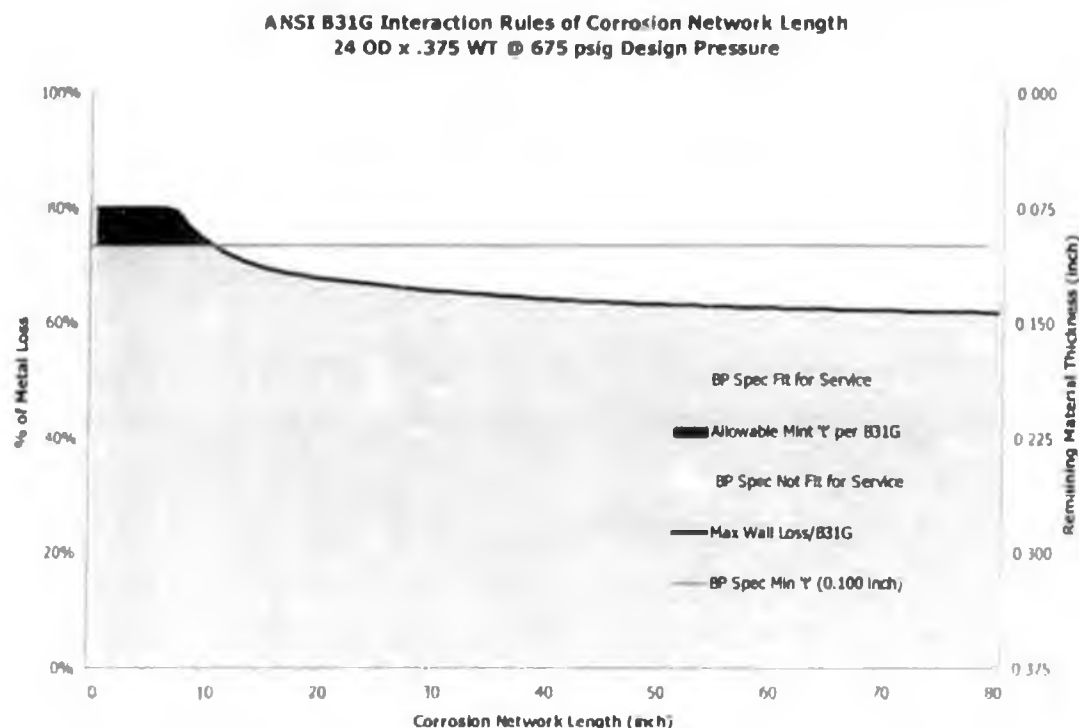


Figure 6 Fitness-for-Service Envelope Based on BP SPC-PP-00090

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,

- 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.

whichever is the greater remaining wall thickness of the assessment criteria. 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 resolution¹² MFL smart pig gives wall thickness measurements that are $\pm 10\%$ 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

Appendix 3 – 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 Mitgating 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 Mitgation 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

Appendix 3 – Corrosion Management System

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

Appendix 3 – Corrosion Management System

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 Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	Continuous Injection Into Individual Wells as Far Upstream As Possible - Currently at Wellhead Protect All Equipment Between Injection Point and Separation Plant Batch Treatments on a Routine Schedule with Injection at the Wellhead	ER Probes WLC's Inspection WLC's Inspection	Corrosion Inhibitor Development Adjust Mitigation Effort Corrosion Inhibitor Development Adjust Mitigation Effort through Reviews
1.2.2 Mitigation – Operational Control, Maintenance, and Material Selection	Mitigate Corrosion Through Operational Controls Mitigate Erosion through Operational Controls Mitigate Corrosion through Maintenance Pigging Corrosion Resistant Alloys	Operational Guidelines Mixture Velocity Limits Regulatory compliance Compliance with Industry standard Operational Guidelines Well POP $V/V_e < 2.5$ Achieve Scheduled Frequency Zero Increases (I's)	Operations Acceptance of Mixture Velocity Guidelines Operations Acceptance of Erosion Guidelines High Risk Well Inspection Program (ERM) Maintenance Pigging Selected Facilities & Equipment	Mixture Velocities Review Alarm List to determine true offenders Monthly Reviews to Determine High Risk Equipment and Repeat Offenders Inspection Pigging Returns Inspection Applicability For Service Requirements	Adjust Process Conditions Adjust Process Conditions Adjust Maintenance Pigging Schedule 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

Appendix 3 – Corrosion Management System

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

Appendix 3 – Corrosion Management System

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 travelling 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

Appendix 3 – Corrosion Management System

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 O ₂ Microbiological Activity	CRM FIP CIP CUI	Biocide Treatment O 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

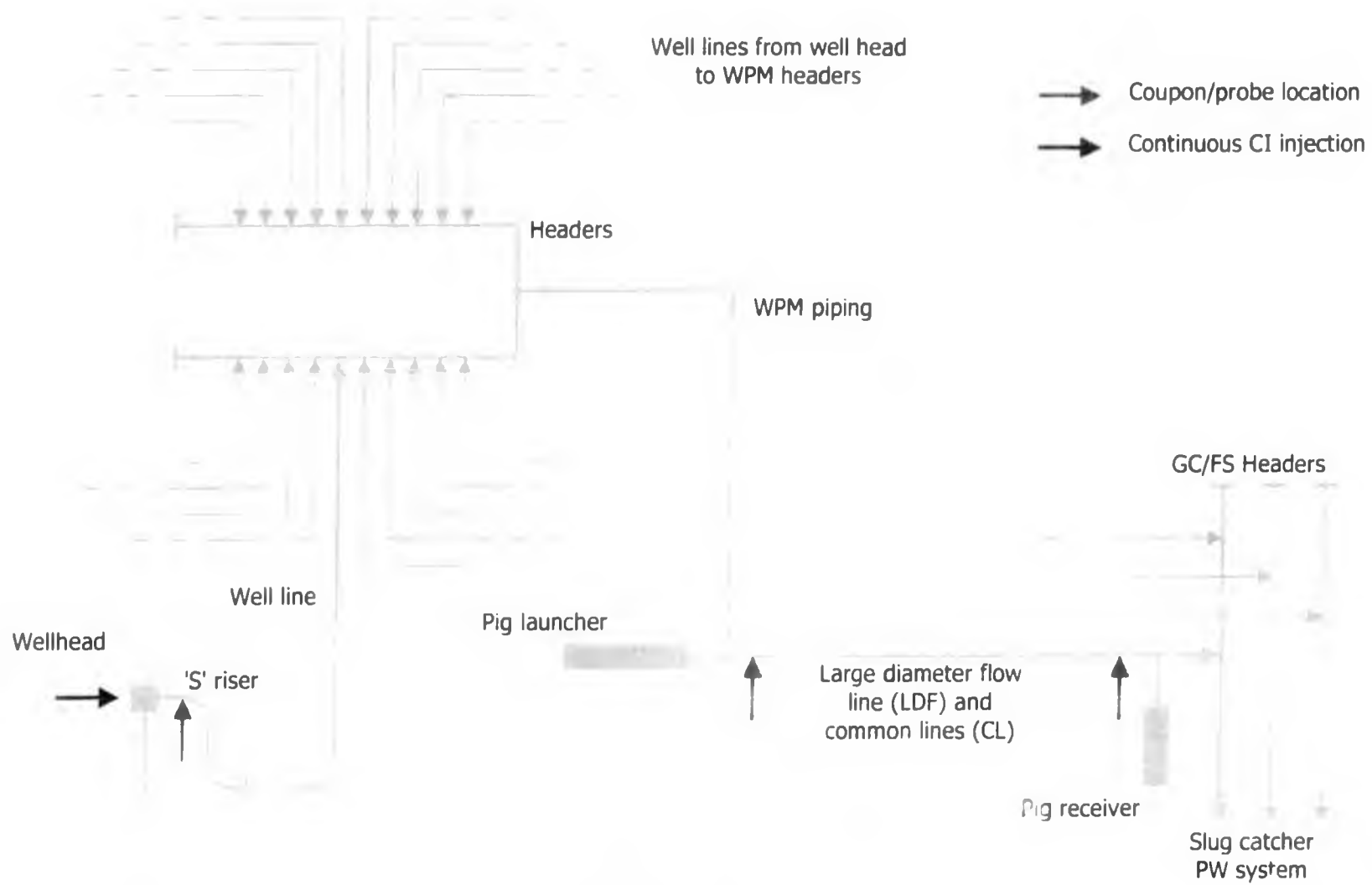


Figure 7 Facility Schematic

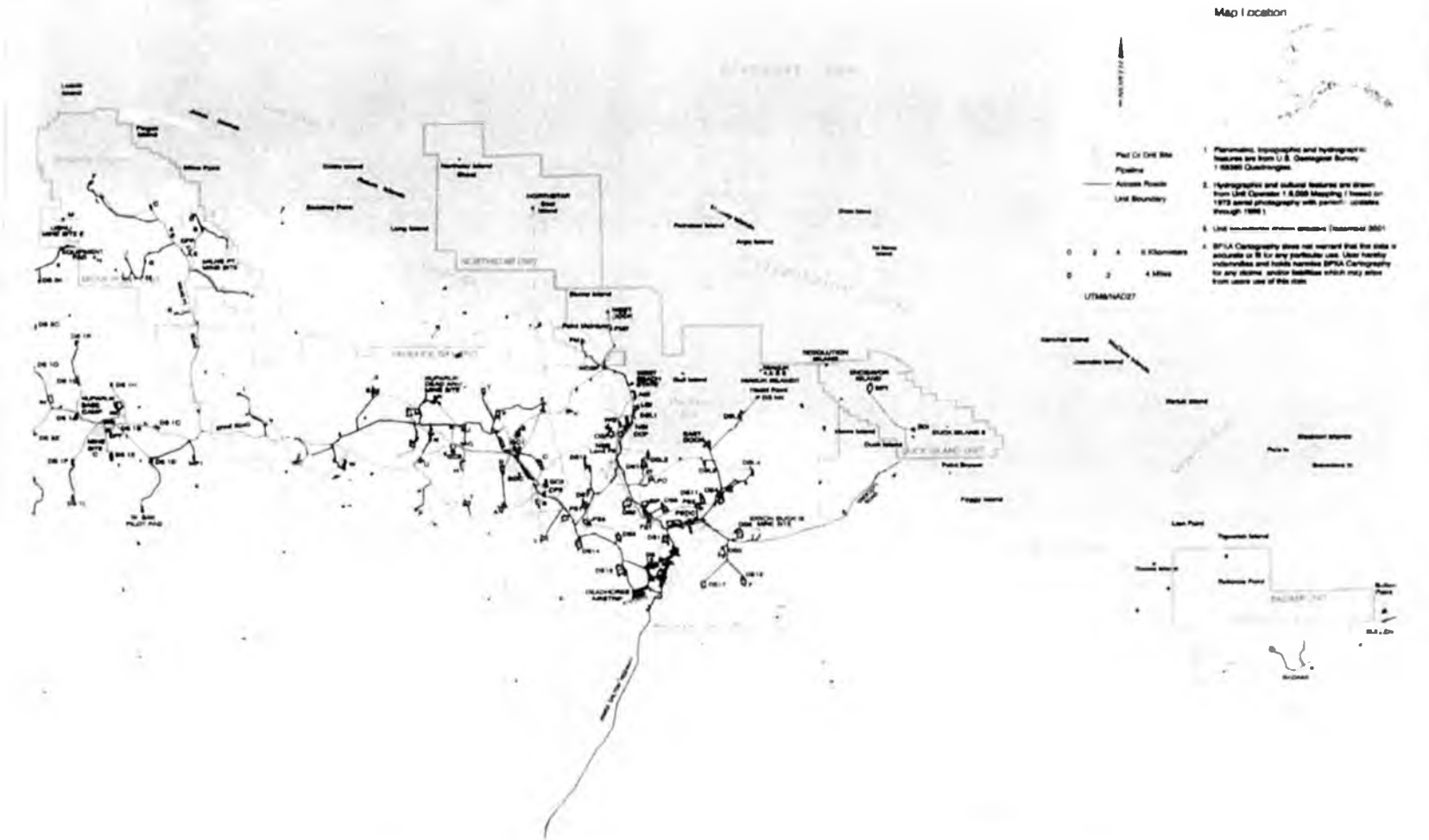


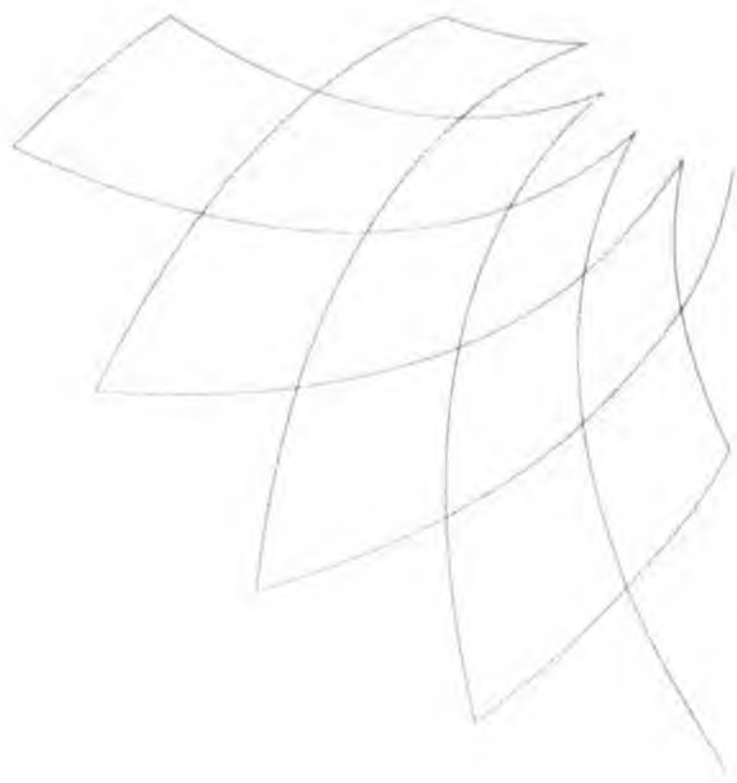
Figure 8 Map of North Slope

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	171
	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
P. 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

Appendix 3 – Corrosion Management System

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
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
900 E Benson Boulevard
Anchorage, Alaska 99519

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PRUDHOE

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**ConocoPhillips Alaska
Commitment to Corrosion Monitoring
Annual Reports 2000 – 2005**

**Charter for Development of the Alaskan North Slope
Section II.A.6**

2000



PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

Greater Kuparuk Area (GKA) Corrosion Programs Overview

March 29, 2001

Commitment to Corrosion Monitoring
1st Annual Report to the Alaska Department of Environmental Conservation

**Prepared by
Kuparuk Corrosion Team**

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1.0 OVERVIEW

There are over \$4MM in capital assets in the Greater Kupařuk Area (GKA). Over the past few years, the corrosivity of the produced fluids at Kupařuk has increased to a level that has the potential to cause internal corrosion damage to the facilities. This corrosivity is increasing as water production and H₂S levels increase. External corrosion has also become a potential problem on aging pipeline systems. Effective management of corrosion at Kupařuk is critical to maintain environmental and facility integrity, reduce field operating costs, and to extend the life of the field infrastructure to meet future needs. This corrosion management system is also being applied to the new Alpine field.

The purpose of this 1st Annual Report is to communicate the Kupařuk Corrosion Strategy, as well as details of the individual programs that implement the strategy. This document describes the basic philosophies of managing pipeline corrosion in the GKA as well as specific strategies for the various pipeline assets and for each corrosion management program.

2.0 KUPARUK CORROSION STRATEGY

The basic assumption in developing the Kuparuk Corrosion Strategy is that the fluids produced from the Kuparuk field are increasing in corrosivity and will continue to increase through the end of field life based on increasing water and H₂S rates.

The purpose of the Kuparuk Corrosion Strategy is to establish programs that prevent unacceptable damage to production facilities and pipelines. From a long-term standpoint it is more cost effective to prevent the damage than to manage the damage once it occurs. Specific program strategies to meet this objective are:

- Utilize resources, both internal and external to Phillips, to better understand the corrosion mechanism at work at Kuparuk.
- Utilize chemical corrosion inhibitors as the primary method for corrosion mitigation of internal corrosion damage. Inject corrosion inhibitor into systems at a dosage high enough to stop corrosion once corrosion is detected. Utilize data from corrosion probes, coupons and CRM (Corrosion Rate Monitoring) inspections to then optimize the inhibitor dosage. Inject inhibitor as far upstream as practical to protect the maximum amount of piping from internal corrosion damage. Install chemical injection facilities at all new drill sites. Actively support development of and field testing of more cost-effective corrosion inhibitors.
- Maintenance pigging is key to mitigating the effects of under deposit corrosion. Maintain pigging programs on existing facilities so equipped (Water Injection lines, Wet Oil lines, Sea Water Transfer Line). Provide capability for maintenance pigging on all new cross-country pipelines.
- Pursue improvements in chemicals which increase the cost effectiveness of corrosion mitigation, improve capabilities for monitoring fluid corrosivity, and increase the efficiencies of road crossing and weld pack inspections.
- Develop specific risk based corrosion mitigation, monitoring, and inspection programs based on an understanding of the corrosion mechanism for a given system. Develop a risk assessment methodology based on both consequence and likelihood of corrosion related failures, to be used for prioritizing corrosion resources.
- Maintain a Kuparuk Corrosion Database to allow efficient management of the large amount of corrosion data that will be required to effectively monitor and analyze the status of corrosion in the field.

More specific strategies for each type of pipeline asset and each component of the corrosion program are described in Sections 3 and 4 of this overview.

The risk assessment methodology used to develop the Strategy was based on a subjective assessment of the consequence of a single failure of the particular type asset. The consequences considered were risk to personnel, the environment, production, and the asset itself. The risk to personnel was based on the likelihood that personnel would be in close proximity in the event of a pipeline or facility failure and the type of potential failure (pin-hole leak vs. rupture, water vs. hydrocarbons). The environmental risk was based on the type of potential failure and the potential location of the failure (on-pad vs. open tundra). The asset risk was based on the potential cost of repair or replacement of a single failure. The production risk was based on the expected lost production and duration of loss for a single failure.

The risk assessment conducted did not include consideration of the frequency of the risk occurring; however, the likelihood of a failure was taken into account in developing the asset specific corrosion mitigation, monitoring and inspection strategies.

3.0 ASSET SPECIFIC STRATEGIES

3.1 Well Flow Lines

The drill site well flow lines extend from the wing valve at each individual well head to the drill site manifold building where the wells are manifolded together then fed into a common line feeding injection water/MI to or collecting produced fluids from the drill site. The well lines at Kuparuk account for approximately 15% of the total pipeline mileage at Kuparuk. The well flow lines primarily consist of 6" diameter, 0.375 wall insulated pipe. However, there are also some thin walled flow lines (0.280" and 0.250"), as well as thicker-walled flow lines (0.432" and above).

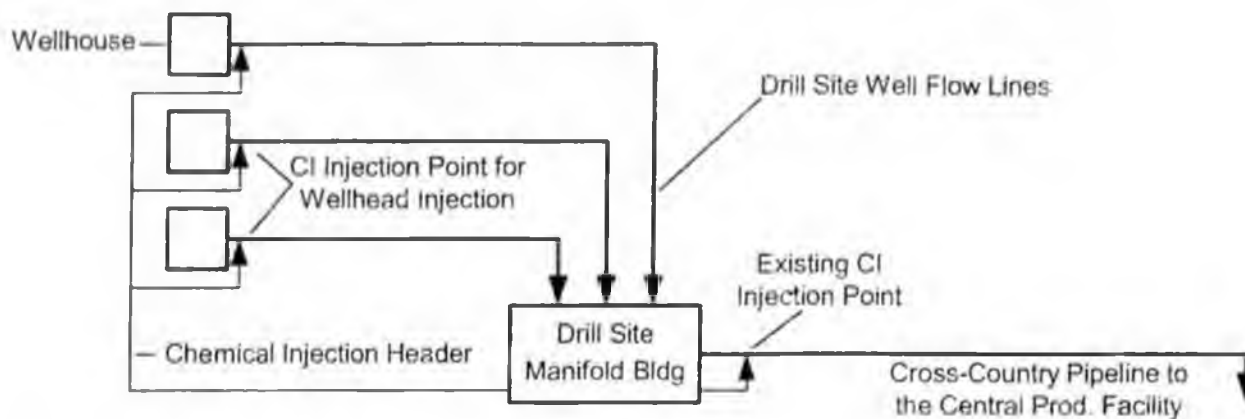
3.1.a. Production Lines

3.1.a.i. Corrosion

Many of these lines contain deposits (formation sand, scale and fracture proppant) that can exacerbate under deposit corrosion. None of the well flow lines are currently treated with corrosion inhibitor. Personnel exposure from a production well flow line internal corrosion failure is low to moderate. The predominant type of leak will probably be a pinhole leak from internal corrosion rather than a rupture. Environmental exposure with a well flow line failure is low to moderate because most of the flow lines in the field are located over pits and on gravel pads and the chance of tundra contamination with a failure is relatively low. Possible exceptions to this could occur with a high GOF well creating a plume of spray that could be blown onto the tundra or failures on some of the Kuparuk drill sites without pits. The production impacts with well flow line failures are limited to the individual well line associated with the failure and are minimal unless numerous producing wells are impacted at the same time.

The current strategy is to conduct surveillance with appropriate NDT techniques and identify and repair the corrosion damage before failure. Current inspection methodology includes the use of a real time radiographic system (RTR) to survey the lines. This system has a crawler that moves down the line and generates images of the pipe wall. These inspections define the extent of damage and progression from past inspections. The inspection strategy will focus on inspection of the older, thinner-walled well flow lines and well flow lines with 'C' or worse coupons. If significant pitting damage is found in any line, the damage will be evaluated and additional inspection scheduled as appropriate.

Presently at Kuparuk, corrosion inhibitor is applied in the well line manifold or at the inlet to the production common line exiting the drill site manifold building. An alternative arrangement, which provides for treating well flow lines with corrosion inhibitor, involves installing a dedicated chemical injection line for each well flow line. The advantage of this technique is that it applies the corrosion inhibitor continuously at the wellhead, protecting piping from the producing well all the way to the processing facility. Kuparuk is adopting a staged approach for installation of wellhead chemical injection facilities. The plan calls for the conversion of 3 to 5 drill sites per year, starting in 2001 and continuing until the appropriate level of inhibition has been provided for the drill sites. A schematic representation of the chemical injection layout for wellhead injection is shown below.



Typical Well Flow line Flow Diagram

3.1.a.ii. Erosion

Many of the production lines contain formation sand and fracture proppant that can erode the piping. In the GKA, using a simple ratio of the calculated mixture velocity to the API RP 14E erosional velocity identifies the majority of wells with erosion potential; when the ratio is 1.5 or greater, erosion damage may occur. When frac jobs are completed, erosion surveys are conducted one, seven, and twenty-one days after the frac job is flowed back.

3.1.b. Produced Water Injection Lines

Produced water injection lines from the drill site manifold building to the well head can also suffer corrosion damage. Many of these lines contain some degree of solids buildup and pitting damage. There is no dedicated chemical inhibition of these lines. However, there is carry over of corrosion inhibitor with the produced water from the separation process, but no additional 'make up' treatment is added specifically to the produced water system. There is also biocide carryover from treatments of the process vessels and the produced water tank.

As with the production well flow lines, the risk categories are low, but the probability for failure is higher than some other lines because of the higher temperature of the produced water (for both internal and external corrosion) and the complication of deposits in these lines.

The strategy for produced water injection lines is to continue to treat the produced water via the residual corrosion inhibitor and biocide treatments upstream of the facilities. Any lines with recurring 'D' or 'F' coupons will be inspected to determine if corrosion damage is progressing. Routine RTR surveillance is also conducted on water injection well lines to detect internal and external corrosion damage. The focus of inspection will be on lines constructed with thin walled pipe (0.280" and 0.250"), with high coupon corrosion rates, older lines, and lines with known damage.

3.1.c. Sea Water Injection Lines

The sea water injection flow lines are generally in the low risk/probability category for internal corrosion because of the high quality water discharged by the STP and by the dedicated maintenance of the upstream transfer and injection lines (routine biocide and pigging). The external corrosion problem is also minimized because of the relatively low temperature of the sea water. The current strategy of biocide and oxygen scavenger treatments at the STP and pigging of the upstream lines is adequate. In addition any lines which have recurring 'D' or 'F' corrosion coupons or with elevated Fe counts will be inspected to determine if damage is occurring.

3.1.d. Miscible Injectant Lines

MI lines are low temperature non-corrosive service and the risk and probability are very low for failures in this service. The strategy is to perform occasional random inspections only, and expand the survey only if damage is detected.

3.1.e. Gas Lines

Although there is moderate personnel risk associated with drill site gas injection and lift lines, the dew point specification of -50° F assures a dry gas stream. This dry gas is non corrosive so the probability of failure is very low. External corrosion can be a problem in hot lines, but the likelihood is lower than production or PW lines. The strategy is to perform occasional random internal inspections and expand the survey only if damage is detected.

3.1.f. External Corrosion

The potential for external corrosion damage depends upon the age and the temperature of the lines. Since all of the lines are constructed with the same type insulation systems, there is equal potential for water ingress under the insulation of any line. However, only the lines with a high temperature (to generate a significant corrosion rate) which are allowed to operate for a long period of time (long enough to produce significant metal loss) are at risk. Therefore, inspection priorities will be focused on the hottest, oldest, thinnest walled lines that have locations where water could potentially enter the insulation system. The current status of our external inspection activities on well lines is discussed later in this document.

3.2 Cross-country Pipelines

Cross-country pipelines are defined as any lines that carry fluids over the tundra between facilities. This includes drill site common lines carrying produced fluids from the drill site manifold buildings to the processing facilities and water and gas injection lines carrying fluids from the processing facilities back out to the drill site manifold buildings for distribution to injection wells. The wet oil line from CPF-3 to CPF-1 and CPF-2 is also included in this category. All of the cross-country lines are above-ground insulated lines that are supported on vertical support members (VSM's). Experience has shown that both external and internal corrosion can be a potential problem with these lines.

3.2.a. Production and Wet Oil Lines

Because of the relatively high risks involved if a cross-country production or wet oil line failure occurs, they are the highest priority for corrosion mitigation, monitoring and inspection efforts.

The risk for personnel exposure for either external or internal corrosion failures in cross-country pipelines is considered low because personnel are normally not in close proximity to the lines and, in most cases, the bulk of the lines are not easily accessible by personnel. Internal corrosion failures are normally small leaks that are well-indicated (noise of gas escaping, crude mist or water icicle) if personnel are in the vicinity. Environmental exposure can be high for these failures because the lines are over the tundra. Accordingly, it is important to locate leaks in a timely manner, especially in winter. The Forward Looking Infrared System (FLIR) that has been installed on the Otter adds to our leak detection capabilities for cross-country pipelines. In addition, production impacts can be severe with cross-country pipelines. In some cases, a line may be carrying the production from several drill sites. The combined risks of environmental and production impacts with a cross-country oil line failure justify a significant investment in corrosion mitigation for these lines.

Internal corrosion of a pipeline occurs because of the corrosive nature of the process fluids carried by the line. Normally, corrosion coupons (which are intended to flag increases in fluid corrosivity) indicate this condition. The problem with internal corrosion by an aggressive fluid is that the entire internal surface of the pipeline (and therefore the entire asset) is at risk if the aggressive condition cannot be mitigated. The primary mode of mitigating internal corrosion is by the addition of corrosion inhibitors. This is the technique that is utilized at Kuparuk as well as the other oil fields around the world. The key to maintaining the high integrity of the asset is to ensure a rapid response to any aggressive condition in order to negate the corrosion mechanism and minimize the occurrence and progression of damage in the system. Once it is certain that the corrosion inhibitor dosage has stopped the corrosion reaction, then monitoring tools can be

used to reduce the dosage to optimal levels. This approach minimizes future inhibition, inspection, and replacement costs.

3.2.a.i. Road Crossings

All of the cross-country pipelines contain road crossings and/or caribou crossings to allow vehicle and wildlife access across pipeline routes. These road crossings consist of an elevation change from the VSM elevation on each side of the roadway (2 – 45° elbows and a transition piece) connected by a straight run of pipe through a conductor under the roadway. There are some 750 of these locations throughout the Kuparuk River field.

This design has been a concern at Kuparuk because the pipe under the roadway can not be inspected with standard RTR and manual radiographic techniques. In the past, the only way to inspect these lines reliably was to utilize a smart pig. Since the common lines at Kuparuk weren't equipped with pig launchers/receivers during construction, this was not a viable option.

Recent developments in inspection technology have resulted in two techniques that can be utilized to inspect the inaccessible piping in road crossings. One of these techniques is based on electromagnetic waves and the other is based on long wave ultrasonic signals transmitted through the unexposed pipe. Approximately 100 road crossings were inspected in 1999 and, approximately, another 100 in 2000 utilizing these techniques. Five of these road crossings had indications significant enough to justify excavation to expose the pipe for visual evaluation; however, no significant corrosion damage was found on any of the locations.

These are conservative inspection techniques as they give indications of defects that are either very minor or are not actually present. The results may trigger an unnecessary excavation of a line (a false positive) but there is a high level of confidence that the techniques will NOT miss a significant defect if it exists. This technology will be utilized for routine surveillance of road crossings at Kuparuk. Since there has been so little corrosion damage found in the road crossings, the current level of surveillance will continue at around 100 road crossings per year. This road crossing piping is officially part of the Below Grade Piping program.

3.2.b. Produced Water Lines

The produced water lines have a high environmental risk and moderate production risk for internal corrosion failures; but, the probability of failure in these lines is relatively low because of the monthly maintenance pigging program, which keeps the lines free of solids and biological accumulation. Also, there is residual carryover of corrosion inhibitor and biocide from upstream treatment of production vessels and cross-country gathering lines, which provides additional protection. There are corrosion coupons in the pipelines from each CPF and at most injection well heads, which monitor the corrosion rates of the produced water at each end of the cross-country injection lines. Many times the CPF's mix the sea water and produced water sources at the plants. In these cases, the CPF's add scale inhibitor to reduce scale formation. Because of the potential for scale formation, the lines are considered to have a higher risk factor than the produced water lines.

3.2.c. Sea Water Lines

The sea water lines have a lower risk and probability of internal corrosion failure than do the production lines or produced water lines because of the high quality of the water produced by the Kuparuk STP, and because of the dedicated biocide treatments and maintenance pigging program for the sea water transfer and injection lines. The dissolved oxygen (DO) specification for water discharged from the STP is 50 ppb and the plant routinely produces water below 30 ppb dissolved oxygen. The sea water transfer lines (low pressure lines from the STP to the CPF's) are pigged and treated with 300 ppm of biocide for 2 hours every three weeks. The high pressure sea water injection lines from the CPF's to the drill sites are pigged on a quarterly basis. Supplemental biocide can be added at the CPF's but this has been seldom necessary.

3.2.d. Gas Lines

The -50° F dew point specification for the lift and injection gas makes this a non-corrosive service and internal corrosion damage has a very low probability.

3.2.e. Miscible Injectant Lines

This is a non-corrosive service. The probability for internal corrosion is very low.

3.2.f. External Corrosion

External corrosion creates a significant environmental exposure in cross-country lines but it is of lesser significance as an asset risk (based on the cost of a single repair). Any external corrosion problems will be isolated to discrete portions of the line (weld packs) which can be identified, inspected, and repaired. Once an external corrosion problem is identified and fixed (weld pack configured to exclude water) future corrosion has a very low probability of recurring at that location. Inspection priorities have focused on cross-country lines over tundra first, then those portions of cross-country lines that are on-pad. Current status of our external inspection activities on cross-country lines is discussed later in this document.

3.3 Alpine

The Alpine field began production in November 2000 and has not yet produced free water. Until water break-through occurs, corrosion rates will be extremely low. The most likely cause of potential pipeline damage will be erosion. In the early stages of production, new wells produce formation solids and fracture proppant that tends to increase the erosion potential. As the new Alpine wells are brought on to production, erosion surveys are conducted one, seven, and twenty-one days after production begins.

To help characterize fluid corrosivity, corrosion coupons and corrosion probes are currently being installed in the well flow lines and the cross-country lines at Alpine. Coupons and probes are discussed in greater detail below. Our coupon and probe database is currently being modified to incorporate the new Alpine system. The Alpine piping systems will be inventoried and gradually incorporated into our inspection programs starting in 2001.

4.0 CORROSION PROGRAM SUMMARIES

4.1 Corrosion Mechanisms

Corrosion is caused by electrochemical reactions that result in the dissolution of the metal (pipe material) into an electrolytic solution (water). This is the common corrosion cell that contains an anode and cathode in an electrolyte. In piping, the anode and cathode are localized positively and negatively charged sections of the same system. The primary chemical components that cause corrosion reactions to occur in the Kuparuk field are oxygen, acid, sulfur, or chlorine, which are dissolved in the water in the system. Just like any chemical reaction, changing the balance between the reactants (oxygen, acid, sulfur, and chlorine) and reaction products (hydrogen, iron sulfide, iron carbonate, etc.) will affect the reaction rate. Increasing the ratio of reactant to product will cause the reaction rate to increase in an attempt to reach equilibrium.

There are numerous mechanisms active at Kuparuk that impact the corrosion rate. The mechanism(s) present in a given piping system vary based on the fluid composition, service, location, geometry, temperature, etc. In all cases, the electrolyte (water) must be present for the reaction to occur. Both internal and external corrosion mechanisms are of concern. Understanding the corrosion mechanisms is key to designing successful mitigation, monitoring and inspection programs at Kuparuk.

4.1.a. Internal Corrosion

Internal corrosion has become an increasing problem at Kuparuk as water cuts have increased and previously oil wet pipe surfaces have become water wet (providing the electrolyte for the corrosion cell) and as bacterial activity increases in the production systems. The mechanisms that have the largest impact on the corrosion rates in the produced crude systems are microbial induced (bacteria) corrosion, erosion (flow-enhanced) corrosion, and under deposit (concentration cell) corrosion. Each of these mechanisms impacts the corrosion cell reaction by increasing the reaction rates.

4.1.a.i. Erosion Corrosion

The erosion corrosion mechanism increases the corrosion reaction rate by continuously removing the passive layer of corrosion products from the wall of the pipe. The passive layer is a thin film of corrosion product that actually serves to stabilize the corrosion reaction and slow it down. As a result of turbulence and high shear stress in the line, this passive layer can be removed, causing the corrosion rate to increase. This mechanism is called erosion corrosion. The erosion corrosion mechanism is not the same as pure erosion, which is a physical mechanism whereby pipe metal is removed from the pipe surface by an abrasive process. The erosion corrosion mechanism is normally more prevalent at elevation changes and inside diameter surface disruptions where strong turbulent flow conditions exist.

Since erosion corrosion seems to be the dominant mechanism for generating metal loss (and eventually causing failures), the focus of mitigating efforts should be on controlling this mechanism. If the erosion corrosion mechanism can be controlled by some technique, the other mechanisms may generate low enough corrosion rates not to be of concern.

4.1.a.ii. Under Deposit Corrosion

The under deposit mechanism can increase the corrosion reaction rate by causing a localized chemical concentration which results in pitting of the metal surface under the solid deposits. These deposits appear to be composed of a scale/corrosion product matrix with entrapment of formation solids, sand, and iron sulfide. Pitting normally occurs under the deposits, but the associated corrosion rates are usually significantly lower than that experienced with the erosion corrosion mechanism.

The primary way of controlling under deposit corrosion is to remove the deposits and maintain a clean pipe surface with routine maintenance pigging. Since the Kuparuk crude production lines are not equipped with launchers/receivers, this is not a viable alternative. Other possibilities include inhibition, but the ability of inhibitors to penetrate the deposits and reach the pipe surface to provide effective inhibition can be questionable. So far, corrosion inhibitors seem to be controlling the problem so that the rate of metal loss, if any, is indistinguishable with the inspection techniques utilized for surveillance of damaged areas.

4.1.a.iii. Microbially Induced Corrosion

Microbial induced corrosion (MIC) is caused by bacterial activity. The impact of the bacterial activity is three-fold. The bacteria produce waste products including CO₂, H₂S, and organic acids that are corrosive and serve to increase the corrosive nature of the production fluids. In addition, some bacteria (SRB in particular) consume hydrogen that is a product in the standard corrosion reaction process. This activity causes the existing corrosion reaction rates to increase in an attempt to reach reaction equilibrium by replacing the hydrogen consumed by the bacteria. Bacteria also accumulate on the pipe walls, creating deposits and under deposit corrosion. MIC is recognized by the appearance of black slimy organic waste material or nodules on the pipe surface, as well as, pitting of the pipe wall underneath these deposits.

MIC is controlled in much the same way as under deposit corrosion. Physical removal of the biofilm is usually necessary to arrest the corrosion mechanism; however, in some cases, microbial biofilms are softer and more easily penetrated than regular scale and corrosion product deposits. In these cases, chemical inhibitors with surfactants or biocidal properties may provide adequate penetration to control corrosion. If this is not possible, physical removal of the deposit, as with the under deposit mechanism, is required to mitigate damage. MIC is found throughout the Kuparuk production systems, but, fortunately, it is not producing significant damage.

4.1.b. External Corrosion

The pipeline systems at Kuparuk are installed above ground on vertical support members (VSM's) and are insulated to maintain the temperature of the process fluids. External corrosion is caused when water penetrates the insulation system and is trapped between the insulation and the external pipe wall. The corrosion cell is fueled by a continual supply of water and oxygen from external sources (rain, blowing snow, etc.). The main area where external corrosion is found is at field applied weld insulation packs, but it can also be present in any location where the galvanized insulation jacket has been punctured or torn. Weld pack installations that are not well sealed allow water ingress and, to date, 23% of the weld packs surveyed have been wet. The pipeline construction specification has been revised to eliminate this problem from occurring in new construction. A fairly high line temperature is also needed to drive the corrosion mechanism and the longer the mechanism has been active, the worse the damage will be. Therefore, the hottest and oldest lines in the field should have the highest likelihood for having an external corrosion problem. However, there is no certainty that the highest risk locations can be identified by this methodology alone. Weld pack locations in pipe support saddles atop VSM's have also been found to be susceptible to damage because of the inability of water to drain from these locations. Since removal of water from the corrosion cell arrests the corrosion reaction, it is imperative that locations with the highest risk for external corrosion failure be identified and refurbished to minimize the risk of failure.

An inspection program has been implemented to evaluate weld packs for the presence of water and for corrosion damage. When a wet weld pack is identified, it is either refurbished or placed on a recurring inspection surveillance. If significant corrosion damage is evident, the line is lifted from the VSM and the weld pack insulation removed so that the extent of the damage can be evaluated and the weld pack refurbished to eliminate water ingress.

Overall inspection priorities have focused on asset groups with the highest environmental and economic risk factors first. Therefore, our overall priorities have been to inspect the cross-country lines over tundra first, the cross-country lines on-pad, and then the well lines. For each asset group, inspection priorities have been based on the hottest, oldest, and thinnest-walled lines within the group.

There are around 67,000 weld packs on off-pad cross-country pipelines at Kuparuk. A tangential radiographic inspection program was initiated in 1998 to evaluate all of these weld packs and this program is currently 99+% complete. As of this date 23% of the weld packs inspected were found to be wet, 1.3% were found to be heavy wet, 1.9% contained corrosion damage and 43 required repairs by the installation of pipeline sleeves. All weld packs classified as 'heavy wet' (water actually contacting the pipe) or containing observable corrosion damage have been (or will be) stripped, visually inspected and refurbished utilizing a procedure that will exclude future water ingress. This program has greatly reduced the probability that external corrosion will be a causal factor for off-pad cross-country pipeline failures at Kuparuk. A recurring inspection program for the weld packs not refurbished the first time through is tentatively planned to begin in

2003, five years after the first round of inspections began. Comparisons between current and previous inspection results will dictate the aggressiveness of the recur inspection program.

In addition, there are approximately 10,500 on-pad cross-country pipeline weld packs to be inspected. This program was begun after the start of the off-pad program and is approximately 30% complete. We are finding similar quantities of wet and corroded locations on these locations as were found on the off-pad piping. We expect to complete this program by the end of 2004. A recur inspection program is tentatively planned to begin in 2005.

There are an estimated 24,000 weld packs on well flowlines (production and water injection). An inspection program for these weld packs was begun in 1999. We have completed approximately 25% of these inspections, with similar results as the cross-country pipelines. We expect to complete this program by the end of 2005. Ranking the lines by operating temperature, wall thickness, and time in service prioritizes the inspections. A recur inspection program is tentatively planned to begin in 2006.

Gas Injection well lines are mostly small diameter (2"), and are estimated to contain 19,000 weld packs. The inspection of these weld packs is being deferred since they are not considered at high risk from external corrosion (lower process temperature lines, wall thickness is sufficient to not de-rate until -75% wall loss, environmental risk is low).

4.2 Monitoring

The primary purpose of a corrosion monitoring system is to identify changes in the corrosivity of process fluids in a system and to trend these changes in corrosivity. Corrosion monitoring data does not indicate how fast the pipe wall is corroding or how many years of remaining life before failure of a system, it simply shows changes and trends in fluid corrosivity from one monitoring interval to the next. The most common types of monitoring techniques utilized in the oil industry include corrosion coupons and corrosion probes (electrical resistance probes, galvanic probes and polarization probes). There are other monitoring techniques (such as electrochemical noise and the FSM) that are used in specialty applications that are not suitable for field applications.

Corrosion coupons and electrical resistance probes are the two monitoring techniques utilized most frequently at Kuparuk. Galvanic probes are also used but their service is limited to clean seawater service.

4.2.a. Techniques

4.2.a.i. Corrosion Coupons

Corrosion coupons are the most widely used monitoring technique at Kuparuk. There are over 1100 coupon monitoring locations throughout the field utilized to monitor fluid corrosivity in almost every process at Kuparuk (produced crude, produced/sea water, wet gas, lift gas, utility and process glycol and sales oil). Coupons are exposed to the process fluid for a predetermined period (3 months, 6 months or 12 months) depending upon the service and the corrosivity of the fluid. After a specific time period, the coupons are extracted and analyzed for general weight loss and for pitting corrosion. This information is then compared with previous coupon data from the same location to determine if changes in fluid corrosivity have occurred. Changes are analyzed to identify trends in the fluid characteristics, which may require a modification to the operating process or to the corrosion mitigation programs. One of the limitations of corrosion coupons is that they integrate the fluid corrosivity over the exposure period giving an average for the entire time period (90 day, 180 day, 1 year, etc.). Transient events in the process that may give a very high corrosion rate for a short period of time will be averaged over the entire exposure time and may be missed unless other monitoring techniques are utilized to complement the coupon data.

4.2.a.ii. Corrosion Probes

Electrical resistance (ER) probes are the primary monitoring probe used at Kuparuk. Electrical resistance probes consist of a conducting element with a known cross sectional area that is placed in a corrosive fluid. If the process fluid is corrosive, it removes metal from the probe, resulting in a reduction in the cross sectional area and an increase in the resistance of the probe element. This change in resistance is used to determine a corrosion rate. The advantage of electrical resistance probes over coupons is that ER probes

can be read at frequent intervals (hourly, daily, weekly, etc.) to provide real time corrosion information. Corrosion probes are designed to be much more sensitive than corrosion coupons and are a good tool for providing detailed information on short-term transient corrosion events occurring in the system.

Having both coupons and ER probes in common line locations is necessary to provide reliable feedback on the performance of corrosion inhibitor effectiveness. The feedback system is discussed in more detail in the Mitigation section.

4.3 Inspection

The goal of the inspection program is to: 1) identify and track corrosion damage and provide information on rate of degradation of equipment so that maintenance can be planned to minimize equipment downtime and production losses, and 2) to provide feedback information for optimization of corrosion inhibition programs. Non destructive testing (NDT) inspection techniques are utilized to verify the actual condition of piping and equipment. The inspection program is intended to be a proactive program to prevent failures; however, inspections must be prioritized to address the highest risk areas first. This concept requires an understanding of the risk factors associated with the equipment covered by each inspection program.

There are various inputs that drive the inspection program to look for damage in piping and equipment. Some of these are: corrosion monitoring information, production information (fluid rates/GOR's), input from facility/drill site personnel, information from other fields, breakdown reports, PM inspections, and the occurrence of leaks and failures.

There are several component programs that make up the overall inspection effort. These include the well flow line program, cross-country common line program, and the corrosion rate monitoring (CRM) program. Each of these programs consists of baseline and recurring inspections. There are two types of recurring: 1) based on known damage in the line/equipment, 2) based on risk assessment regardless of known damage. One known damage recur program is the CRM program. The CRM program is a component of the inhibitor feedback system and is used in conjunction with corrosion coupon and ER probe data to provide information on corrosion inhibitor performance. The inhibitor feedback system is discussed in detail under the Chemical Inhibition section (4.4).

4.3.a. Techniques

Radiography and ultrasonics are the primary NDT techniques utilized in the Kuparuk inspection programs. However, there are variations in the types of radiographic and ultrasonic equipment used for the various programs.

The basic radiography process utilizes a radiation source (X-ray tube or isotopic camera) to expose and capture an image of a work piece on film. The major difference between radiography and general photography is that in radiography, the exposing radiation passes through the work piece to expose the film. In photography, the light is reflected off of the subject. Because the radiation must pass through the work piece to generate an image, radiography has limitations in its application because of adsorption and scattering of the radiation. Iridium 192 is used as the radiation source at Kuparuk. The energy of the gamma radiation from this source will penetrate around 3 inches of steel with reasonable exposure times. In the case of pipeline radiography, the diameter and content of the line exacerbate the problem. The limit for radiography of water packed lines is about 12" diameter and for oil packed lines about 16" for Iridium. This precludes use of radiography on large diameter cross-country common lines without first removing the liquids from the lines to reduce the attenuation of the gamma radiation.

4.3.a.1. Manual Radiography (RT)

Manual radiography is as described above - an Ir 192 camera is used as a radiation source to expose a standard piece of x-ray film. This film is then processed (much like conventional photographic film) to produce an image of the work piece. The image can then be evaluated for corrosion defects visually for gross evaluation or with densitometry for more quantitative information. This technique is used on well flow lines and cross-country common lines. Manual radiography is a very manpower intensive activity. The shot set up for pipeline surveillance is cumbersome, the exposure times are sometimes lengthy (30 minutes) and the area that can be inspected is limited to a 14" X 17" area.

4.3.a.ii. Real Time Radiography (RTR)

Real time radiography (RTR) utilizes the same basic radiographic process as manual radiography but the hardware and imaging system are completely different. The RTR system utilizes a solid state imager instead of film to produce an image. The source and imager are mounted on a crawler that is designed to ride atop pipelines and produce an image of the pipe wall in a matter of seconds. The area inspected is limited to about 1/3 of the pipe diameter, usually the bottom 1/3. The operator in a van views the images of the pipe inner diameter as the crawler moves down the pipe - anytime a defect is observed, the position is noted and the image is saved on video tape and on a CD disk. RTR is used to inspect straight run sections of well flow line and common lines - it is not capable of inspecting elbows or elevation changes. It is a very fast technique compared to manual radiography - up to 1000 feet/day of line can be inspected under optimum conditions.

4.3.a.iii. Tangential Radiography (TRT)

Tangential radiography (TRT) is used to evaluate field applied weld packs for the presence of moisture and for external corrosion of the underlying pipe. This is another radiographic technique utilizing the basic radiographic configuration of a source and film to generate an image. In this case, however, the source/film are positioned so the radiation passes through the insulation system tangential to the surface of the pipe. This produces an image of the insulation and the edge profile of the pipe. This image can then be evaluated for the presence of water in the insulation and for corrosion products on the outer diameter of the pipe. A procedure was developed at Kuparuk to apply this technique successfully to the inspection of weld packs in VSM saddles. This has resulted in a tremendous time saver for inspection of high risk weld packs because the previous procedure required physical lifting of the line and removal of the insulation to verify line condition.

The TRT process can be done with both manual and automated equipment. The automated system utilizes the same crawler assembly as the RTR equipment described above but the source and imager are configured to produce an image of the edge profile of the pipe versus an image of the pipe wall as with RTR. The weld pack inspection program will be an ongoing program in future years as there are literally thousands of weld packs that must be tracked on a recurring basis. A hand held radiographic system, known as the C-arm, is also capable of conducting TRT examination of weld packs. The C-arm system is used mainly for on-pad piping where frequent direction and elevation changes limit the usage of manual or automated TRT inspection equipment.

4.3.a.iv. Ultrasonics (UT)

Ultrasonic NDT techniques (UT) are used to supplement all of the RT inspection programs described above because UT is more sensitive than radiography in determining remaining wall thickness of a pipe. Whenever significant corrosion damage is discovered with radiography, follow-up inspection is done with an ultrasonic technique to better define the extent of damage. UT is not typically used for general surveillance of equipment except for specific purposes because it is much less efficient than RT. UT techniques are used to gather and monitor pressure vessel and pipe wall thickness changes where accurate wall thickness data is required to determine if equipment is fit for service.

4.3.a.v. Corrosion Rate Monitoring (CRM)

One area where UT measurements will be used routinely is in Corrosion Rate Monitoring of inhibited cross-country, common lines to provide feedback information for corrosion inhibitor performance evaluations. The CRM program consists of numerous discrete thickness monitoring locations established on the cross-country crude gathering common lines. Washers permanently mounted to the pipe delineate these locations. The thickness from each location is measured on a quarterly basis and the information evaluated to determine if a statistically significant change in the pipe wall is occurring and, if so, determines the rate of metal loss. This information is then utilized to determine if the line is receiving the optimum dosage of corrosion inhibitor.

4.3.a.vi. Below Grade Specialty Inspections

The Kuparuk River Unit has hundreds of pipes that cross under roads and gravel pads. Almost all of these pipes pass through a culvert or casing made of larger open-ended pipe. There are no pipes containing crude oil that are directly buried in gravel or soil. Two recently developed inspection techniques have been found to inspect these pipes in the inaccessible locations inside the casing. Inspections are performed from the pipe where they enter and exit the casing. These technologies are from the Welding Institute (TWI) in Cambridge, England (long-range ultrasonic system), and Profile Technologies Inc. (PTI) in Roslyn, New York (electromagnetic wave pulse system). Inspections, and follow up examinations, to date have shown that, due to 'false positives', the results are extremely conservative. Improvements are being made each year to refine these techniques into useful tools.

4.3.b. Schedules

Schedules for conducting inspections are varied depending upon the program and the risk factors associated with various components in the program. Generally, the shortest re-inspection interval is 3 months for a high-risk location. More frequent inspections do not provide meaningful data because of the resolution of the NDT techniques. In rare situations, where an extremely high corrosion rate occurs, more frequent monitoring is done.

4.4 Mitigation - Chemical Inhibition

Chemical treatment is the primary method for mitigating the damaging effects of corrosive fluids carried by the Kuparuk pipelines. The type of inhibitors used at Kuparuk provides a very thin molecular coating of chemical on the pipe wall to separate the pipe from the corrosive fluid. In most cases, these inhibitors only work when they are being continuously applied to the system as they have relative poor persistence without being replenished. Inhibitor dosages are based on the water volume of the fluids. The field average for the bulk fluids at Kuparuk is around 100 ppm at this time. At a 20 year remaining field life and a PW rate of 590MBPD, the volume of corrosion inhibitors becomes staggering - somewhere between 11 and 44 million gallons of inhibitor. This represents a considerable operational cost and significant savings can be realized by optimizing chemical treatments so that inhibitor is not wasted. However, the optimization process must be done prudently to balance chemical costs with long-term asset integrity. There is little value realized if chemical costs are reduced but equipment is damaged to the point of requiring repair or replacement. A successful optimization process requires the development of a feedback system that provides accurate and meaningful information about specific inhibitor performance.

4.4.a. Optimization

The primary purpose of an inhibitor feedback system is to provide timely and meaningful information on the performance of inhibitors so that the levels of inhibition can be adjusted to optimum levels. Since the optimum inhibitor dosage rate will vary from line to line (and will vary in the same line over time based on production characteristics) it is important that timely feedback be obtained so that the proper treatment levels can be maintained. The inhibitor performance feedback system consists of monitoring and inspection components.

The monitoring component provides a measure of the corrosivity of the inhibited fluid via corrosion probes and coupons. As described above, corrosion probes provide short-term feedback on the corrosivity of the inhibited fluid and are capable of identifying short term transient corrosive events (such as an acid flow back from a well) in the system. Corrosion coupons also measure the corrosivity of the inhibited fluid but provide longer-term feedback.

The inspection component of the feedback system consists of ultrasonic (UT) and radiographic (RT) inspections. Areas of known damage or known susceptibility to damage (elbows, direction changes, etc.) are inspected on a recurring basis to track/detect progression of damage. Inspection provides information on the effect of the inhibited fluid on the pipe wall and provides long term feedback on inhibitor performance. In addition, the Corrosion Rate Monitoring ultrasonic measurements are used to provide the pipe wall loss information for the inhibitor feedback system.

The feedback information used to adjust the levels of inhibition has the following hierarchy:

1) The shortest-term indication of any change in the system is obtained from the ER probe. If the ER probe is corroding, then there is a likelihood that the pipe wall is also corroding and an increase in inhibition is warranted. However, if the ER probe is not corroding, it does not necessarily mean that the associated pipe wall is not corroding. A corroding probe is defined as a probe with a reading exceeding 1.0 mpy for a 30 day period. The corrosion inhibitor dosage levels will not be adjusted in response to short-term ER probe excursions.

2) Corrosion coupons are examined every 6 months (on average) and graded. Industry experience has shown that coupons are more sensitive than ER probes - often ER probes will not be corroding but corrosion coupons pulled from the same system show corrosion. If the corrosion coupons are corroding, it is also likely that the associated pipe wall is corroding and an increase in inhibition is warranted. The fact that corrosion coupons do not show corrosion does not necessarily indicate that the associated pipe wall is not corroding. Corrosion coupons are defined as corroding if the corrosion rates exceed 3 mpy general corrosion or 10 mpy pitting corrosion for two consecutive exposure intervals.

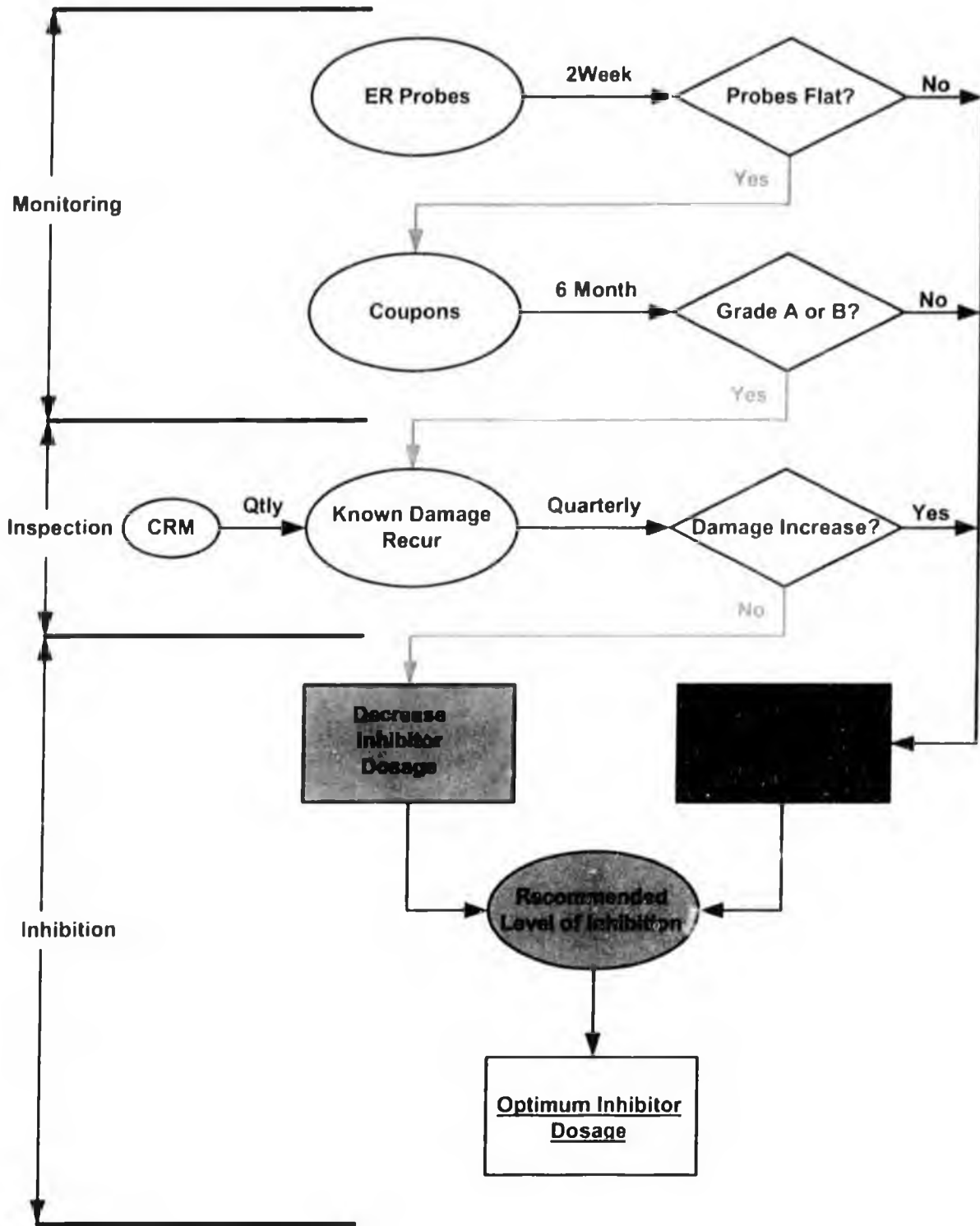
3) Direct inspection of the pipe wall with UT or RT is the only way to verify that the actual pipe wall is not corroding. If ER probes and corrosion coupons show no indication of corrosion activity, the pipe wall may still be corroding, but probably at a low rate. If a pipe is corroding at a low rate, a fairly long time period is required to generate sufficient wall loss to be detected by UT or RT techniques. Quarterly inspection intervals are most appropriate for Kuparuk conditions. The Corrosion Rate Monitoring ultrasonic inspection equipment is be used to conduct quarterly recurring inspections on critical known damage networks to assess inhibitor performance. If measurable progression (pipe wall loss) is detected, the inhibitor dosage is increased regardless of the probe or coupon results.

The dosage of corrosion inhibitor recommended for each common line is adjusted per the information from the feedback system as outlined above - flatten the probes, obtain 'B' or better coupons, and no measurable pipe wall loss.

Once an adequate feedback system is in place, an appropriate level of treatment can be established for any particular corrosion inhibitor. It is also important that production data be monitored on a frequent basis to ensure that the dosage applied is correct for the water volume of the line. For example, if a 96 ppm dosage is established for a line with 30,000 barrels of water per day and the water increases to 50,000 BWPD, the actual chemical treatment drops to 58 ppm. An additional 80 gpd of inhibitor is required to bring the 50,000 BWPD up to the desired 96 ppm dosage. This information needs to be included in the feedback system so that optimum usage of inhibitor/line protection is maintained. Tracking the recommended chemical injection rates versus the actual rates is done for each drill site on inhibition on a monthly basis. The target established for the inhibitor program is that the actual amount of corrosion inhibitor injected fall between 90% and 105% of the recommended rate for each drill site each month.

A flow diagram of the Kuparuk Inhibitor Optimization System is shown below.

Kuparuk Inhibitor Feedback System



4.5 Maintenance Pigging

Maintenance pigging is an integral part of the corrosion control methodology at Kuparuk. Solids and deposits in pipelines can increase the potential for corrosion damage because of an 'under deposit' (or concentration cell) corrosion mechanism. Also, solids interfere with the effectiveness of corrosion inhibitors by both reducing the ability of the chemical to form a protective film on the surface of the pipe wall and also by increasing the dosage requirements due to adsorption of the corrosion inhibitor on the solids. The lines equipped with pig launchers/receivers (L/R) at Kuparuk include the sea water transfer and injection lines, the produced water injection lines from the Central Production Facilities to the drill sites, and the wet oil lines from CPF-3 to CPF-1 and 2.

4.5.a Crude Gathering Lines

None of the cross-country crude gathering lines (other than the wet oil lines) at Kuparuk were designed with pig L/R's nor were any provisions made for future installations during the initial design of the field. The trunk and lateral (T/L) design of the field complicates retrofitting the lines because of the many line size changes associated with a T/L system. A launcher/receiver pilot program was initiated on two infield common lines utilizing a portable launcher receiver concept but the results of the program showed that this methodology was not viable for full field installation. However, significant advancements in corrosion inhibitor and surfactant chemistry have resulted in products that provide good corrosion protection without the support of maintenance pigging.

4.5.b Wet Oil Lines

The wet oil line from CPF-3 was designed to carry partially processed crude to CPF-1 and 2 for final processing. The system consists of a 16" line from CPF-3 to CPF-1 and a 12" branch from the CW skid to CPF-2. Both the 16" and 12" sections are equipped with L/R's and the maximum recommended pigging interval is quarterly. The wet oil lines are the only in-field crude oil lines at Kuparuk that included L/R's in the original design. These lines are scheduled to be pigged on a quarterly basis. A 24" wet oil line parallels the 16" wet oil line for approximately 2.9 miles of the 16" lines' total 8.4-mile length. The 24" line is normally in wet oil service, and is scheduled for quarterly maintenance pigging.

4.5.c Produced Water Lines

Monthly pigging, combined with biocide and corrosion inhibitor carryover from the gathering system application, minimizes deposits that aggravate under deposit corrosion and provides routine maintenance for the produced water lines. The only lines in PW service that are not routinely pigged are the well injection lines. The corrosivity of the produced water system is measured via corrosion coupons in the injection header at the CPF and with well head coupons at most produced water injection wells.

4.5.d Sea Water Lines

Sea water service is generally less corrosive than produced water service as long as dissolved oxygen levels are kept below 30 ppb in the system. The source water from the Seawater Treatment Plant is very clean and has fewer nutrients than produced water so bacterial activity is manageable with a dedicated biocide program. The standard pigging/biociding interval for the sea water transfer line is every 3 weeks and the sea water injection lines from the CPF's to the drill sites are pigged on a quarterly basis. Sea water corrosivity is measured with corrosion coupons at the STP, in the CPF's and at the sea water injection well heads. Dissolved iron measurements are also made at various points along the sea water transfer/injection route to determine if active corrosion of the steel pipe is occurring.

4.5.e Mixed Water Lines

Lines in mixed water service (combination of produced water and sea water) are pigged on a monthly basis. Mixed water service is probably the most severe service encountered at Kuparuk. The mixing of waters results in the potential for scale formation and also for enhanced microbial activity. Therefore, the potential for solids generation in a mixed water system is greater than for individual produced water or sea water lines alone. Adjustments in the scale inhibitor program appear to be controlling the mixed water problems.

4.6 Data Management

Having an effective data management system to handle a large scale corrosion monitoring, inspection, and mitigation program is essential. In response to that need, Kuparuk implemented a corrosion data management system, and has continued to refine and increase the system's capacity and capabilities over the years. Currently, Kuparuk is actively pursuing plans to further integrate and automate the corrosion data systems (minimize manual data entry, and manual spreadsheet generation/manipulation) including importing real time process variables.

5.0 Other Stand Alone Corrosion Programs at Kuparuk

5.1 Kuparuk Pipeline Corrosion Program - DOT

5.2 Oliktok Pipeline Corrosion Program - DOT

5.3 Pressure Vessel Program – DOL

5.4 Tank Program – ADEC/DOT

5.5 Below Grade Piping Program – ADEC/DOT

6.0 Program Status Summary

6.1 Year 2000 Overview

6.1.a Monitoring & Mitigation

Monitoring:

Average monitoring data for Year 2000 is presented in the table below:

Asset Group	Coupon Average Pitting Rate, mpy (target=<10)	Coupon Average General Rate, mpy (target=<3)	Average Probe Rate, mpy (target=<1)
Produced Crude Common Lines	8	0.1	<1
Wet Oil Lines	36	2.5	<1.4
Water Injection Common Lines	22	1	N/A
Production Well Flow Lines	2	1	N/A
Water Injection Well Flow Lines	7	1	N/A

Produced Crude common lines: The monitoring data summarized above suggests that corrosion is under control. Recurring CRM inspections also support this conclusion. 386 CRM inspections were conducted, with 10 minor increases found (i.e. less than 3% of total CRM inspections resulted in an increase). Ongoing internal inspection data is discussed below, which also supports this data. Where corrosion rates exceeded targets, corrosion inhibitor concentrations were increased. In 2000, corrosion inhibitor concentrations were increased in 12 Produced Crude common lines.

Wet Oil Lines: The monitoring data suggests that corrosion rates exceeded targets. It should be noted that the average corrosion rates shown above are biased "high" due to the 24" Wet Oil Line, which under current operating conditions is in relatively stagnant service. That is, flow rates are currently very low in this line, which contributes to accelerated buildup of solids and the associated under-deposit corrosion. Inspection data, in general, supports the monitoring data. Ongoing maintenance pigging of this line coupled with increases to the corrosion inhibitor dosage should help to lower coupon corrosion rates below targets; however, the relatively stagnant service will continue to make corrosion control more difficult in this line than in the other Wet Oil Lines. The need for this line to remain in service, given current operating conditions, is being evaluated. A potential outcome of this evaluation is for the line to be decommissioned in 2001.

Water Injection Common Lines: The monitoring data suggests that pitting corrosion rates exceeded targets, however, inspection data suggests that, in this service, corrosion tends to manifest itself primarily in unpiggable, relatively stagnant sections of line (such as on well lines verses common lines, dead-legs verses mainline segments, etc.). This information helps to prioritize ongoing inspection efforts. General corrosion rates have improved steadily over the last 15 years, and are within the target rate, while the pitting rate remains at approximately the historical average.

Production and Water Injection Well Flow Lines: While the monitoring data suggests that corrosion rates are below targets, inspection data indicates that higher rates are actually being experienced. The well line inspection data is discussed below, and is a good example of why monitoring data alone cannot be relied upon to characterize corrosion in a given system. This is an opposite example to that of the Water Injection Common Lines discussed above, where the monitoring data suggests more, rather than less, aggressive corrosion than the inspection data.

Mitigation:

The current field-wide corrosion inhibitor is Cortron 276. A new corrosion inhibitor, Cortron 2000-25, passed the laboratory evaluation criteria and was field-tested to confirm its performance. As a result of these performance tests, it was recommended for field wide usage. The implementation of the new corrosion inhibitor will occur in 2001.

The metrics for the mitigation program are described in the inhibitor feedback flow chart, monitoring data table, and discussion above.

6.1.b Well Line Inspection

There are 922 well lines (PO, WI and MI) at Kuparuk. Repair recommendations were initiated on 18 lines in 2000 due to internal corrosion damage (8 injectors, 10 producers). Repairs typically consist of either sleeves or replacement of the de-rated section of line. The level of inspection is summarized as follows:

- RTR: 21,000 feet on 70 well lines.
- Manual RT: 2,650 radiographs on 297 well lines. 20 lines showed increased damage.
- Manual UT: 4,137 locations on 277 well lines were inspected under internal corrosion inspection programs. 95 lines showed increased damage.
- UT for internal damage done in conjunction with External program: 358 locations on 156 well lines during visual inspection of stripped locations under the External Corrosion (CUI) Program. These were all baseline inspections so no increases were noted.

6.1.c Cross-Country Line Inspection

There are 237 cross-country lines at Kuparuk. No (0) repair recommendations were initiated on cross-country lines due to internal corrosion damage in 2000. The level of inspection is summarized as follows:

- RTR: 21,200 feet on 16 cross-country lines.
- RT: 1,530 radiographs on 101 cross-country lines. One line showed increased damage.
- UT: 497 locations on 43 cross-country lines were inspected under internal corrosion inspection programs. 12 lines showed increased damage.
- UT for internal damage done in conjunction with CUI program: 366 locations on 88 cross-country lines during visual inspection of stripped locations under the External Corrosion (CUI) Program. These were all baseline inspections so no increases were noted.

6.1.d External (Weld-Pack) Program

The table below summarizes the progress made in 2000.

GKA External Weld Pack Inspection Summary Table

Asset	Total # of WPs	# of WPs Inspected by TRT		% of Total Inspected by TRT		# of WPs that were TRT'd which required supplemental VT		% of WPs that were TRT'd which required supplemental VT		# of WPs VT'd and Refurbished		VT Backlog	Inspection Completion Goal (TRT)
		Year 2000	To Date	Year 2000	To Date	Year 2000	To Date	Year 2000	To Date	Year 2000	To Date		
CC Lines Off Pad	67,291	434	67,241	0.64%	99.9%	13	252	3.0%	3.8%	366	346	142	YE 2001
CC Lines on Facility Pads	900	330	669	36.7%	74.3%	1	29	0.3%	4.3%	2	8	21	YE 2004
CC Lines on Drill Site Pads	9,500	1,185	2,638	12.5%	27.8%	27	198	2.3%	6.0%	27	95	85	YE 2004
Well Flow Lines	24,000	4,902	6,233	20.4%	26.0%	207	390	4.2%	6.3%	358	396	40	YE 2006
Totals	101,691	6,851	76,781	6.7%	75.5%	248	3,103	3.6%	4.0%	753	3,963	288	

This table depicts Year 2000 and To-Date status, for each asset category:

- The quantity of weld packs inspected using TRT, expressed both as a total number and also as a percentage of total inventory.
- The quantity of weld packs that required supplemental visual/UT inspection based upon the initial TRT inspection, expressed as both a total number and also as a percentage of the number of TRT inspections.
- The number of weld packs that were visually/UT inspected and refurbished.
- The number of weld packs that remain to be visually/UT inspected and refurbished (i.e. backlog).

Note: As can be seen from the table, the number of weld packs which are actually VT'd/Refurbished can (and often does) exceed the number of weld packs which required VT/Refurbishment. This is due to additional VT/Refurbishment done as part of other work (special projects, etc.)

During Year 2000, repair recommendations were initiated for 3 Well Line locations and 4 CC Line locations for External-only damage. These external-damage-only repairs consisted of sleeve-type repairs.

6.1.e Below Grade Piping Program

The annual report for the Kuparuk Below Grade Piping Program was transmitted to ADEC under a separate agreement. This can be discussed during the April, 2001 semi-annual "meet and confer" meeting.

6.1.f Spills/Incidents

- 2M-01 Well Line Riser Failure – 5/6/00 – This was a fatigue-type failure due to slugging, combined with snow loading and subsidence of pipe supports. Several subsidence mitigation initiatives have been developed and are being implemented, and options for eliminating or mitigating the effects of snow loads are being evaluated.

- 2X-16 External Corrosion Well Line Leak – 7/3/00 – This line had been shut-in for supplemental external corrosion inspection, and had been displaced with diesel, at the time of the leak. Thermal expansion of the diesel while trapped in the shut-in well line appears to have caused the leak.
- 1G-08 Internal Corrosion Well Line Leak – 12/27/00 – This line was a lower-tier line in our inspection prioritization schema. Inspection priorities were evaluated and adjusted as a result of this leak. See discussion below on well line inspection plans for 2001.

6.2 Year 2001 Forecast

6.2.a Monitoring & Mitigation

- Convert the field wide corrosion inhibitor to Cortron 2000-25.
- Test new corrosion inhibitors in an effort to improve corrosion inhibition technology.
- Develop and implement wellhead chemical injection systems for the production well lines at select drill sites, as discussed in Paragraph 3.1a above.
- Decrease wet oil line corrosion exposure through maintenance pigging and inhibitor adjustments.
- Continue with installation of probes and coupons on the Alpine pipelines as well as the incorporation of Alpine data into our data management system.

6.2.b Well Line Inspection

Based on the 2000 well line inspection programs, the following enhancements/modifications are planned for 2001:

- Increase the percentage of our RTR budget spent on well lines from 50% in 2000 to 75% in 2001. Well line RTR footage estimate for 2001 is approximately 18,000 feet.
- The strategy for RTR inspection consists of performing an "initial inspection" for each line. If significant damage is found during this stage of the inspection, a "100%" inspection is then performed on the line. (Note: this is never actually 100% due to saddles, etc.). If no significant damage is found on the initial inspection of a line, the inspection crew will proceed to the next targeted line. A 30% line target was used as the "initial" footage in 2000. The plan for the 2001 inspection program is to decrease this initial target area to 25% or possibly 20%. By decreasing the size of the initial target area, the program can increase the number of lines inspected. Based on prior year results, the risk of missing severely damaged lines will not be increased, since the type of damage found in well lines to date, if significant, has been generalized (i.e. not localized) in nature.
- Initiate a "Wandering Can" RTR program where several lower-priority, previously uninspected lines can be given a brief inspection, of approximately 30 feet each, while the inspection crew is at a given drill site doing the scheduled RTR inspections of the higher priority lines. This will allow a "snap shot" of some of the lower priority lines, and should increase the likelihood of identifying random lines with significant damage (like 1G-08) that are lower-priority in our inspection prioritization scheme.
- Change the well line RTR prioritization scheme FROM: 1) No previous RTR, 2) Water Injection Service, 3) Wall Thickness; TO: 1) No RTR in past 10 years, 2) Wall thickness, 3) Age of Line, 4) Production Service, 5) Coupon History. The 1G-08 well line leak demonstrated the need to place less emphasis on injectors versus producers, and use wall thickness and age as higher-tier ranking criteria. Because injectors received the bulk of the inspection in 2000 under the "old" ranking scheme, the plan is to focus more on producers in 2001 within a given subset of older, thinner-walled lines.

2001



PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

Greater Kuparuk Area (GKA) Corrosion Programs Overview

March 28, 2002

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

Prepared by
Kuparuk Corrosion Team

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Appendix A Corrosion Monitoring Exception Data and External Corrosion Inspection/Leak/Save Results

Appendix B Glossary of Terms used in this Report

1.0 OVERVIEW

There are over \$4MMM in capital assets in the Greater Kuparuk Area (GKA). Over the past few years, the corrosivity of the produced fluids at Kuparuk has increased to a level that has the potential to cause internal corrosion damage to the facilities. The corrosivity is increasing as water production and H₂S levels increase. External corrosion has also become a potential problem on aging pipeline systems. Effective management of corrosion at Kuparuk is critical to maintain environmental and facility integrity, reduce field operating costs, and to extend the life of the field infrastructure to meet future needs. This corrosion management system is also being applied to the new Alpine field.

The purpose of this 2nd Annual Report is to communicate the details of the individual programs that implement the Kuparuk Corrosion Strategy. In addition to the requirements of the North Slope Charter Agreement between Phillips Alaska, Inc., BP Exploration (Alaska), and the Alaska Department of Environmental Conservation, previous reporting requirements pertaining to the Below Grade Piping Program will be incorporated into this and future North Slope Charter Corrosion Reports.

Because of the large amount of data from corrosion monitoring and corrosion inspections, Appendix A has been added. Appendix A contains corrosion coupon exception data and external corrosion inspection and leak/save historical results.

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

2.0 SIGNIFICANT ENHANCEMENTS TO CORROSION PROGRAMS

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

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

3.0 Program Status Summary

3.1 Year 2001 Overview

3.1.a Monitoring & Mitigation

Monitoring:

Average general and pitting coupon corrosion rate data for Year 2001 are presented in Tables 1 and 2.

Table 1. Average general corrosion rates for corrosion coupons by service category.

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average General Corrosion Rate, mpy (target=<3)	Number of Lines with Conformant General Corrosion Rates	Percent of Lines with Conformant General Corrosion Rates
Three-phase Production Cross-Country Lines	61	0.1	60	98
Seawater Cross-Country Lines	2	2.1	1	50
Mixed Water Injection Cross-Country Lines	22	0.1	22	100
Production Well Flow Lines	386	0.2	380	98
Mixed Water Injection Well Flow Lines	471	0.4	453	96

Table 2. Average pitting corrosion rates for corrosion coupons by service category.

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Percent of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Cross-Country Lines	61	7.9	48	81
Seawater Cross-Country Lines	2	4.3	2	100
Mixed Water Injection Cross-Country Lines	22	7.1	18	82
Production Well Flow Lines	386	1.6	369	96
Mixed Water Injection Well Flow Lines	471	6.6	371	79

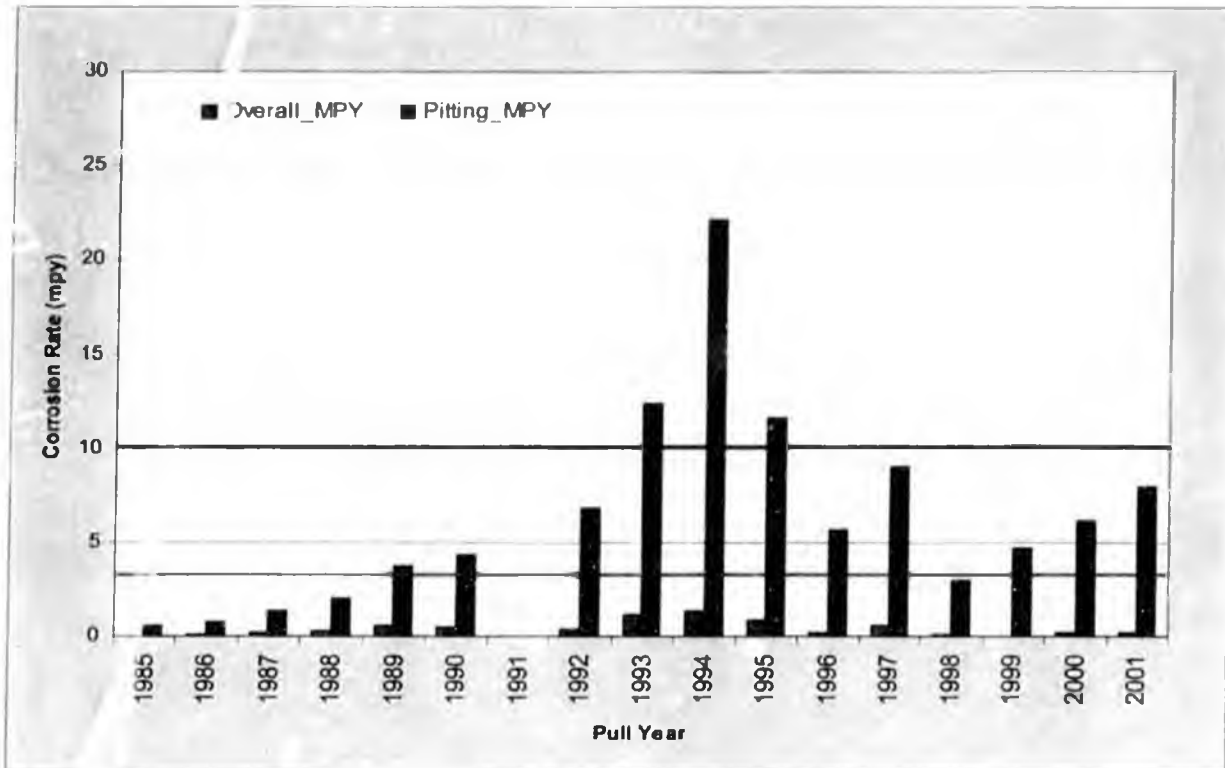


Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Cross-Country Lines: The monitoring data summarized in Tables 1 and 2 and presented in Figure 1 suggest that general corrosion is under control. The data presented in the Tables 1 and 2 and in Figure 1 include corrosion coupon data from the wet oil lines.

Recurring CRM inspections also support the conclusion that corrosion is under control in the three-phase production cross-country lines. In 2001, 464 corrosion-rate monitoring (CRM) inspections were conducted, with 11 minor increases found (i.e. less than 3% of total CRM inspections resulted in an increase). Ongoing internal inspection data support these CRM data and are discussed in section 3.1.c, below.

Where corrosion rates exceeded targets, corrosion inhibitor concentrations were increased and/or the amount of inspection was increased. In 2001, coupon or probe corrosion rates exceeded targets on 19 lines and corrosion inhibitor concentrations were increased on all 19 of these lines. In 2001, inspection results indicated minor corrosion had occurred on nine lines that did not have coupons that exceeded the target corrosion rates; corrosion inhibitor concentrations were increased in all nine of these lines. A complete listing of the 28 lines with corrosion rates that exceeded targets is given in Table A1 of Appendix A.

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

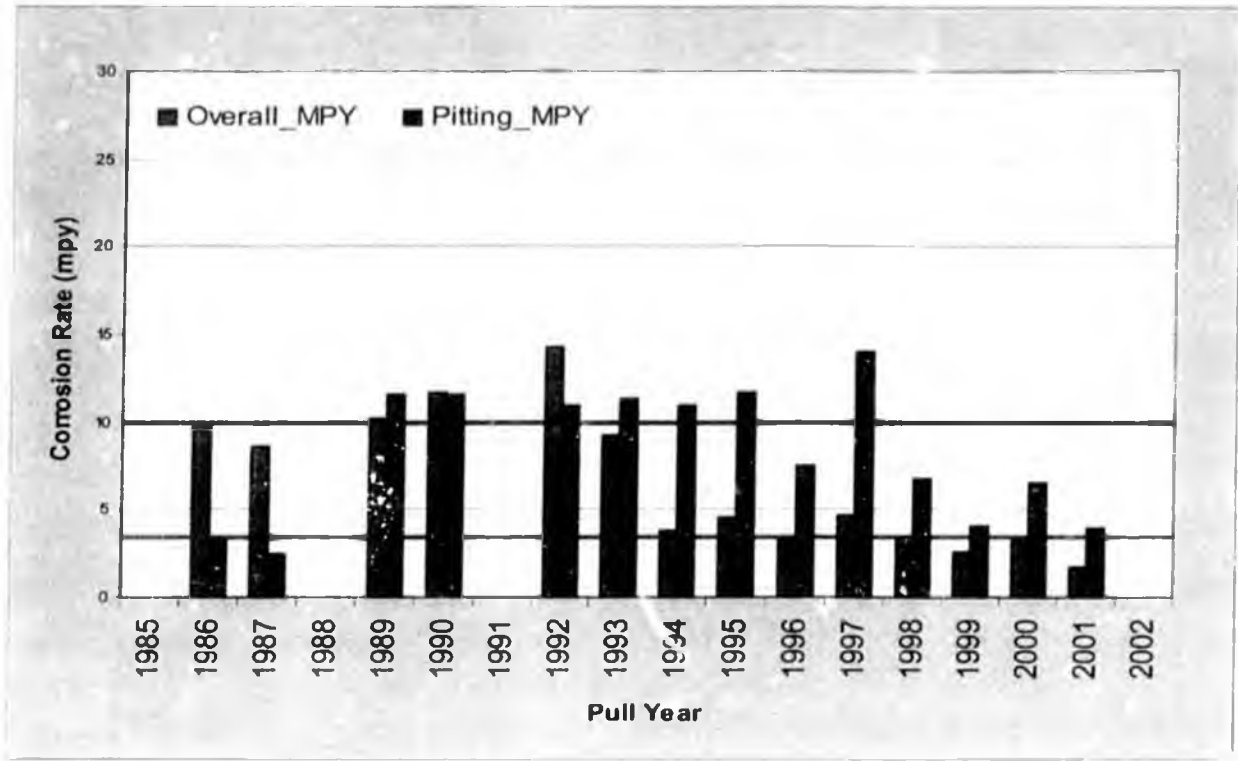


Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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

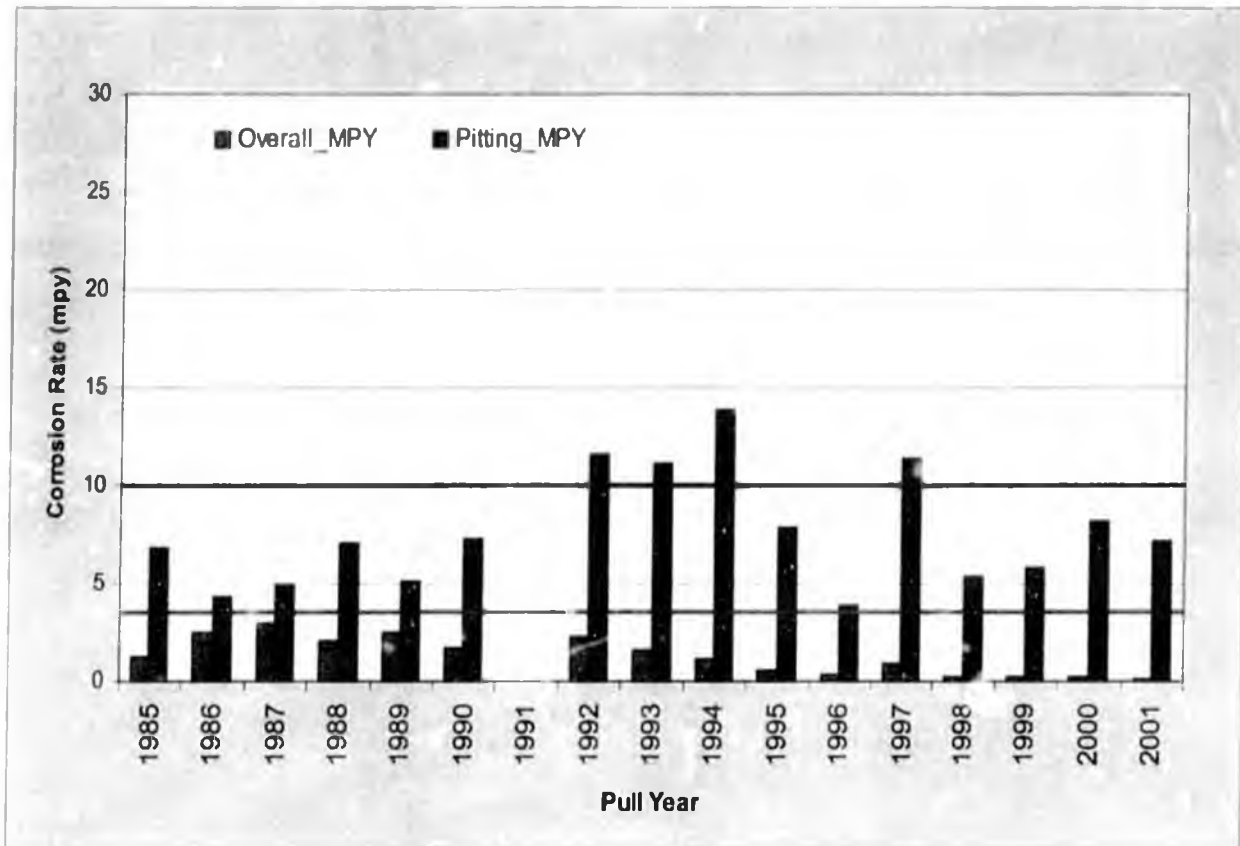


Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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

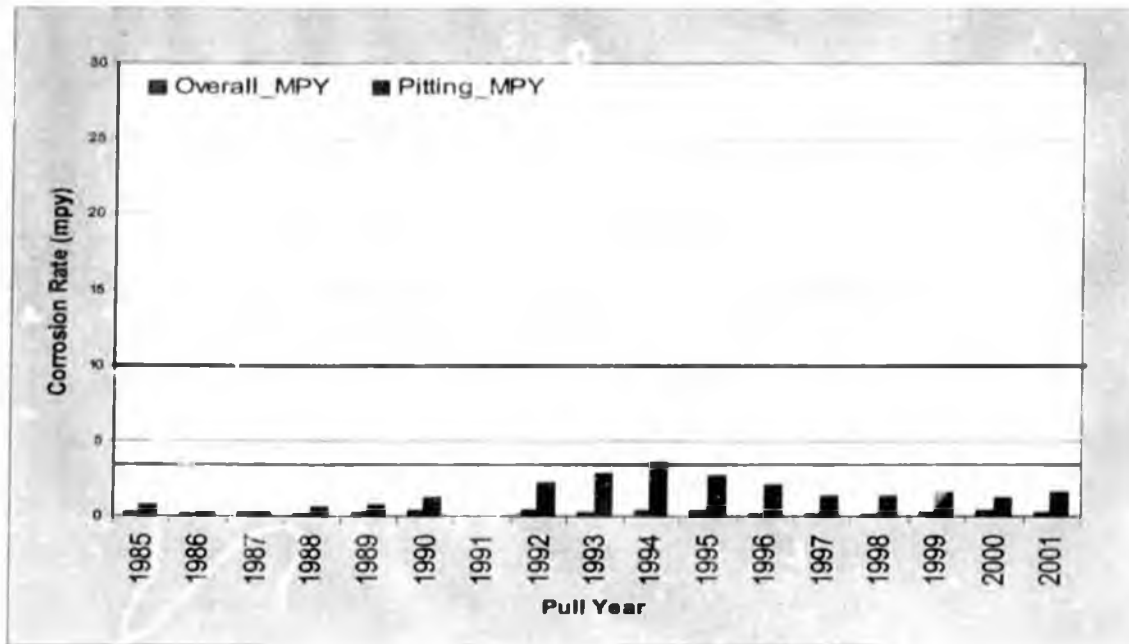


Figure 4. Three-phase Production Well Line Coupons - general and pitting corrosion rates as a function of time.

Three-phase Production and Mixed Water Injection Well Flow Lines: While the monitoring data summarized in Tables 1 and 2 and presented in Figures 4 and 5 suggest that corrosion rates are below targets, inspection data indicates that higher rates are actually being experienced. The well line inspection data are discussed in section 3.1.b below, and are a good example of why monitoring data alone cannot be relied upon to characterize corrosion in a given system.

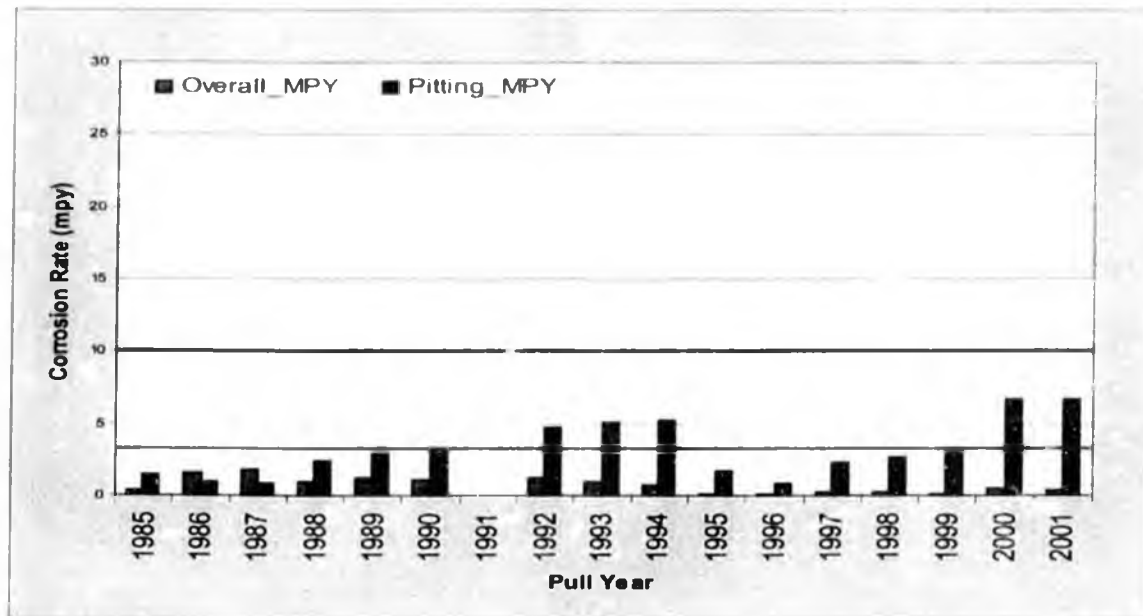


Figure 5. Water Injection Well Line Coupons - general and pitting corrosion rates as a function of time.



Mitigation:

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

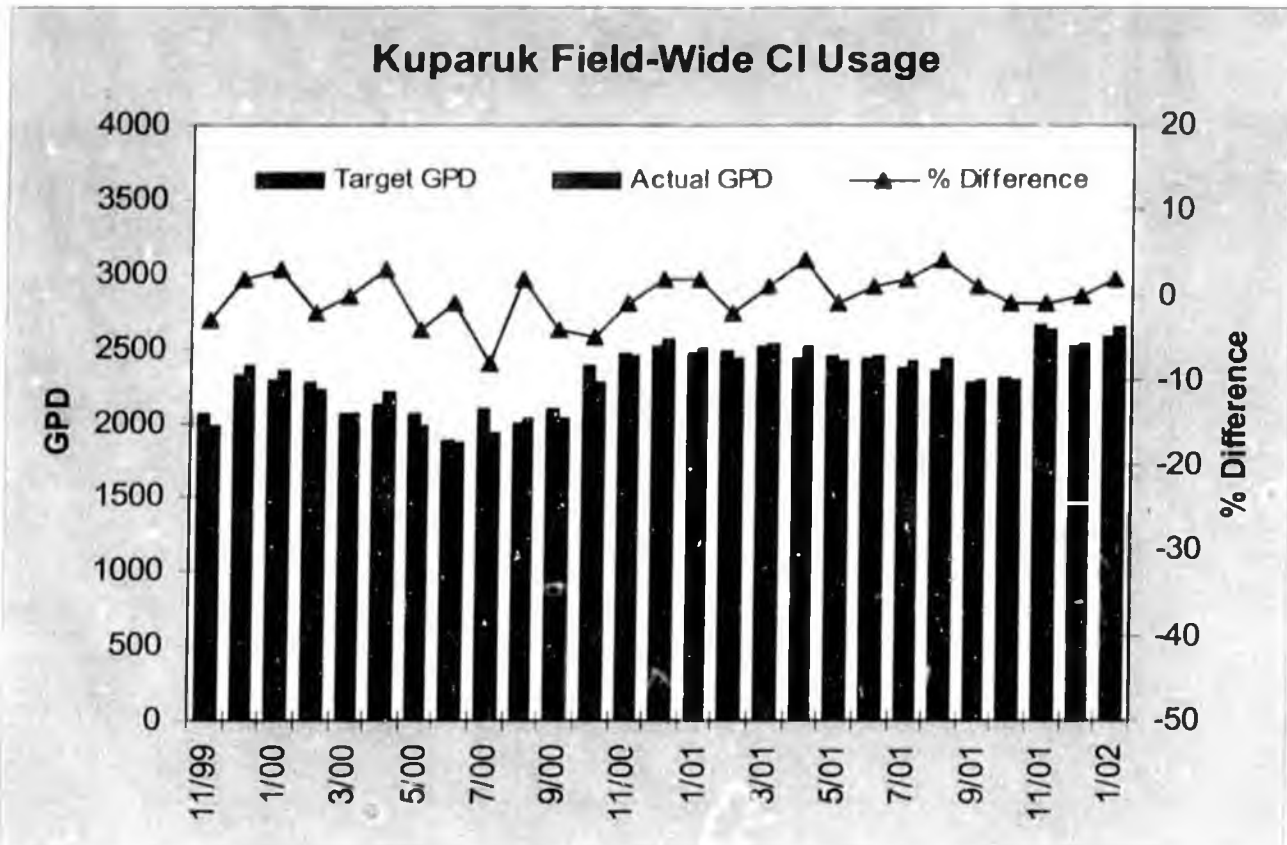


Figure 6. Field-wide Corrosion Inhibitor Use – actual amount of corrosion inhibitor used per day, recommended amount of corrosion inhibitor used per day, and the percent difference between the actual and the recommended amounts.

For the Kuparuk field, Figure 6 shows the actual number of gallons of corrosion inhibitor pumped per day, the recommended number of gallons of corrosion inhibitor per day, and the percent difference between the two. The difference fluctuated around zero percent deviation from the recommended amount of corrosion inhibitor; the average deviation for the year was 0.7%.

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

Kuparuk Inhibitor Feedback System

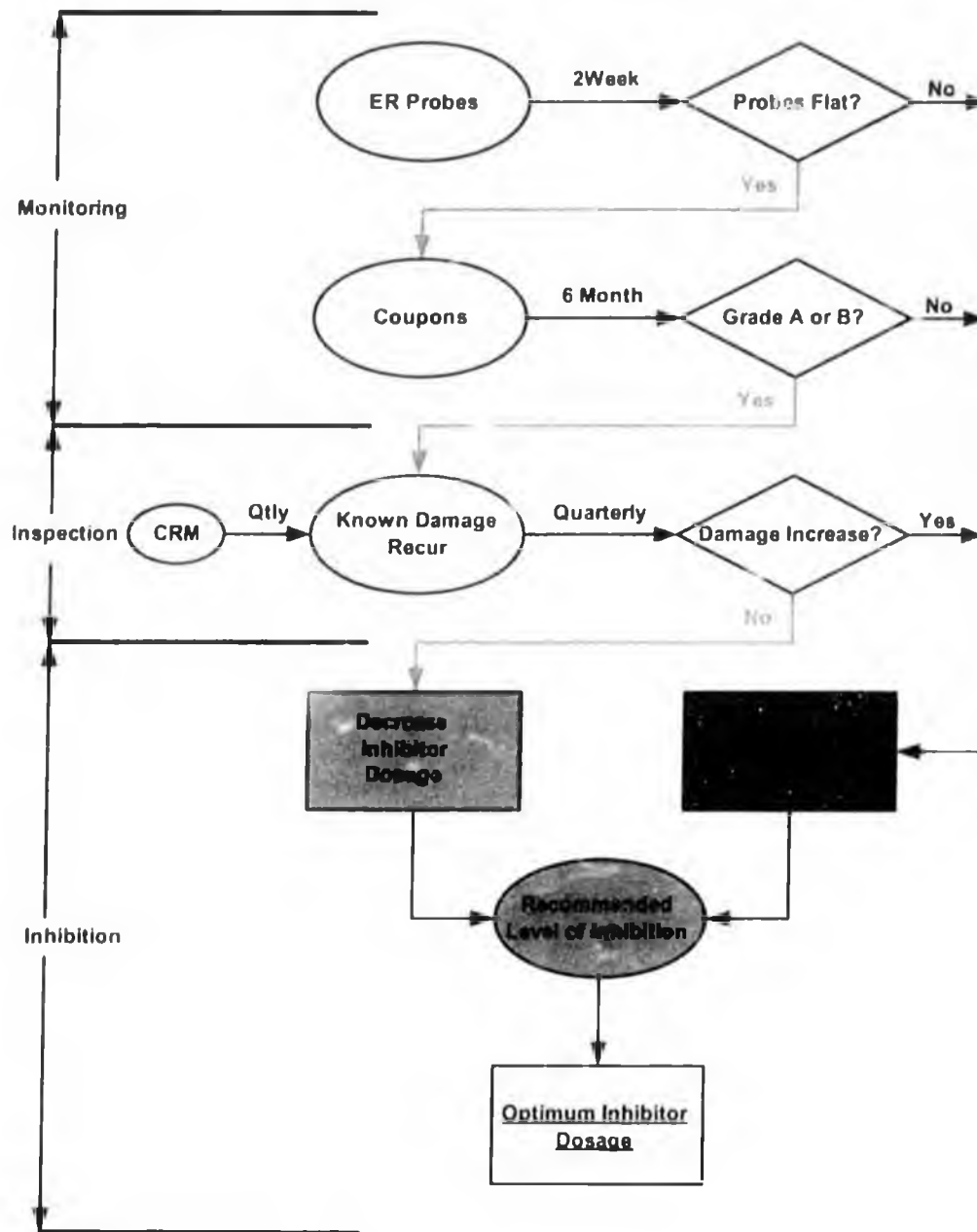


Figure 7. Corrosion Inhibitor Feedback System.



3.1.b Well Line Inspection

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

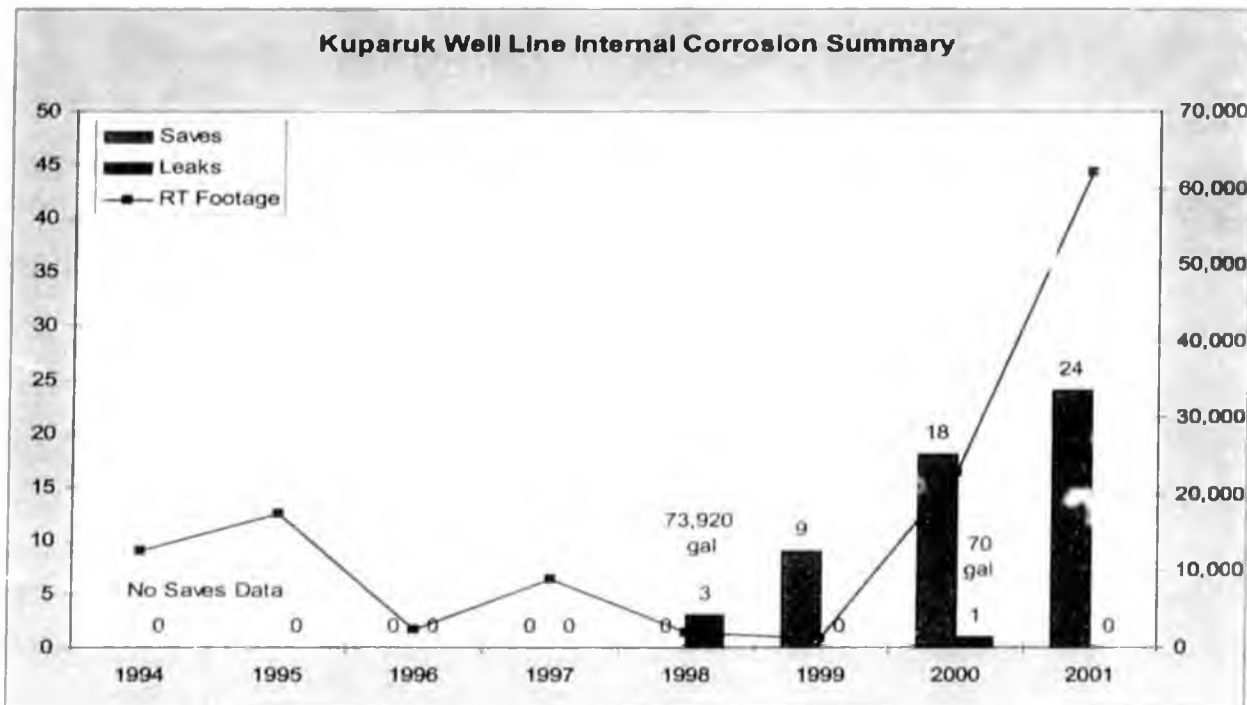


Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

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

• RTR:

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

• Manual RT:

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% Of Repeat Radiographs with Increases
Three-phase Production	252	2,122	350	21	6
Water Injection	97	1,400	209	25	12
Total	349	3,522	559	46	8



• Manual UT:

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	300	2,588	1,144	103	9
Water Injection	56	680	201	14	7
Total	356	3,268	1,345	117	9

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

3.1.c Cross-Country Line Inspection

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

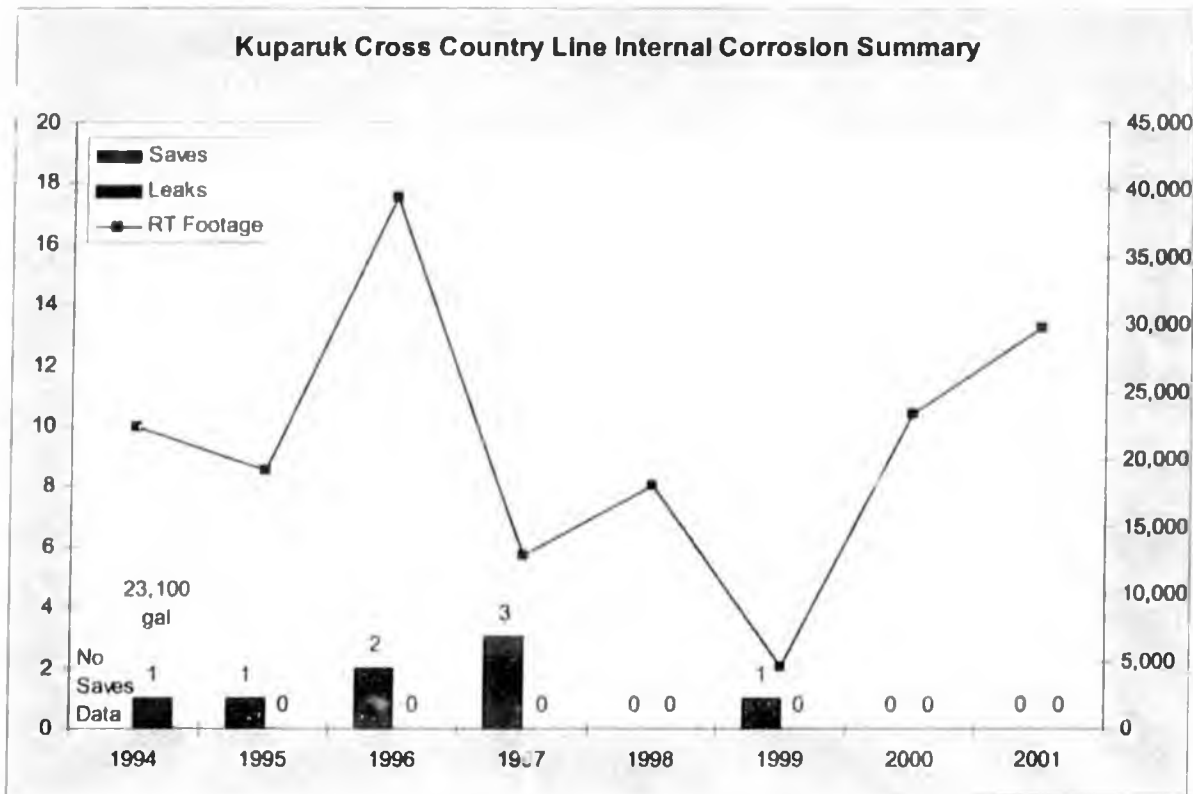


Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

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

- RTR:

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

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

- Manual RT:

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% Of Repeat Radiographs with Increases
Three-phase Production	100	998	600	18	3
Water Injection	23	821	20	0	0
Total	123	1819	620	18	3

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

- Manual UT:

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	79	787	567	17	3
Water Injection	28	74	1	0	0
Total	107	861	568	17	3

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

3.1.4 External (Weld-Pack) Program

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



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

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

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

The number of weld packs TRT'd, number of weld packs corroded, and the percentage of weld packs corroded for the cross-country lines over tundra, cross-country lines on-pad, and well lines are given in Figures 10, 11, and 12.

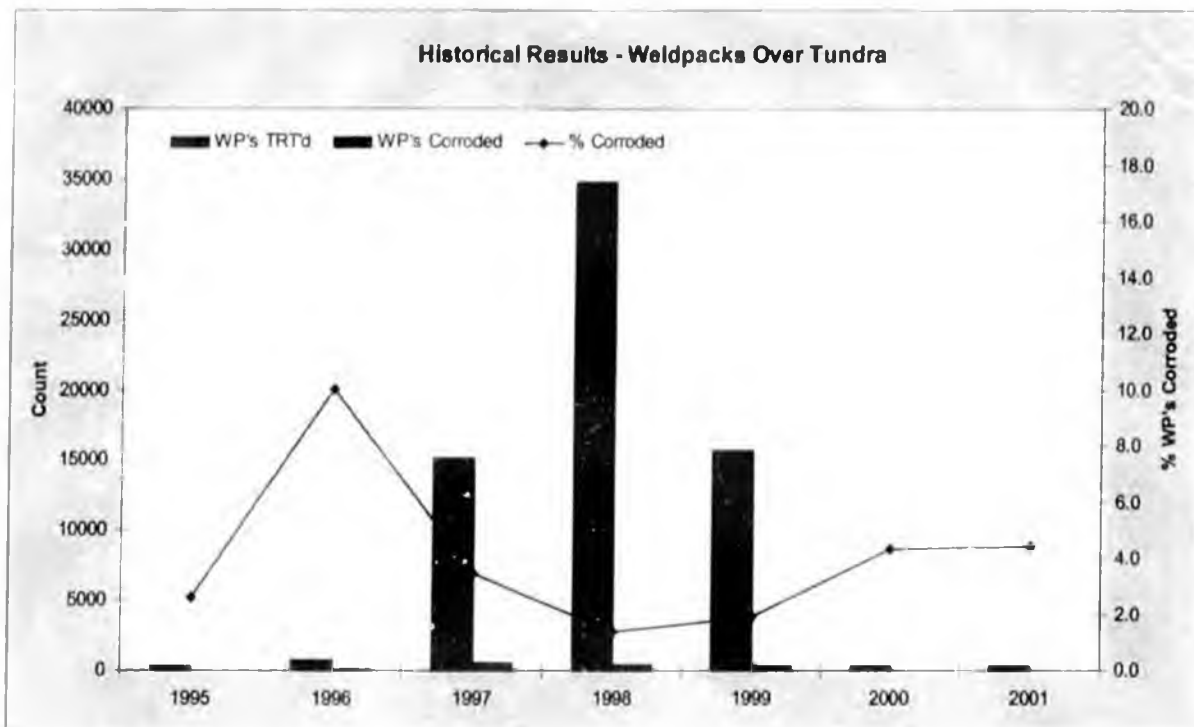


Figure 10. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad) – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

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