PRUDHOE BAY CORROSION CRISIS, 8/18/06 (FILE 9)

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Commitment to Corrosion Montiroring
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Charter for Development of the Alaskan North Slope
Section II.A.6

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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 $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. This corrosivity is increasing as water production and H_2S 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 1st Annual Report is to communicate the Kuparuk 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 H_2S 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).

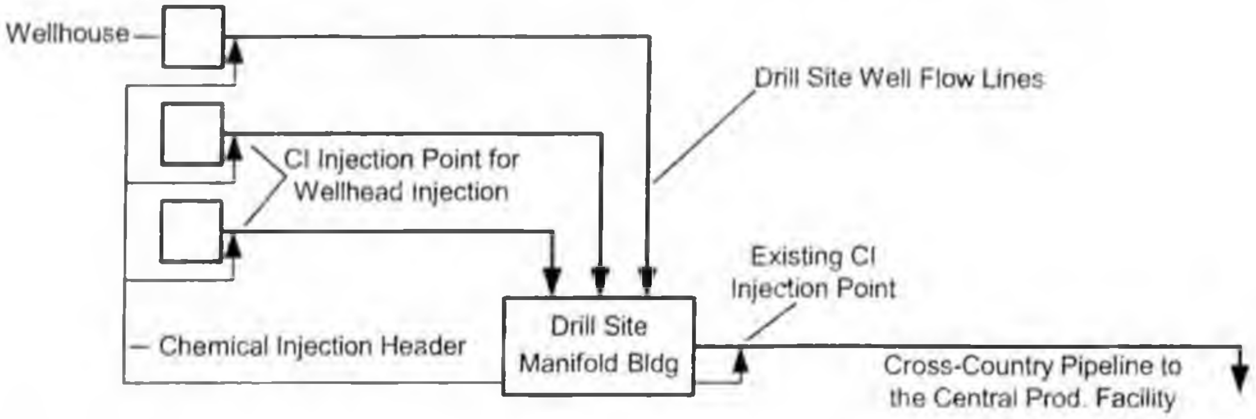
3.1.a. Production Lines

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 GOR 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 jusify 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 CO_2, H_2S, 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 <u>off-pad</u> 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, 1.8% 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 recur 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 recurs: 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.i. 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, know 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) is it 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.

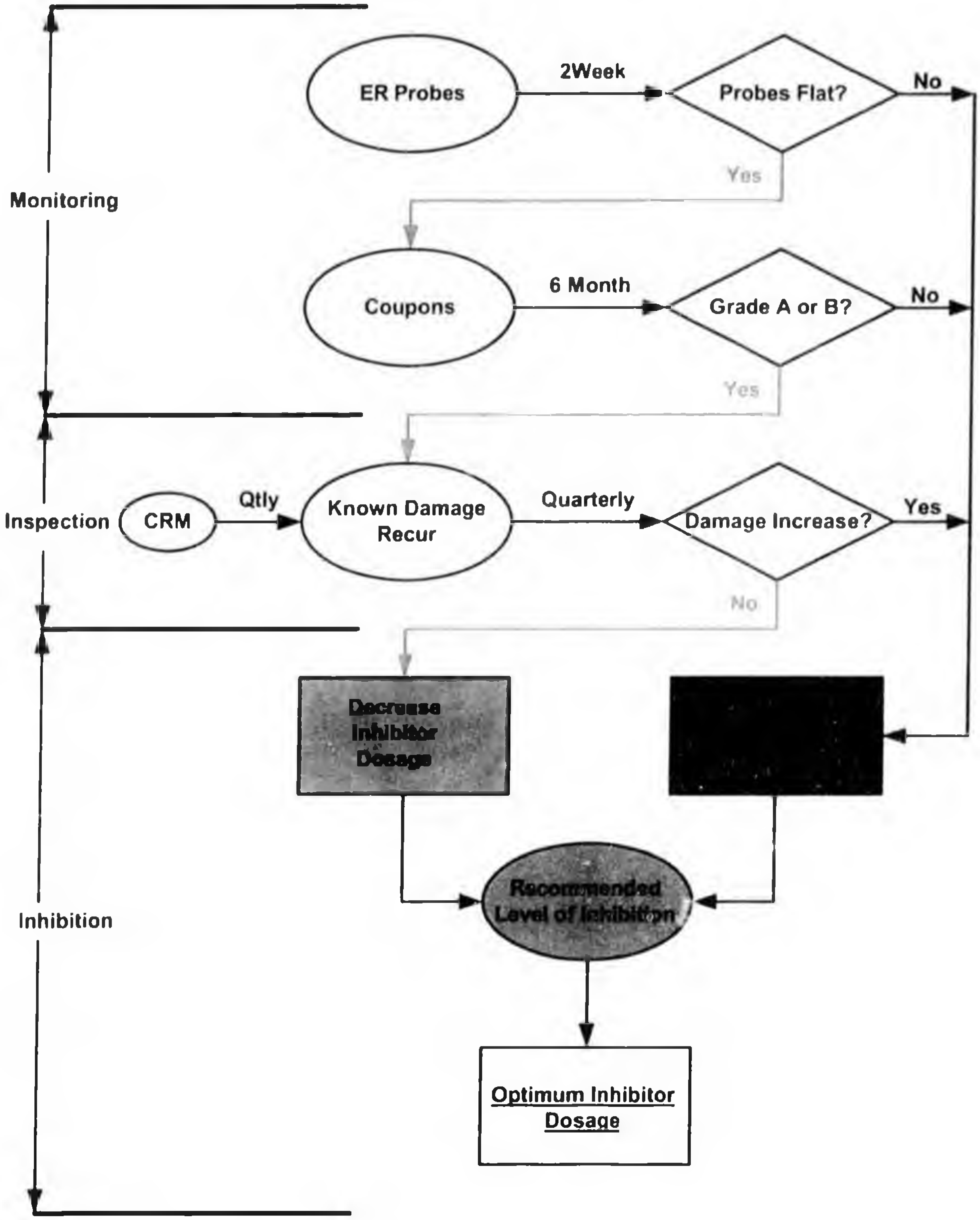
3) Direct inspection of the pipe wall with UT or RT is the only way to verify that the actual pipe wall is not corroding. If ER probes and corrosion coupons show no indication of corrosion activity, the pipe wall may still be corroding, but probably at a low rate. If a pipe is corroding at a low rate, 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: 4137 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	67241	0.64%	99.9%	13	2525	3.0%	3.8%	366	3463	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	159	2.3%	6.0%	27	96	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 scheme. 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 verses 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

Table of Contents

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 H_2S 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

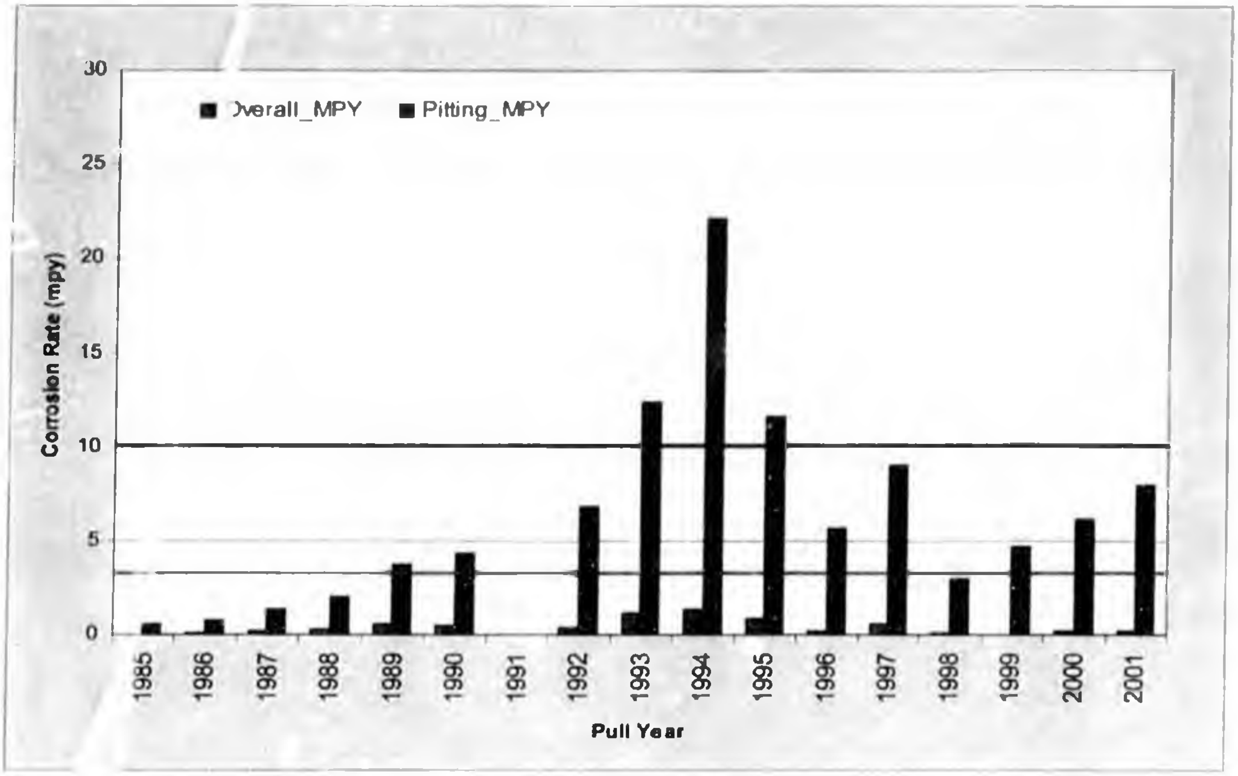


Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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 give 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.

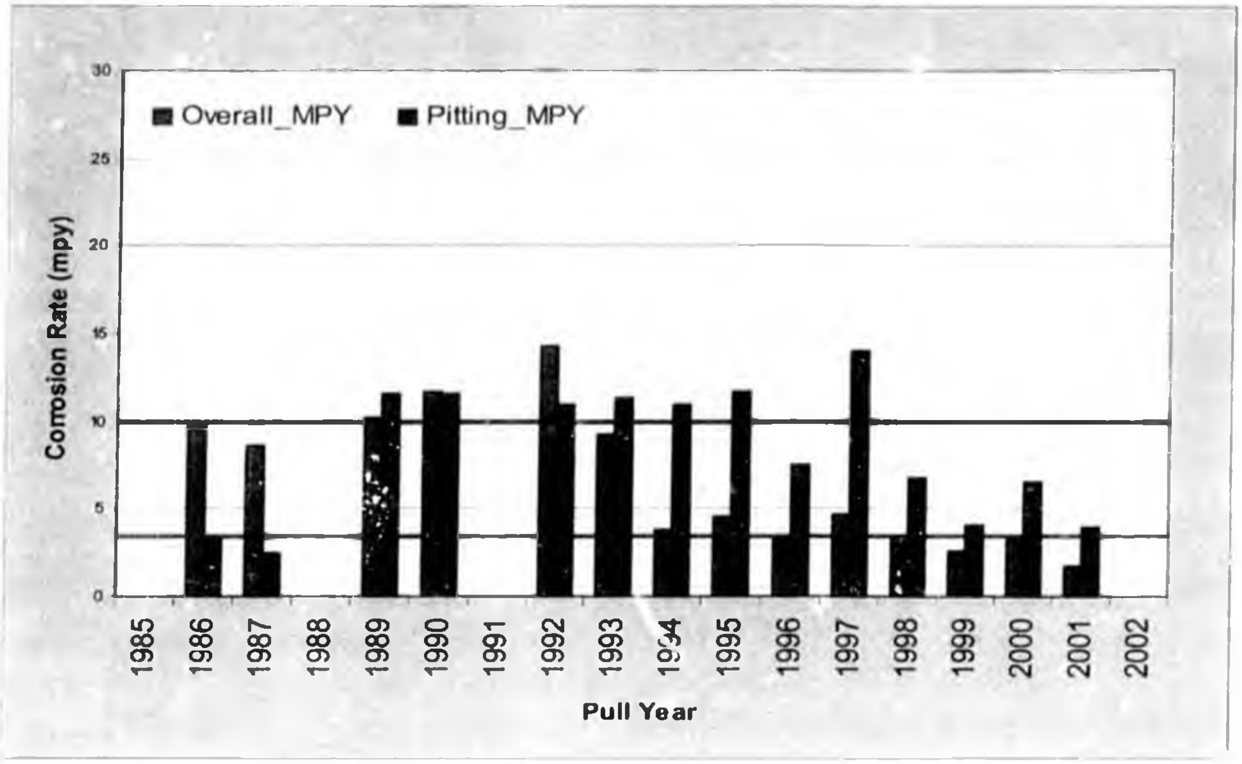


Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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).

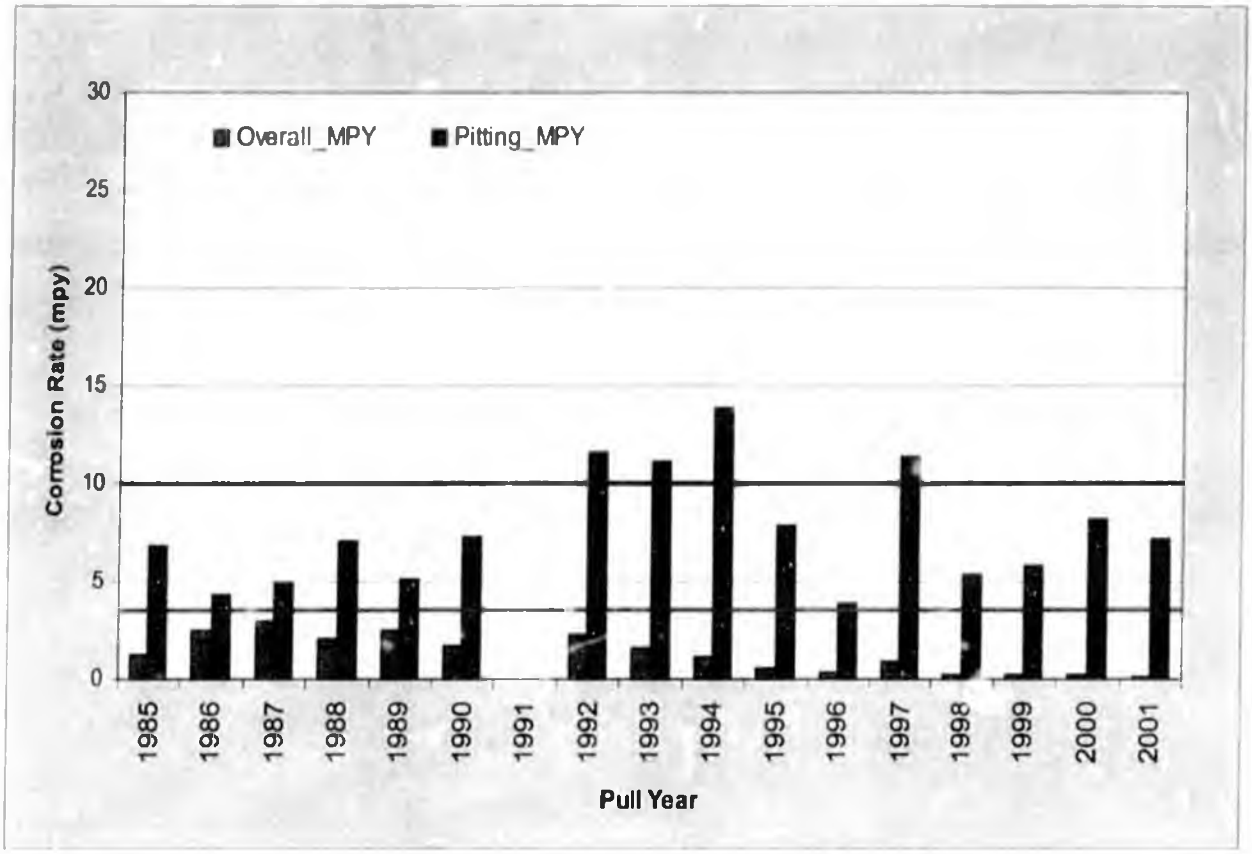


Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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.

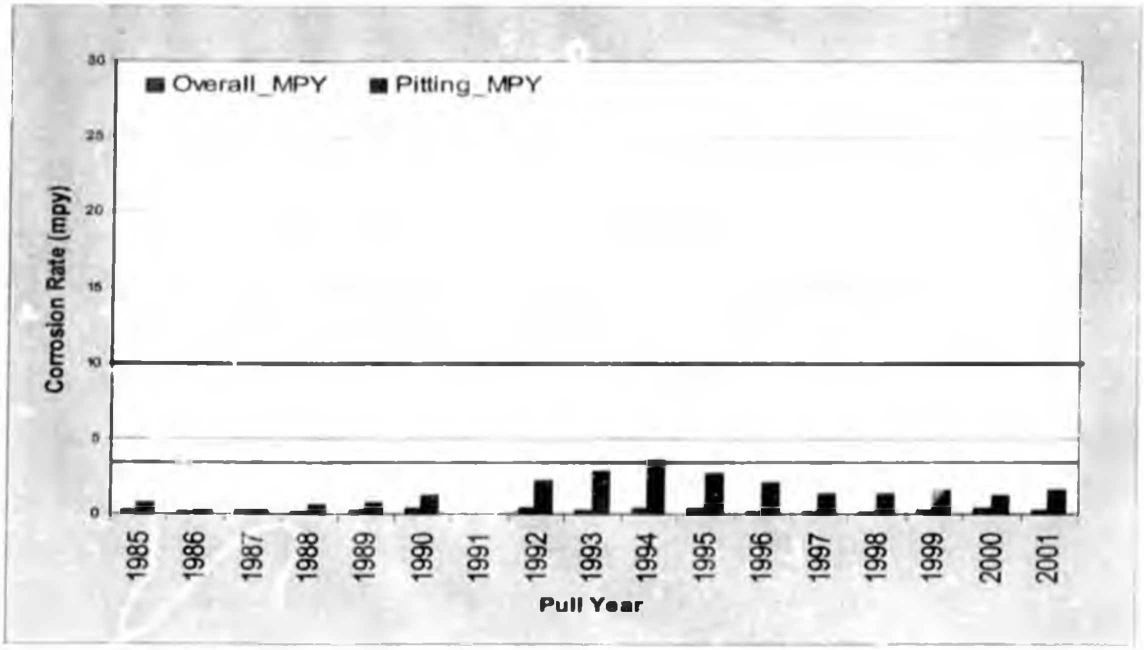


Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

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.

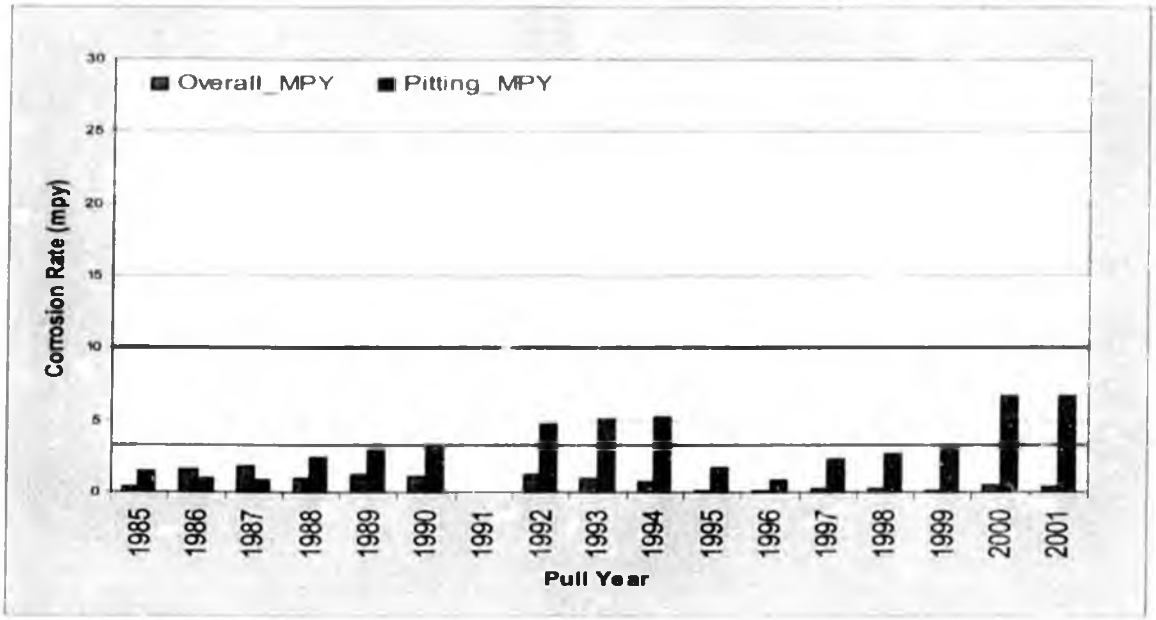


Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

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.

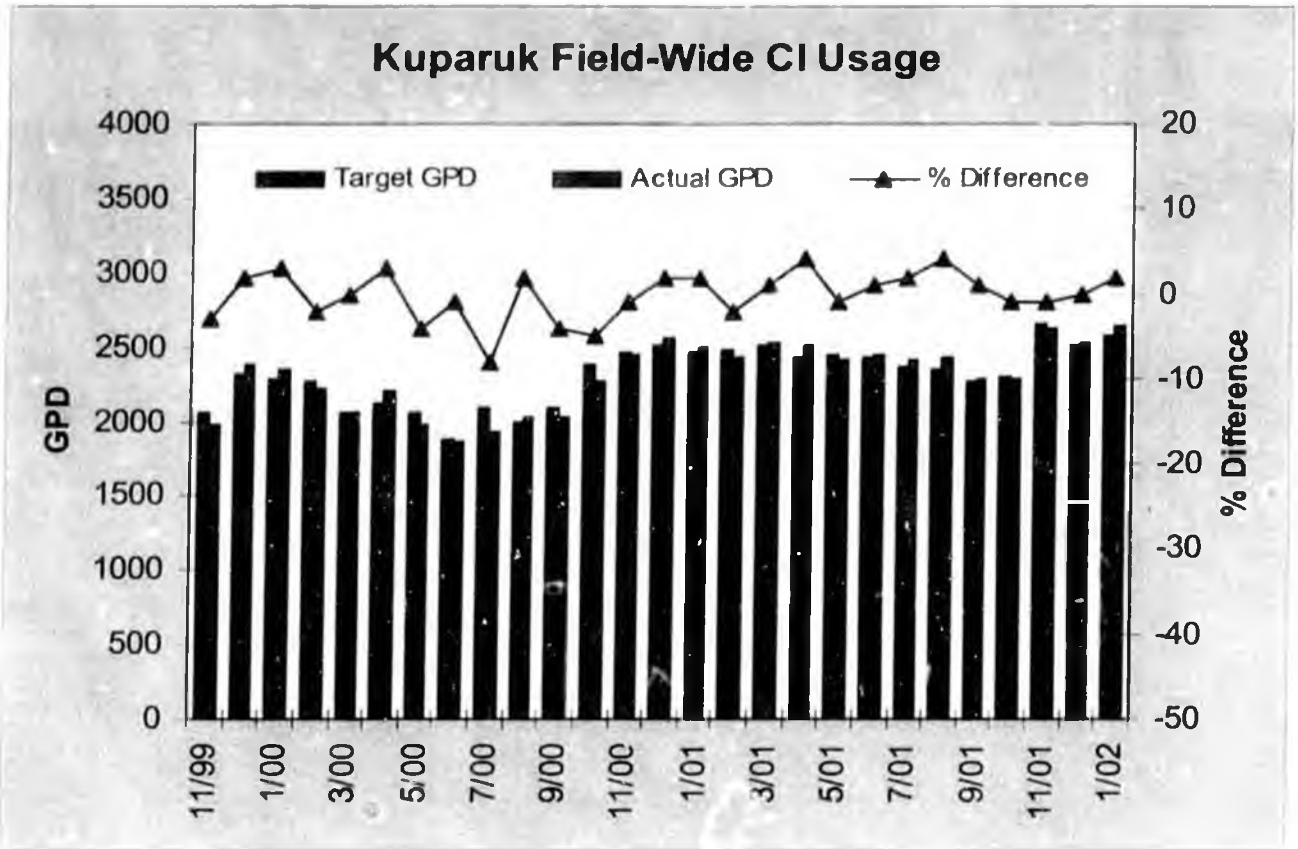


Figure 6. Field-wide Corrosion Inhibitor Use – actual amount of corrosion inhibitor used per day, recommended amount of corrosion inhibitor used per day, and the percent difference between the actual and the recommended amounts.

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

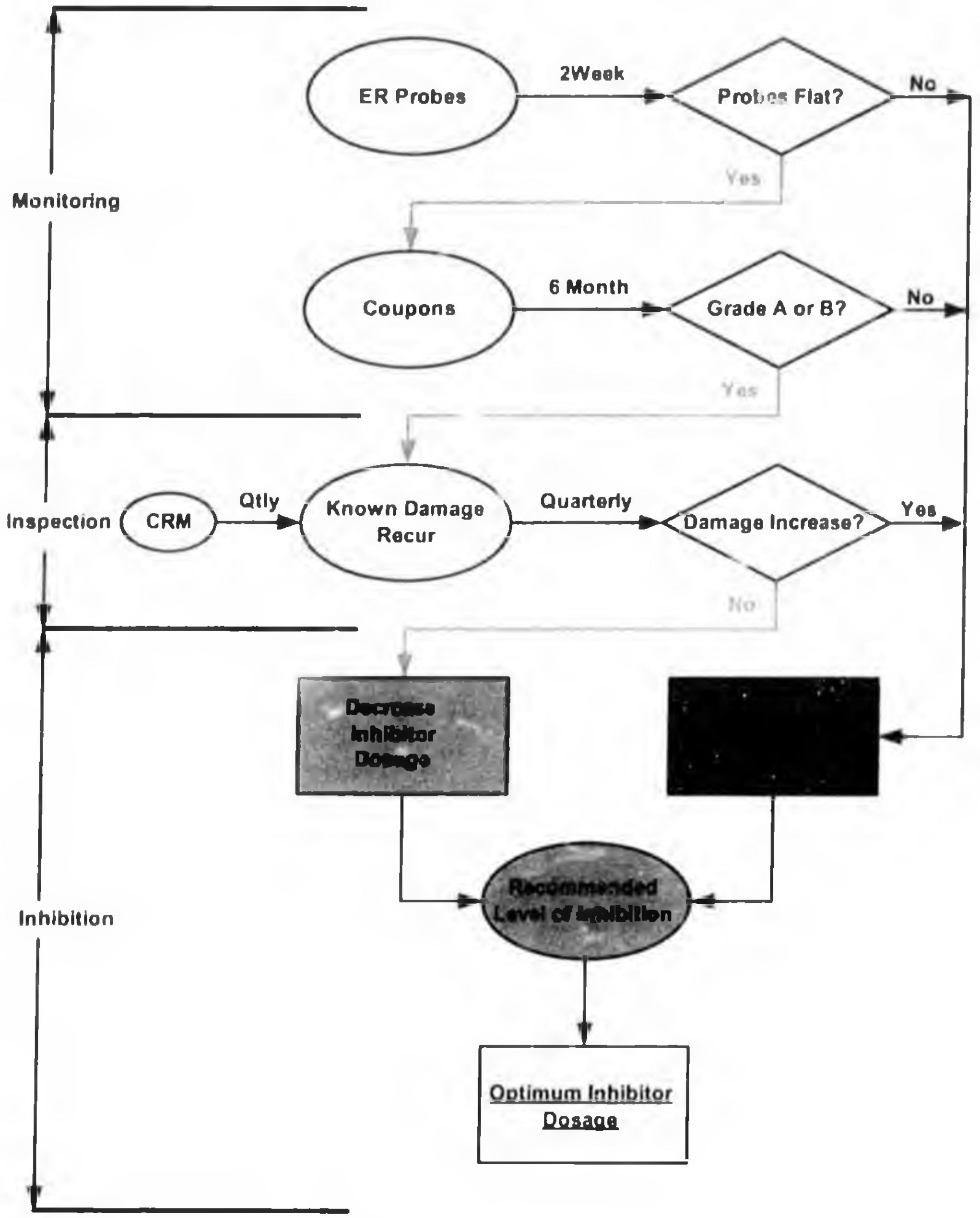


Figure 7. Corrosion Inhibitor Feedback System.

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.

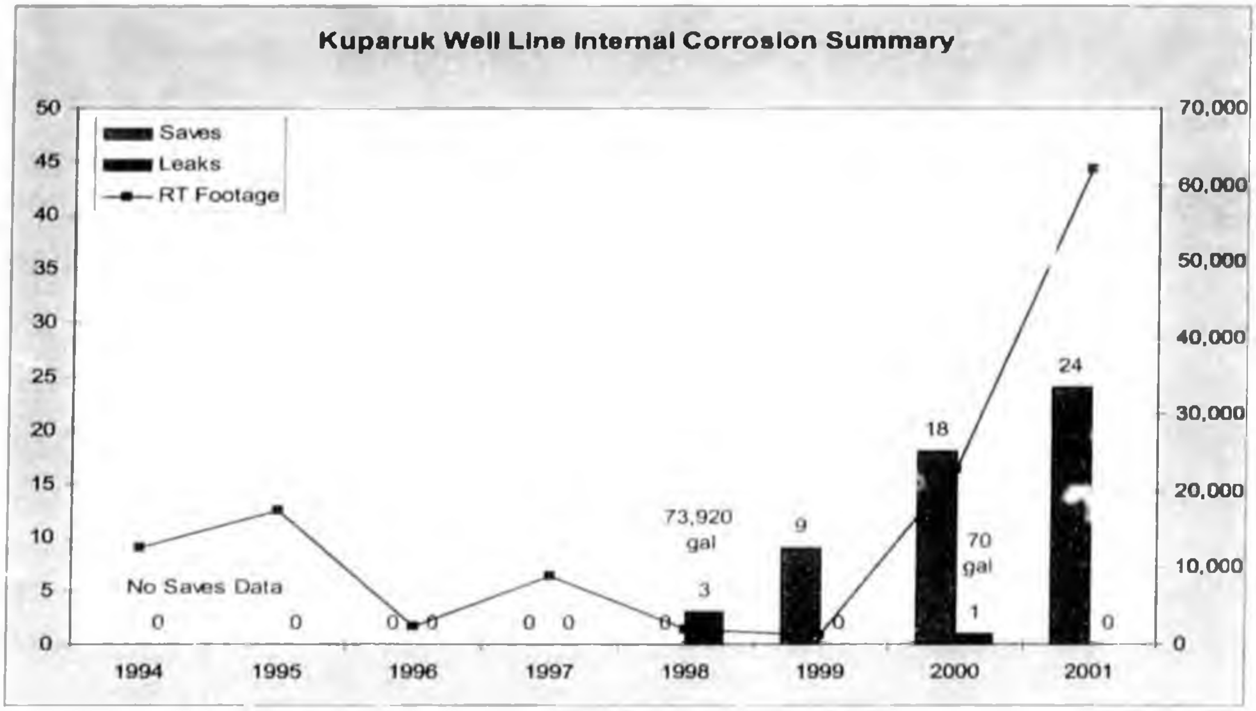


Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

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.

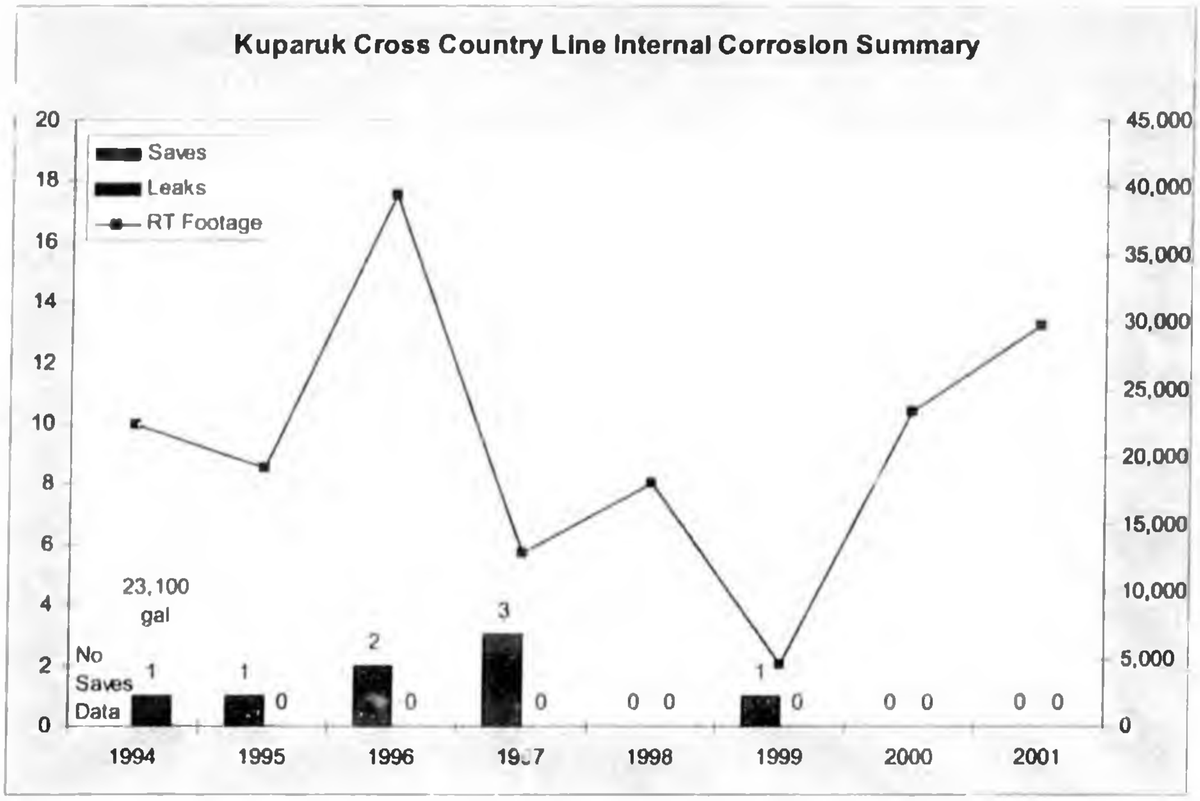


Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

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.

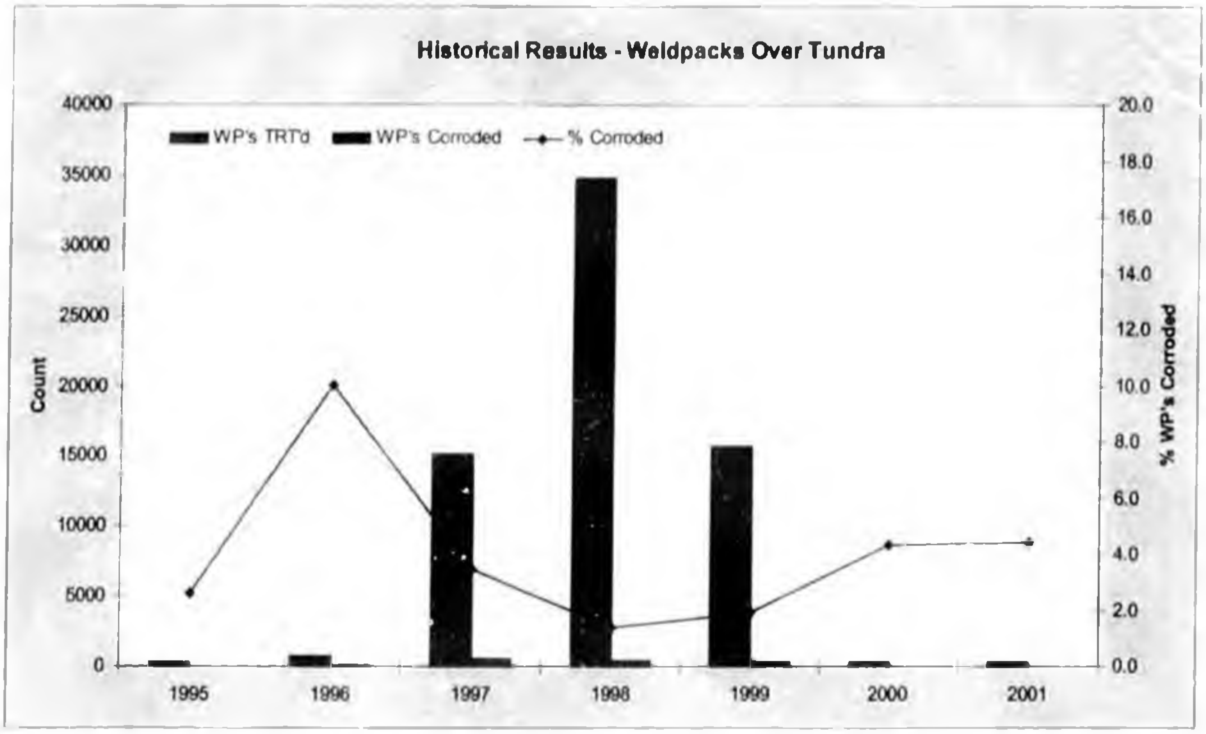


Figure 10. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad) – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

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.

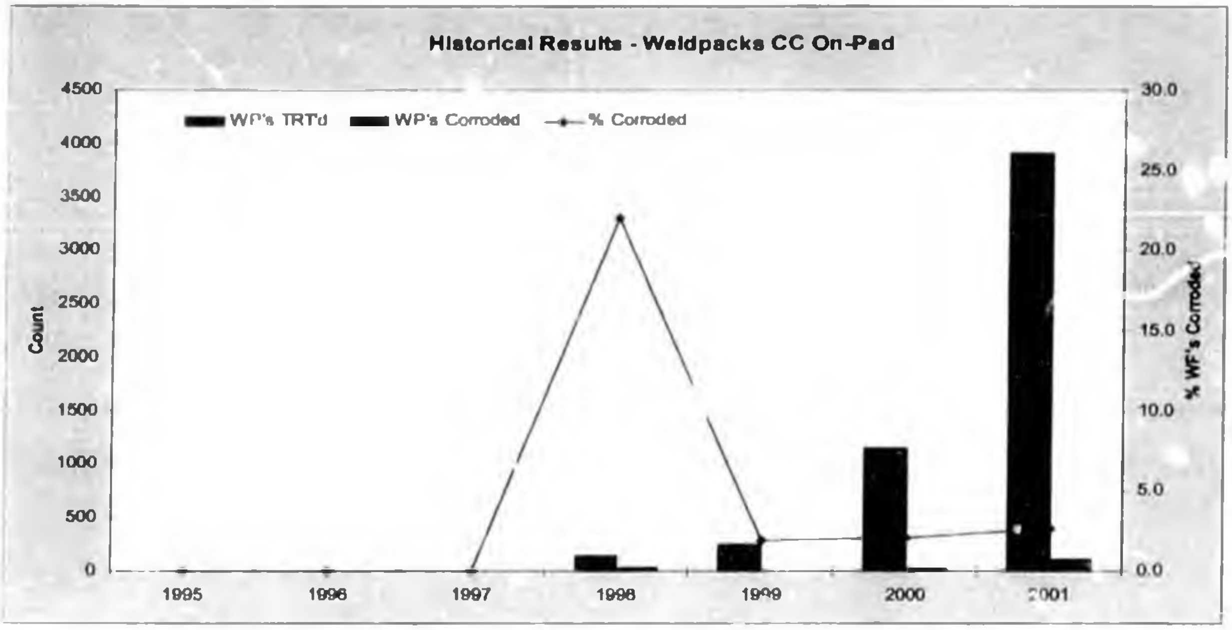


Figure 11. Summary of Weld Packs on Cross-Country Lines on Pads – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

Figures 11 and 12 depict the results of the major focus of the external weld pack inspection program in 2001. The cross-country on-pad weld packs were inspected using a prioritization scheme based on the historical corroded to wet ratios of the over-tundra portions of the cross-country lines. The well line weld packs were inspected using a prioritization scheme that examined the oldest, the hottest, and thinnest-walled lines first. Based on the results in Figure 12, it appears that the worst weld packs have been inspected and the risk of a future leak has been minimized. Continued inspections in 2002 will confirm if this hypothesis is correct. As of Year-End 2001, 61% of the cross-country on-pad weld packs and 43% of the well line weld packs have received their baseline TRT inspection.

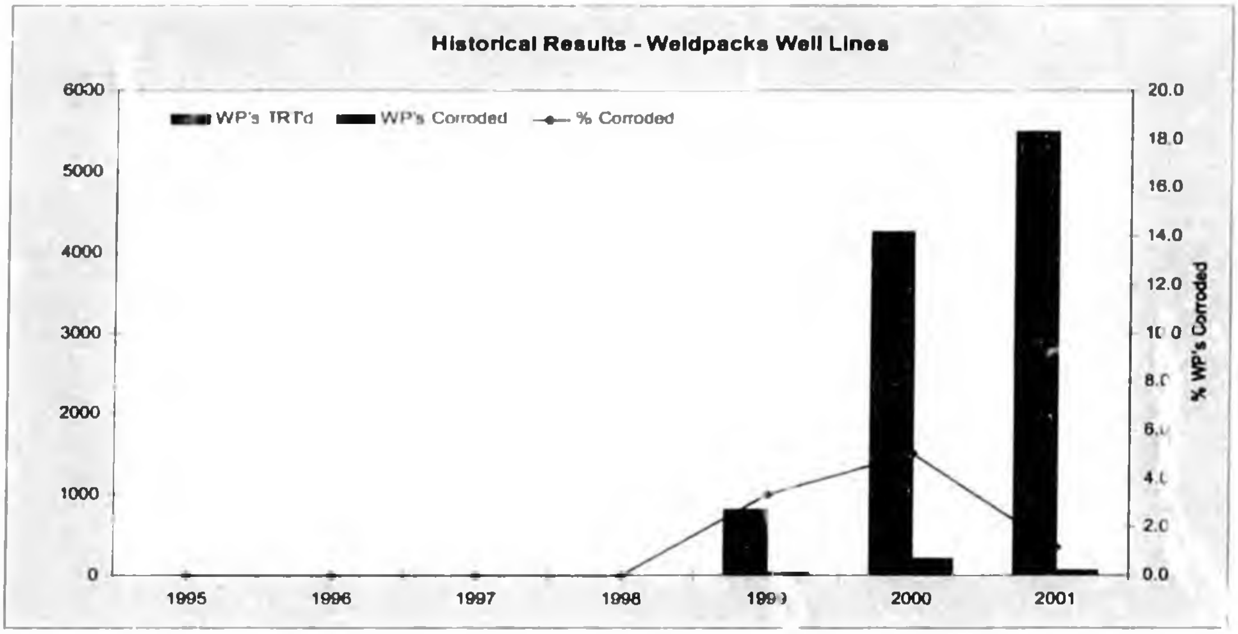


Figure 12. Summary of Weld Packs on Well Lines – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

3.1.e Below Grade Piping Program

In 2001, ADEC and Phillips Alaska, Inc., agreed to consolidate the Below Grade Piping Program report with the Commitment to Corrosion Monitoring Report. This section details the inventory and survey of below grade locations and the results of Specialty Testing. The plans for future inspections are given in section 3.2.e.

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

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

PAI has 431 locations of below grade "oil" piping in the GKA oil fields. Of these, one is contained in a utilidor. The remaining locations are cased lines, the majority of which are either road or caribou crossings. In addition to the "oil" piping, PAI has 210 significant below grade locations with lines in other services.

Utilidor Line
Inspection Status:
The one line in a utilidor was inspected in 1999 and the results were reported in 2000.

Cased Lines
Inspection Status:
The annual visual survey of all the cased lines was conducted in 2001. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

Results and Remedial Action:
Of all the below-grade oil lines, 52 locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. Of the 52 locations requiring remediation, the Corrosion inspector cleaned 40 locations. Twelve other locations required more extensive gravel work by others; these 12 locations were cleaned by the Roads and Pads group and reinspected by the Corrosion inspector.

3.1.e (2) Results of Specialty Testing

Inspection Status:
In 2001, both the long-range ultrasonic system technology from The Welding Institute (TWI) and the electromagnetic wave pulse system from Profile Technologies, Inc. (PTI) were used. Testing with PTI was limited to those lines without a significant risk for internal corrosion. PTI is used to find external electromagnetic anomalies such as external corrosion, but cannot find internal corrosion. The TWI technology was applied to lines with a risk for internal corrosion. TWI was also used to evaluate any positive indications detected by PTI, since PTI finds electromagnetic anomalies and is prone to finding false positives.

In addition to using TWI's long-range ultrasonic system technology, PAI evaluated the guided-ultrasonic (GUL) inspection technique from MQS-Cooperheat. PAI has determined that the GUL technique is not superior to the TWI long-range ultrasonic system and PAI will not use the GUL technique unless further improvements are made.

Results and Remedial Action:

Tables 4 and 5 show the results of the specialty testing performed by PTI and TWI, respectively.

Table 4. Results from the PTI inspections by service.

Service	Number of Cased Pipes Inspected	Number without any Electromagnetic Anomalies (N)	Number of Electromagnetic Anomalies (E)	Number of Significant Electromagnetic Anomalies (S)
Oil[a]	88	71	15	2
Other	106	87	18	1
Total	194	158	33[b]	3[b]

Notes:

(a) Oil service is defined as natural gas liquids, oil sales, three-phase production, two-phase production (wet oil), Produced Water, and Mixed Water.

(b) All "S" and "E" locations were inspected with TWI, except for two pipes with "E," the results of which were received after TWI had left the North Slope. These will be inspected with TWI in 2002.

Table 5. Results from the TWI inspections by service.

Service	Number of Cased Pipes Inspected	Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Moderate Anomalies (M)	Number of Severe Anomalies (S)
Oil[c]	52	3	44	3	1	1
Other	22	3	17	1	0	1
Total	74	6[d]	61	4[e]	1[f]	2[g]

Notes:

(c) Oil service is defined as natural gas liquids, oil sales, three-phase production, two-phase production (wet oil), Produced Water, and Mixed Water.

(d) All "I" locations will be prioritized based on other local and line concerns, and added as appropriate to the excavation/inspection list.

(e) All "L" locations will be re-inspected every two years.

(f) "M" location will be excavated and inspected in 2002.

(g) One "S" location was excavated and inspected in 2001. The other "S" location is in a line that is now abandoned.

3.1.e (3) Results of Crossing Digs

Nine cased pipes were excavated in 2001:

- Two of the nine pipes had moderate external damage. One of the two is now out-of-service. The other, an NGL line, was repaired with a sleeve.
- Seven of the nine pipes excavated and inspected did not require de-rating, repair, or replacement. Only minor damage was found.

For the eight cased pipes that were excavated in 2001 and remained in service, the insulation was refurbished and the pipe wrapped with Densyl tape to prevent further corrosion.

3.1.f Other Structural Concerns

Subsidence:

Existing Well Upgrade Program

- In 2001, 16 floors with riser piping supports were installed in well houses at Drill Site 2M. Well house floors are supported by the well conductor and provide table riser piping supports.
- More than thirty heat tubes were installed at 1A, 1C, 2A, 2K, 2N, 3G. Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

New Wells & Producer to Water Injection Well Conversions

- All new wells brought on line in 2001 had heat tubes, and floors with permanent pipe supports, installed as part of their packages.
- All existing producers converted to water injection wells were also upgraded to include heat tubes and floors with permanent pipe supports.

Wind-Induced Vibration:

- As a result of the DS2X 8" MI line failure which occurred in December 2001 (described below), Kuparuk is in the process of reviewing existing pipelines to evaluate the need for vibration dampeners. The line that failed is oriented 1-degree outside the design wind direction envelope designated for Kuparuk in 1991. To date, we have identified one area that falls within the design wind direction envelope but does not have dampeners installed. We plan on covering these sections of lines in 2002. We are also reviewing the existing PAI specification to determine if it needs to be revised to include a larger degree area than is currently specified.
- Engineering performs an annual inspection of all vibration dampener (PVD) locations to verify integrity of the PVD's. This information is sent to the facilities for corrective action. Typically, corrective action consists of replacement of worn elastomers and reinstallation of PVD weights.

3.1.g Corrosion and Structural-Related Spills/Incidents

- 1HBWI External Corrosion Water Injection Line Leak – 4/15/01 – The 10-inch injection line serving drill sites 1H and 1B failed due to external corrosion at a weld pack in a cased road crossing, spilling 92,000 gallons of produced water. This road crossing had not yet been inspected using electromagnetic wave (PTI) or long-range ultrasonic (TWI) techniques. Prior to the spill, 149 above-grade weld packs on this line had been inspected with no de-rating damage found. The eight above-grade weld packs remaining to be inspected were completed in 2001 with no de-rating damage found.

- No leaks were caused by internal corrosion in 2001.

- DS 2X Miscible Injectant Line Incident – 12/31/01 – The eight-inch miscible injection line serving Drill Site 2X developed a crack at a weld, possibly due to wind-induced vibration. We are still awaiting metallurgical analysis results to rule out the possibility of a weld defect. No liquids were spilled. This line was oriented one degree outside of the susceptible wind direction for the Kuparuk field. As noted above, we are evaluating other line segments that are without PVD's and close to the susceptible wind direction to determine the need for PVD installation.

- No leaks were caused by subsidence in 2001.

Figures 8 and 9, and Figure A1 in Appendix A show the number of leaks and the volumes of leaks as a function of time. Figure 8 depicts the leaks caused by internal corrosion for the well lines. Figure 9 depicts the leaks caused by internal corrosion for the cross-country lines. Figure A1 shows the leaks caused by external corrosion for both cross-country and well lines.

3.2 Year 2002 Forecast

3.2.a Monitoring & Mitigation

- Convert the field wide corrosion inhibitor back to Cortron RU-276.
- Test new corrosion inhibitors in an effort to improve corrosion inhibition technology.
- Test schmoo-be-gone in the water injection system for one drill site.
- Develop and implement wellhead chemical injection systems for the production well lines at select drill sites.
- Decrease wet oil line corrosion exposure through increased maintenance pigging and inhibitor adjustments.

3.2.b Well Line Inspection

Based on the 2001 well line inspection programs, the following enhancements/modifications are planned for 2002:

- Inspect approximately 200 well lines at Kuparuk.
- 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 25% line target was used as the "initial" footage in 2001. The plan for the 2002 inspection program is to maintain the same percentage of the initial target area.

3.2.c Cross-Country Line Inspection

Based on the 2001 cross-country line inspection programs, the following enhancements/modifications are planned for 2002:

- Maintain an equivalent level of RTR inspection as in 2001.
- Continue to implement the risk-ranked Elbow Inspection Program that increases the effectiveness of the produced crude (three-phase) cross-country line inspection program. The purpose of this program is to identify higher-risk areas on a given line, taking into account flowing conditions and pipeline geometries, so that more effective inspection schedules can be established.
- Evaluate the possibility of smart pigging cross-country water injection lines larger than 8" outside diameter.

3.2.d External (Weld-Pack) Program

- Inspect approximately 17% of well line weld packs (approximately 4,000 weld packs). All well line weld packs will be inspected by YE 2005.
- Inspect 20% of the of CC <u>On-Pad</u> weld packs (approximately 1,780 weld packs). All CC On-Pad weld packs will be inspected by YE 2004.

3.2.e Below Grade Piping Program

- Visually inspect all of the cased lines. The appropriate PAI field department will be notified of any corrective actions that need to be taken early enough to complete clean out and re-inspection during the summer.

- Complete the first-pass inspection of the remaining priority 1 cased lines using PTI and/or TWI techniques. There are approximately 150 cased lines that will require inspection in 2002. Based on the results from TWI and PTI, certain lines will be excavated.

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

3.2.f Other

- Complete enhancements to the Kuparuk Corrosion Database.

- Continue to review existing Kuparuk pipeline locations to assure correct placement of WIV dampeners.

- Continue Alpine piping layout and piping information database development.

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

- Continue to evaluate snow fences to minimize snow accumulation on well lines.

APPENDIX A

Table A1. Three-phase Production Cross-Country lines with corrosion rates that exceeded targets and the action that was taken.

Common Line	Date	Coupon Grade	Probe Rate	Inspection	Insp Incr	Action Taken
1-2Z1QGPO	06/18/01	A	<0.5 mpy		yes	Raised target inhibition
1-2Z1QPO	11/12/01	NA	NA		yes	Raised target inhibition
1APO	11/12/01	A	<0.5 mpy		yes	Raised target inhibition
1BPO	11/06/01	D	>0.5 mpy			Raised target inhibition
1DPO	11/06/01	D	<0.5 mpy			Initiated inhibition 12/01
1GPO	07/01/01	C	>0.5 mpy	yes	yes	Raised effective inhibitor
1L10PO	11/05/01	D	<0.5 mpy		yes	Raised target inhibition
1QPO	11/05/01	D	<0.5 mpy			Raised target inhibition
1RPO	Jan, July, Nov	F, D	> 1 mpy	yes	yes	Raised target inhibition
1YPO	11/02/01	A	<0.5 mpy		yes	Raised target inhibition
1YRPO	11/15/01	A	<0.5 mpy		yes	Raised target inhibition
24" WO at 1Q	Feb, June	D, C	> 1 mpy			Raised target inhibition then line taken out of service
2HPO	11/16/01	B	<0.5 mpy		yes	Raised target inhibition
2KPO	11/03/01	D	<0.5 mpy			Raised target inhibition
2TAMKHPO	11/10/01	A	<0.5 mpy		yes	Raised target inhibition
2TPO	11/03/01	D	>0.5 mpy			Raised target inhibition
2UPO	02/07/01	A	<0.5 mpy		yes	Raised target inhibition
3CPO	11/02/01	D	<0.5 mpy			Raised target inhibition
3GFPO	07/01/01	C	>0.5 mpy	no		Raised target inhibition
3GPO	11/01/01	C	<0.5 mpy			Raised target inhibition
3HPO	Aug, Nov	D, F	<0.5 mpy	yes		Raised target inhibition
3M	08/13/01	D	<0.5 mpy	no		Raised effective inhibiton
3MPO	11/01/01	C	<0.5 mpy			Raised target inhibition
3OPO	07/01/01	A	>0.5 mpy			Raised target inhibition
3RPO	11/02/01	C	<0.5 mpy			Raised target inhibition
3RQOPO	07/01/01	D	>0.5 mpy	yes	yes	Raised target inhibition
XCL/WO at CPF1 w. of flare pit	11/05/01	D	<0.5 mpy			Raised target inhibition
XCL/WO at CPF2	May, Nov	F, C	<0.5 mpy			Raised target inhibition

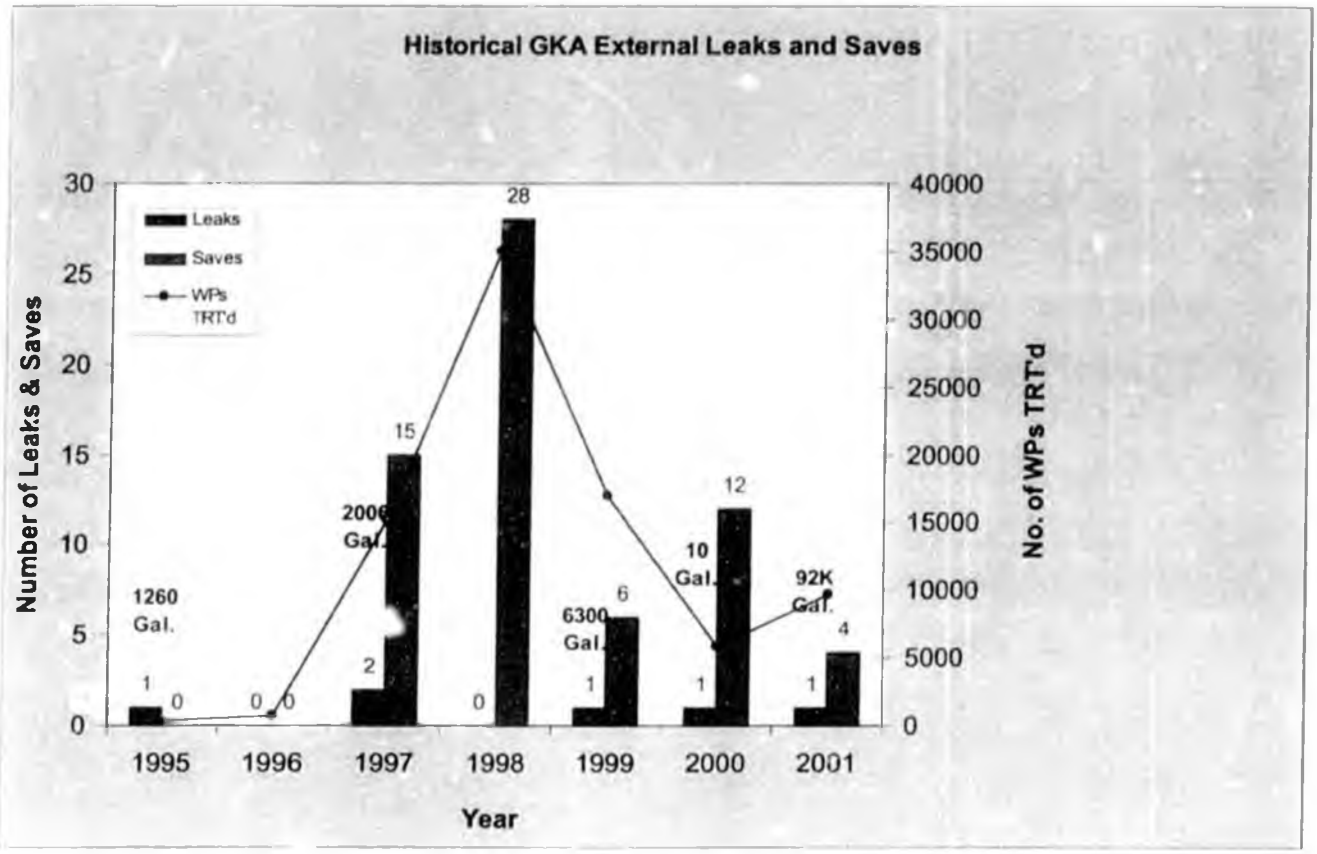


Figure A1. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

Note: The leak in 2001 due to external corrosion was located in a weld pack in a below-grade piping segment, and as such, would not have been detected by the TRT inspection program. The location had not yet received PTI/TWI inspection.

APPENDIX B
Glossary

Equipment Classification:

- **Well Line** – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.
- **Cross-Country Line** – Pipe from the Drill Site manifold to the Central Processing Facility (CPF).
- **Below-Grade Location** – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

Service Definitions:

- **Three-phase Production** – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.
- **Seawater (SW)** – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration, oxygen stripping using produced gas, and biociding.
- **Produced Water (PW)** – The water separated at the CPF from three-phase production.
- **Mixed Water (MW)** – Produced water and seawater that have been commingled.
- Gas – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible injectant.
- **Produced Oil** – The liquid hydrocarbon separated at the CPF from three-phase production.

2002

ConocoPhillips

Greater Kuparuk Area (GKA)
Alpine Field
Corrosion Programs Overview

April 7, 2003

Commitment to Corrosion Monitoring

3rd Annual Report to the Alaska Department of Environmental Conservation

Prepared by

ConocoPhillips Corrosion Team

Table of Contents

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 H_2S 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.

Alpine is ConocoPhillips' newest development and the largest onshore oil field discovered in North America in the past decade. Alpine has a gross processing capacity of 100,000 BOPD. The Alpine development produces from a pad area of 97 acres, and has 2 Drill Sites. The corrosion management system used at Kuparuk is also being applied to the new Alpine field.

The purpose of this 3rd Annual Report is to communicate the details of the individual programs that implement the ConocoPhillips Alaska Corrosion Strategy. In addition to the requirements of the North Slope Charter Agreement between ConocoPhillips Alaska, Inc., BP Exploration (Alaska), and the Alaska Department of Environmental Conservation, previous reporting requirements pertaining to the Below Grade Piping Program will be incorporated into this and future North Slope Charter Corrosion Reports.

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

- Developed a corrosion inhibitor-screening lab in the Bartlesville technology center. In doing so we established our lab qualification testing protocols for use of Rotating Cylinder Autoclave (RCA), Interfacial Tension measurements (IFT) and Total Organic Carbon (TOC) analysis. In addition we established a method for evaluation of lab data generated during testing using statistics, allowing us to better rank performance between inhibitors for selection to actual field-testing.

- Started Corrosion Inhibitor injection at Alpine CD1 Drill Site Cross Country Line.

- Initiated a Turbulent Flow Survey (TFS) on cross-country three-phase oil lines. This program is designed to schedule fittings, such as elbows and tees, for recurring inspection based on flow characteristics, which may cause velocity assisted corrosion damage. The TFS supplements our RTR inspection program, which is designed to find internal damage in straight runs of pipe.

- Implemented use of Intrinsically safe UT machine.

- Initiated the CUI Buffer Spike test on 76 test locations during summer of 2002.

3.0 Program Status Summary

3.1 Year 2002 Overview

3.1.a Monitoring & Mitigation

Monitoring Kuparuk:
Average general and pitting coupon corrosion rate data for Year 2002 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	60	0.03	60	100
Seawater Cross-Country Lines	2	2.0	1	50
Mixed Water Injection Cross-Country Lines	22	0.6	21	95
Production Well Flow Lines	437	0.2	433	99
Mixed Water Injection Well Flow Lines	549	0.4	527	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	60	4.3	50	83
Seawater Cross-Country Lines	2	2.3	2	100
Mixed Water Injection Cross-Country Lines	22	19	14	64[a]
Production Well Flow Lines	437	1.7	417	95
Mixed Water Injection Well Flow Lines	549	6.9	412	75

Notes:
a See graph and discussion on page 8 of this report.

Monitoring Alpine:
Average general and pitting coupon corrosion rate data for Year 2002 are presented in Tables 3 and 4.

Table 3. 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	1	0	1	100
Seawater Cross-Country Lines	1	0.7	1	100
Seawater Injection Cross-Country Lines	1	0	1	100
Production Well Flow Lines	17	0.3	17	100
Seawater Injection Well Flow Lines	5	0	5	100

Table 4. 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	1	1.0	1	100
Seawater Cross-Country Lines	1	1.0	1	100
Seawater Injection Cross-Country Lines	1	0	1	100
Production Well Flow Lines	17	0.2	17	100
Seawater Injection Well Flow Lines	5	0.2	5	100

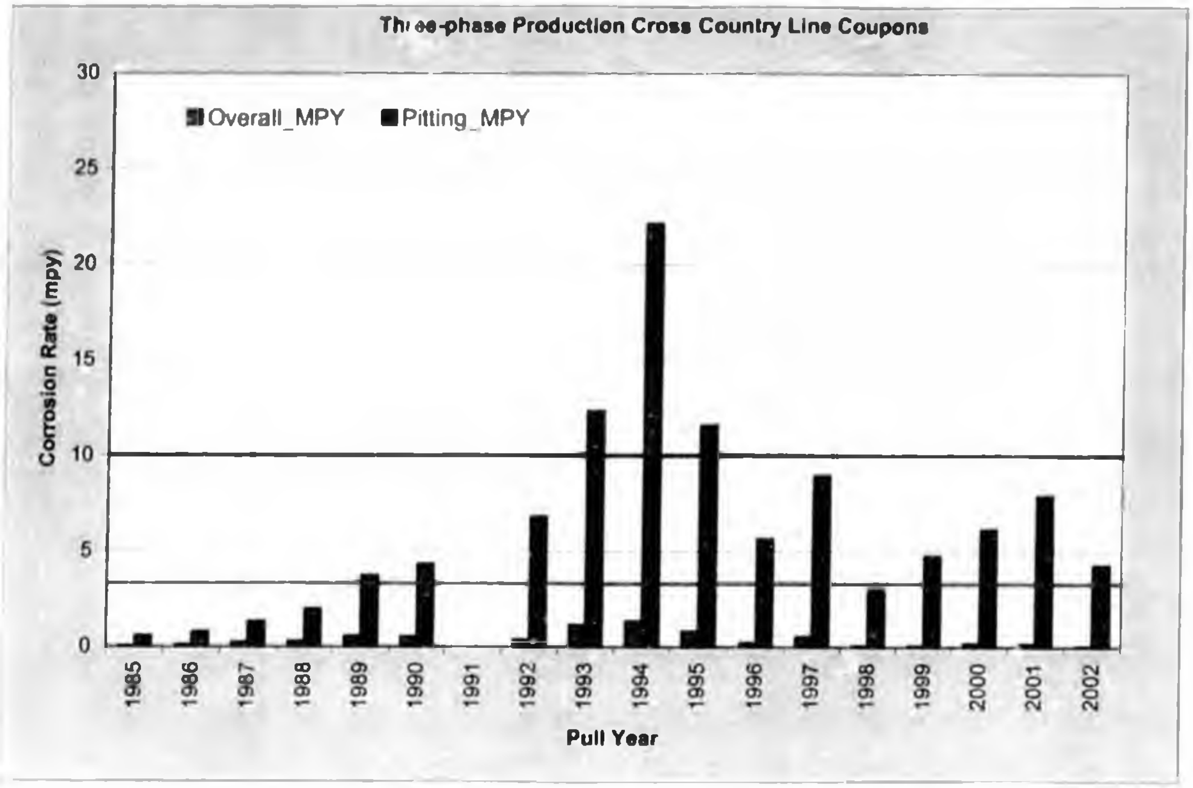


Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Cross-Country Lines: The monitoring data summarized in Kuparuk 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 2002, 517 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). Other internal inspection data also support the CRM data conclusions 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 2002, coupon or probe corrosion rates exceeded targets on 10 lines and corrosion inhibitor concentrations were increased on all 10 of these lines. In 2002, inspection results indicated minor corrosion had occurred on 7 lines that did not have coupons or probes that exceeded the target corrosion rates; corrosion inhibitor concentrations were increased in all 7 of these lines. A complete listing of the 20 lines with corrosion rates that exceeded targets or where inspection indicated increase damage, is given Table A 1 of Appendix A.

In 2002, of the three wet oil lines only the 12" CPF2 Wet Oil Line showed any significant coupon corrosion rate; the corrosion inhibitor concentration was increased on this line.

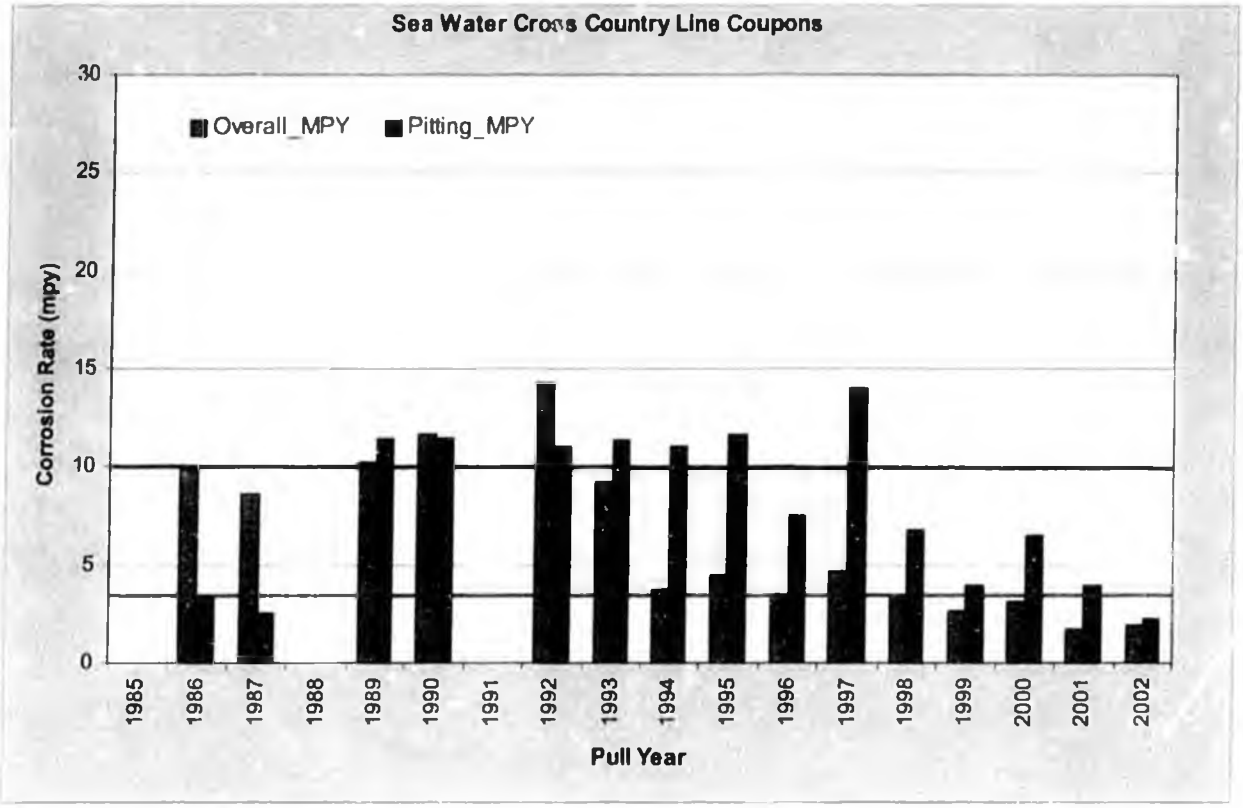


Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Sea Water Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 2 above, shows the average corrosion rates for the sea water cross-country line coupons remained under thresholds in 2002. UT inspections were conducted in the area of the coupons with the high general corrosion rates and no increases to existing minor damage were found. An ER probe has been installed in the same area with no appreciable corrosion rate noted.

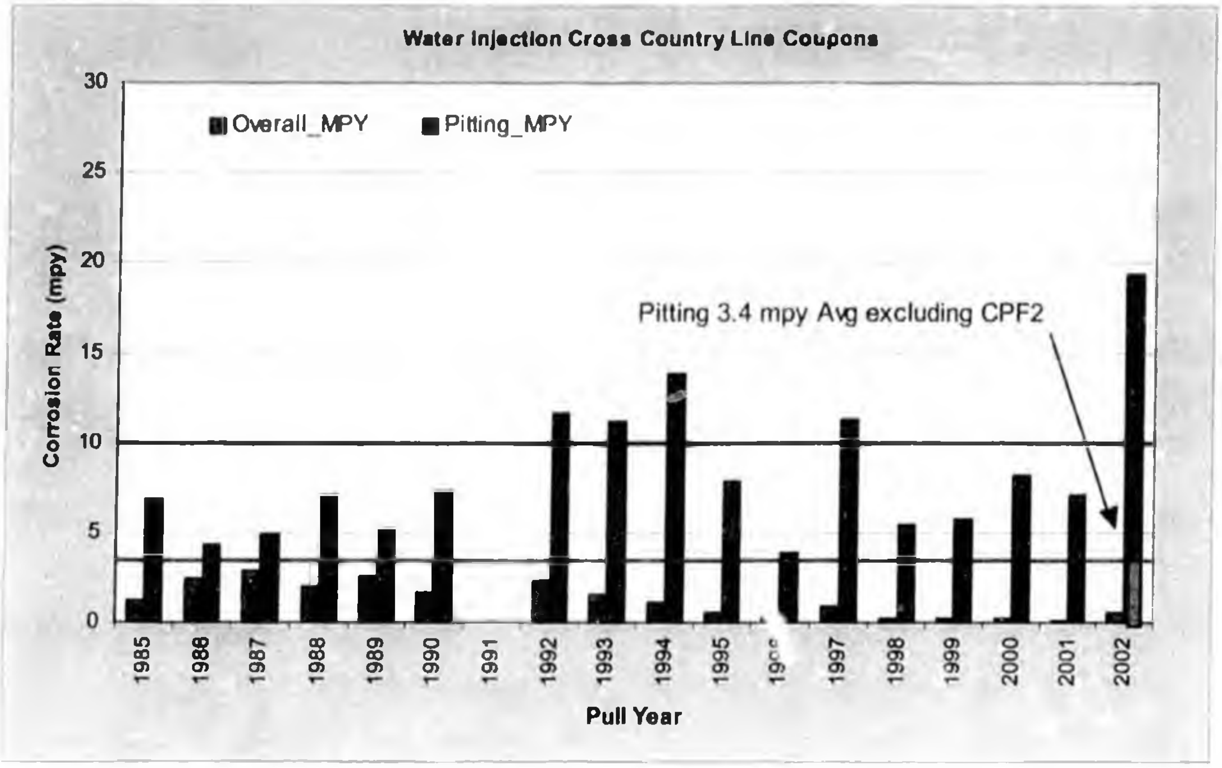


Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Mixed Water Injection Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 3 show that average general corrosion rates are below the threshold, but that pitting rates for the field are above the threshold. Closer analysis of the data shows that the average pitting rate excluding CPF2 locations is well under the threshold. Recent inspection data from the CPF2 lines show some damage on three lines. This information, along with coupon results, was used to prioritize 2003 inspection efforts. RTR inspection work for 2003 will target 15,000 feet of cross-country water injection lines.

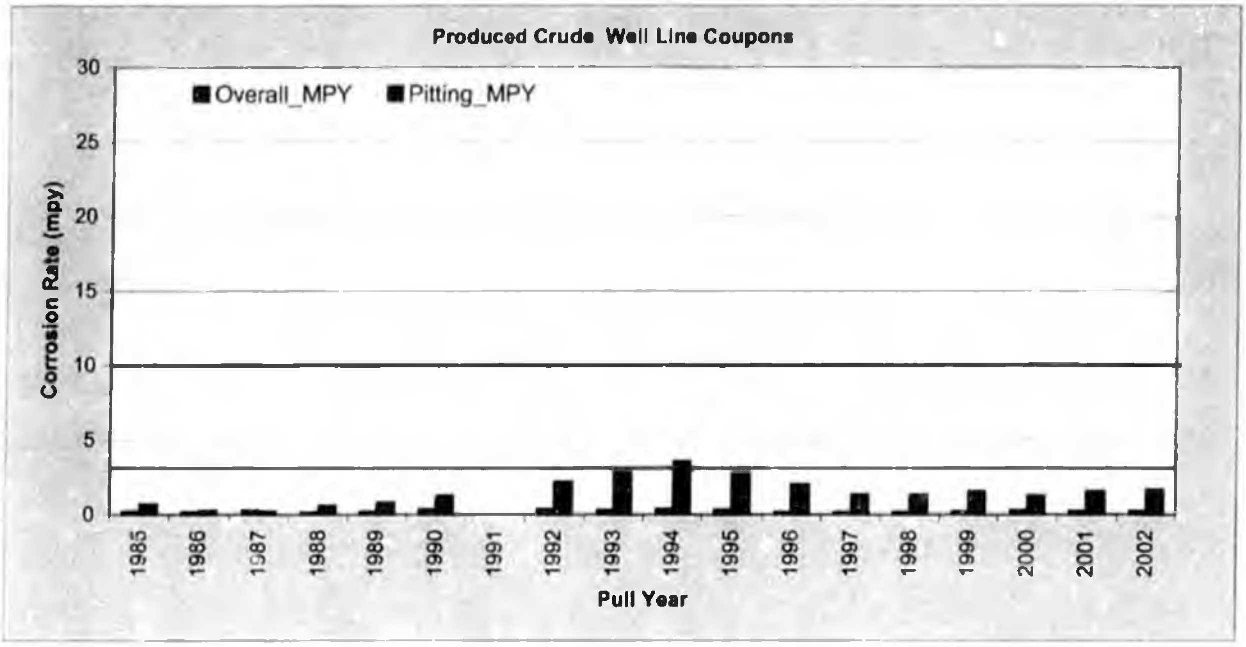


Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production and Mixed Water Injection Well Flow Lines: While the monitoring data summarized in Kuparuk 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.

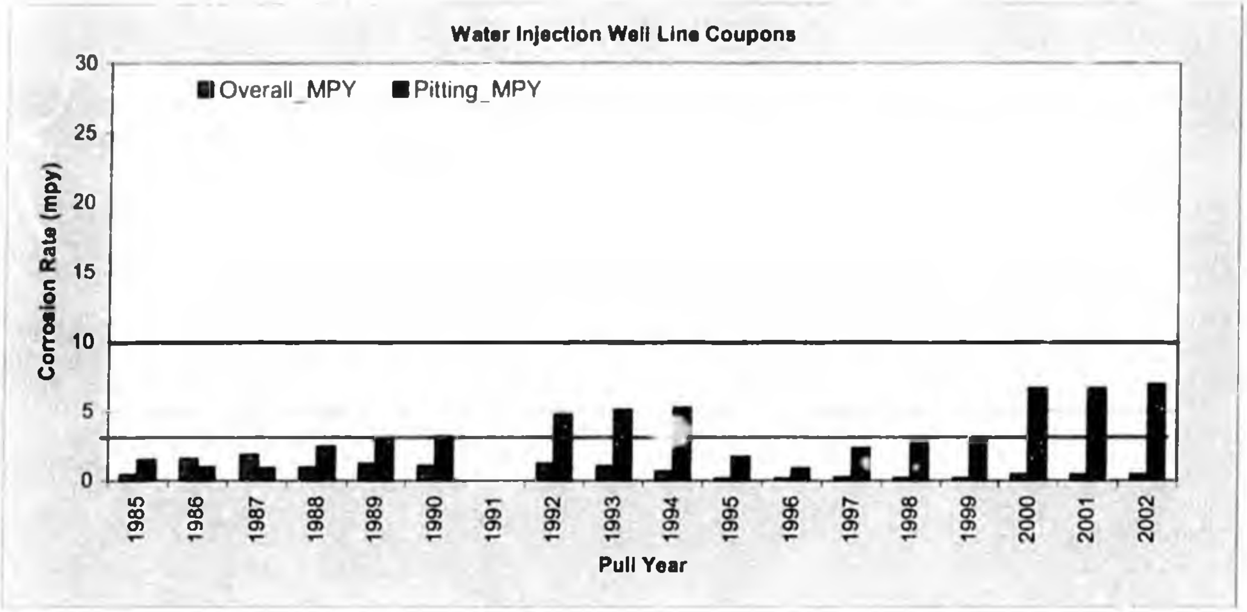


Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

Mitigation:
In first quarter 2002, the field was converted from Cortron 2000-25 to Cortron RU-276 based on poor performance of the 2000-25. One new inhibitor VX6789 was tested at DS1R; the test yielded good monitoring data, however the inhibitor did not out-perform the incumbent inhibitor.

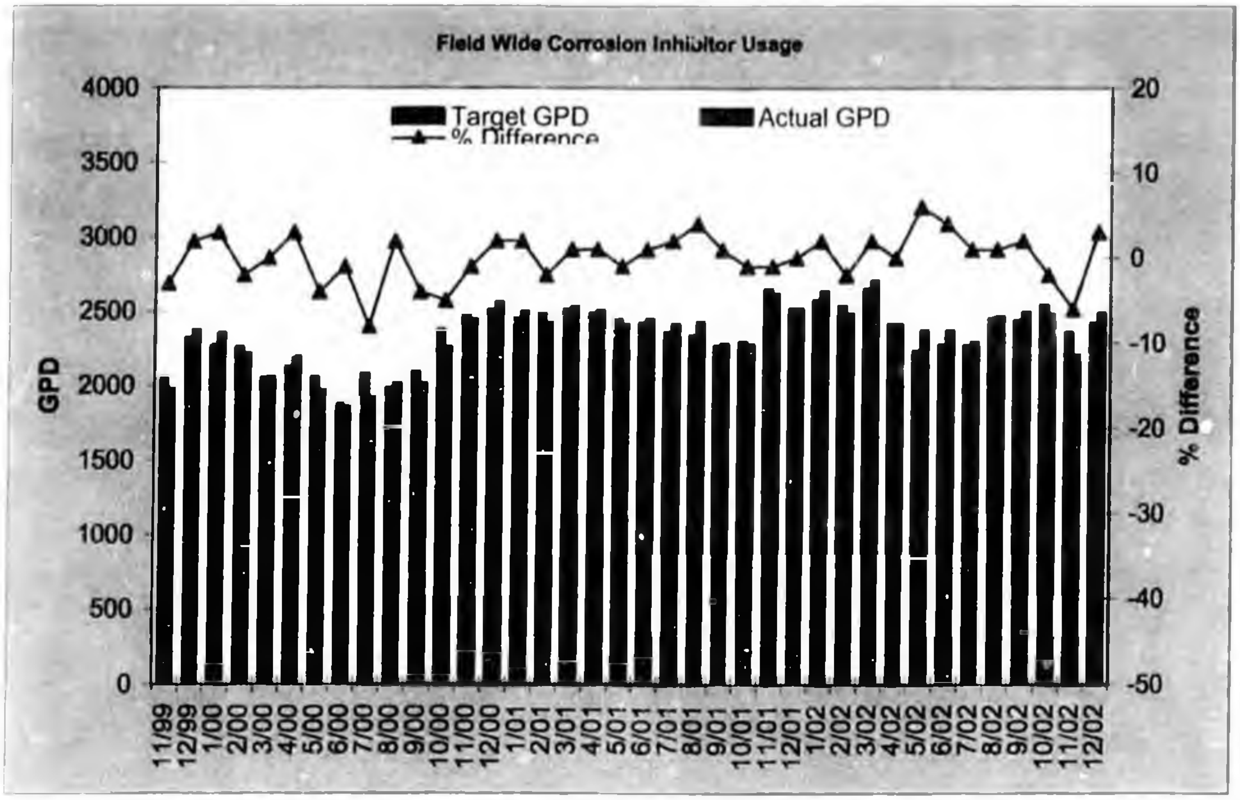


Figure 6. Field-wide Corrosion Inhibitor Use – actual amount of corrosion inhibitor used per day, recommended amount of corrosion inhibitor used per day, and the percent difference between the actual and the recommended amounts.

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 0.9%. The extreme variation seen in the November data was caused by the production upsets associated with the earthquake prorations.

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

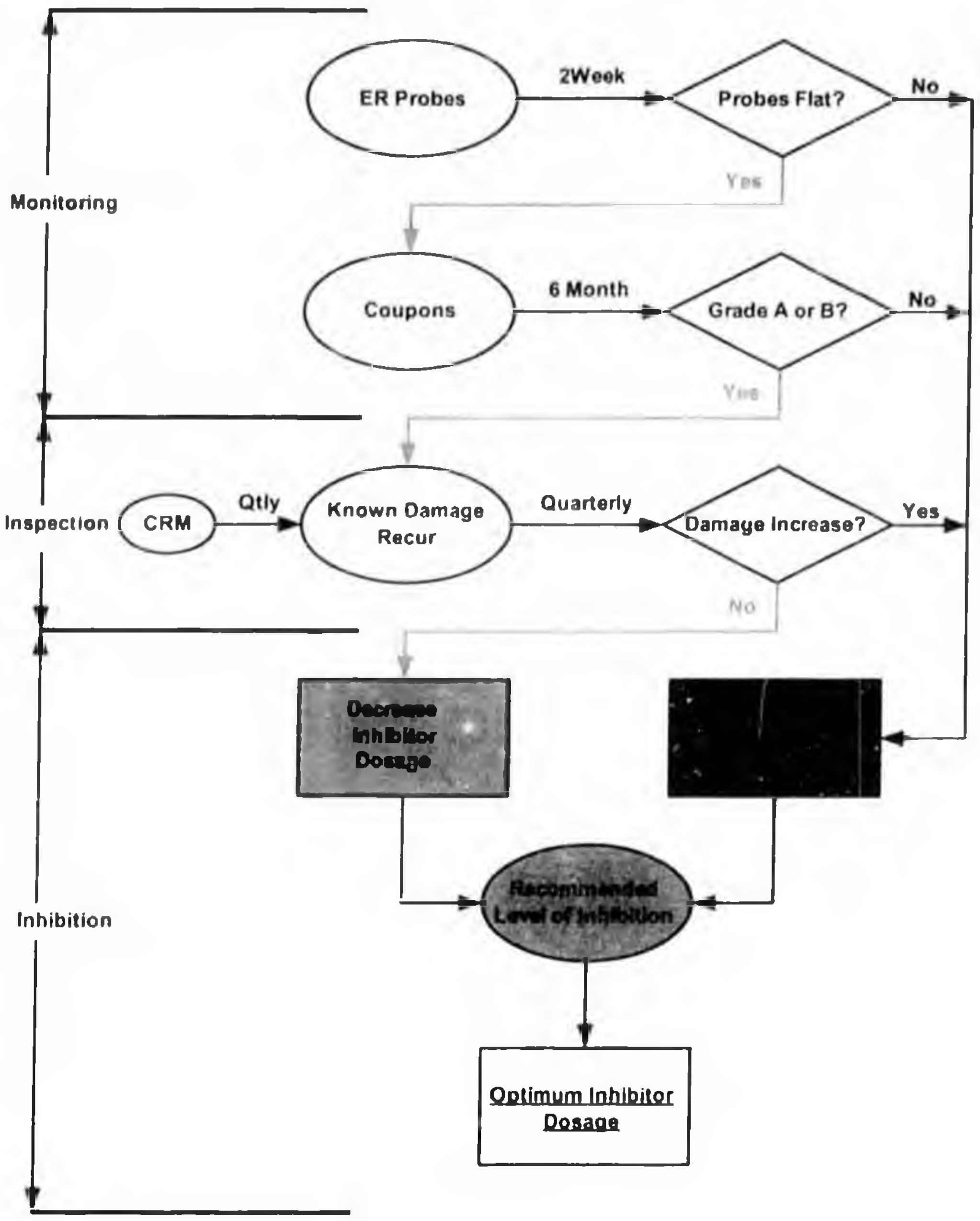


Figure 7. Corrosion Inhibitor Feedback System.

3.1.b Well Line Inspection

As indicated in Figure 8 below, repair recommendations were initiated on 17 lines (8 injection, 9 production) in 2002 because of internal corrosion damage. The two leaks were on production lines. Repairs typically consist of either sleeving or replacing the de-rated section of line. The graph indicates a decrease in inspection footage from 2001 to 2002. This was the first year we encountered well lines with obstructions that did not allow efficient use of the RTR crawler. As a result, these lines required manual RT as the primary inspection method. We met our primary 2002 goal of inspecting all well lines with a 0.312" nominal pipe wall thickness.

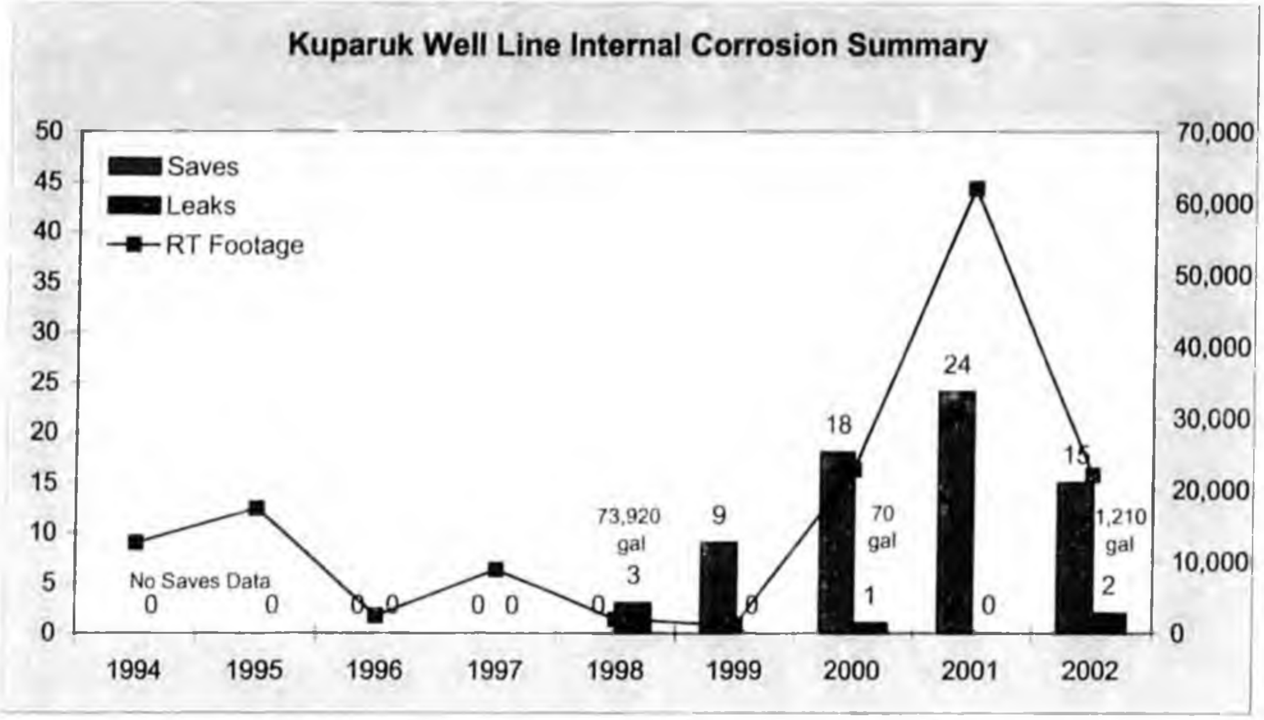


Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2002 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables.

- RTR of Well Lines:

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	12,411	108
Water Injection	5,881	40
Total	18,292	148

The 2002 RTR well line data indicated no new damage trends.

- Manual RT of Well Lines:

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% Of Repeat Radiographs with Increases
Three-phase Production	361	2,535	633	19	3
Water Injection	145	1,207	167	15	9
Total	506	3,742	800	34	4

The 2002 manual RT well line data indicated no new damage trends.

- Manual UT of Well Lines:

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	373	3,041	2,063	165	8
Water Injection	82	616	383	23	6
Total	455	3,657	2,446	188	8

The 2002 manual UT well line data indicated no new damage trends.

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 2002. Inspection results in Figure 9 indicate that the corrosion mitigation programs are adequately protecting the three-phase lines and the water injection lines.

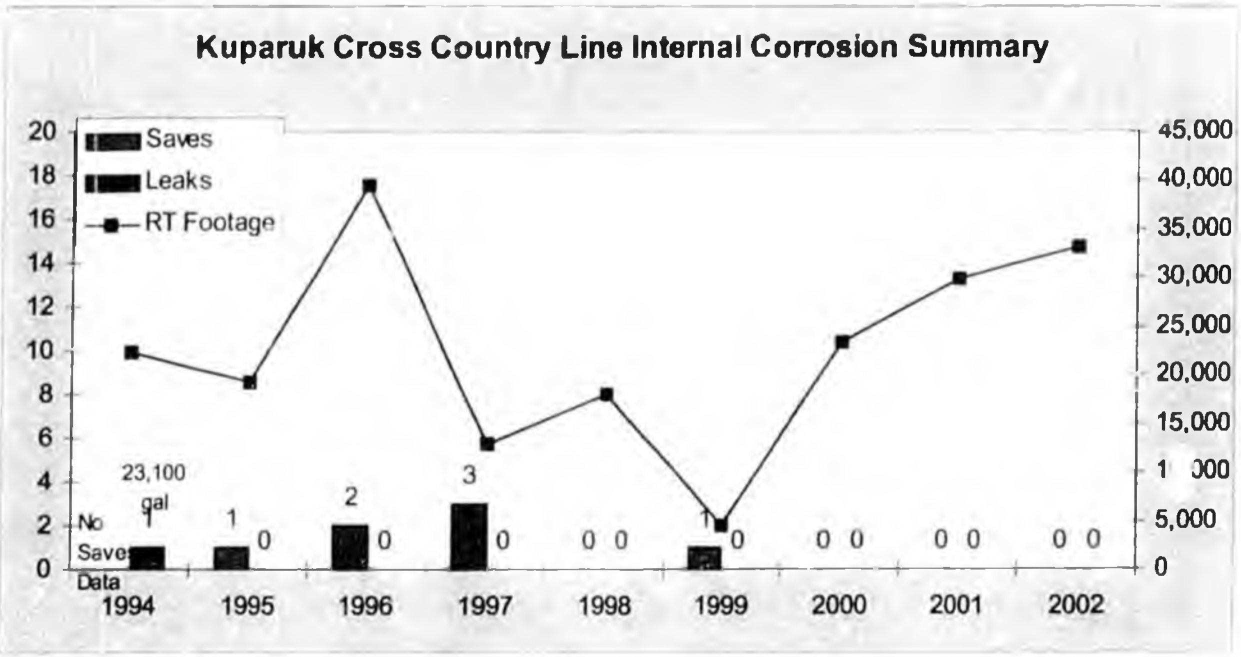


Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2002 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

- RTR of Cross Country (CC) Lines:

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	14,858	11
Water Injection	15,086	5
Total	29,944	16

The 2002 RTR CC line data indicated no new damage trends

- Manual RT of CC Lines:

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% of Repeat Radiographs with Increases
Three-phase Production	229	2,869	500	10	2
Water Injection	10	292	14	4	29
Total	239	3,161	514	14	3

The four increases in the water injection system were the first identified in this system to date. These four increases were confined to two of the ten WI lines inspected in 2002 (2EDCWI had three increases and 3GFB2WI had one increase).

It should be noted that manual RT is limited to those lines that are less than or equal to 10" outside diameter. For water injection service lines that are too large to effectively RT, Kuparuk relies on spot UT. Smart pigging is not an economical option at this time.

- Manual UT of CC lines:

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	105	933	600	18	3
Water Injection	28	112	9	1	11
Total	133	1,045	609	19	2

The one increase in the water injection system was the first identified in this system to date. The 2002 manual UT data supports the RT data (above) by reporting an increase in the 2EDCWI line.

3.1.d External (Weld-Pack) Program

Cross-Country Lines (On-Pad)

In 2002, significant progress was made towards the goal of completing the baseline inspections by the end of 2004. A total of 2,658 locations were inspected using tangential radiography (TRT), exceeding the goal for 2002 by 150% and placing the overall completion at 92%.

Of the 2,658 locations inspected in 2002, three locations were sleeved and one was repaired by pipe replacement.

Cross-Country Lines Over Tundra (Off-Pad)

The baseline inspection of these weld-packs was complete by year-end 2001. In 2002, an effort was initiated to verify weld pack locations and inspection data. No piping repairs were required as a result of this on-going effort. Several locations, previously identified as 'medium wet' were re-inspected, only 12% of these were found to have become more water saturated.

Well Lines

During 2002, 4116 well line weld packs were inspected, exceeding the goal of 4000. Corrosion was found at 3.5% of these locations, which were all stripped and refurbished. Two of the locations were repaired. An additional 220 locations, found to be heavy wet, were also stripped and refurbished.

Table 5: External Weld Pack Inspection Summary for 2002, 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	2002 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines (On-Pad)	1780	2658	48	1.8	223
Cross-Country Lines Over Tundra (Off-Pad)	0	1024	24	2.3	261
Well Lines	4000	4116	143	3.5	363
Total	**5780**	**7798**	**215**	**2.76**	**847**

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.

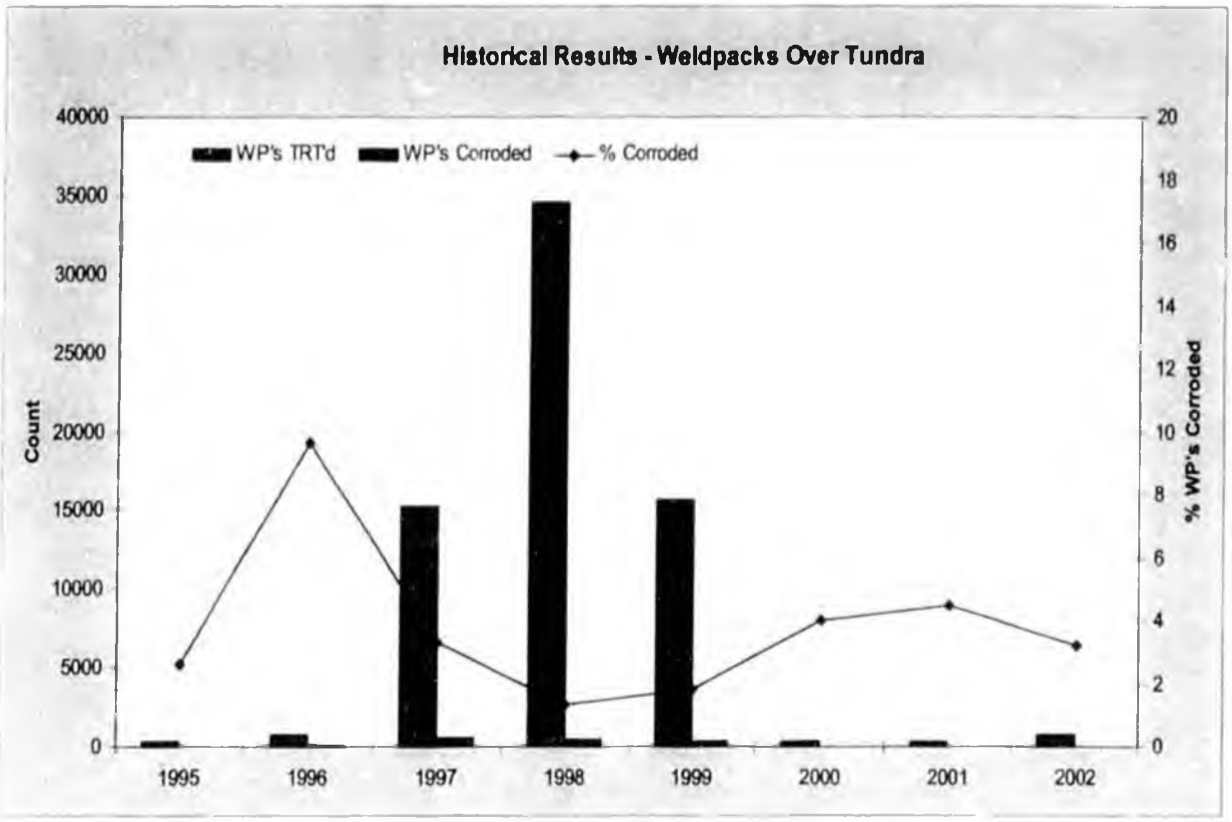


Figure 10. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad) – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

Figure 10 illustrates the most-mature external corrosion inspection program of the three external corrosion programs. A review of results, obtained early in this program was initiated in 2002. A larger recur inspection program for these weld packs is scheduled to begin in 2003.

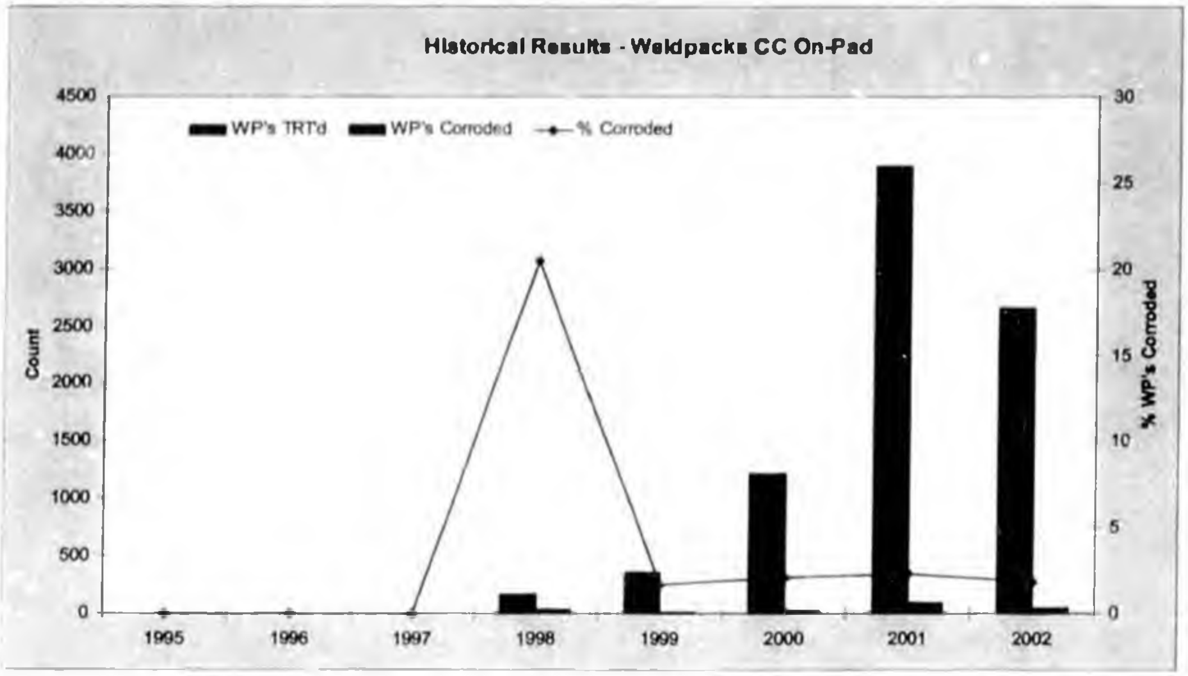


Figure 11. Summary of Weld Packs on Cross-Country Lines on Pads – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

Figures 11 and 12 depict the results of the major focus of the external weld pack inspection program in 2002. The cross-country on-pad weld packs were inspected using a prioritization scheme based on the historical corroded-to-wet ratios of the over-tundra portions of the cross-country lines. The well line weld-packs were inspected using a prioritization scheme that examined the oldest, the hottest, and thinnest-walled lines first. As of year-end 2002, 92% of the cross-country on-pad weld-packs and 60% of the well line weld-packs have received their baseline TRT inspection.

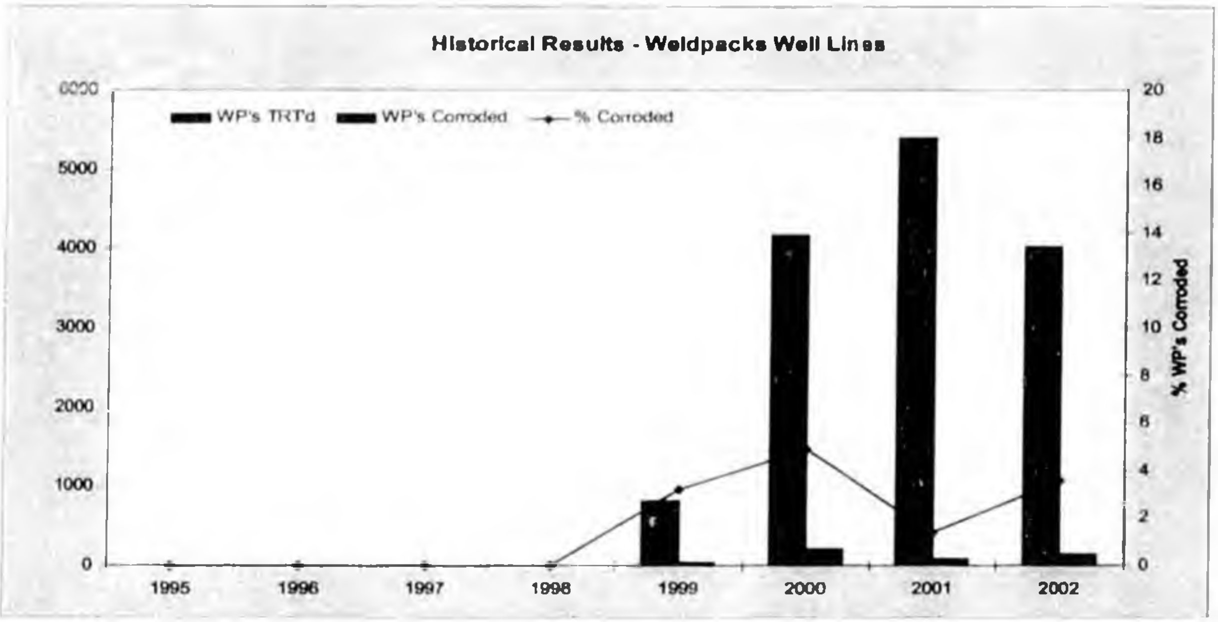


Figure 12. Summary of Weld Packs on Well Lines – number of weld packs inspected, number of weld packs corroded, and percent of weld packs corroded.

CUI Buffer Spike Test:

A test of "CUI Buffer Spikes" was initiated on 76 locations. The sodium phosphate salt contained in these spikes dissolves in wet insulation and raises the pH to 10. Prior to installation of these spikes, wet insulation measurements fell within a consistent 6 to 7 pH range. Corrosion of carbon steel is minimized in alkaline conditions.

3.1.e Below Grade Piping Program

In 2001, ADEC and ConocoPhillips Alaska, Inc., agreed to consolidate the Below Grade Piping Program report with the Commitment to Corrosion Monitoring Report. This section details the inventory and survey of below grade locations and the results of Specialty Testing. The plans for future inspections are given in section 3.2.e.

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

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

CPAI has 416 locations of below grade "oil" piping in the GKA and Alpine oil fields. Of these locations, one is contained in an utilidor. The remaining locations are cased lines, the majority of which are either road or caribou crossings. In addition to the "oil" piping, PAI has 243 significant below grade locations with lines in other services.

Utilidor Line

Inspection Status:
The one line in an utilidor (below-grade identification number 286) was inspected in 1999 and again in 2002. The 2002 radiographic inspection showed no change in the damage identified in the 1999 inspection.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2002. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

Results and Remedial Action:
Of all the below-grade oil lines, 43 locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. All 43 were remediated in 2002.

3.1.e (2) Results of Specialty Testing

Inspection Status:

In 2002, we completed the PTI/TWI inspections on all remaining priority one locations.

Both the long-range ultrasonic system technology from The Welding Institute (TWI) and the electromagnetic wave pulse system from Profile Technologies, Inc. (PTI) were used. Testing with PTI was limited to those lines without a significant risk for internal corrosion. PTI is used to find external electromagnetic anomalies such as external corrosion, but cannot find internal corrosion. The TWI technology was applied to lines with a risk for internal corrosion. TWI was also used to evaluate any positive indications detected by PTI, since PTI finds electromagnetic anomalies and is prone to finding false positives.

In addition to using TWI's long-range ultrasonic system technology, CPAI evaluated the torsional wave inspection technique from TWI. CPAI has determined that the torsional wave technique is not superior to the TWI long-range ultrasonic system and CPAI will not use the torsional wave technique unless further improvements are made.

Results and Remedial Action:

Tables 6 and 7 show the results of the specialty testing performed by PTI and TWI, respectively.

Table 6. Results from the PTI inspections by service.

Service	Number of Cased Pipes Inspected	Inconclusive Results (I)[b]	Number without any Electromagnetic Anomalies (N)	Number of Electromagnetic Anomalies (E)	Number of Significant Electromagnetic Anomalies (S)
Oil[a]	53	3	30	10	10
Other	81	1	59	15	6
Total	134	4	89	25[c]	16[c]

Notes:

(a) Oil service is defined as natural gas liquids (NGL), oil sales, three-phase production, two-phase production (wet oil), Produced Water, and Mixed Water.

(b) One gas line inconclusive scheduled for TWI inspection in 2003. One NGL location excavated, with no de-rating damage found. One line was abandoned and one line was inspected with TWI.

(c) All "S" and "E" locations were inspected with TWI, except for two pipes with "E" that will be inspected with TWI in 2003. The two pipes with "E" in 2002 that were not inspected by TWI in 2002 were:

- ID #533 (3RWI) was added to the 2003 TWI inspection list.
- ID #573 (STP-to-3-SW) was added to the 2003 TWI inspection list.

Table 7. Results from the TWI inspections by service

Service	Number of Cased Pipes Inspected	Incomplete or Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Moderate Anomalies (M)	Number of Severe Anomalies (S)
Oil[d]	27	9	14	0	2	2
Other	28	4	21	0	1	0
Total	53	13[e]	35	0[f]	3[g]	2[h]

Notes:

(d) Oil service is defined as natural gas liquids, oil sales, three-phase production, two-phase production (wet oil), Produced Water, and Mixed Water.

(e) "I" locations are prioritized based on other local and line concerns, and added as appropriate to the excavation/inspection list.

(f) "L" locations are re-inspected (PTI/TWI) every two years.

(g) "M" locations are typically evaluated, excavated, inspected and refurbished during the next excavation season. Regarding the three "M" locations found in 2002:

- ID #159 (1YRPO) was added to the excavation list. It will be evaluated for excavation along with all other locations on the list. It does not appear this location will be excavated during the 2003 season because of the liberal "corrosion allowance" resulting from the combination of thick pipe wall (0.938") and low operating pressure.
- ID #160(CPF1 WO) was excavated in 2002. Moderate to severe CUI was found and the damage was sleeved.
- ID #763 (KIC fuel gas supply line) had damage reported outside the casing that was further evaluated by RT. No damage was found. The indications originated from a foamed-in-place anchor rather than from corrosion damage.

(h) "S" locations are typically excavated inspected and refurbished during the excavation season. Regarding the two 2 "S" locations found in 2002:

- ID #575 (3RPO) had damage reported outside the casing that was further evaluated by RT. No damage was found. The indication originated from weld fit up rather than from corrosion damage.
- ID #97 (1E-13 well line) was de-pressured and put on the Long Term Shut-In List.

3.1.e (3) Results of Crossing Digs

Eight cased pipes were excavated in 2002:

- Two of the eight pipes had severe to moderate damage, one internally damaged and one externally damaged. The section of line that was internally damaged was replaced. The section of line that had external damage was sleeved.
- Six of the eight pipes excavated and inspected did not require de-rating, repair, or replacement. Only minor damage was found.

For all eight cased pipes that were excavated in 2002, the insulation was refurbished and the pipe wrapped with Densyl tape to prevent further corrosion.

3.1.f Other Structural Concerns

Subsidence:

Existing Well Upgrade Program

- In 2002, 45 floors with riser piping supports were installed in well houses at Drill Sites 1A, 1D, 2T, 3F, 3O, and 3Q. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2002, 44 heat tubes were installed at Drill Sites 1C, 1D, 1R, 2K, 2N, and 2T. Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

New Wells & Producer to Water Injection Well Conversions

- In 2002, nine new wells brought on line had heat tubes, and floors with permanent pipe supports, installed. Three new wells were installed with insulated conductors.
- In 2002, all 13 existing producers converted to water injection wells were upgraded to include heat tubes. Previously, these wells had installed conductor-supported floors.

Wind-Induced Vibration:

- As a result of the DS2X 8" MI line failure that occurred in December 2001, Kuparuk evaluated the need for vibration dampeners on existing pipelines. The line that failed is oriented one-degree outside the design wind direction envelope designated for Kuparuk in 1991. We identified six other lines that fall within the design wind direction envelope but did not have dampeners installed. One of these six lines has had tuned vibration absorbers (TVA's) installed. The design of TVA's for two of these six lines is complete and installation is scheduled. The remaining three lines at DS 3N are on the edge of the wind fan; strain gauges will be attached on all three of these lines and the movement of the lines will be monitored.
- An annual inspection of all pipeline vibration dampener (PVD) locations is conducted to verify integrity of the PVD's. This information is sent to the facilities for corrective action. Typically, corrective action consists of replacement of worn elastomers and reinstallation of PVD weights.

3.1.g Corrosion and Structural-Related Spills/Incidents

- 2A-18 Internal Corrosion Production Well Line Leak – 4/07/02 – The six-inch production line serving well 2A-18 failed because of internal corrosion just above a corrosion access fitting. Total spill volume was 1200 gallons of product (8% oil and 92% produced water) that was confined to the pad. No other locations on this line required repair. Similar locations on 283 other lines were inspected and no repairs were required because of a similar corrosion mechanism.

- 2T-13 Internal Corrosion Production Well Line Leak – 7/25/02 – The six-inch production line serving well 2T-13 failed because of internal corrosion in a straight-run section of pipe; the failure was caused by under-deposit corrosion in the low-velocity pipeline. Total spill volume was 10 gallons of product (41% oil and 59% produced water) that was confined to pad. All well lines (34) at DS 2T were inspected, with no damage found on 28 well lines. Six well lines showed damage similar to 2T-13, but no de-rating damage was found; one section of another well line, though not de-rated, has also been recommended for replacement.

- No leaks were caused by external corrosion in 2002.

- No leaks were caused by wind-induced vibration in 2002.

- No leaks were caused by subsidence in 2002.

Figures 8 and 9, and Figure A1 in Appendix A show the number of leaks and the volumes of leaks as a function of time. Figure 8 depicts the leaks caused by internal corrosion for the well lines. Figure 9 depicts the leaks caused by internal corrosion for the cross-country lines. Figure A1 shows the leaks caused by external corrosion for cross-country lines, well lines, and below-grade piping locations.

3.2 Year 2003 Forecast

3.2.a Monitoring & Mitigation

- Test new corrosion inhibitors in an effort to improve corrosion inhibition technology. Testing of Champion 2002-49a is underway in the DS1R cross-country line.
- Test schmoo-be-gone in the water injection system for DS1E.
- Implement wellhead chemical injection systems for the production well lines at Drill Sites 1A, 1H, 1Y, and 2T.
- Continue analysis of the CPF2 mixed water and associated systems to determine the cause of higher corrosion rates.

3.2.b Well Line Inspection

Complete baseline inspection of all six-inch OD, 0.312" and 0.375" wall-thickness well lines that are six years of age or older.

3.2.c Cross-Country Line Inspection

The following enhancements/modifications are planned for 2003:

- RTR ~15,000 feet of cross country lines in 2003 concentrating on water injection lines.
- Complete inspection of elevation-change elbows scheduled as part of the Cross-Country Line Turbulent Flow Survey.

3.2.d External (Weld-Pack) Program

Complete evaluation of the initial CUI Buffer Spike test and determine the way forward.

Cross-country lines over tundra:
- Complete recur TRT inspections on approximately 1500 CUI locations; use results to help establish a prioritization scheme for future recurring inspection schedule and continue to monitor Denso tape protocol.
- Complete approximately 100 TRT inspections on the Tarn weld pack design established in 1997.
- Complete visual inspections of Medium Wet weld packs in saddles on large diameter sea water lines. Strip, inspect and refurbish these directly without performing TRT inspections because of the lengthy shot times involved.

For cross-country lines on-pad, inspect half of the remaining weld packs without a baseline inspection. This supports the goal of YE 2004 completion.

For well lines, inspect approximately 17% of the remaining weld packs without a baseline inspection. This supports the goal of YE 2005 completion.

3.2.e Below Grade Piping Program

- Visually inspect all of the cased lines. The appropriate PAI field department will be notified of any corrective actions that need to be taken early enough to complete clean out and re-inspection during the summer.
- Initiate recurring PTI/TWI inspections of priority-1 cased lines.
- Complete the first-pass inspection of the remaining priority-2 cased lines using visual inspection and gas sniffing procedures as noted in our ADEC approved procedure.
- Complete excavations of five-to-nine lines in road crossing for visual inspection, refurbishment and repair, as necessary.
- Continue to work with PTI/TWI and ConocoPhillips R&D to refine inspection data reduction and interpretation

3.2.f Other

- Continue enhancements to the Kuparuk Corrosion Database.
- Continue Alpine piping layout and piping information database development.
- Continue to evaluate, and prioritize subsidence mitigation efforts at the existing drill sites.

APPENDIX A

Table A1. Three-phase Production Cross-Country lines with corrosion rates that exceeded targets and the action that was taken.

Common Line	Coupon Grade	Probe Rate	Insp Incr	Action Taken
1-2Z1QGPO	A	<.5	yes	Target CI Rate increased
1-2ZPO	A	<.5	yes	Target CI Rate increased
1FPO	NA	NA	yes	Actual CI Rate increased
1RPO	C	<.5		Target CI Rate increased
2APO	A	0.5	yes	Target CI Rate increased
2CPO	NA	NA	yes	Target CI Rate increased
2FPO	A	<.5	yes	Target CI Rate increased
2KPO	C	<.5		Target CI Rate increased
2TAMKHPO	A	<.5	yes	Target CI Rate increased
2TPO	D	<.5		Target CI Rate increased
2UPO	A	<.5	yes	Target CI Rate increased
2WUPO	C	<.5		Target CI Rate increased
2WUVPO	F	<.5	yes	Target CI Rate increased
3CPO	D	<.5		Target CI Rate increased
3MIPO	D	<.5		Target CI Rate increased
3NPO	C	<.5		Target CI Rate increased
3RQONKPO	C	1.2		Target CI Rate increased
3RQOPO	C	<.5		Target CI Rate increased
XCL/WO at CPF2	C	<.5		Target CI Rate increased
XCL/WO to CPF1	B	NA	yes	Target CI Rate increased

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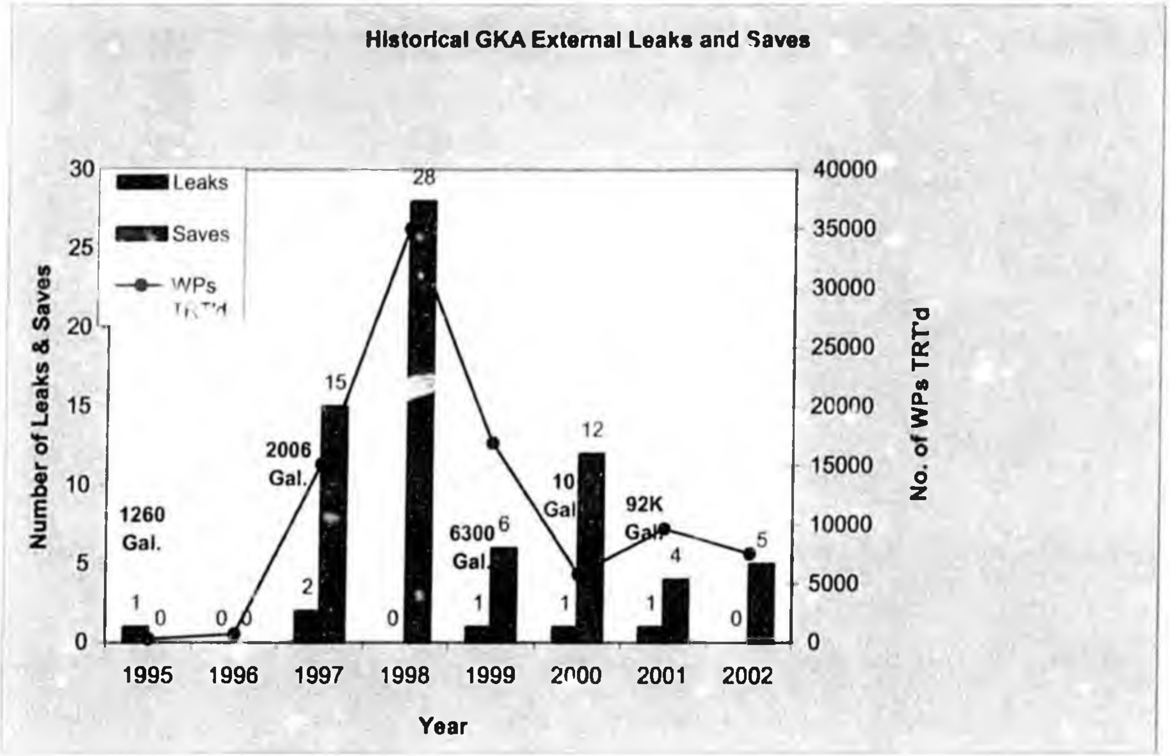


Figure A1. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

Note: The leak in 2001 due to external corrosion was located in a weld pack in a below-grade piping segment, and as such, would not have been detected by the TRT inspection program. The location had not yet received PTi/TWI inspection.

APPENDIX B
Glossary

Equipment Classification:

- **Well Line** – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.
- **Cross-Country Line** – Pipe from the Drill Site manifold to the Central Processing Facility (CPF).
- **Below-Grade Location** – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

Service Definitions:

- **Three-phase Production** – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.
- **Seawater (SW)** – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration, oxygen stripping using produced gas, and biociding.
- **Produced Water (PW)** – The water separated at the CPF from three-phase production.
- **Mixed Water (MW)** – Produced water and seawater that have been commingled.
- **Gas** – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible Injectant.
- **Produced Oil** – The liquid hydrocarbon separated at the CPF from three-phase production.

Inspection Terminology:

- **CRM** – Corrosion rate monitoring.
- **UT**- Ultrasonic testing
- **RT** – Radiographic testing
- **RTR** – Real time radiographic testing
- **TRT** – Tangential radiographic testing
- **PTI** – Profile Technologies Inc. (Electro magnetic inspection)
- **TWI** – The Welding Institute (Long range UT)\
- **KDR** – Known damage recur inspection

2003

ConocoPhillips

Greater Kuparuk Area (GKA)
Alpine Field
Corrosion Programs Overview

April 1, 2004

Commitment to Corrosion Monitoring

4th Annual Report to the Alaska Department of Environmental Conservation

Prepared by

ConocoPhillips Corrosion Team

ConocoPhillips

Table of Contents

1.0 OVERVIEW

There are over $4 Billion in capital assets in the Greater Kuparuk Area (GKA). The internal corrosion potential in Kuparuk lines continues to rise as water production and H_2S levels increase. Additionally, an external corrosion potential exist where moisture penetrates and is trapped in insulation. 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.

Alpine is ConocoPhillips' newest development and the largest onshore oil field discovered in North America in the past decade. Alpine has a nominal processing capacity of 100,000 BOPD. The Alpine development produces from a pad area of 97 acres, and has two Drill Sites; additional satellite drill sites are planned. The corrosion management system used at Kuparuk is being applied to the Alpine field.

The purpose of this 4th Annual Report is to communicate the details of the individual programs that implement the ConocoPhillips Alaska Corrosion Strategy. In addition to the requirements of the North Slope Charter Agreement between ConocoPhillips Alaska, Inc., BP Exploration (Alaska), and the Alaska Department of Environmental Conservation, previous reporting requirements pertaining to the Below Grade Piping Program will be incorporated into this and future North Slope Charter Corrosion Reports.

Because of the large amount of data from corrosion monitoring and corrosion inspections, corrosion coupon exception data and external corrosion inspection and leak/save historical results are contained in Appendix A.

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

2.0 SIGNIFICANT ENHANCEMENTS TO CORROSION PROGRAMS

- Completed an initial Turbulent Flow Survey (TFS) on cross-country three-phase oil lines. This program is designed to schedule fittings, such as elbows and tees, for recurring inspection based on flow characteristics, which may cause velocity assisted corrosion damage. The TFS supplements our RTR inspection program, which is designed to find internal damage in straight runs of pipe.

- Completed a baseline inspection of all well lines and cross-country lines requiring inspection.

- Wellhead corrosion inhibition design specifications have been finalized and new installations are in progress.

- Enhancements to our Bartlesville corrosion inhibitor lab screening and installation of additional monitoring points have allowed for field-testing of four new corrosion inhibitors in 2003.

3.0 Program Status Summary

3.1 Year 2003 Overview

3.1.a Monitoring & Mitigation

Monitoring Kuparuk:
Average general and pitting coupon corrosion rate data for Year 2003 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	62	0.03	62	100
Seawater Cross-Country Lines	2	3.1	1	50
Mixed Water Injection Cross-Country Lines	22	0.4	22	100
Production Well Flow Lines	451	0.3	446	99
Mixed Water Injection Well Flow Lines	551	0.6	521	95

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	62	4.5	54	87
Seawater Cross-Country Lines	2	3.3	2	100
Mixed Water Injection Cross-Country Lines	22	19	12	55[a]
Production Well Flow Lines	451	1.5	433	96
Mixed Water Injection Well Flow Lines	551	8.9	376	68

Notes:

a See graph and discussion on page 8 of this report.

Monitoring Alpine:
Average general and pitting coupon corrosion rate data for Year 2003 are presented in Tables 3 and 4.

Table 3. 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	1	0	1	100
Seawater Cross-Country Lines	1	0.4	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	29	0.1	29	100
Seawater Injection Well Flow Lines	8	0	8	100

Table 4. 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	1	1.0	1	100
Seawater Cross-Country Lines	1	0.7	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	29	0.1	29	100
Seawater Injection Well Flow Lines	8	0.1	8	100

* *NOTE: This coupon location is currently not accessible because of a new piping obstruction.*

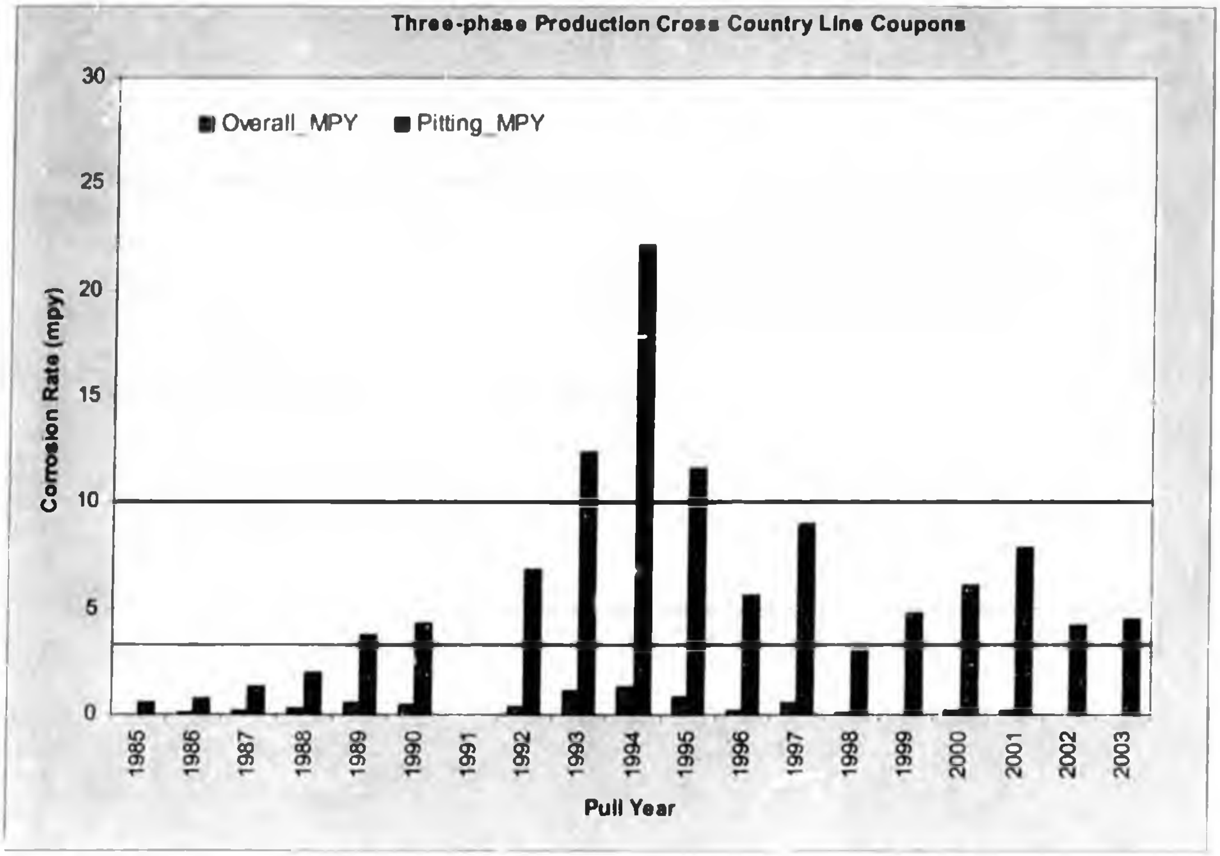


Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Cross-Country Lines: The monitoring data summarized in Kuparuk 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 starting at CPF3 and going to CPF1 and CPF2.

Recurring CRM inspections also support the conclusion that corrosion is under control in the three-phase production cross-country lines. In 2003, 584 corrosion-rate monitoring (CRM) inspections were conducted, with five minor increases found (i.e. less than 1% of total CRM inspections resulted in an increase). Other internal inspection data also support the CRM data conclusions 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 2003, coupon or probe corrosion rates exceeded targets on 17 lines and action was taken on all 17 of these lines. In 2003, inspection results indicated minor corrosion had occurred on five lines; corrosion inhibitor concentrations were increased in all five of these lines. A complete listing of the 22 lines with coupon/probe corrosion rates that exceeded targets or where inspection indicated increased damage, is given Table A1 of Appendix A.

In 2003, the 16-inch CPF3-to-CPF1 Wet Oil Line showed coupon pitting corrosion rates above the threshold of 10 mpy; actual inhibitor concentration was verified and adjusted based on coupon results. Additionally, later in the year this line experienced a lower water cut and the corrosion inhibitor concentration was adjusted.

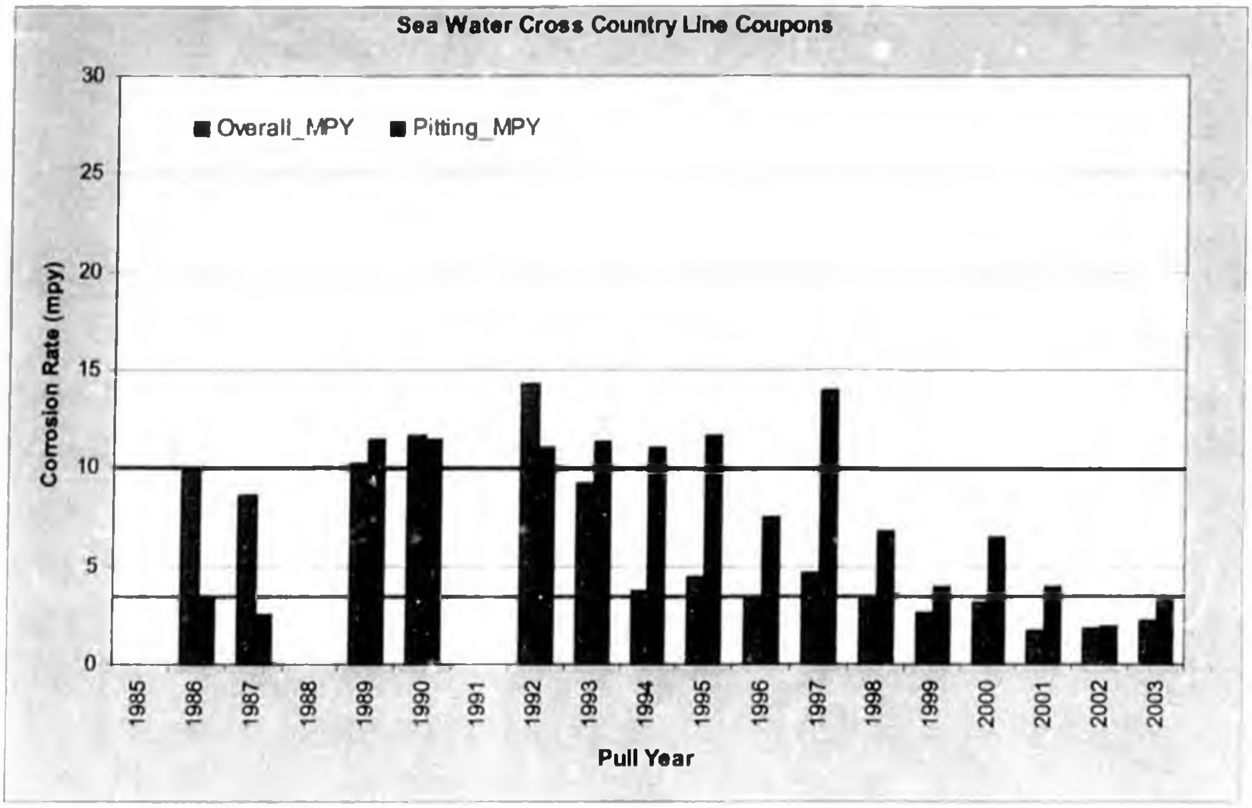


Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Sea Water Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 2 above, shows the average corrosion rates for the sea water cross-country line coupons remained under thresholds in 2003. The coupon location on the 30" STP discharge line showed general corrosion rates above threshold in 2003. This is likely due to short term increased dissolved oxygen levels, the origin of which is under investigation.

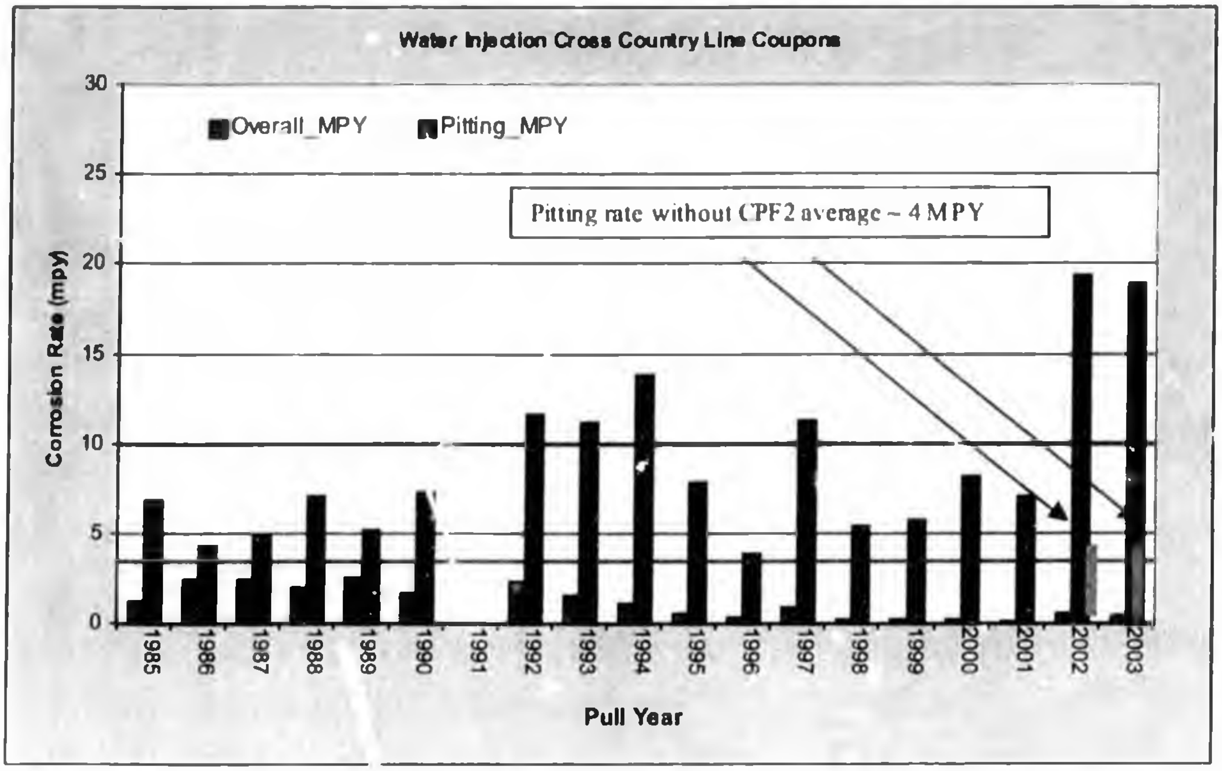


Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Mixed Water Injection Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 3 show that average general corrosion rates are below the threshold, but that pitting rates for the field are above the threshold. Closer analysis of the data shows that the average pitting rate excluding CPF2 locations is well under the threshold. Recent inspection data from the CPF2 lines show some damage on three lines. This information, along with coupon results, was used to prioritize 2003 inspection efforts. RTR inspection performed in 2003 included 23,099 feet on 28 cross-country water injection lines. A review of the CPF biocide programs has been conducted and new treatment procedures are in place.

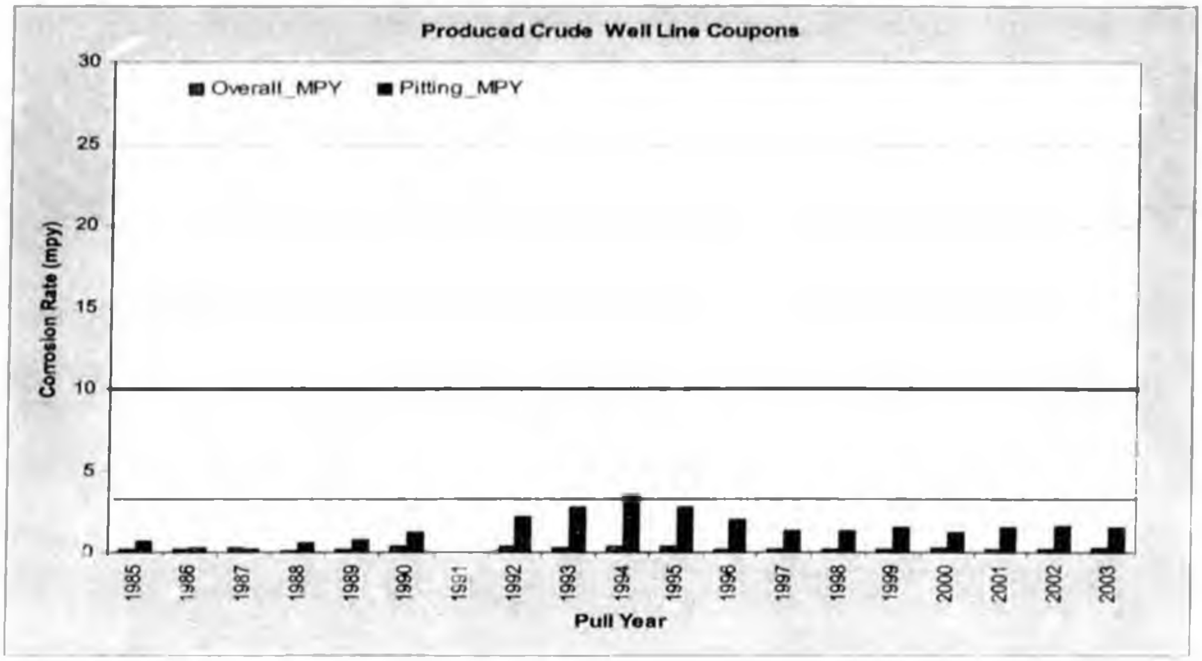


Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Well Flow Lines: While the monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figures 4 and 5 suggest that corrosion rates are below targets, inspection data indicate that higher corrosion rates have been experienced historically. The well line inspection data are discussed in section 3.1.b below, and are a good example of why monitoring data alone cannot be relied upon to characterize corrosion in a given system. For three-phase production, coupons monitor free flowing fluid and have not shown the predominant, under-deposit corrosion mechanism.

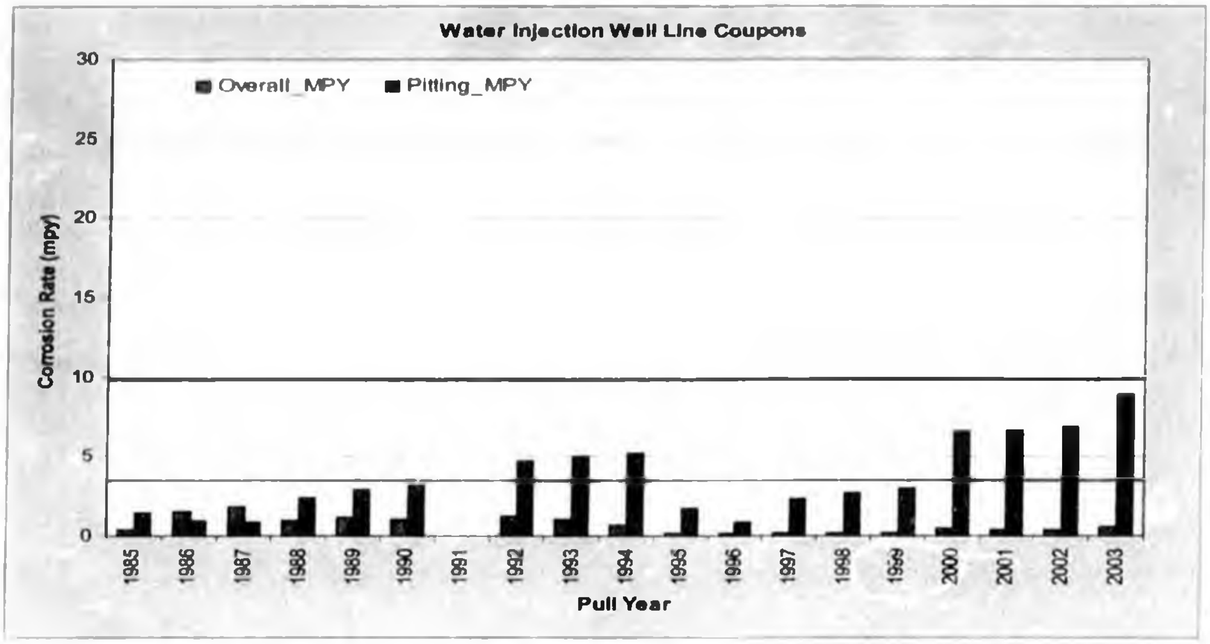


Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

Water Injection Well Flow Lines: There is an increasing trend in the coupon pitting rates. As discussed in section 3.1.b below, the well line inspection data on water injectors show that there are a significant (22) and an increasing number of corrosion related repairs.

Mitigation:

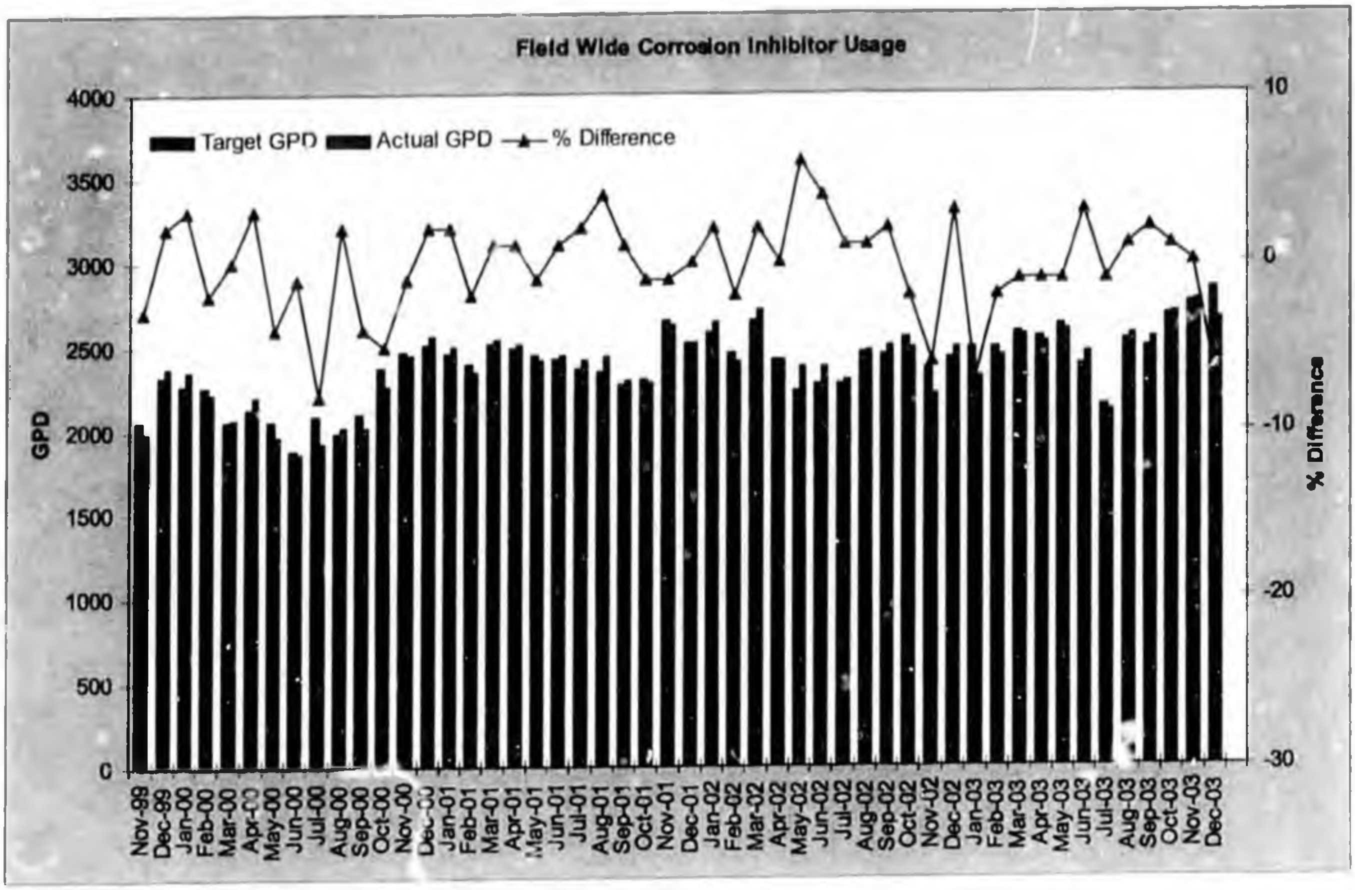
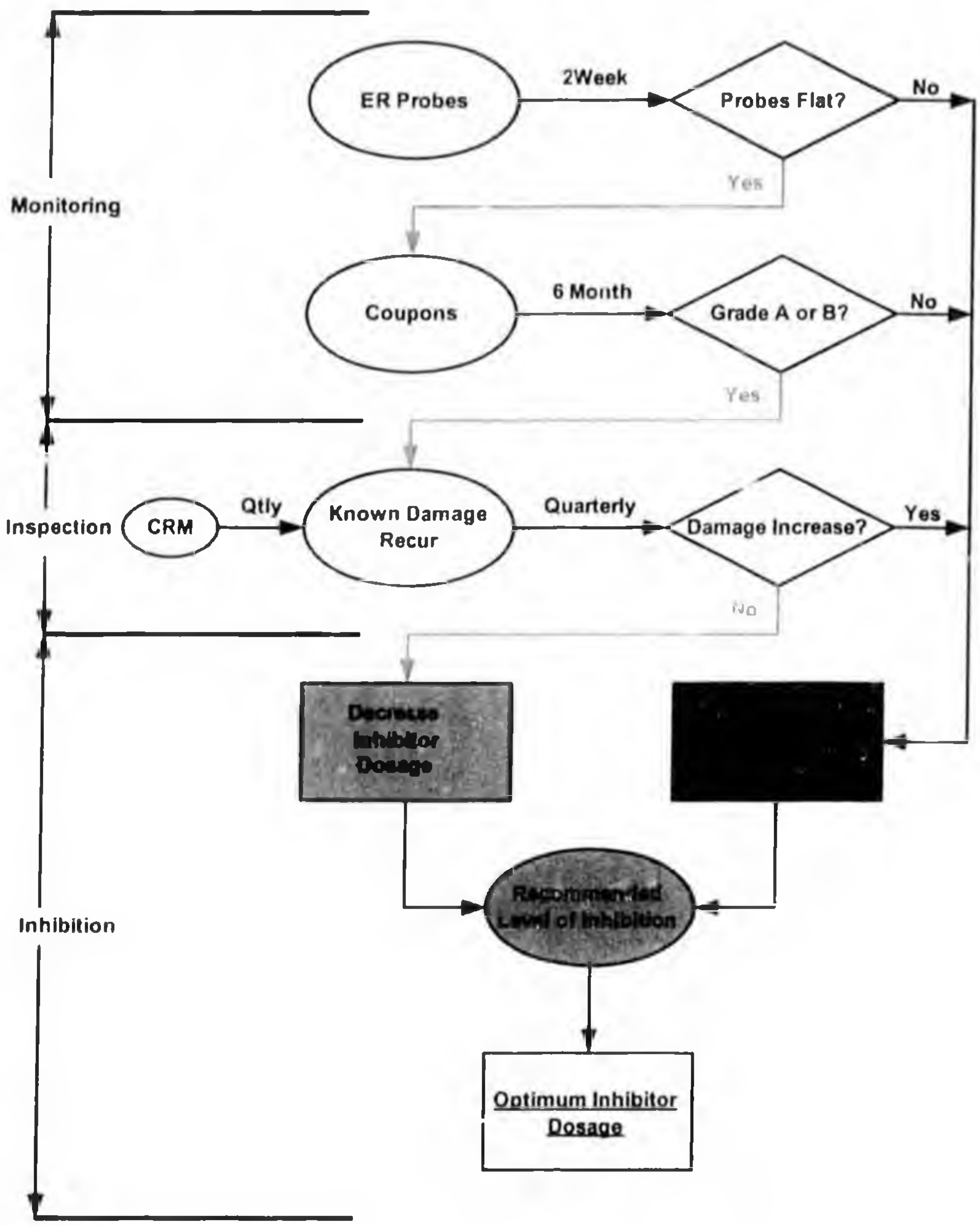


Figure 6. Field-wide Corrosion Inhibitor Use.

For the Kuparuk field, Figure 6 shows the actual number of gallons of corrosion inhibitor pumped per day, the recommended 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 −1.0%. The larger variation seen in the December 2003 data was caused by the extreme weather that caused delays in routine pump rate checks and refilling of chemical tanks.

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



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 (22 injection, 2 production) in 2003 because of internal corrosion damage. Repairs typically consist of either installing a sleeve or replacing the de-rated section of line. We met our primary 2003 goal of completing the inspection of all well lines requiring baseline inspection.

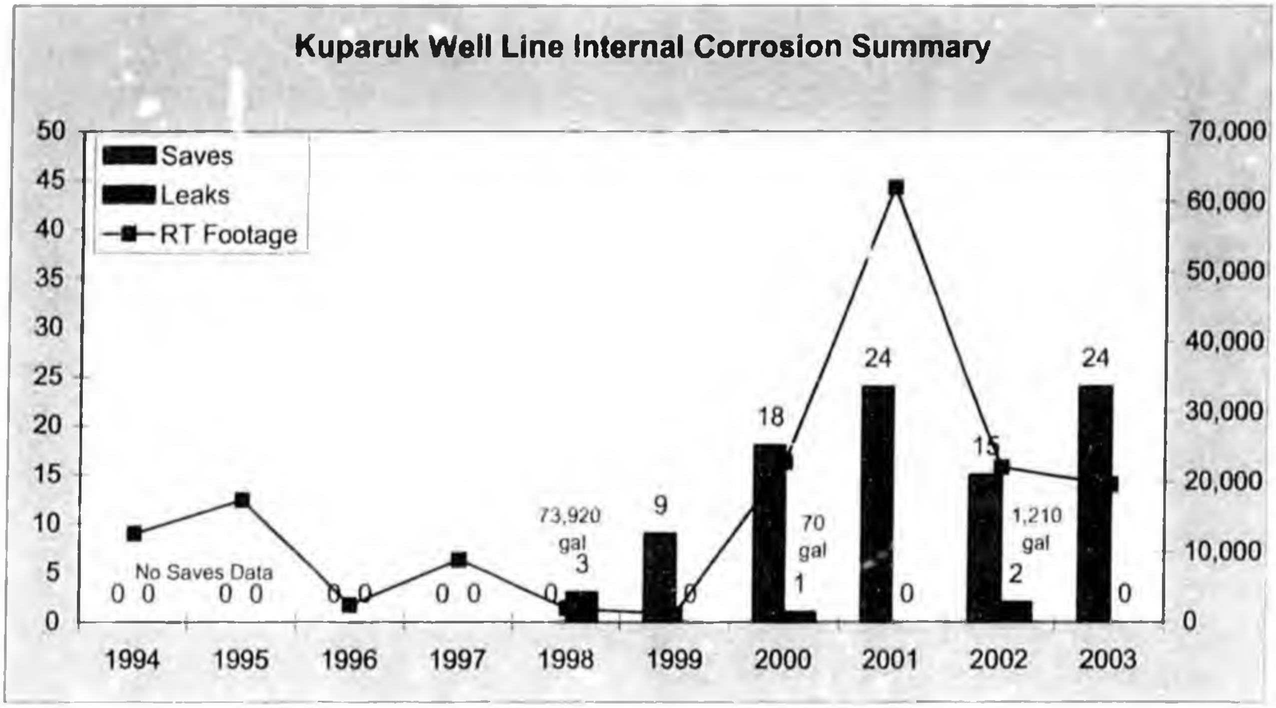


Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2003 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables.

- **RTR of Well Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	8,783	104
Water Injection	6,960	76
Total	15,743	180

The 2003 RTR well line data indicated no new damage trends.

- **Manual RT of Well Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% Of Repeat Radiographs with Increases
Three-phase Production	344	2,137	856	24	3
Water Injection	208	1,715	334	26	8
Total	552	3852	1,190	50	4

The 2003 manual RT well line data indicated no new damage trends.

- **Manual UT of Well Lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	201	1600	1,374	92	7
Water Injection	92	784	553	40	7
Total	493	2,384	1,927	132	7

The 2003 manual UT well line data indicated no new damage trends.

3.1.c Cross-Country Line Inspection

As indicated in Figure 9, nine repair recommendations were initiated on cross-country lines because of internal corrosion damage in 2003. The corrosion mechanisms were deadleg corrosion (five repairs), under deposit corrosion (three repairs) and weld attack on a flowing line (one repair). Because of large increase in repairs we will increase our inspection effort on deadlegs in 2004.

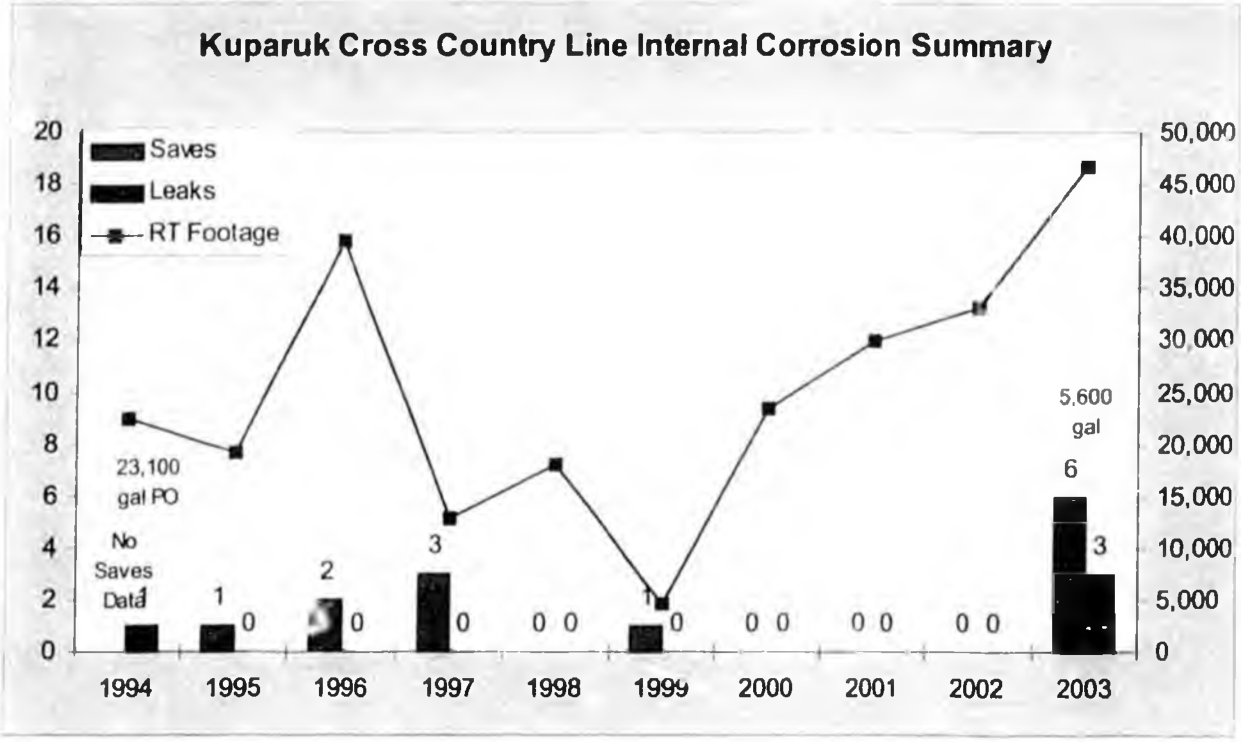


Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2003 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

- **RTR of Cross Country (CC) Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	20,447	31
Water Injection	23,099	28
Total	43,546	59

The 2003 RTR CC line data indicated no new damage trends

- **Manual RT of CC Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% of Repeat Radiographs with Increases
Three-phase Production	217	2,660	581	10	2
Water Injection	17	563	18	1	6
Total	234	3,223	599	11	2

It should be noted that effective manual RT is limited to those lines water that are less than approximately 10" to 12" outside diameter. The maximum diameter for RT of three-phase production lines depends on the percentage of gas. For water injection service lines that are too large to effectively RT, Kuparuk relies on spot UT. Smart pigging is not an economical option at this time.

- **Manual UT of CC lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	104	660	789	22	3
Water Injection	30	128	21	8	38
Total	134	2,788	810	30	8

The eight increases on WI lines in 2003 represents a significant jump from previous years. The jump was caused by our increased inspection on one significantly damaged line (2EDCWI). Six of the eight increases were on this line. As a result of our 2003 inspection efforts, 2EDCWI received extensive repairs.

3.1.d External (Weld-Pack) Program

Cross-Country Lines (On-Pad)

In 2003, significant progress was made towards the goal of completing the baseline inspections by the end of 2004. A total of 580 locations were inspected using tangential radiography (TRT), significantly exceeding the goal of 343 for 2003 and placing the overall completion at 96%.

Of the 580 locations inspected in 2003, none of the locations needed repair while 122 locations were refurbished.

Cross-Country Lines Over Tundra (Off-Pad)

The baseline inspection of these weld-packs was believed complete by year-end 2001. However, in 2003 a walk down verification survey revealed that several corrosion-under-insulation (CUI) locations had been missed during the initial layout. In 2003, 2712 CUI locations were inspected. These numbers include inspections of weld packs that had been inspected previously, as well as weld packs where documentation of a previous inspection could not be verified (approximately 1000 locations). No piping repairs were required as a result of this on-going effort and 466 locations were refurbished. Although the goal in 2003 was to inspect 2746 CUI locations, severe weather in mid- to late-December delayed our ATRT inspection work and only 2712 were completed.. During the first four days of 2004, we completed ATRT inspections of 119 CUI locations, bringing the total up to 2831. So, for all intents and purposes, the 2003 goal was surpassed.

Additionally, 100 of the new style weld packs used on the Tarn line were TRT inspected to see how they are holding up. None of the weld packs inspected showed any ingress of water or presence of corrosion, indicating good performance thus far.

Well Lines

During 2003, 2728 well line weld packs were inspected, exceeding the goal of 2500. Corrosion was found at 1.9% of these locations. Also during 2003, 105 well line CUI locations were refurbished.

Table 5: External Weld Pack Inspection Summary for 2003.

Type of Equipment	2003 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines (On-Pad)	343	580	26	4.5	122
Cross-Country Lines Over Tundra (Off-Pad)	2746	2712	97	3.6	466
Well Lines	2500	2728	53	1.9	105
Total	**5589**	**6020**	**176**	**2.92**	**693**

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.

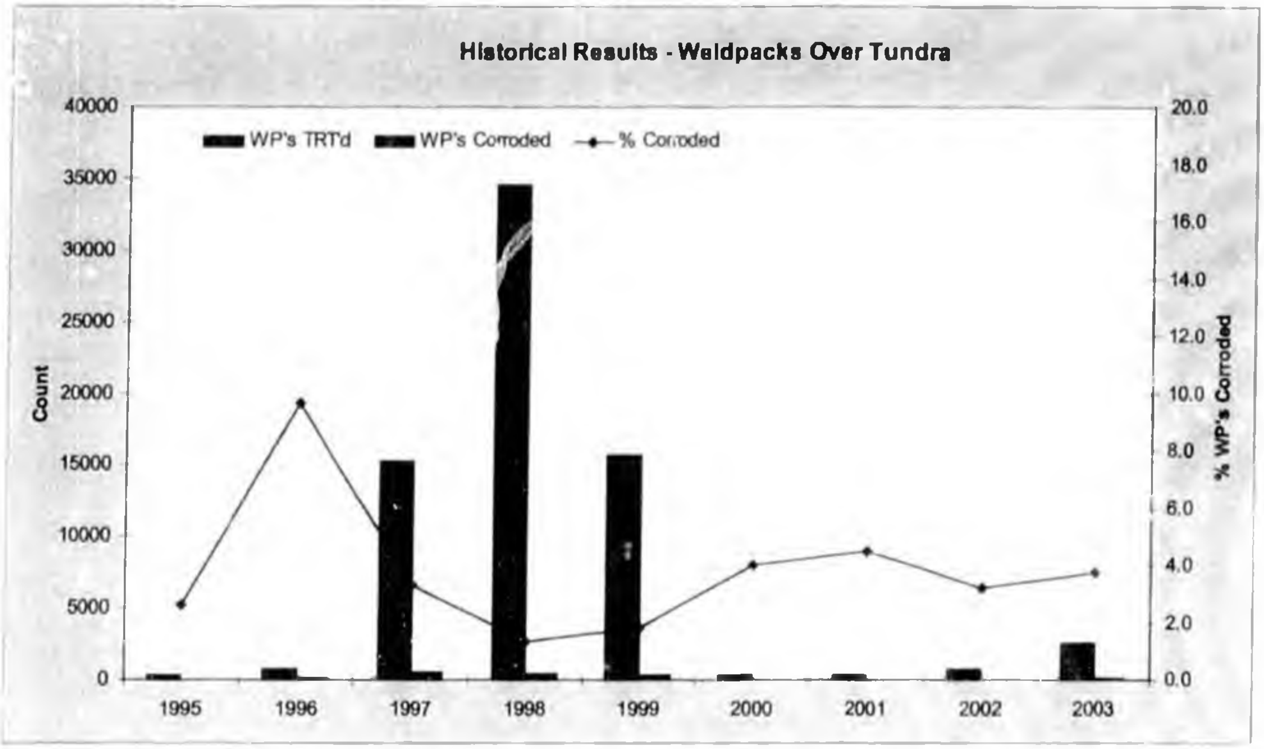


Figure 10. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad).

Figure 10 illustrates the most-complete external corrosion inspection program of the three external corrosion programs. 2002 and 2003 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

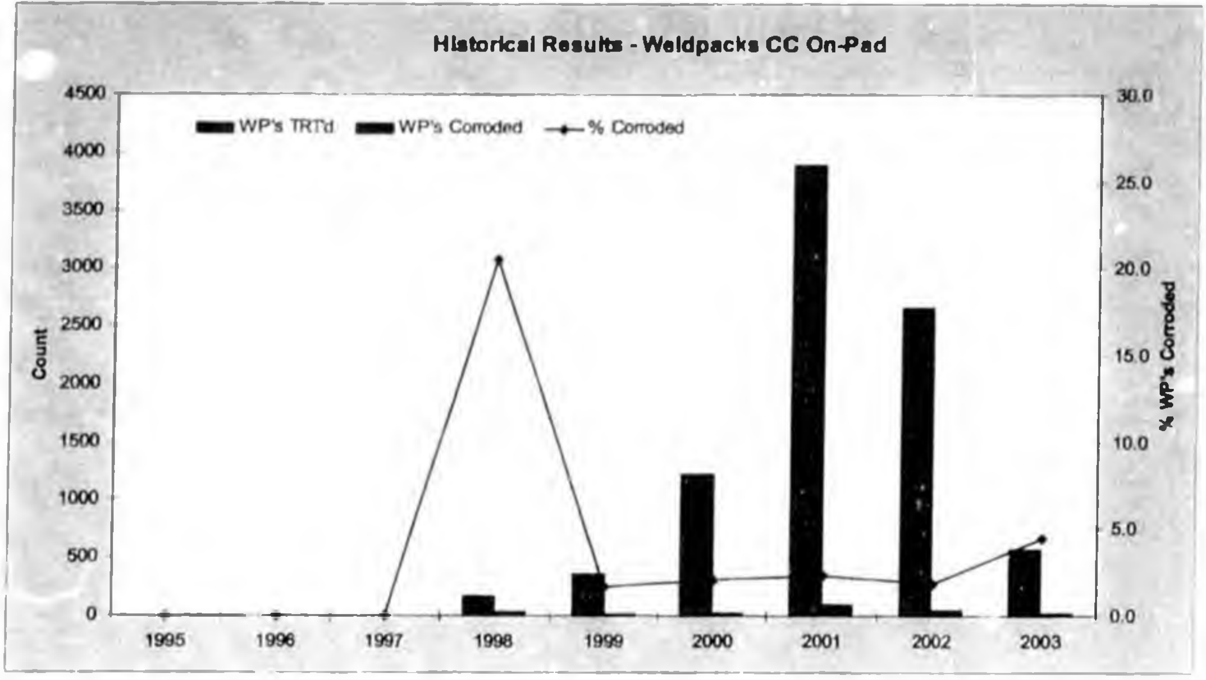


Figure 11. Summary of Weld Packs on Cross-Country Lines on Pads.

Figures 11 and 12 depict the results of the major focus of the external weld pack inspection program in 2003. The cross-country on-pad program is nearing completion and all baseline inspections should be complete by year-end 2004. The well line weld-packs were inspected using a prioritization scheme that examined the oldest, the hottest, and the thinnest-walled lines first. As of year-end 2003, 96% of the cross-country on-pad weld-packs and 91% of the well line weld-packs have received their baseline TRT inspections.

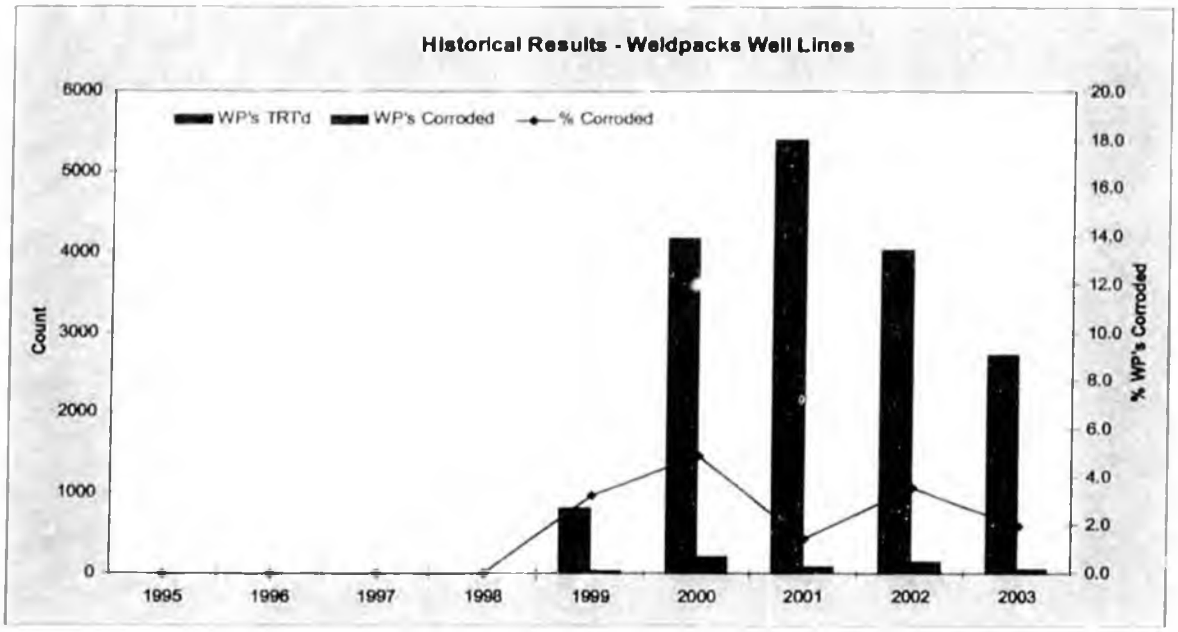


Figure 12. Summary of Weld Packs on Well Lines.

In 2002, a test of "CUI Buffer Spikes" was initiated on 76 locations. The sodium phosphate salt contained in these spikes dissolves in wet insulation and raises the pH to 10. Prior to installation of these spikes, wet insulation measurements fell within a consistent 6 to 7 pH range. Corrosion of carbon steel is minimized in alkaline conditions. During 2003, each of these locations was monitored for pH increase. The 2003 follow-up inspections showed that the pH did rise in the wet areas of the weld pack. TRT inspection of these areas is scheduled for 2004.

3.1.e Below Grade Piping Program

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

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

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

CPAI has 416 locations of below grade (BG) "oil" piping in the GKA and Alpine oil fields. Of these locations, one is contained in an utilidor. The remaining locations are cased lines, the majority of which are either road or caribou crossings. In addition to the "oil" piping, CPAI has 243 significant below grade locations with lines in other services.

Utilidor Line

Inspection Status:
The line in the utilidor (Oily Waste Injection Line, BG ID #286) was inspected in 1999 and again in 2002. The 2002 radiographic inspection showed no change in the damage identified in the 1999 inspection. This line is evaluated for re-inspection every two years.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2003. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

Results and Remedial Action:
Of all the below-grade lines, 45 locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. All 45 locations were remediated in 2003.

3.1.e (2) Results of Specialty Testing

Inspection Status:
In 2003, we completed the PTI/TWI inspections on 82 priority one locations. This was the first year of our recurring inspection program where each priority one pipe will be inspected at a maximum ten-year interval.

Both the long-range ultrasonic system technology from The Welding Institute (TWI) and the electromagnetic wave pulse system from Profile Technologies, Inc. (PTI) were used. Testing with PTI was limited to those lines without a significant risk for internal corrosion. PTI is used to find external electromagnetic anomalies such as external corrosion, but cannot find internal corrosion. The TWI technology was applied to lines with a risk for internal corrosion. TWI was also used to evaluate any positive indications detected by PTI, since PTI finds electromagnetic anomalies and is prone to finding false positives.

In addition to using TWI's long-range ultrasonic system technology, CPAI evaluated the torsional (guided) wave inspection technique from B&E. CPAI has determined that the torsional wave technique offered by B&E is not superior to the TWI long-range ultrasonic system and CPAI will not use the torsional wave technique unless further improvements are made.

Results and Remedial Action:

Tables 6 and 7 show the results of the specialty testing performed by PTI and TWI, respectively.

Table 6. Results from the PTI inspections by service.

Service	Number of Cased Pipes Inspected	Inconclusive Results (I)	Number without any Electromagnetic Anomalies (N)	Number of Electromagnetic Anomalies (E)	Number of Significant Electromagnetic Anomalies (S)
Oil[a]	30	0	18	11	1
Other	3	0	1	2	0
Total	33	0	19	13[b]	1[b]

Notes:

(a) Oil service is defined as natural gas liquids (NGL), oil sales, three-phase production, two-phase production (wet oil), Produced Water, and Mixed Water.

(b) All "S" and "E" locations were inspected with TWI. The two "E" pipes remaining from 2002 were inspected with TWI in 2003.

Table 7. Results from the TWI inspections by service.

Service	Number of Cased Pipes Inspected	Incomplete or Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Minor to Moderate and Moderate Anomalies (M)	Number of Moderate to Severe and Severe Anomalies (S)
Oil[c]	62	8	28	13	8	5
Other	04	0	1	2	0	1
Total	66	8[d]	29	15[e]	8[f]	6[g]

Notes:

(c) Oil service is defined as natural gas liquids, oil sales, three-phase production, two-phase production (wet oil), Produced Water, and Mixed Water.

(d) "I" locations are prioritized based on other local and line concerns, and added as appropriate to the excavation/inspection list.

(e) "L" locations are re-inspected (with PTI and/or TWI) every two years.

(f) "M" locations are added to the excavation candidate list and evaluated for excavation, further inspection, refurbishment and repair during subsequent excavation seasons. The eight "M" pipes found by TWI in 2003 are listed here:

- -ID #71 (14" 1CPO)
- -ID #78 (14" 1EPO)
- -ID #83 (14" 1EPO)
- -ID #231 (24" 1YPO)
- -ID #327 (14" 2DPO)
- -ID #438 (8" 2FWI)
- -ID #458 (12" 2FPO)
- -ID #533 (8" 3R SW Supply line)

(g) "S" locations are added to the excavation candidate list and evaluated for excavation, further inspection, refurbishment and repair during subsequent excavation seasons. The six "S" locations found by TWI in 2003 are listed here:

- -ID #15 (6" 1A Test Line) abandoned in '03 due to extensive internal under deposit corrosion.

-ID #314 (12" 2BPO) was excavated in 2003, scheduled for replacement in 2004.
-ID #331 (12" 2DPO) will probably be excavated in 2004.
-ID #159 (18" 1YRPO) will not be excavated in 2004 because of its large corrosion allowance.
-ID #165 (6" 1A Test) abandoned in '03 due to extensive internal under deposit corrosion.
-ID #573 (30" SW Supply line) will probably not be excavated in 2004 due to a low internal and external corrosion risk factor and the possibility this line will be smart pigged in the near future.

3.1.e (3) Results of Crossing Digs

Eight cased pipes were excavated in 2003:

- Two of the eight pipes had repair recommendations issued. One pipe was found to be derated below the design pressure of the pipe and it was replaced in 2003. The other is not derated yet and is scheduled for replacement in 2004.
- Six of the eight pipes excavated and inspected did not require de-rating, repair, or replacement. Only minor damage was found.

For all eight cased pipes that were excavated in 2003, the insulation was refurbished and the pipe wrapped with Densyl tape to prevent further corrosion.

3.1.f Other Structural Concerns

Subsidence:

Existing Well Upgrade Program

- In 2003, 22 floors with riser piping supports were installed in well houses at Drill Sites 1D, 2A, 2K, 2T, and 3O. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2003, 65 heat tubes were installed at Drill Sites 1C, 1D, 3F, 3G, 3J, and 3Q. Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

New Wells & Producer to Water Injection Well Conversions

- In 2003, ten new wells brought on line had heat tubes and floors with permanent pipe supports installed. In 2003, 43 new wells were installed with insulated conductors.
- In 2003, all 13 existing producers converted to water injection wells were upgraded to include heat tubes and conductor-supported floors.

Wind-Induced Vibration:

- As a result of the Drill Site (DS) 2X 8" MI line failure that occurred in December 2001, Kuparuk performed a field-wide evaluation of the need for vibration dampeners on existing pipelines. The line that failed is oriented one-degree outside the design wind direction envelope designated for Kuparuk in 1991. Based on this field-wide evaluation, tuned vibration absorbers (TVA's) have been installed on all the lines identified with pipeline sections that did not have WIV mitigation (2B, 2U, and 3G) and that fall within the design wind-direction envelope, with the exception of three lines at DS 3N. The three lines at DS 3N are on the periphery of the design wind-direction envelope and were selected for monitoring to better understand variables associated with WIV and to further validate the orientation of design wind-direction envelope. All hardware has been installed and all equipment has been functionally checked out. Final programming of the data logger will be completed this spring. Once completed, data such as line movement frequency, line movement amplitude, wind speed, and wind direction will be collected for approximately 18 months. The data will them be used to develop a better understanding of the effects of the variables on the propensity for WIV on lines oriented on the periphery of the current design wind-direction envelope.
- An annual inspection of all pipeline vibration dampener (PVD) locations is conducted to verify integrity of the PVD's. This information is sent to the facilities for corrective action. Typically, corrective action consists of replacement of worn elastomers and reinstallation of PVD weights.

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

- 3GFBWI cross country sea water injection line leaked because of internal weld area attack in March of 2003 - The eight-inch line providing sea water to drill sites 3B, 3F and 3G failed because of internal corrosion in a circumferential weld. Total spill volume was 5,600 gallons of sea water on the tundra. Similar damage was found on several other welds and the line was de-inventoried and abandoned in place. None of the other 27 water injection lines inspected by RTR in 2003 had this type of damage.

- 3HAMIPO cross county produced crude oil line leaked because of internal deadleg corrosion in July of 2003 - The two-inch drain line branch off the main line bringing crude oil from drill sites 3I, 3M, 3A and 3H failed because of stagnant flow conditions. The spill volume was less than one gallon on the CPF3 gravel pad. Similar damage has been found on several deadlegs at Kuparuk. There is an ongoing effort to inspect all similar deadlegs.

- 2TABASCOPO cross county produced crude oil line leaked because of internal deadleg corrosion in November of 2003 – The 10" line bringing crude oil from DS 2Tabasco failed because of stagnant flow conditions. The spill volume was less than one gallon on the 2T gravel pad. Similar damage has been found on several deadlegs at Kuparuk. There is an ongoing effort to inspect all similar deadlegs.

- No leaks were caused by external corrosion in 2003.

- No leaks were caused by wind-induced vibration in 2003.

- No leaks were caused by subsidence in 2003.

- On May 24th, 2003 workers driving on the Meltwater/Tarn access road noticed a failure of the Meltwater/Tarn pipeline supports. Investigation revealed that the fillet welds connecting the vertical support member (VSM) cap plate to the horizontal support member (HSM) on 13 pipeline supports (VSM/HSM 997 thru 1025 in the Miluveach River drainage area) had failed causing the four supported pipelines to move from their original as-built positions. There was no release from any of the affected pipelines (24-inch and 16-inch produced oil pipelines, a 12-inch water injection (WI) pipeline, and an 8-inch miscible injectant pipeline), and there was no damage to the tundra or environment.

A qualitative and quantitative assessment of the pipelines by the Field Mechanical/Piping Engineer determined that the sustained stress loads (internal pressure, self-weight, etc.) were within design limits of the piping system for every case evaluated. Based on the combination of favorable qualitative and quantitative results, the pipelines were lifted back into their original centerline positions. No repairs to the pipelines were necessary and temporary cribbing pile installation, to both support and secure the pipelines, were completed without incident.

Initial examination by Engineering Staff personnel indicated fatigue cracking in 12 of the 13 fillet-welds connecting the VSM cap plate to the HSM. The fatigue loading resulted from a combination of wind-induced vibration (WIV) on the pipelines, and forces created by hydraulic slugs in the production pipelines. From a dynamic/cyclic load design basis, selection of a fillet weld as the primary load connection proved to be less robust than anticipated. Upon evaluating support structure designs from past North Slope projects, it was concluded that use of balanced, non-cantilevered support with pre-stressed bolted connections has proven to be the optimal design configuration for all loading conditions (static and dynamic) encountered in a HSM/VSM support structure's lifetime. As such, this type of design has been adopted as a best practice to be implemented to insure that this type of failure is avoided for future support structure designs.

Post-failure, knee-braces were installed on the unbalanced side of the Meltwater/Tarn pipeline system support structure for the approximate 1,100 remaining VSM/HSM supports. This construction effort is nearly complete with all remaining locations, based on accessibility issues over open water, to be completed once winter tundra travel is permitted.

From a field-wide survey, similar welded support installations were discovered on two relatively-short pipelines. However, an engineering analysis confirmed that these supports are fit-for-service under the specific loading conditions characteristic of each pipeline configuration.

Figures 8 and 9, and Figure A1 in Appendix A show the number of leaks and the volumes of leaks as a function of time. Figure 8 depicts the leaks caused by internal corrosion for the well lines. Figure 9 depicts the leaks caused by internal corrosion for the cross-country lines. Figure A1 shows the leaks caused by external corrosion for cross-country lines, well lines, and below-grade piping locations.

3.2 Year 2004 Forecast

3.2.a Monitoring & Mitigation

- Test four additional new inhibitor formulations; first test will be Baker Re-5273 at DS3R. Additionally, we are discussing a possible field-wide test of concentrated blend of Champion RU-276 for the summer months.
- Test schmoo-be-gone in the water injection system for DS1E. Chemical is currently being mixed at Great Western in Fairbanks.
- Consider wellhead chemical injection systems for the production well lines at two more Drill Sites.
- Continued analysis of the CPF2 mixed water and associated systems to determine the cause of higher corrosion rates and possible mitigation options.

3.2.b Well Line Inspection

Our baseline inspection of all six-inch OD, 0.312" and 0.375" wall-thickness well lines that are six years of age or older was completed in 2003. Our recurring inspection program will start in 2004. No line in active oil service will go longer than 10 years without an inspection.

3.2.c Cross-Country Line Inspection

The following enhancements/modifications are planned for 2004:

- Our baseline RTR inspection of all CC lines requiring inspection was completed in 2003. Our recurring inspection program will start in 2004. No line in active oil service will go longer than 10 years without an inspection.
- Our baseline inspection of all elevation-change elbows scheduled as part of the Cross-Country Line Turbulent Flow Survey was completed in 2003. Based on 2003 inspection findings we will add water injection lines to the scope of work for 2004.

3.2.d External (Weld-Pack) Program

Complete evaluation of the initial CUI Buffer Spike test and determine the way forward.

Cross-country lines over tundra:

- Complete baseline TRT inspections on the remaining 711 CUI locations that were identified by the walk down verification survey completed in 2003.
- Complete recur TRT inspections on approximately 2210 CUI locations; use results to help fine-tune the prioritization scheme for future recurring inspections. Continue to monitor Denso tape protocol.
- Complete approximately 100 TRT inspections on the Tarn weld pack design established in 1997.
- Complete visual inspections of ten previously Medium Wet weld packs in saddles on large diameter sea water lines. Strip, inspect and refurbish these directly without performing TRT inspections because of the lengthy shot times involved.

For cross-country lines on-pad, inspect the remaining weld packs without a baseline inspection (approximately 500) to meet the goal of YE 2004 completion.

For well lines, inspect more than 50% of the remaining weld packs without a baseline inspection. This supports the goal of YE 2005 completion.

3.2.e Below Grade Piping Program

- Visually inspect all of the priority one and two cased lines. The appropriate CPAI field department will be notified of any corrective actions that need to be taken early enough to complete clean out and re-inspection during the summer.
- Continue recurring PTI/TWI inspections of priority one cased lines.
- Excavate, inspect, refurbish, and repair (as necessary) five-to-nine lines in road crossings.
- Continue to work with TWI and ConocoPhillips R&D to refine inspection data reduction and interpretation.

3.2.f Other

- Continue enhancements to the Kuparuk Corrosion Database.
- Continue Alpine piping layout and piping information database development.
- Continue to evaluate, and prioritize subsidence mitigation efforts at the existing drill sites.

APPENDIX A

Table A1. Three-phase Production Cross-Country lines with corrosion rates that exceeded targets and the action that was taken.

Common Line	Coupons	Probe Rate	Insp Incr	Action Taken
1EPO			x	Actual CI Rate increased, CI pump repaired
1L10"PO	x			Target CI Rate increased
1RPO	x			No CI change, due to temp CI test
2EPO	x			Target CI Rate increased
2GPO			x	Target CI Rate increased
2TPO		x		Target CI Rate increased
2TAMKHPO			x	Target CI Rate increased
2UPO			x	Target CI Rate increased
2WUPO	x			Target CI Rate increased
2XPO			x	Target CI Rate increased
3HPO	x			Target CI Rate increased
3HAMIPO		x		Target CI Rate increased
3MIPO	x			Target CI Rate increased
3BFGSPO		x		Target CI Rate increased
3CPO	x			Target CI Rate increased
3IPO	x			Target CI Rate increased
3QRONKPO	x	x		Target CI Rate increased
3KPO	x			Target CI Rate increased
3OPO		x		Target CI Rate increased
3QRONKCPO		x		Target CI Rate increased
3QROPO	x			Target CI Rate increased
3WOto1	x			Target CI Rate increased

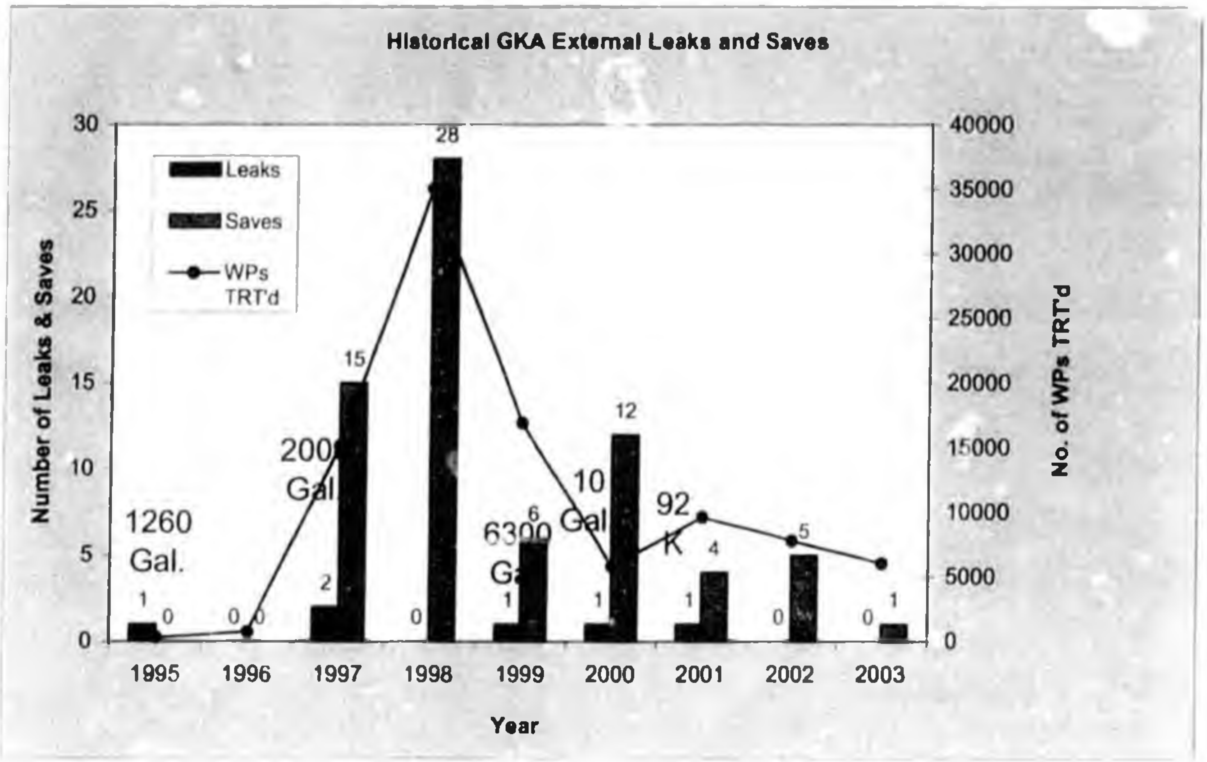


Figure A1. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

Note: The leak in 2001 due to external corrosion was located in a weld pack in a below-grade piping segment, and as such, would not have been detected by the TRT inspection program. The location had not yet received PTI/TWI inspection.

APPENDIX B
Glossary

Equipment Classification:

- **Well Line** – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.
- **Cross-Country Line** – Pipe from the Drill Site manifold to the Central Processing Facility (CPF).
- **Below-Grade Location** – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

Service Definitions:

- **Three-phase Production** – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.
- **Seawater (SW)** – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration, oxygen stripping using produced gas, and biociding.
- **Produced Water (PW)** – The water separated at the CPF from three-phase production.
- **Mixed Water (MW)** – Produced water and seawater that have been commingled.
- **Gas** – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible Injectant.
- **Produced Oil** – The liquid hydrocarbon separated at the CPF from three-phase production.

Inspection Technology.

- **CRM** – Corrosion rate monitoring.
- **UT**- Ultrasonic testing
- **RT** – Radiographic testing
- **RTR** – Real time radiographic testing
- **TRT** – Tangential radiographic testing
- **PTI** – Profile Technologies Inc. (Electro magnetic inspection)
- **TWI** – The Welding Institute (Long range UT)\
- **KDR** – Known damage recur inspection
- **Leak** – Through-wall pipe damage that causes loss of product. Product volume may not be sufficient to be classified as a "spill".
- **Save** – When the Corrosion Group recommends a repair before a leak occurs.
- **Below Grade (priority 1)** – These are pipes with a higher probability and consequence of failure. In general they have larger diameters and higher pressures and would probably cause damage to the environment or cause safety concerns if they leaked.
- **Below Grade (priority 2)** – These are pipes with a lower probability or consequence of failure. In general, these have smaller diameters and lower pressures and would probably cause little, if any, environmental damage or safety concern if they leaked. Examples include un-insulated dry gas lines and flare lines.
- **Below Grade (priority 3)** – These are pipes with a low probability and consequence of failure. Examples include decommissioned pipes, pipes in fresh or fire water service and pipes constructed of corrosion resistant materials. In addition, they contain product that would cause little, if any, environmental damage or safety concern the pipe leaked.

2004

ConocoPhillips

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

March 31, 2005

Commitment to Corrosion Monitoring
5th Annual Report to the Alaska Department of Environmental Conservation

Prepared by
ConocoPhillips Corrosion Team

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Appendix A Glossary of Terms used in this Report

1.0 OVERVIEW

There are over $4 Billion in capital assets in the Greater Kuparuk Area (GKA). The internal corrosion potential in Kuparuk lines continues to rise as water production and H_2S levels increase. Additionally, an external corrosion potential exist where moisture penetrates and is trapped in insulation. 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.

Alpine is ConocoPhillips' newest development and the largest onshore oil field discovered in North America in the past decade. Alpine has a nominal processing capacity of 120,000 BOPD. The Alpine development produces from a pad area of 97 acres, and has two Drill Sites; two additional satellite drill sites are being built. The corrosion management system used at Kuparuk is being applied to the Alpine field.

The purpose of this 5th Annual Report is to communicate the details of the individual programs that implement the ConocoPhillips Alaska Corrosion Strategy. In addition to the requirements of the North Slope Charter Agreement between ConocoPhillips Alaska, Inc., BP Exploration (Alaska), and the Alaska Department of Environmental Conservation, previous reporting requirements pertaining to the Below Grade Piping Program will be incorporated into this and future North Slope Charter Corrosion Reports.

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

2.0 SIGNIFICANT ENHANCEMENT TO CORROSION PROGRAMS

In 2004 we implemented linear array testing which allowed us to inspect all large-diameter cross country water lines that could not be inspected with conventional Real Time Radiography (RTR), with the exception of the 30-inch and the two 24-inch sea water supply lines. This technology allowed us to greatly increase our inspection coverage of 12 water injections lines with diameters of 12" to 16".

3.0 Program Status Summary - Kuparuk

3.1 Year 2004 Overview

3.1.a Kuparuk Monitoring & Mitigation

In 2004 we had several significant accomplishments:

- Tested four new corrosion inhibitor formulations.
- Started testing of schmoo-be-gone (SBG) in the DS1E water injection system to evaluate mitigation effectiveness.
- Installed wellhead corrosion inhibitor injection systems for production well lines at three drill sites.
- Improved the existing biocide treatments of the water injection system at CPF2.

Average general and pitting coupon corrosion rate data for Year 2004 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	0.09	61	100
Seawater Cross-Country Lines	2	2.6	1	50
Mixed Water Injection Cross-Country Lines	22	1.1	19	86
Production Well Flow Lines	501	0.2	494	99
Mixed Water Injection Well Flow Lines	644	0.8	593	92

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	4.5	53	87
Seawater Cross-Country Lines	2	5.1	2	100
Mixed Water Injection Cross-Country Lines	22	26	11	50
Production Well Flow Lines	501	1.5	471	94
Mixed Water Injection Well Flow Lines	644	9.3	442	69

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

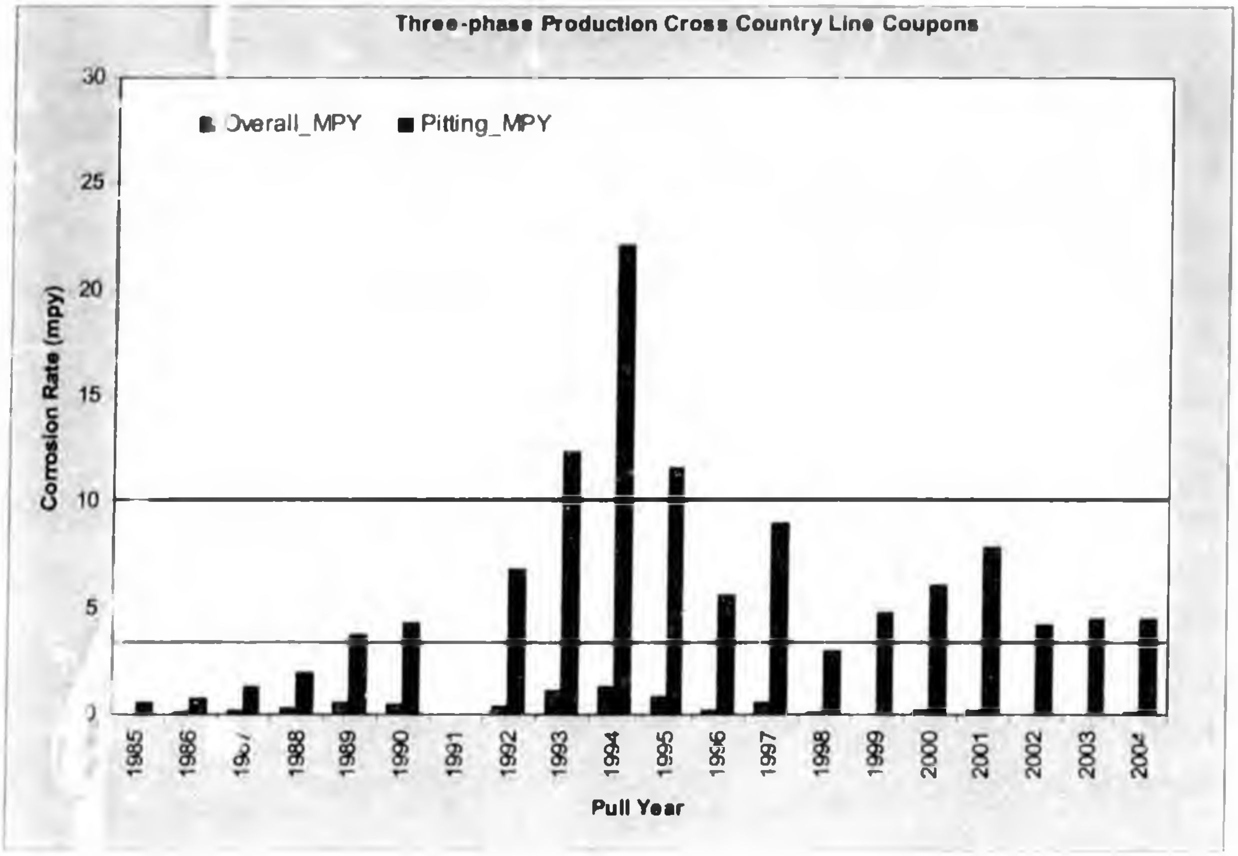

Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Cross-Country Lines: The monitoring data summarized in Kuparuk 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 starting at CPF3 and going to CPF1 and CPF2.

Recurring CRM inspections also support the conclusion that corrosion is under control in the three-phase production cross-country lines. In 2004, 587 corrosion-rate monitoring (CRM) inspections were conducted, with two minor increases found. Other internal inspection data also support the CRM data conclusions 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 excluding: one corrosion inhibitor test location (2WUVPO); and one location that had increased inspection damage over a 12-month period and that had its corrosion inhibitor concentration increased at the end of 2003 (1L10PO). In 2004, coupon or probe corrosion rates exceeded targets on fifteen lines and action was taken on all fifteen of these lines. In 2004, inspection results indicated minor corrosion had occurred on six lines; corrosion inhibitor concentrations were increased in four of these lines. A complete listing of the lines with coupon/probe corrosion rates that exceeded targets and/or where inspection indicated increased damage is given in Table 3.

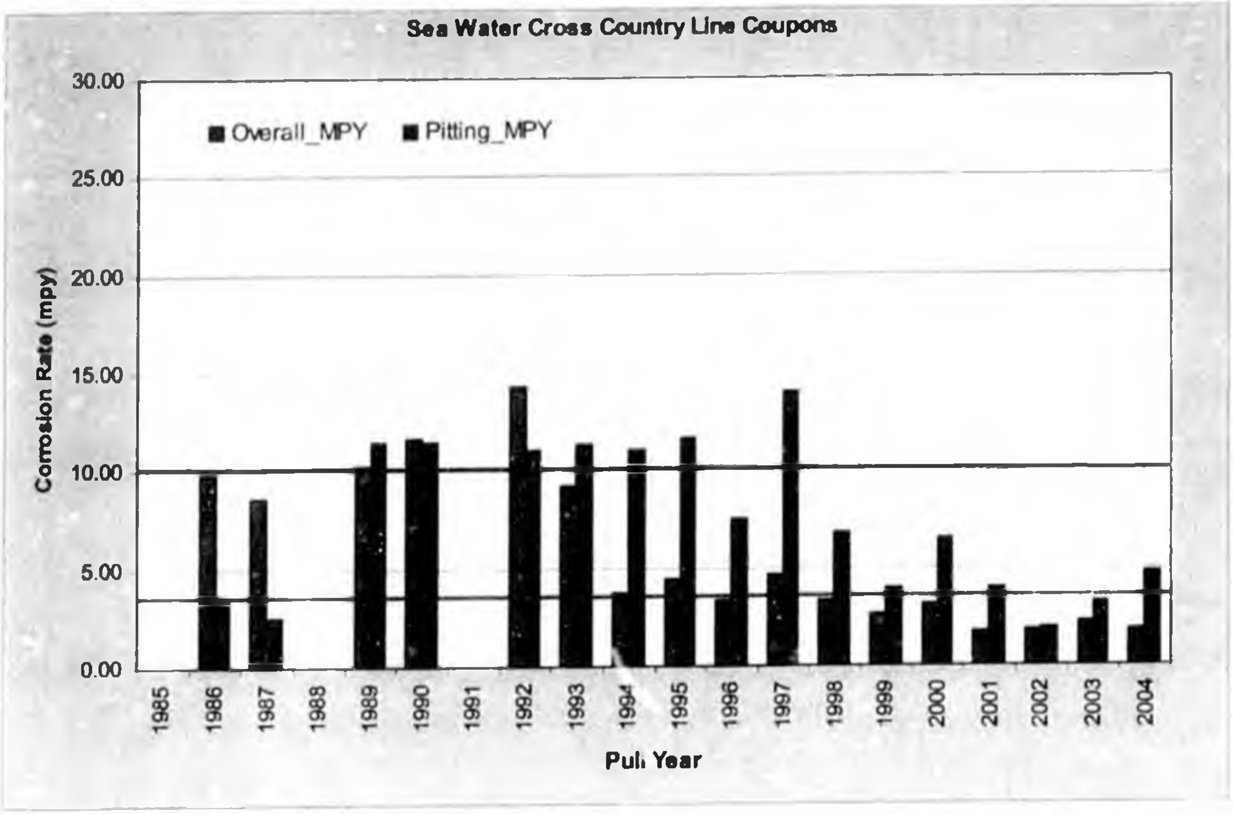

Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Sea Water Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 2 above, shows the average corrosion rates for the sea water cross-country line coupons remained under thresholds in 2004.

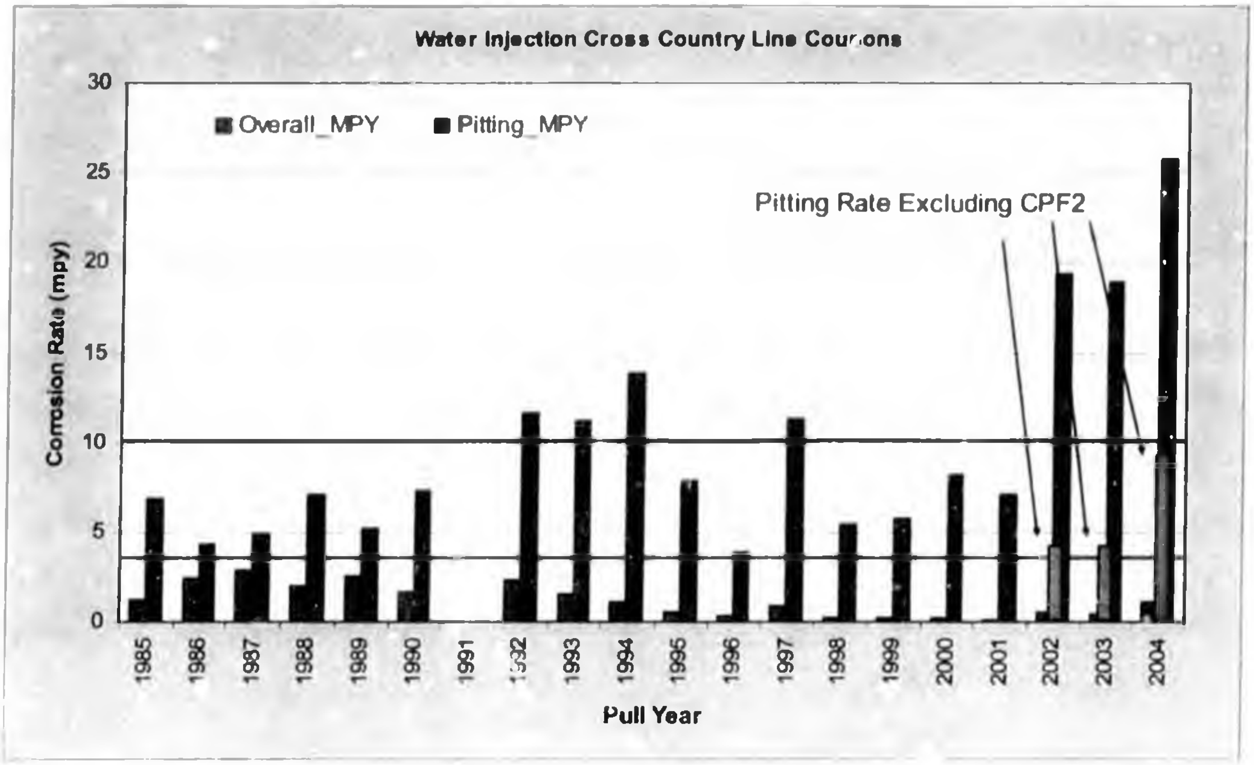

Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Mixed Water Injection Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 3 show that average general corrosion rates are below the threshold, but that pitting rates for the field are above the threshold. Closer analysis of the data shows that the average pitting rate excluding CPF2 locations is under the threshold. Coupon results are used to prioritize inspection efforts. During the second half of 2004, equipment was installed and procedures were implemented to provide enhanced biocide treatments at CPF2. The first quarter 2005 coupon pulls from CPF2 show that pitting rates are lower than the 2004 average, but are still above threshold. In addition to the biocide treatment enhancements, an additional 80K BWPD of SW has been added to CPF2. This will increase line velocities and is anticipated to help reduce the under-deposit corrosion seen on many of these coupons.

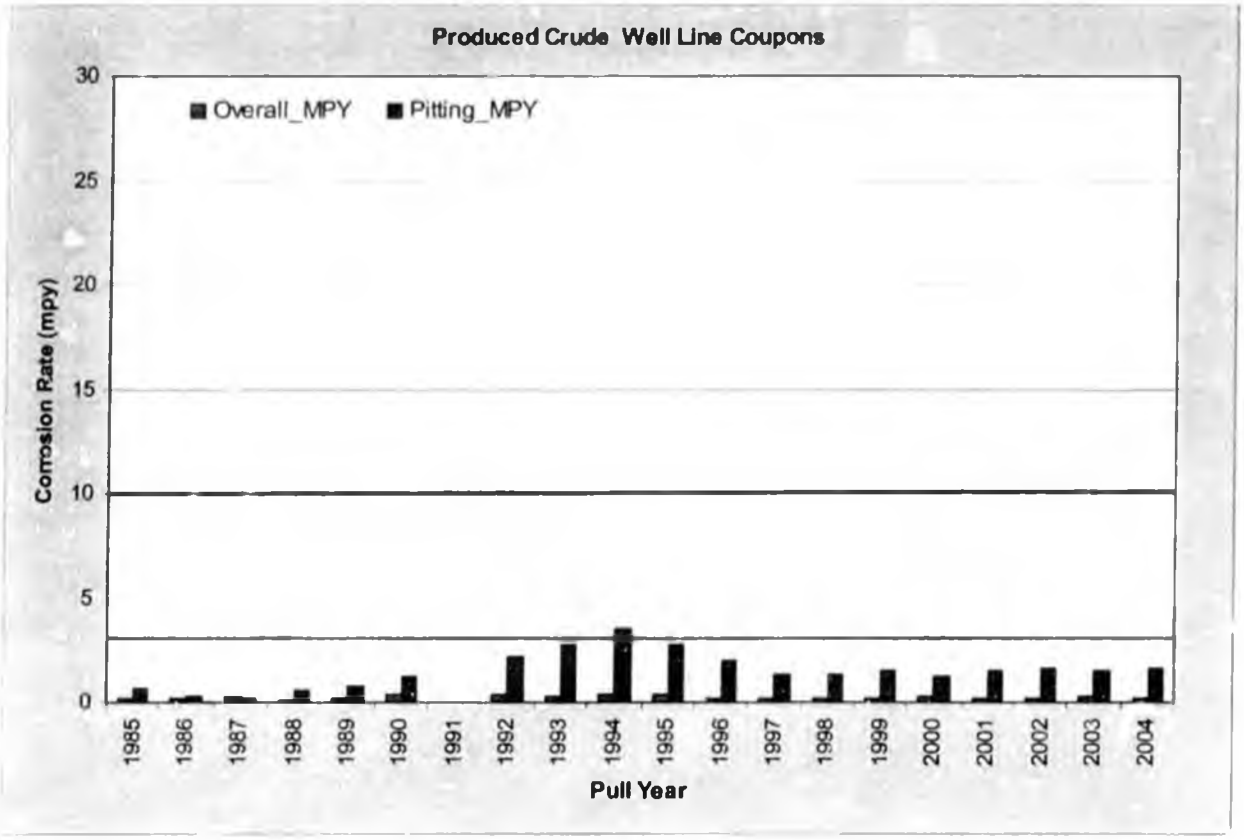

Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Well Flow Lines: While the monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figures 4 and 5 suggest that corrosion rates are below targets, inspection data indicate that higher corrosion rates have been experienced historically. The well line inspection data are discussed in section 3.1.b below, and are a good example of why monitoring data alone cannot be relied upon to characterize corrosion in a given system. For three-phase production, coupons monitor free flowing fluid and have not shown the predominant, under-deposit corrosion mechanism.

ConocoPhillips

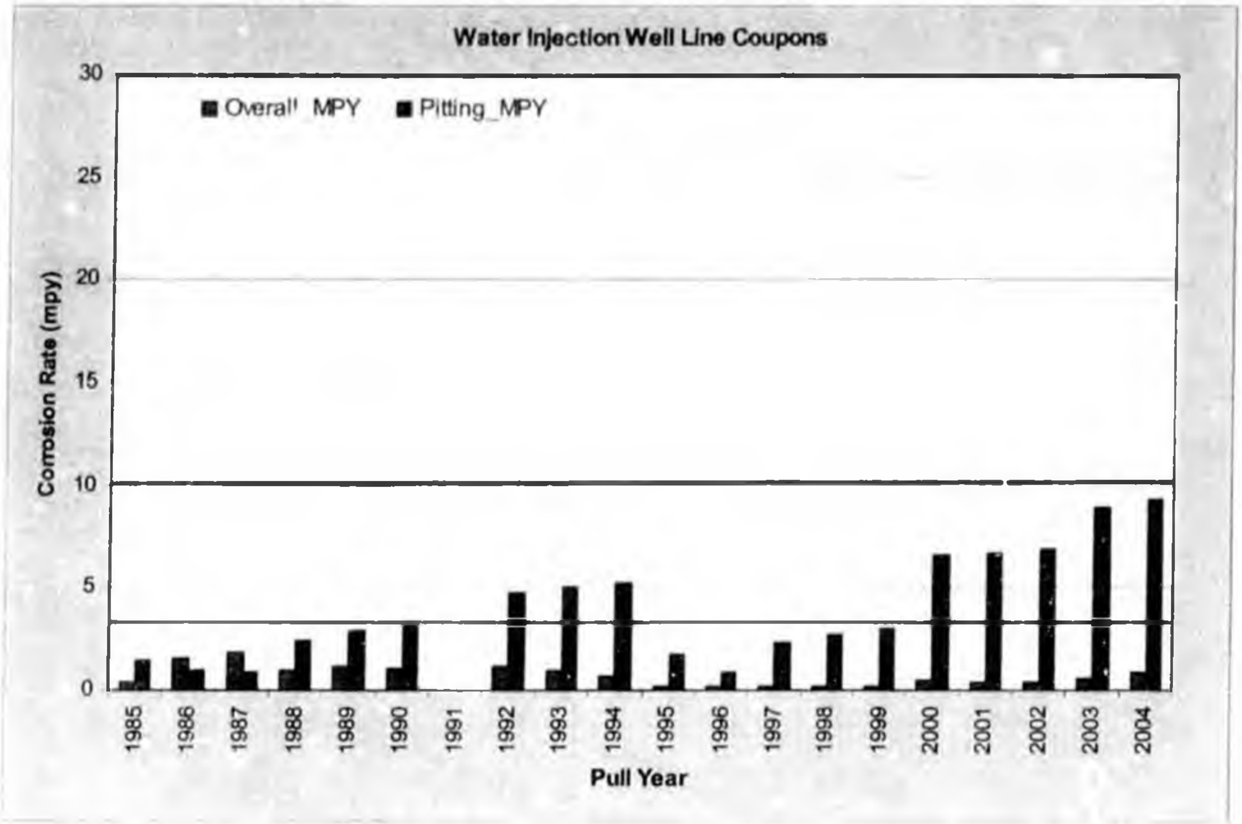

Figure 5. Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.

Water Injection Well Flow Lines: As discussed in section 3.1.b below, the well line inspection data on water injectors show that there are a significant number of corrosion related repairs. The water feeding this system is treated at the facilities with biocide and is discussed under Figure 3 - Water Injection Cross-Country Line Coupons

Mitigation:

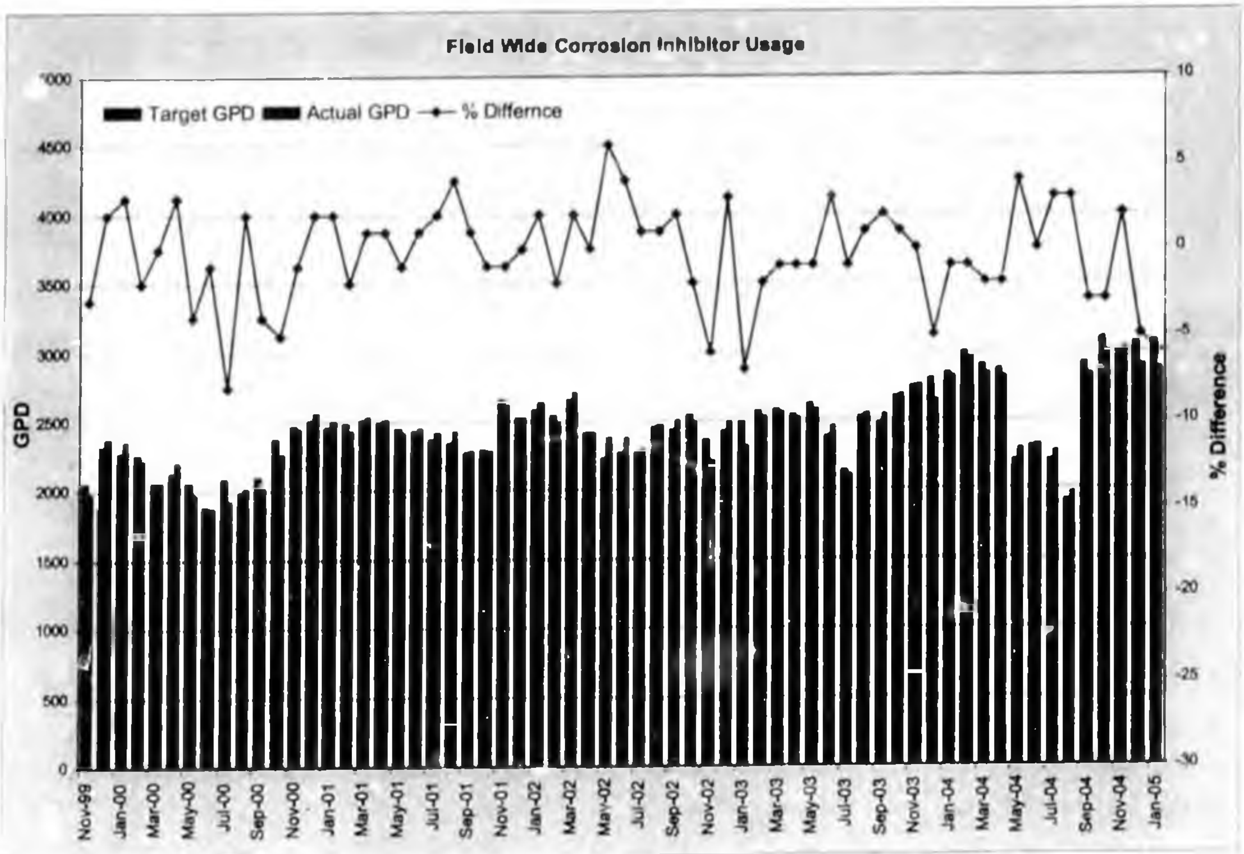

Figure 6. Field-wide Corrosion Inhibitor Use.

For the Kuparuk field, Figure 6 shows the actual number of gallons of corrosion inhibitor pumped per day, the recommended number of gallons of corrosion inhibitor per day, and the percent difference between the two. The average deviation for the year was –0.85%. The larger variation seen in the November and December 2004 data was caused by the extreme weather. The lower usage seen in May through August was due to pumping a more concentrated blend of the same field-wide corrosion inhibitor (the concentration of active components in both blends is the same).

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

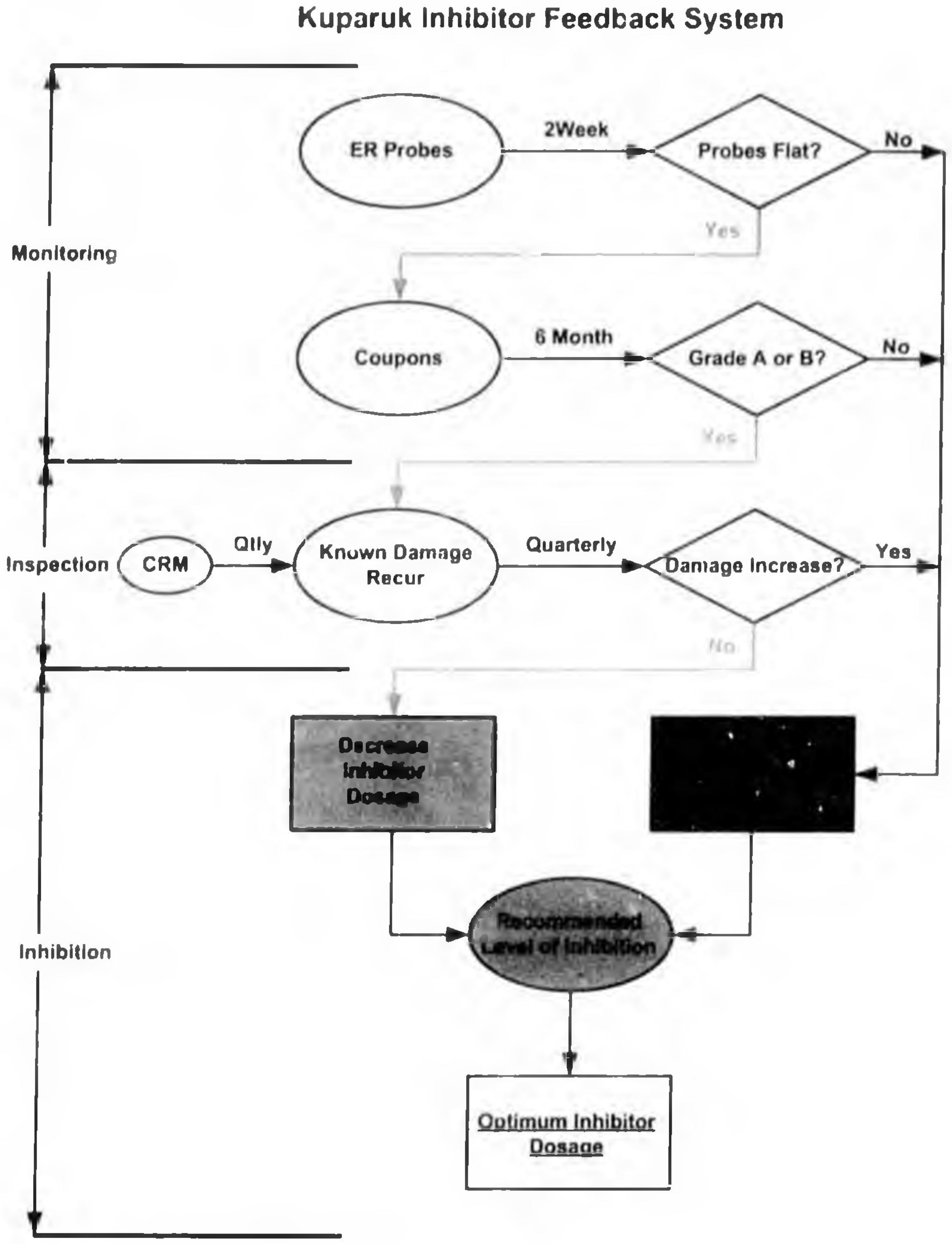

Figure 7. Corrosion Inhibitor Feedback System.

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

Common Line	Probes	Coupons	Inspection	Action Taken
1-2ZPO			x	Increase Target PPM
1DPO		x		Increase Target PPM
1L10PO			x	Hold (see Fig. 1 discussion)
2APO		x		Increase Target PPM
2BPO			x	Increase Target PPM
2NPO		x		Increase Target PPM
2TAMKHPO			x	Increase Target PPM
2WUVPO			x	Hold until after 50B Test
3HPO		x		Increase Target PPM
1BPO	x			Increase Target PPM
1CPO	x			Increase Target PPM
1RPO	x	x	x	Increase Target PPM
2EDPO		x		Increase Target PPM
2TPO	x	x		Increase Target PPM
3CPO		x		Increase Target PPM
3KPO		x		Increase Target PPM
3MIPO		x		Increase Target PPM
3RPO		x		Increase Target PPM
3RQONKPO		x		Increase Target PPM
3WO to CPF2		x		Increase Target PPM

3.1.b Well Line Inspection

One notable accomplishment in 2005 was that we met our primary 2004 goal by completing interval surveys on 132 well lines.

As indicated in Figure 8 below, repair recommendations were initiated on 24 lines (16 water injection, 8 production) in 2004 because of internal corrosion damage. Except for the leak, the corrosion mechanisms were all underdeposit corrosion. The leak, determined not to be an ADEC-reportable spill, was in a water injection line and was caused by erosion associated with a straightening vane pack. More information on the leak can be found in section 3.1.g.

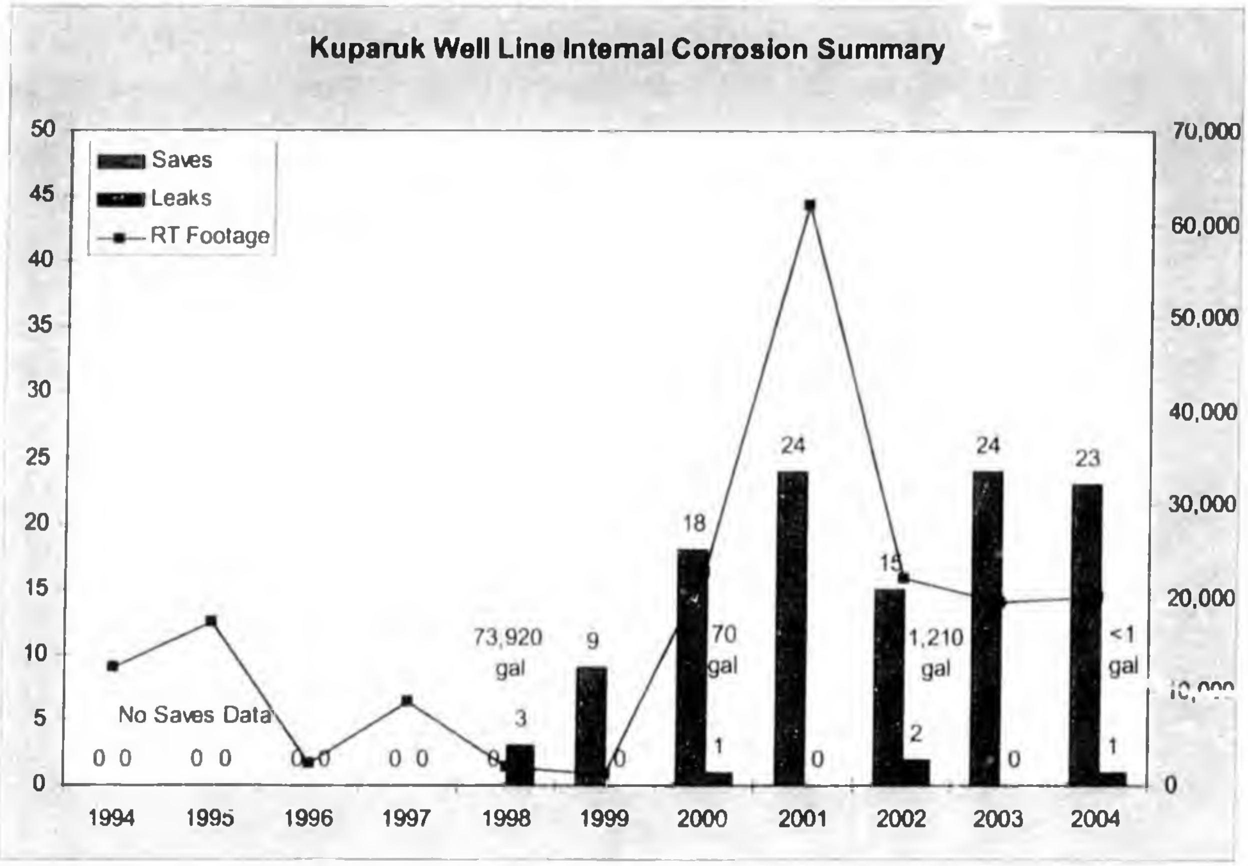

Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2004 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables.

- **RTR of Well Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	10,217	56
Water Injection	7,530	44
Total	17,747	100

The 2004 RTR well line data indicated no new damage trends. The number of lines inspected by RTR decreased from previous years because we completed our initial baseline inspection in 2003 and started our interval recur program in 2004.

- **Manual RT of Well Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% Of Repeat Radiographs with Increases
Three-phase Production	196	898	386	16	4
Water Injection	111	1,017	179	16	9
Total	207	1,915	565	32	6

The 2004 manual RT well line data indicated no new damage trends. The number of lines inspected by RT decreased from previous years because we completed our initial baseline inspection in 2003 and started our interval recur program in 2004.

- **Manual UT of Well Lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	170	1,442	1,254	93	7
Water Injection	69	512	384	29	8
Total	239	1,954	1,638	122	7

The 2004 manual UT well line data indicated no new damage trends. The number of lines inspected by UT decreased from previous years because we completed our initial baseline inspection in 2003 and started our interval recur program in 2004.

3.1.c Cross-Country Line Inspection

In 2004 we had several significant accomplishments:

- Completed the inspection survey of all over tundra dead-legs and weld-o-lets on cross country pipelines.
- Met our primary 2004 goal by completing interval surveys on 32 cross country lines.

As indicated in Figure 9, four repair recommendations were initiated on cross-country lines (1 seawater injection, 3 production) because of internal corrosion damage in 2004. The corrosion mechanism for the three production lines was deadleg corrosion. The corrosion mechanism for the seawater injection line leak, determined not to be an ADEC-reportable spill, was microbiologically induced corrosion. More information on the leak can be found in section 3.1.g.

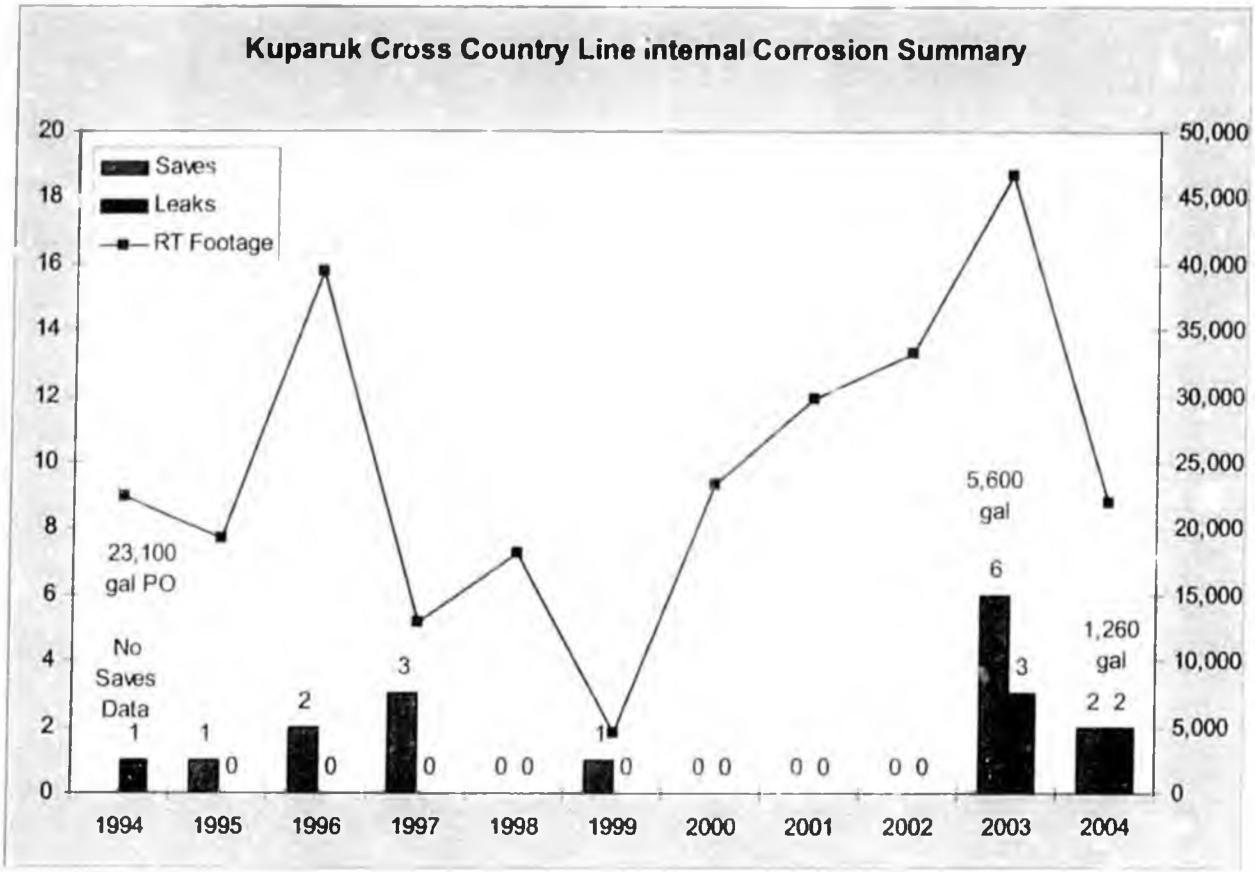

Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2004 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

- **RTR of Cross Country (CC) Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	13,020	21
Water Injection	6,099	10
Total	19,119	31

The 2004 RTR CC line data indicated no new damage trends. The number of lines inspected by RTR decreased from previous years because we completed our initial baseline inspection in 2003 and started our mature recurring program in 2004.

- **Manual RT of CC Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% of Repeat Radiographs with Increases
Three-phase Production	254	2,410	413	10	2
Water Injection	75	387	11	3	27
Total	329	2,797	424	13	3

The 2004 RT CC line data inspection results corroborated the increases seen by monitoring

- **Manual UT of CC lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	103	1,050	678	19	3
Water Injection	36	256	39	2	5
Total	139	1,306	717	21	3

The 2004 UT CC line data indicated no new damage trends

3.1.d External (Weld-Pack) Program

In 2004 we had several significant accomplishments:

- Completed baseline tangential radiography testing (TRT) survey of all well line weld packs due for inspection, ahead of our scheduled 2005 planned completion date.
- Completed baseline TRT survey of all cross country line weld packs due for inspection.
- Completed our goal of inspecting at least 100 Tarn-style weld packs to ensure this new design is working properly.
- Completed our visual inspection and refurbishment of ten 30" sea water pipeline weld packs.

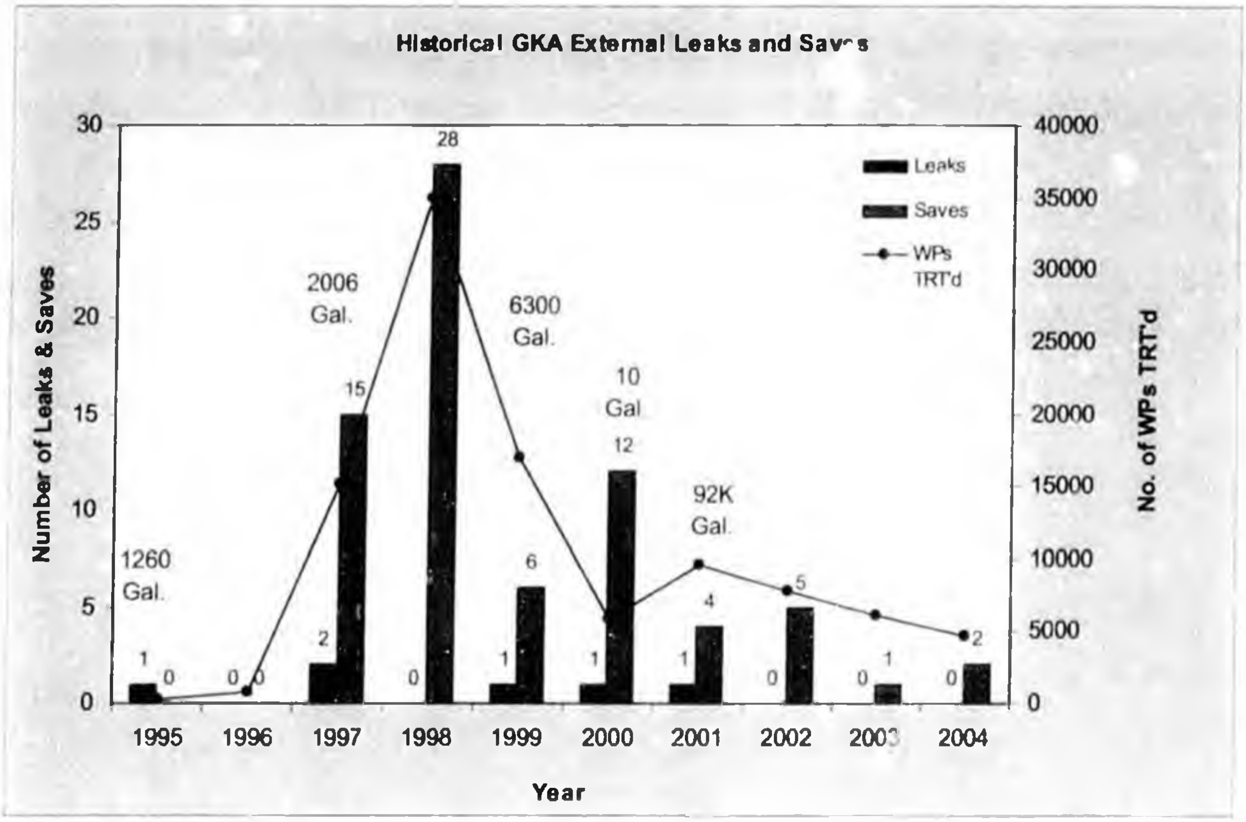

Figure 10. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

Cross-Country Lines (On-Pad)

A total of 672 locations were inspected using tangential radiography (TRT), significantly exceeding the goal of 406 for 2004. Of the 672 locations, none needed repair while 96 locations were refurbished. The baseline inspections on all weld packs due for inspection is now considered complete

Cross-Country Lines Over Tundra (Off-Pad)

The baseline inspection of these weld-packs was believed complete by year-end 2001. However, in 2003 a walk-down verification survey revealed that several weld pack locations had been missed during the initial layout. In 2004, 3094 CUI locations were inspected, surpassing our goal of inspecting 3020 locations. These numbers include inspections of weld packs that had been inspected previously (recurs), as well as weld packs where documentation of a previous inspection could not be verified. Two piping repairs were required as a result of this on-going effort and 354 locations were refurbished. The baseline inspections on all weld packs due for inspection is now considered complete.

Additionally, 111 of the new, Tarn-style weld packs were inspected with TRT to see how they are holding up. All 111 locations had no previous inspection history. A total of six weld packs were found with light wet insulation. The rest were found to be completely dry. No corrosion under insulation (CUI) was found in any of the areas inspected. This is the first year that we have discovered any water in this style of weld pack; the insulation does not contact the pipe so even though the insulation is wet, it should not cause CUI.

Well Lines

In 2004, 885 well line weld packs were inspected. With this effort, the baseline inspection and documentation of all well line weld packs due for inspection was considered complete. Our stated goal was 1700 weld packs; the reason for the overestimate of the number of weld packs is the uncertainty in the total count of the well line weld packs before inspections commenced. Corrosion was found at 17 (or 1.9%) of the 885 locations. Also during 2004, 38 well line weld pack locations were refurbished.

Table 5: External Weld Pack Inspection Summary for 2004.

Type of Equipment	2004 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines (On-Pad)	406	672	18	2.7	96
Cross-Country Lines Over Tundra (Off-Pad)	3020	3094	71	2.3	354
Well Lines	1700	885	17	1.9	38
Total	**5126**	**4651**	**106**	**2.3 (avg.)**	**488**

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 11, 12, and 13.

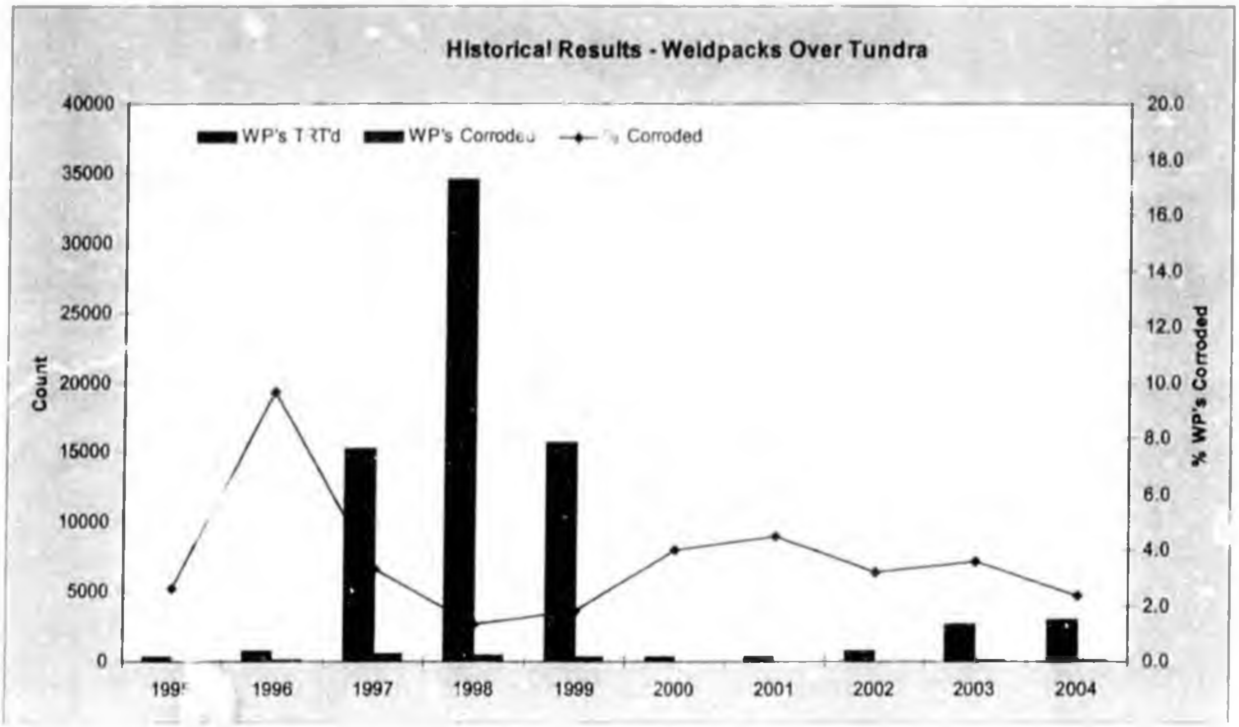

Figure 11. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad).

Figure 11 illustrates the most-complete external corrosion inspection program of the three external corrosion programs. 2002, 2003, and 2004 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

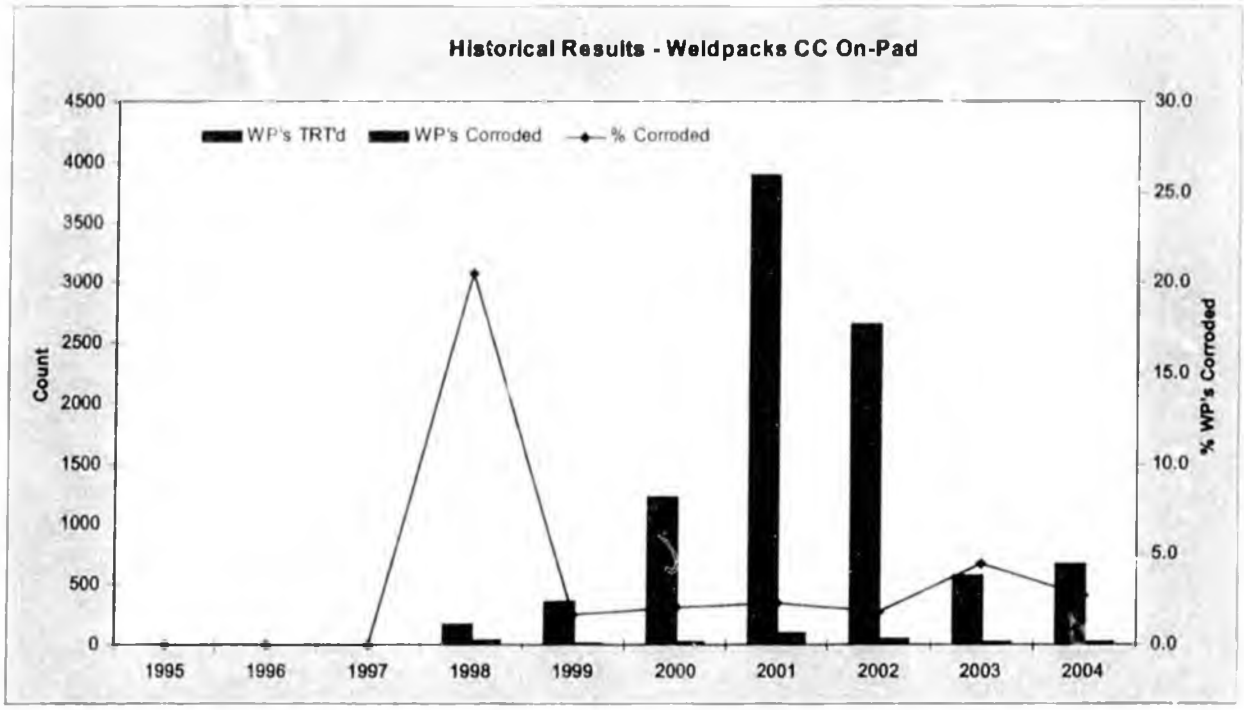

Figure 12. Summary of Weld Packs on Cross-Country Lines on Pads.

Figures 12 and 13 depict the results of the major focus of the external weld pack inspection program in 2004. The cross-country program and the well line weld pack program met milestones in 2004 by completing all of the baseline TRT inspections of all weld packs in their respective areas.

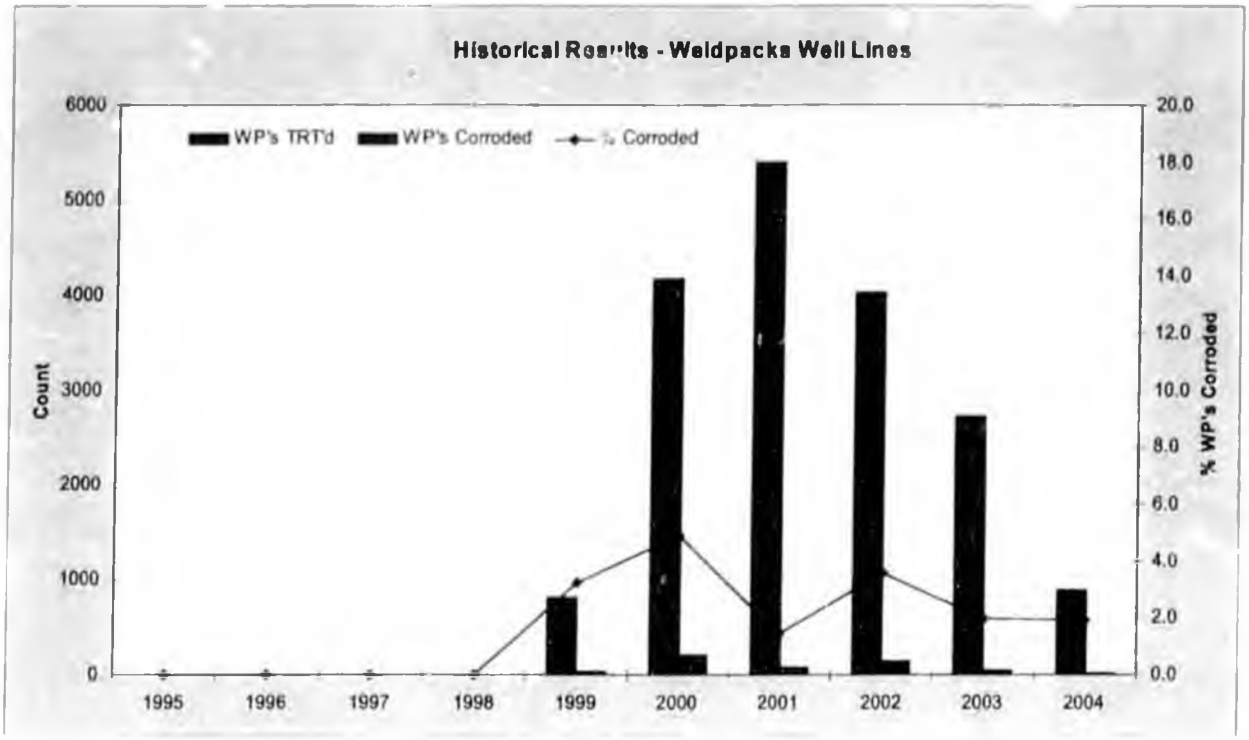

Figure 13. Summary of Weld Packs on Well Lines.

Corrosion Under Insulation Buffer Spike Program

In 2002, a test of "CUI Buffer Spikes" was initiated on 50 over-tundra cross-country weld pack locations. The program was expanded later in 2002 to include weld packs on drillsite well and facility piping. In addition, two electric resistance probes were installed in two heavy water weld packs at DS1E to monitor potential corrosion activity. The sodium phosphate salt contained in these spikes dissolves in wet insulation and raises the pH to 10. Prior to installation of these spikes, wet insulation measurements fell within a consistent 6 to 7 pH range. Corrosion of carbon steel is minimized in alkaline conditions. During 2003, each of these locations was monitored for pH. The 2003 follow-up inspections showed that the pH did rise in the wet areas of the weld packs. Three locations were also stripped and verified with an indicator dye the pH probe results.

TRT inspections were proposed for all buffer spike locations in 2004. These follow-up inspections were not conducted due to priorities elsewhere in the field to complete the baseline weld pack inspection before year-end. The TRT survey has been scheduled for 2005.

Monitoring of the ER probes at DS 1E indicated low, but not zero, corrosion rates.

3.1.e Below Grade Piping Program

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

In 2004 we had several significant accomplishments:

- Visually inspected and cleaned all debris from all cased below grade pipe locations.
- Completed our specialty inspection (TWI) scope of work.
- Excavated, inspected, refurbished and repaired (as required) nine cased below grade pipe locations.
- Continued to work with TWI by testing a focused ultrasonic inspection method.

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

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

CPAI has 764 locations (includes priority 1, priority 2, priority 3, and Alpine lines) of below grade piping located in the GKA. Of these locations, one is contained in an utilidor. The remaining locations are cased lines, the majority of which are either road, gravel pad or caribou crossings.

Utilidor Line

The line in the utilidor (Oily Waste Injection Line, BG ID #286) was taken out of service in 2004. It had been on a two year inspection cycle and was last inspected in 2002. Because it has been taken out of service the 2004 inspection was deferred.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2004. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

Results and Remedial Action:
Of all the below-grade lines, 123 locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. All 123 locations were remediated in 2004.

3.1.e (2) Results of Specialty Testing

Inspection Status:
In 2004, we completed TWI inspections on 63 priority one locations. This was the second year of our recurring inspection program where each priority one pipe will be inspected at a maximum ten-year interval.

In 2004 only the long-range ultrasonic system technology from The Welding Institute (TWI) was used. TWI technology is capable of finding evidence of both internal and external corrosion damage.

Results and Remedial Action:

Tables 6 and show the results of the specialty testing performed by TWI.

Table 6. Results from the TWI inspections by service.

Service	Number of Cased Pipes Inspected	Incomplete or Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Minor to Moderate and Moderate Anomalies (M)	Number of Moderate to Severe and Severe Anomalies (S)
Oil	23	1	16	5	1	0
Other	40	12	11	15	2	0
Total	63	13	27	20	3	0

The 2004 TWI data indicated no new damage trends.

3.1.e (3) Results of Crossing Digs

Nine cased pipes were excavated in 2004:

- One of the nine pipes had a repair recommendation issued because it was found to be derated because of CUI damage. The location was repaired with a pressure containing sleeve.
- Eight of the nine pipes excavated and inspected did not require de-rating, repair, or replacement because only minor or no corrosion damage was found.

For all nine cased pipes that were excavated in 2004, the insulation was refurbished and the pipe wrapped with Densyl tape to prevent further corrosion.

3.1.f Other Structural Concerns

Subsidence:

Existing Well Upgrade Program

- In 2004, 12 floors with riser piping supports were installed in well houses at Drill Sites 1L, 2C, 2F, 2T, 2V, and 2W. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2004, 24 heat tubes were planned to be installed at Drill Sites 1C, 1E, 1L, 2L, 2N, 2W, 3A, 3F, 3N, and 3R. However, the heat tubes were delayed in manufacturing by the vendor and were installed in March 2005. Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

New Wells & Producer to Water Injection Well Conversions

- In 2004, 16 newly drilled wells at Kuparuk were installed with insulated conductors; of these, 15 had heat tubes installed and one new well was not hooked up.
- In 2004, three newly drilled wells had heat tubes and conductor-mounted steel well house floors installed.
- In 2004, two existing producers converted to water injection wells were upgraded to include heat tubes and steel conductor-supported well house floors.

Wind-Induced Vibration:

As a result of the 3A-I-M eight-inch gas lift line failure that occurred in December 2004 (described in section 3.1.g), Kuparuk is reviewing existing pipelines to evaluate the need for secondary mode vibration dampers. We are also revising the CPAI criteria and specifications to ensure that both primary and secondary mode WIV are considered.

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

- Well 1Y-02 water injection well line leaked in July because of erosion. The erosion was caused by an obstructed straightening vane which forced produced water to flow around the vane pack rather than through it as designed. The subsequent flow impingement on the pipe wall eventually caused a pinhole leak. The spill volume was less than one gallon which was contained by the well house floor and, as such, it was determined not to be an ADEC reportable spill. No fluids contacted the tundra or the gravel pad. As a result of this leak the vane pack areas on all other high velocity water lines in the GKA were inspected. One other damaged location was found and remediated. In addition, this area will be inspected on all future well line interval inspection surveys.

- Drillsite 3R test separator bypass line leaked in October because of internal deadleg corrosion. The spill volume was less than one gallon which was contained on the gravel pad and, as such, it was determined not to be an ADEC reportable spill. As a result of this leak all similar deadlegs on all other drillsites were inspected. No damage requiring a repair recommendation was found. As a result of our 2003 inspection year, deadlegs on cross country lines were made a high inspection priority. Over-tundra deadlegs were our highest priority due to the environmental risk. The inspection of all over-tundra deadlegs was completed in 2004. On-pad deadlegs are scheduled for inspection in 2005.

- Drillsite 3R water injection line leaked in a non-piggable section of the line between the pig receiver and the well injection header. The leak occurred in January and was caused by microbiologically induced corrosion (MIC). The line had seen both produced water injection and sea water injection; however it was on sea water injection at the time of the leak. The released volume was estimated to be 1,260 gallons, but because the material was sea water released to a sea water environment, it was not an ADEC reportable spill. As a result of this leak the WI supply line to 3R (piggable), the rest of the non-piggable line and all similar lines at all other drillsites were inspected. No repairs and very little damage were found during these inspections.

- No leaks were caused by external corrosion in 2004.

- The eight-inch diameter gas lift pipeline running between CPF3 and DS3I experienced a failure at a pipeline girth weld at ¼ span location (one-quarter of the distance from one support to another support) in December. Aside from insulation and jacketing debris, the area was clean with no liquid spill to the tundra. Subsequent field investigation of this pipeline revealed a second girth weld failure. The failure has been attributed to secondary mode wind-induced vibration (WIV).

  Of the 163 welds inspected with phased array UT, only one other crack was found – also on the 8" line at a ¼ span location. No internal or external corrosion was found on the lines during these or previous inspections. Repairs were completed in late January 2005, and the lines were returned to service on 2/3/05.

  The failed pipe section and the other cracked location were sent to the ConocoPhillips Failure Analysis Lab in Bartlesville for evaluation. The evaluation determined that the crack was caused by high-cycle fatigue. No signs of brittle fracture, over-pressure, or impact were present. The welds were of high quality and exhibited excellent toughness.

  The tuned vibration absorbers on the DS-3I/3M gas lift line were installed in March, 2005.

Currently, work is underway to expand the WIV model to better understand when and how secondary modes of WIV can occur, and to develop more robust predictive tools so that potential recurrence of such a failure can be prevented. Once these tools are in place, other pipeline segments will be evaluated for susceptibility to similar WIV fatigue failure and mitigating actions taken as appropriate.

- No leaks were caused by subsidence in 2004.

Figures 8, 9, and 10 show the number of leaks and the volumes of leaks as a function of time. Figure 8 depicts the leaks caused by internal corrosion for the well lines. Figure 9 depicts the leaks caused by internal corrosion for the cross-country lines. Figure 10 shows the leaks caused by external corrosion for cross-country lines, well lines, and below-grade piping locations.

3.2 Year 2005 Forecast

3.2.a Monitoring & Mitigation

- Test four additional inhibitor formulations.
- Evaluate the biocide program changes to the mixed water systems because of the monitoring and inspection data trends.
- Consider internal corrosion inhibition for the mixed water systems.

3.2.b Well Line Inspection

Our recurring inspection program will continue in 2005. No in-service line will go longer than 10 years without an inspection.

3.2.c Cross-Country Line Inspection

Our recurring inspection program will continue in 2005. No in-service line will go longer than 10 years without an inspection.

3.2.d External (Weld-Pack) Program

Inspect all 86 buffer spike locations installed in 2002. Inspect for corrosion using TRT at 3, 6, and 9 o'clock positions. Measure the pH in the buffered weld packs and install ER probes in non-buffered weld packs.

Cross-country lines over tundra:

- Inspect approximately 4200 cross-country line weld packs over tundra as part of our recurring inspection program.
- Inspect a minimum of 100 Tarn-style weld packs (insulation not touching the pipe) with TRT to continue to evaluate the efficacy of the design.
- Inspect a minimum of 100 refurbished weld packs to continue to evaluate the performance of the Densotape system.

Cross-country lines on-pad:
Inspect approximately 50 cross-country line weld packs on-pad as part of our recurring inspection program.

Well lines:
Inspect approximately 1500 well line weld packs as part of our recurring inspection program.

3.2.e Below Grade Piping Program

- Continue our annual visual inspection of all priority one and two cased lines. The appropriate CPAI field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.
- Continue our recurring TWI inspection program of priority one cased lines.
- Excavate, inspect, refurbish, and repair (as necessary) five-to-nine lines in cased crossings.
- Continue to work with TWI and ConocoPhillips R&D to refine inspection data reduction and interpretation.

3.2.f Other

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

4.0 Program Status Summary - WNS

4.1 Year 2004 Overview

4.1.a WNS Monitoring & Mitigation

Average general and pitting coupon corrosion rate data for Year 2004 are presented in Tables 4.1 and 4.2.

Table 4.1. 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	1	0.5	1	100
Seawater Cross-Country Lines	1	0.4	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	31	0.1	31	100
Seawater Injection Well Flow Lines	13	0.1	13	100

Table 4.2. 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	1	1	1	100
Seawater Cross-Country Lines	1		1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	31	0.6	31	100
Seawater Injection Well Flow Lines	13	0.6	13	100

* *NOTE: This coupon location is currently not accessible because of a new piping obstruction.*

4.1.b Well Line Inspection

In 2003, 33 three-phase production lines and 22 water injection lines were inspected; no damage was found. In 2004, 18 three-phase production lines were inspected at direction changes; no damage was found

4.1.b Cross-Country Line Inspection

None performed.

4.1.d External (Weld-Pack) Program

None performed.

4.1.e Below Grade Piping Program

This section details the inventory and survey of below grade locations and the results of Specialty Testing. The plans for future inspections are given in section 4.2.e.

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

CPAI has 15 locations of below grade piping in the WNS. These locations are cased lines at road or pad crossings. There are an additional 15 crossings, located at CPF2 that are associated with the WNS, but included in the GKA section of this report.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2004. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

Results and Remedial Action:
Of all the below-grade lines, zero locations were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing.

4.1.e (2) Results of Specialty Testing

No specialty testing was performed in the WNS in 2004.

4.1.e (3) Results of Crossing Digs

None occurred.

4.1.f Other Structural Concerns

Subsidence:

- No concerns identified.
- In 2004, 15 newly drilled wells at Alpine were installed with insulated conductors; of these, 15 had heat tubes installed.

Wind-Induced Vibration:

No problems identified in 2004.

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

- No leaks were caused by external corrosion in 2004.
- No leaks were caused by wind-induced vibration in 2004.
- No leaks were caused by internal corrosion in 2004.
- No structural or subsidence concerns were identified in 2004.

4.2 Year 2005 WNS Forecast

4.2.a Monitoring & Mitigation

- Pull coupons as scheduled
- Ensure new drill site development provides for adequate monitoring.

4.2.b Well Line Inspection

Inspect 15 lines, 15% of existing total for internal corrosion.

4.2.c Cross-Country Line Inspection

Inspect over 2000 ft of three-phase production lines.

4.2.d External (Weld-Pack) Program

Cross-country lines over tundra:
Complete baseline TRT inspections on the remaining 200 possible CUI locations to verify the new weld pack design is working as anticipated.

Cross-country lines on pad:
Complete baseline TRT inspections on the remaining 200 possible CUI locations to verify the new weld pack design is working as anticipated.

Well lines:
TRT most likely locations for CUI on ten lines.

4.2.e Below Grade Piping Program

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

4.2.f Other

Continue Alpine piping layout and piping information database development.

APPENDIX A
Glossary

Equipment Classification:

- **Well Line** – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.
- **Cross-Country Line** – Pipe from the Drill Site manifold to the Central Processing Facility (CPF).
- **Below-Grade Location** – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

Service Definitions:

- **Three-phase Production** – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.
- **Seawater (SW)** – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration, oxygen stripping using produced gas, and biociding.
- **Produced Water (PW)** – The water separated at the CPF from three-phase production.
- **Mixed Water (MW)** – Produced water and seawater that have been commingled.
- **Gas** – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible Injectant.
- **Produced Oil** – The liquid hydrocarbon separated at the CPF from three-phase production.

Inspection Terminology:

- **CRM** – Corrosion rate monitoring.
- **UT-** Ultrasonic testing
- **RT** – Radiographic testing
- **RTR** – Real time radiographic testing
- **TRT** – Tangential radiographic testing
- **PTI** – Profile Technologies Inc. (Electro magnetic inspection)
- **TWI** – The Welding Institute (Long range UT)\
- **KDR** – Known damage recur inspection
- **Leak** – Through-wall pipe damage that causes loss of product. Product volume may not be sufficient to be classified as a "spill".
- **Save** – When the Corrosion Group recommends a repair before a leak occurs.
- **Below Grade (priority 1) –** These are pipes with a higher probability and consequence of failure. In general they have larger diameters and higher pressures and would probably cause damage to the environment or cause safety concerns if they leaked.
- **Below Grade (priority 2) –** These are pipes with a lower probability or consequence of failure. In general, these have smaller diameters and lower pressures and would probably cause little, if any, environmental damage or safety concern if they leaked. Examples include un-insulated dry gas lines and flare lines.
- **Below Grade (priority 3)** – These are pipes with a low probability and consequence of failure. Examples include decommissioned pipes, pipes in fresh or fire water service and pipes constructed of corrosion resistant materials. In addition, they contain product that would cause little, if any, environmental damage or safety concern the pipe leaked.

2005

ConocoPhillips

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

March 31, 2006

Commitment to Corrosion Monitoring

6th Annual Report to the Alaska Department of Environmental Conservation

Prepared by

ConocoPhillips Corrosion Team

ConocoPhillips

Table of Contents

1.0 OVERVIEW

There are over $4 Billion in capital assets in the Greater Kuparuk Area (GKA). The internal corrosion potential in Kuparuk lines continues to rise as water production and H_2S levels increase. Additionally, an external corrosion potential exists where moisture penetrates and is trapped in insulation. Effective management of corrosion at Kuparuk is critical to maintain environmental and facility integrity, to reduce field operating costs, and to extend the life of the field infrastructure to meet future needs.

Alpine is ConocoPhillips Alaska's newest development and the largest onshore oil field discovered in North America in the past decade. Alpine has a nominal processing capacity of 125,000 BOPD. The Alpine development produces from a pad area of 97 acres, and has two Drill Sites; two additional satellite drill sites are being built. The corrosion management system used at Kuparuk is being applied to the Alpine field.

The purpose of this 6th Annual Report is to communicate the details of the individual programs that implement the ConocoPhillips Alaska Corrosion Strategy. In addition to the requirements of the North Slope Charter Agreement between ConocoPhillips Alaska, Inc., BP Exploration (Alaska), and the Alaska Department of Environmental Conservation, previous reporting requirements pertaining to the Below Grade Piping Program will be incorporated into this and future North Slope Charter Corrosion Reports.

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

2.0 SIGNIFICANT ENHANCEMENT TO CORROSION PROGRAMS

Linear array continues to be a valuable tool for evaluation of corrosion damage in large diameter cross-country water injection lines.

The field-wide pigging program was enhanced by standardizing on the use of brush/disk pigs, monitoring of total suspended solids, and monitoring of biocide application with residual measurements.

The number of below-grade piping circuits excavated was roughly tripled from 2004 to 2005 because of a revised risk assessment of the below-grade piping circuits.

Rope Access Technology (RAT) was added to the Corrosion inspection capabilities to allow the examination of difficult-to-reach areas in piping that would otherwise require extensive scaffolding.

The amount of tangential radiographic (TRT) inspection coverage was increased at weld packs where "medium" water is found at the 6 o'clock (bottom-of-pipe) position to include a minimum of an additional 12 o'clock inspection; a 360-degree inspection is performed where possible.

3.0 Program Status Summary - Kuparuk

3.1 Year 2005 Overview

3.1.a Kuparuk Monitoring & Mitigation

In 2005 we had several significant accomplishments:

- Tested two new corrosion inhibitor formulations and placed one new corrosion inhibitor in a larger scale test.
- Enhanced the maintenance pigging program for the water injection system at CPF-2 using multiple pig runs, improved biocide treatments, and total suspended solids monitoring.
- Deferred commingling of waters at CPF3 based on lessons learned from the 2K WI spill.
- Moved data reporting for the coupon monitoring system from an MS Access based reporting system to an Oracle based reporting and tracking system for ease in future analysis.
- Enhanced the pump performance at selected drill sites to increase consistency of chemical inhibition.

Average general and pitting coupon corrosion rate data for Year 2005 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	55	0.05	55	100
Seawater Cross-Country Lines	2	7.3	1	50
Mixed Water Injection Cross-Country Lines	24	0.5	24	100
Production Well Flow Lines	501	0.2	495	99
Water Injection Well Flow Lines	388	0.8	358	92

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	55	2.6	52	95
Seawater Cross-Country Lines	2	7.4	2	100
Mixed Water Injection Cross-Country Lines	24	19.5	15	63
Production Well Flow Lines	501	2.9	478	95
Water Injection Well Flow Lines	388	14.6	243	63

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

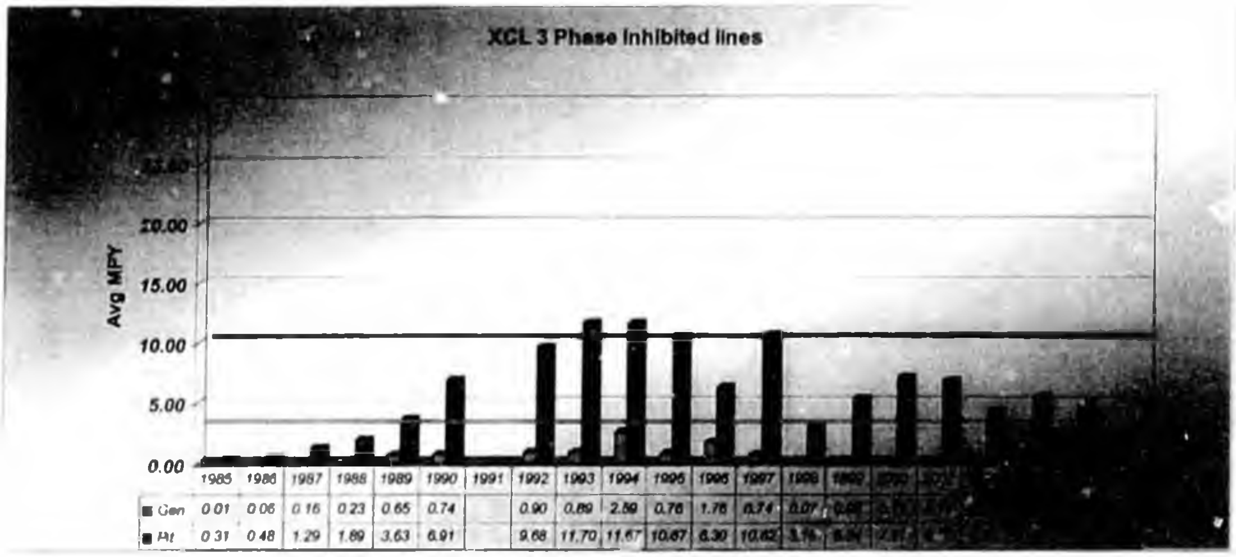

Figure 1. Three-phase Production Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

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

Recurring CRM inspections also support the conclusion that corrosion is under control in the three-phase production cross-country lines. In 2005, 419 corrosion-rate monitoring (CRM) inspections were conducted, with one minor increase found. Other internal inspection data supporting the CRM data are discussed in section 3.1.c, below.

Where corrosion rates exceeded targets, corrosion inhibitor concentrations were increased and/or the amount of inspection was increased. In 2005, coupon, probe or inspection-based corrosion rates exceeded targets or revealed increased damage on eight lines. In 2005, inspection results indicated minor corrosion had occurred in four of these eight lines. A complete listing of the lines with coupon/probe corrosion rates that exceeded targets and/or where inspection indicated increased damage is given in Table 3.

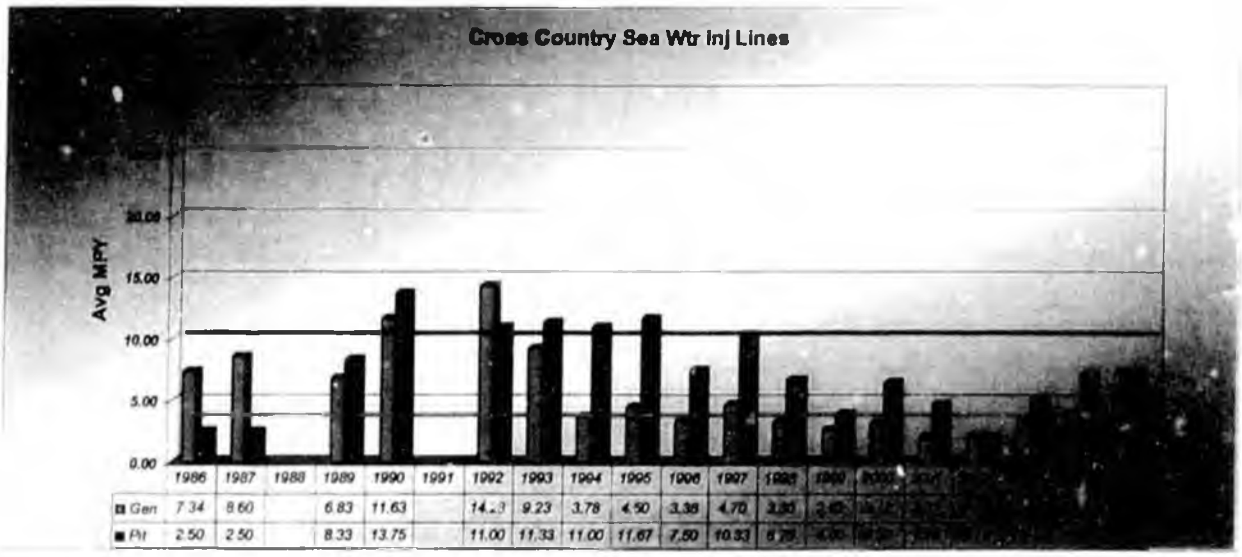

Figure 2. Seawater Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Sea Water Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 2 above, show the average corrosion rates for the sea water cross-country line coupons. Higher coupon corrosion rates were caused by higher dissolved oxygen concentrations seen during 2005 break-up and oxygen scavenger was added to decrease the dissolved oxygen concentration; these coupons are located near the exit of the sea water treatment plant (STP) and are not believed to be indicative of corrosion in the sea water injection system. Increased coupon corrosion rates detected are currently under review, with biocide concentration and pigging frequency increased in early 2006. Smart pigging of the 30-inch sea water line from the STP to the CW Skid is planned for 2006.

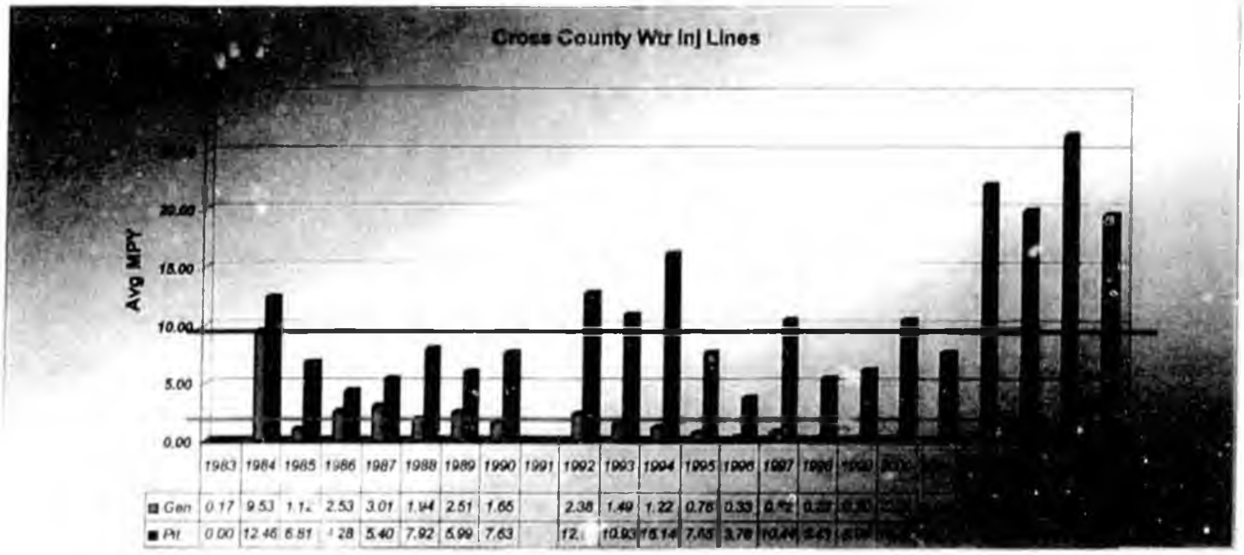

Figure 3. Water Injection Cross-Country Line Coupons – general and pitting corrosion rates as a function of time.

Water Injection Cross-Country Lines: The monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figure 3 show that average general corrosion rates are below the threshold, but that pitting rates for the field are above the threshold. Seawater and produced water commingling was suspended at CPF2 in August 2005 and coupons replaced then; coupons were retrieved from CPF2 in late November with pitting rates reduced markedly from previous pulls. Coupon results are used to prioritize inspection efforts. During 2005 additional equipment was installed and procedures were implemented to provide enhanced biocide treatments at CPF2. Cleaning pigs were upgraded to include brushes in addition to the disks and the pigging procedures changed to included multiple (three) pig runs per monthly cleaning cycle.

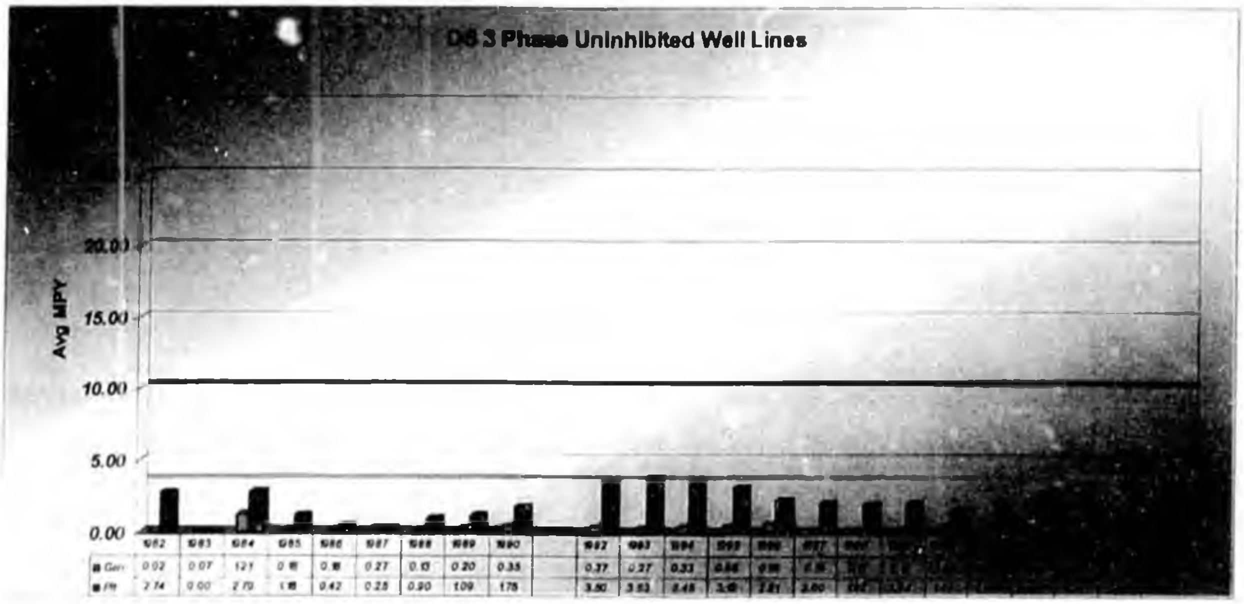

Figure 4. Three-phase Production Well Line Coupons – general and pitting corrosion rates as a function of time.

Three-phase Production Well Flow Lines: While the monitoring data summarized in Kuparuk Tables 1 and 2 and presented in Figures 4 and 5 suggest that corrosion rates are below targets, inspection data indicate that higher corrosion rates have been experienced historically. The well line inspection data are discussed in section 3.1.b below, and are a good example of why monitoring data alone cannot be relied upon to characterize corrosion in a given system. For three-phase production, coupons monitor free flowing fluid and have not shown the predominant, under-deposit corrosion mechanism.

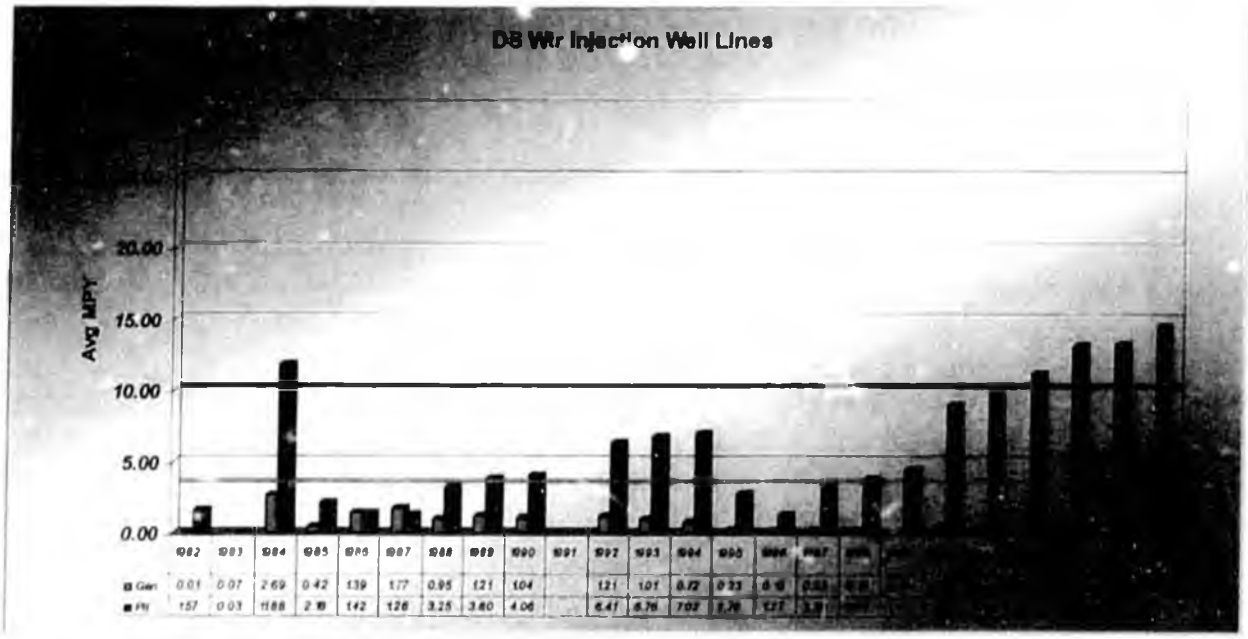

Figure 5. **Water Injection Well Line Coupons – general and pitting corrosion rates as a function of time.**

Water Injection Well Flow Lines: As discussed in section 3.1 b below, the well line inspection data on water injectors show that there are a significant number of corrosion related repairs The water feeding this system is treated at the facilities with biocide and is discussed under Figure 3 - Water Injection Cross-Country Line Coupons. We believe that the increasing trend of coupon corrosion rates in the water injection well lines is caused by additional solids accumulating in the well lines because of low flow rates and improved pigging upstream of the well lines.

Mitigation:

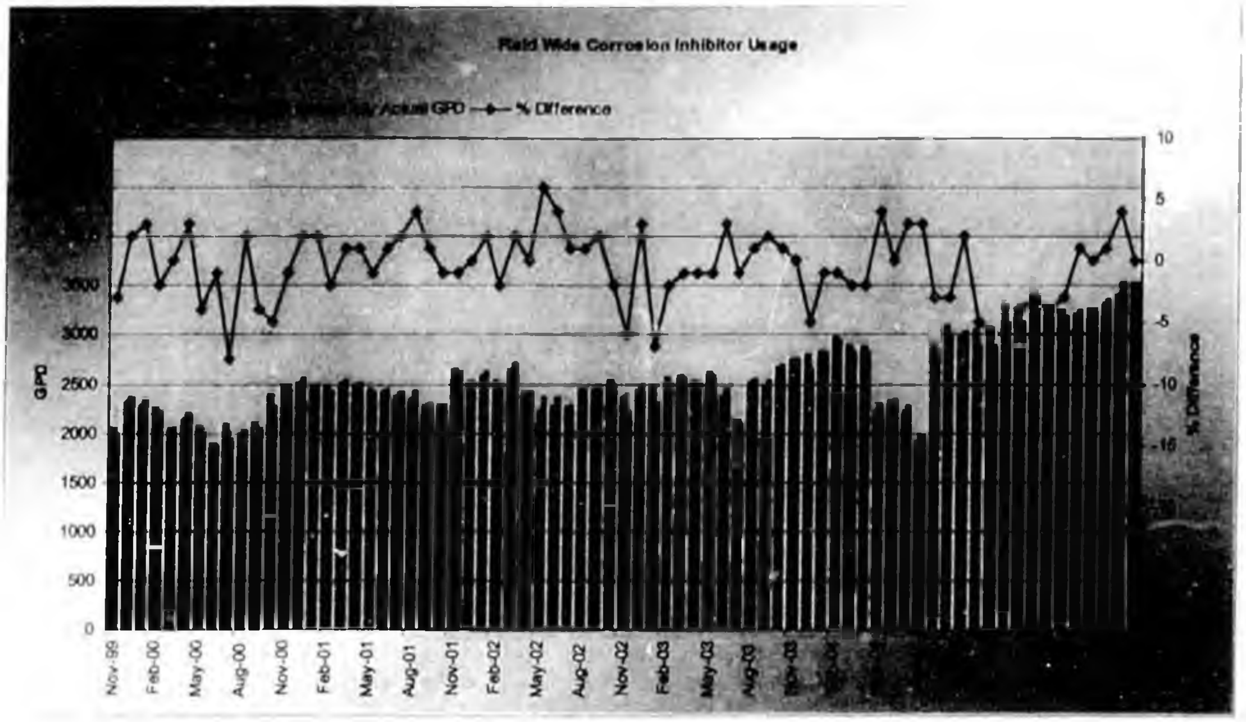

Figure 6. Field-wide Corrosion Inhibitor Use.

For the Kuparuk field, Figure 6 shows the actual number of gallons of corrosion inhibitor pumped per day, the recommended (target) number of gallons of corrosion inhibitor per day, and the percent difference between the two. The average deviation for the year was -1.85%. The large variation seen in the early parts of the year are usually caused by the extreme weather. Several pump upgrades were accomplished in 2005 to accommodate increased volumes.

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

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

Common Line	Probes	Coupons	Inspection	Action Taken
1DPO		x		Increased Target PPM
1EPO			x	Increased Target PPM
1LPO			x	Increased Target PPM
2APO			x	Increased Target PPM
2UPO				Reduced for Baker RE-5273 Test
2VPO				Reduced for Baker RE-5273 Test
2WPO				Reduced for Baker RE-5273 Test
2ZPO			x	Increased Target PPM
3NPO		x		Increased Target PPM
3OPO		x		Increased Target PPM
3QPO		x		Increased Target PPM

Kuparuk Inhibitor Feedback System

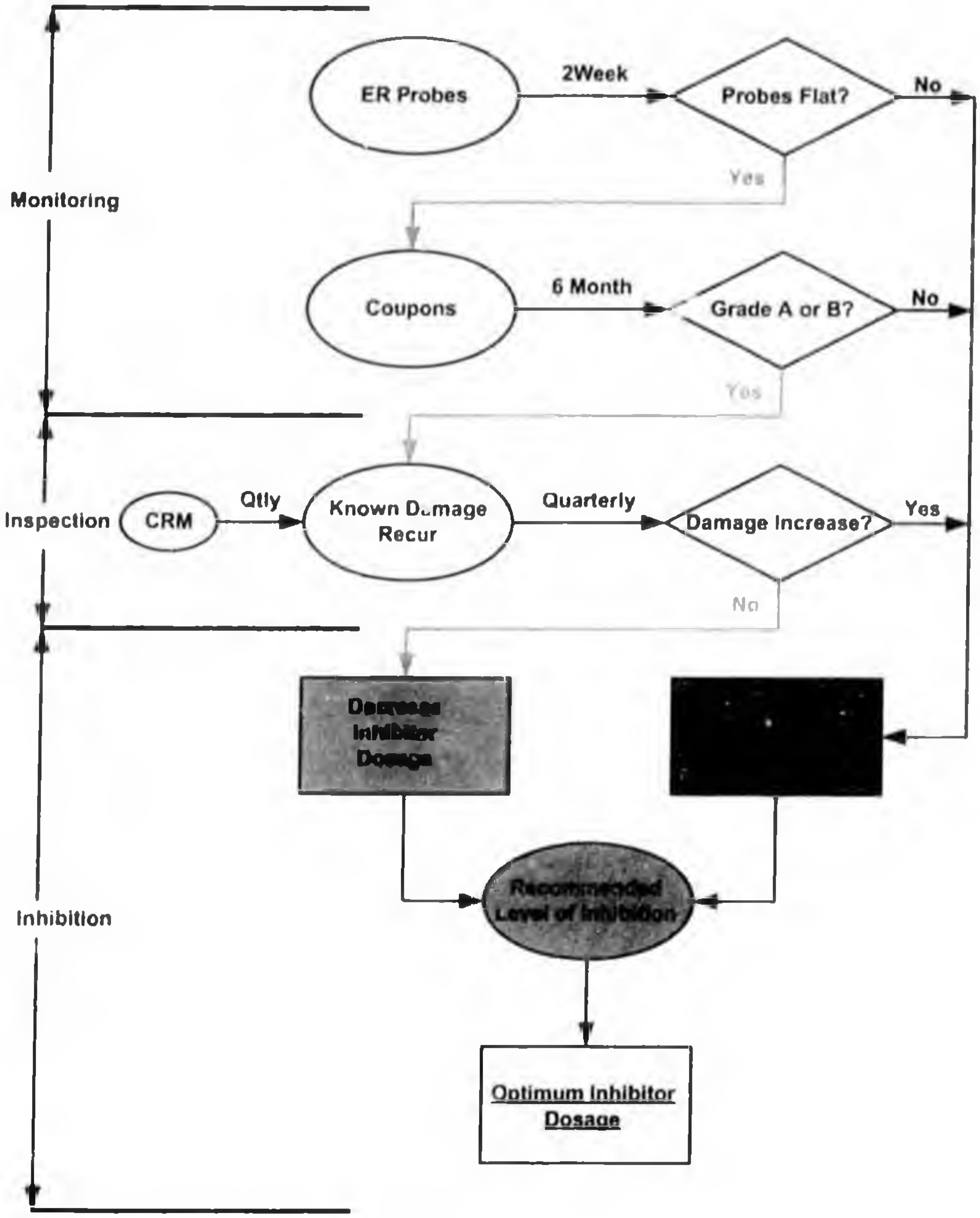

Figure 7. Corrosion Inhibitor Feedback System.

3.1.b Well Line Inspection

We met our primary 2005 goal by completing interval surveys on 133 well lines.

As indicated in Figure 8 below, repair recommendations were initiated on 18 well lines in 2005 because of internal corrosion or erosion damage (11 corroded water injection lines, 6 corroded production lines and 1 eroded production line). Except for the leak that was caused by erosion, the corrosion mechanisms were all underdeposit corrosion. More information on the leaks can be found in section 3.1.g.

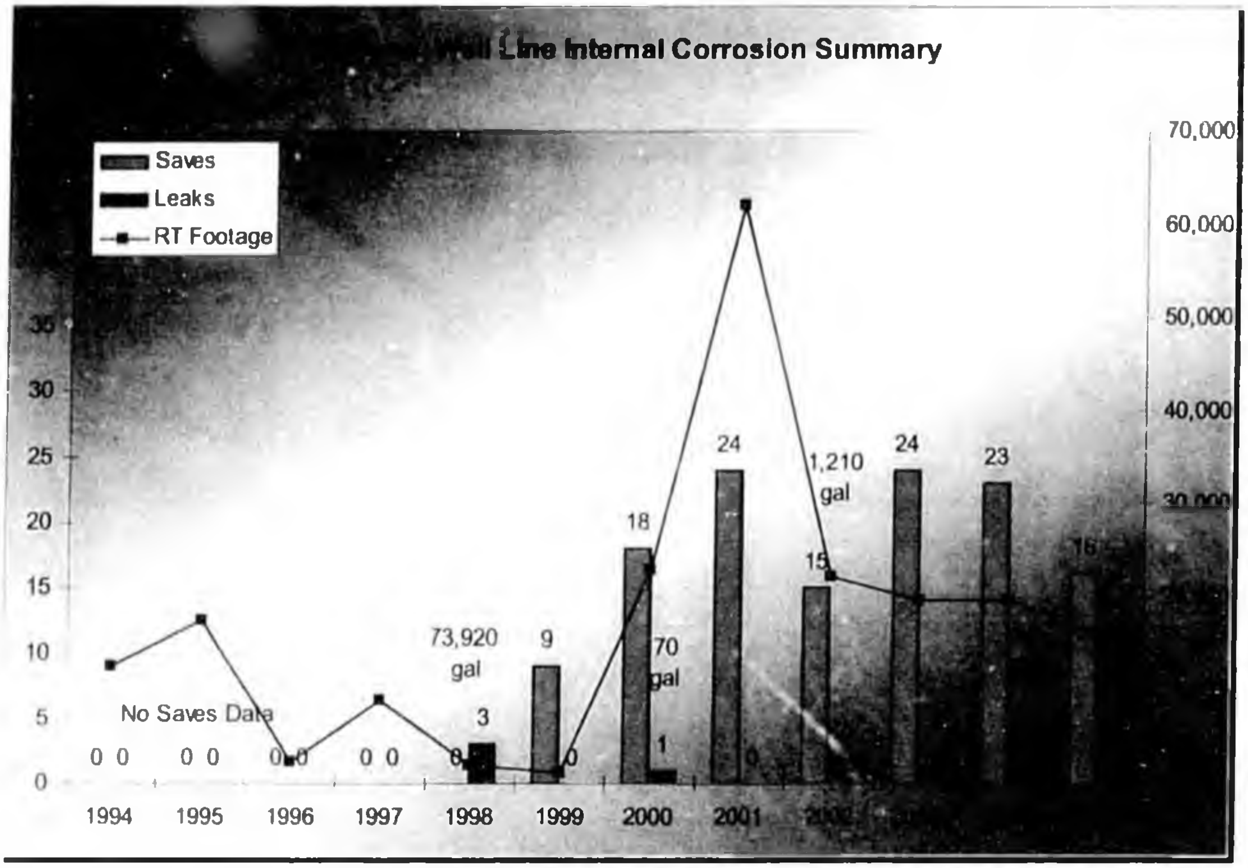

Figure 8. Summary of Well Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2005 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables.

- **RTR of Well Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	8,980	77
Water Injection	5,379	56
Total	14,359	133

The 2005 RTR well line data indicated no new damage trends.

- **Manual RT of Well Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% Of Repeat Radiographs with Increases
Three-phase Production	199	942	311	20	6
Water Injection	120	798	180	35	19
Total	319	1,740	491	55	11

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

- **Manual UT of Well Lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	167	894	769	53	7
Water Injection	65	296	253	31	12
Total	232	1,190	1,022	84	8

The 2005 manual UT well line data indicate a possible increasing damage trend in the water injection well lines. The percentage of radiographs showing increased damage increased from 8% to 12% from 2004 to 2005.

3.1.c Cross-Country Line Inspection

In 2005 we met our primary cross-country line goals by completing:

- Interval surveys on 33 cross country lines and
- An "On-pad Deadleg Inspection Survey" at all drill sites.

As indicated in Figure 9, 12 repair recommendations were initiated on cross-country lines (8 water injection, 4 production) because of internal corrosion damage in 2005. The corrosion mechanism for all repair recommendations was deadleg/underdeposit corrosion. All three leaks were in the water injection system. More information on the leaks can be found in section 3.1.g.

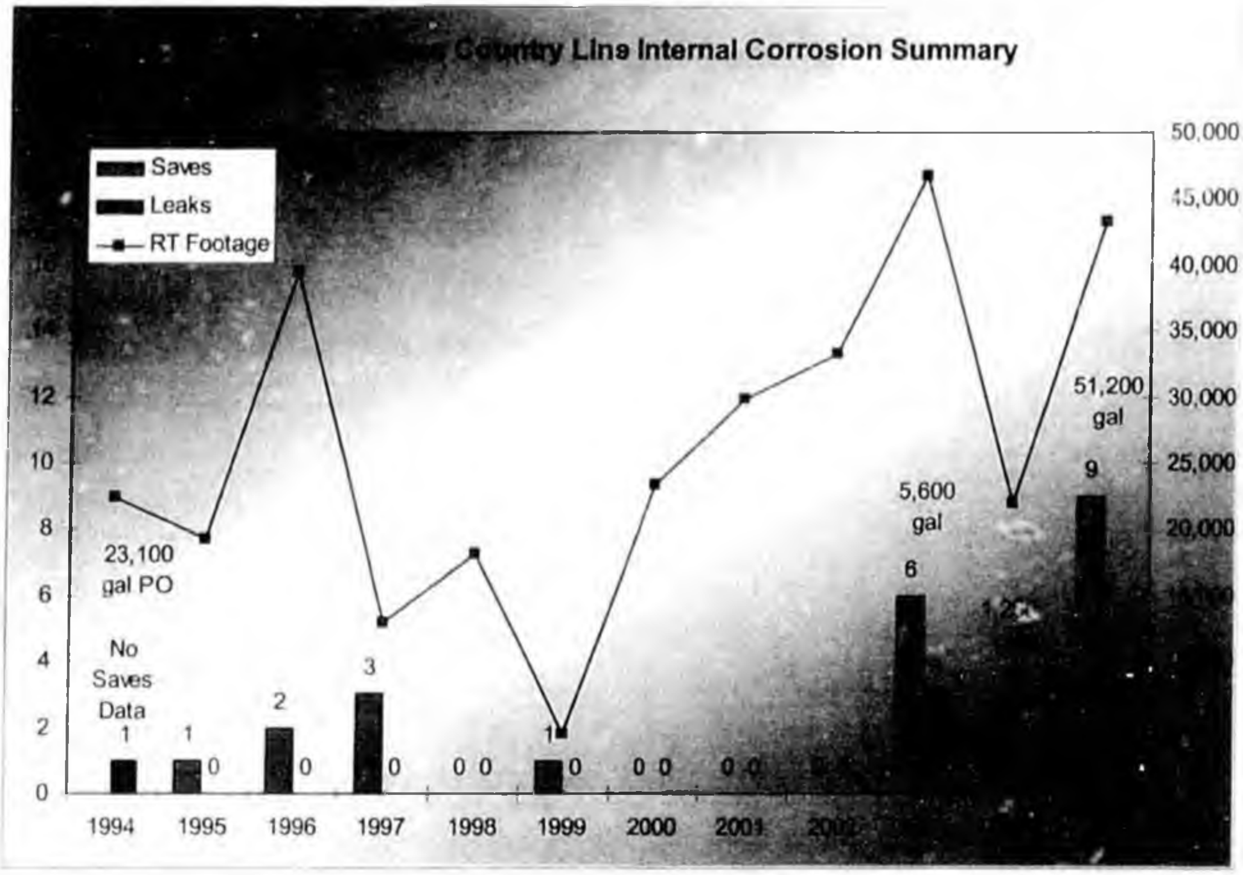

Figure 9. Summary of Cross-Country Line Internal Corrosion Inspections – RT footage, leaks, and saves as a function of time.

The 2005 results from the RTR surveys, manual RT, and manual UT are summarized in the following three tables:

- **RTR of Cross Country (CC) Lines:**

Service	Feet Inspected	Number of Lines Inspected
Three-phase Production	6,067	8
Water Injection	28,267	25
Total	34,334	33

The 2005 RTR CC line data show an increase in the footage and number of lines inspected. This is a result of the failure analysis of the DS2K water injection line leak in 2005.

- **Manual RT of CC Lines:**

Service	Number of Lines Inspected	Number of Radiographs	Number of Repeat Radiographs	Number of Repeat Radiographs with Increases	% of Repeat Radiographs with Increases
Three-phase Production	115	3,274	533	21	4
Water Injection	52	5,633	70	8	11
Total	167	8,907	603	29	5

The only significant change in these data from 2004 to 2005 was that the 2005 RT CC water injection line data inspection results decreased in the percentage of radiographs indicating increased damage from 27% in 2004 to 11% in 2005; however, the 2004 RT inspection data had a small sample size and we believe that the larger 2005 sample size is more indicative of what is happening in the CC water injection system. In addition, the number of radiographs on water injection system increased and the number of repeat inspections increased due to the DS2K WI line failure analysis.

- **Manual UT of CC lines:**

Service	Number of Lines Inspected	Number of UT Inspections	Number of Repeat UT Inspections	Number of Repeat UT Inspections with Increases	% Of Repeat UT Inspections with Increases
Three-phase Production	64	950	378	20	5
Water Injection	39	414	101	21	21
Total	103	1,364	479	41	9

The only significant change in these data from 2004 to 2005 was that the 2005 UT CC water injection line data indicate an increasing damage trend. The percentage of repeat inspections indicating increased damage jumped to 21% in 2005 from 5% in 2004. In addition, the number of inspections on the water injection system increased and the number of repeat inspections increased due to the DS2K WI line failure analysis.

3.1.d External (Weld-Pack) Program

In 2005 we had several significant accomplishments:

- Completed 4,646 TRT surveys of cross country line and well line weld packs due for recur inspection.
- Completed our goal of inspecting 100 additional Tarn-style weld packs (~257 to date) to ensure this new design is working properly. The weld pack design appears to be performing as planned. No corrosion has been detected.
- Inspection of 100 refurbished weld packs to verify the soundness of the Denso Tape refurbishments. The refurbishment technique appears to be performing as planned.

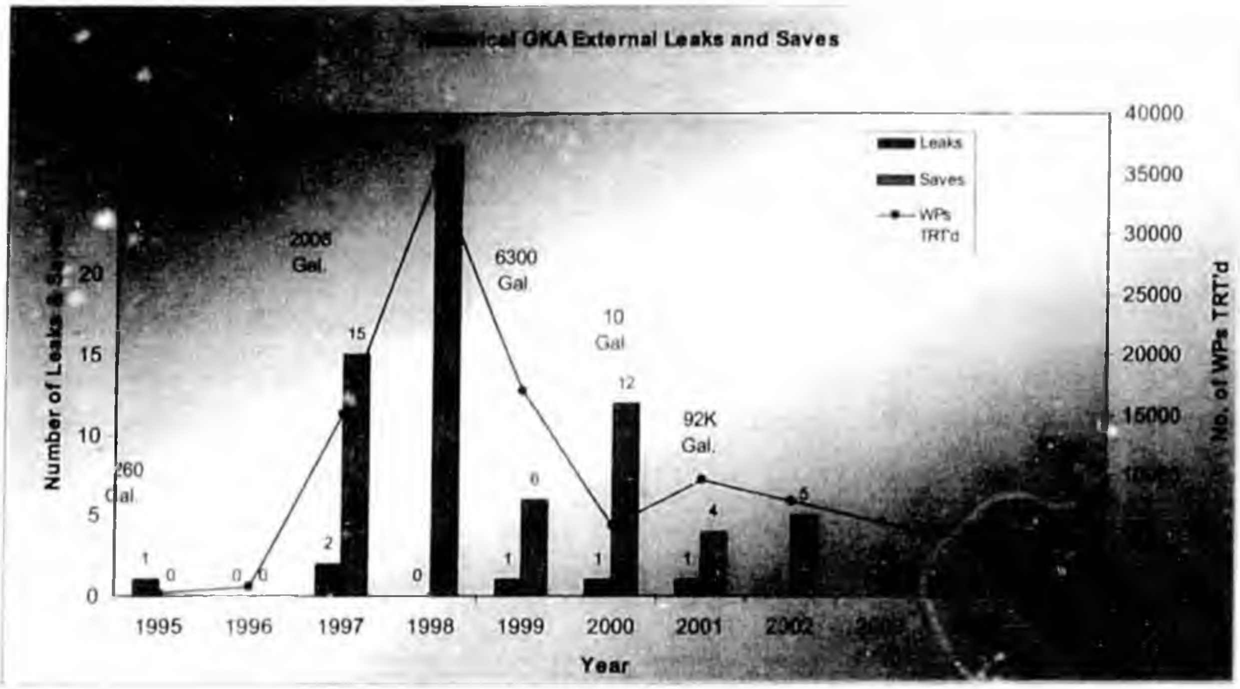

Figure 10. Leaks, saves, number of weld packs inspected with TRT, and volumes of leaks as a function of time.

Cross-Country Lines (On-Pad and Off-Pad)

The baseline inspection effort for all cross-country lines was completed in 2004. Starting in 2005, the focus changed from making sure that all CUI locations were inspected and included in our inspection program to one of recur inspections priority-based on corrosion risk. A goal of 4,250 CUI locations on cross-country lines over tundra (off-pad) and on-pad was set. A total of 3,299 CUI locations were inspected. The goal was missed mainly because of lost TRT crew time spent on special projects such as follow-up work related to the DS2K WI and DS3J PO leaks. An estimate of the number of CUI locations was generated at the beginning of the year. The actual number of CUI locations turned out to be less than the estimate. Lastly, fewer weld packs were inspected late in the year after the TRT inspection guideline was modified as a result of the enhanced inspections related to the findings from the DS3J PO leak. The new guideline involves inspection at the pipe 6 o'clock position as before, and has been expanded to include a minimum of an inspection at 12 o'clock (the top of the pipe) if medium or heavy water is detected at the 6 o'clock position.

A total of 103 locations on the over-tundra lines were found with corrosion. One location required installation of a temporary sleeve (DS3K PO). A total of 94 cross-country on-pad locations were recur inspected in 2005 using TRT. Only one location (DS3J PO near leak) was found to have corrosion; it was placed on the refurbishment list.

Included in the 3,299 TRT inspections noted above, 157 of the new Tarn-style weld packs were inspected with TRT to gauge how they are holding up in service. A total of six weld packs were found with light-wet insulation. The rest were found to be completely dry. No corrosion under insulation (CUI) was found in any of the areas inspected.

External corrosion at on-pad CUI locations was also found while doing other inspection or maintenance work. This effort resulted in two sleeve repairs (CPF1 MI, 2KHWI @ DS2B).

A change in the way external corrosion locations will be reported was started in 2005. In the past, CUI locations in support saddles over a VSM were counted as one location. This report, and all future reports, break each support saddle location into two distinct pieces with the VSM centerline as the dividing point. The motivation behind this change was to aid in the layout and recur inspections at these locations. This will affect the total reported number of CUI locations by essentially doubling the number of CUI locations associated with saddles.

Well Lines

In 2005, 1,347 well line CUI locations were examined. Our stated goal was 1,500 weld packs (based on inspection of seven lines); the reason for the underestimate in the number of weld packs is the uncertainty in the total count of the well line CUI locations before inspections commenced. The number of CUI locations is estimated based on the length of a typical section of pipe. Corrosion was found at 46 of the 1,347 locations. No piping repairs were required. The corroded weld packs were refurbished.

Table 5: External CUI Inspection Summary for 2005.

Type of Equipment	2005 Goal	Number of Locations Inspected	Number of Corroded Locations	Percentage of Locations Corroded	Number of Locations Refurbished
Cross-Country Lines Over Tundra or On-Pad	4,250	3,299	103	3.1	953
Well Lines	1,500	1,347	46	3.4	58
Total	**5,750**	**4,646**	**149**	**3.2**	**1,011**

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

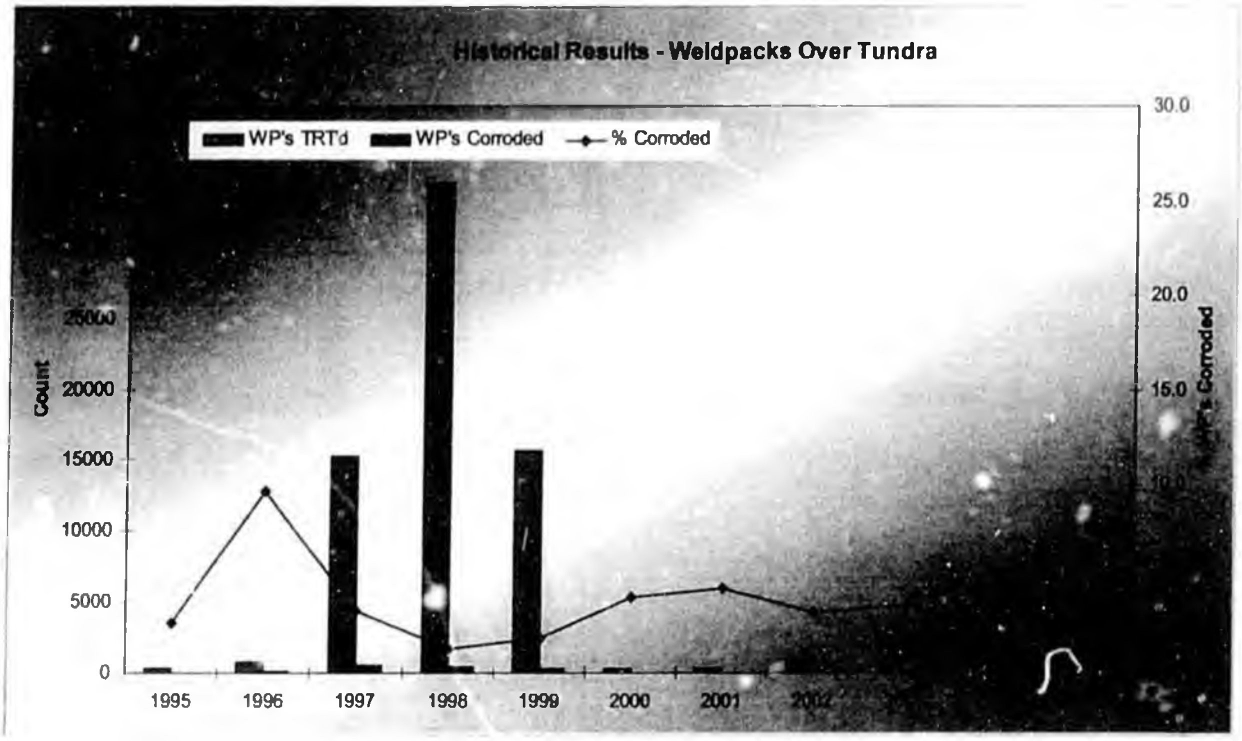

Figure 11. Summary of Weld Packs on Cross-Country Lines over Tundra (off-pad).

Figure 11 illustrates the most-complete external corrosion inspection program of the three external corrosion programs. 2002 through 2005 values include re-inspections and clean-up of locations missed or not properly documented during the original base line effort.

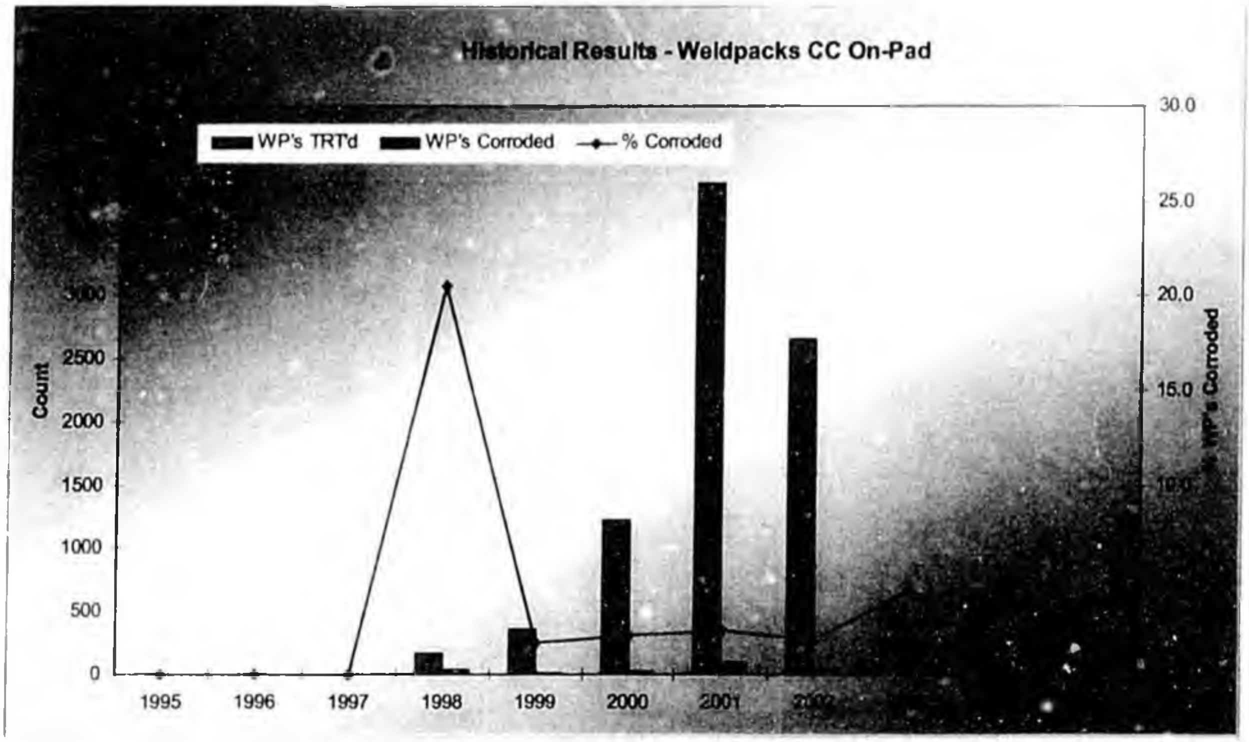

Figure 12. Summary of Weld Packs on Cross-Country Lines on Pads.

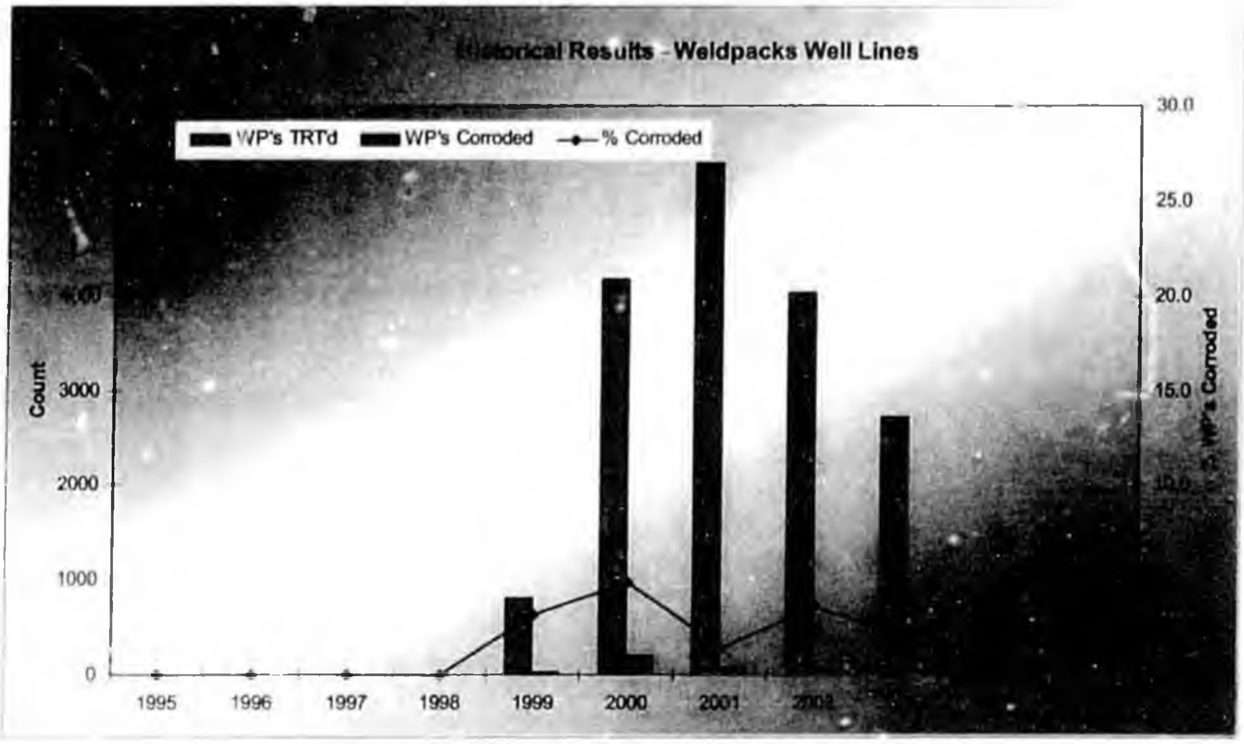

Figure 13. Summary of Weld Packs on Well Lines.

Corrosion Under Insulation Buffer Spike Program

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

The program was expanded later in 2002 by an additional 39 locations to include weld packs on drill site well and facility piping. In addition, two electric resistance probes were installed in two heavy water weld packs at DS1E to monitor potential corrosion activity. The sodium phosphate salt contained in these spikes dissolves in wet insulation and raises the pH to 10. Prior to installation of these spikes, wet insulation measurements fell within a consistent 6 to 7 pH range. During 2003, each of these locations was monitored for pH. The 2003 follow-up inspections showed that the pH did rise in the wet areas of the weld packs. Three locations were also stripped and tested with an indicator dye to verify the pH probe results.

TRT inspections of the buffer spike locations were performed during 2005 and early in 2006. All locations were re-inspected. Seven weld packs indicated an increase in the water content. None of the inspections reported any new corrosion. The survey revealed that 19 of the locations had been inadvertently refurbished. Visual inspection of the exposed pipe in these locations discovered very slight external corrosion (three-to-four percent wall loss) at three of these locations. It is likely that this minor corrosion was present before the buffer spikes were introduced. Corrosion damage that slight would have been difficult to detect using C-Arm (CTRT), especially with water in the insulation.

A pH survey was conducted during the summer of 2005 to test approximately 60 locations. Testing indicated that the spikes were maintaining an alkaline environment inside of the weld packs. An indicator dye check was conducted on two of the weld packs to verify that the pH profile across the insulation thickness was showing a high alkaline environment at the pipe wall. These tests showed that the buffer spikes were maintaining a high pH close to the pipe.

Monitoring of the ER probes at DS 1E indicated low, but not zero, corrosion rates. These probes collect a reading every six hours and the data are downloaded every two weeks.

The buffer spike concept has been tested over a sufficient timeframe to collect meaningful results. A final report on the project is forthcoming from our Bartlesville research center. Review and discussion of the results shall be conducted and a plan determined in 2006.

3.1.e Below Grade Piping Program

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

In 2005 we had several significant accomplishments:

- Visually inspected and cleaned all debris from all cased below grade pipe circuits.
- Completed our specialty inspection (TWI) scope of work.
- Excavated, inspected, refurbished and repaired (as required) 24 cased below-grade pipe circuits.

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

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

GKA has 772 circuits (includes priority 1, priority 2 and priority 3 lines) of below grade piping. Of these locations, one is contained in an utilidor. The remaining circuits are cased lines, the majority of which are either road, gravel pad or caribou crossings.

Utilidor Line

The line in the utilidor (Oily Waste Injection Line, BG ID #286) was taken out of service in 2004. It had been on a two year inspection cycle and was last inspected in 2002. Because it has been taken out of service the 2004 inspection was deferred and no 2005 inspection was done.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2005. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

Results and Remedial Action:
Of all GKA below-grade circuits, 107 were found to have pipe in direct contact with gravel/soil or debris in the casing. All locations were remediated in 2005.

3.1.e (2) Results of Specialty Testing

Inspection Status:
In 2005, we completed TWI inspections on 127 GKA priority one circuits. This was the third year of our recurring inspection program where each priority one circuit will be inspected at a maximum ten-year interval.

In 2005 only the long-range ultrasonic system technology from The Welding Institute (TWI) was used. TWI technology is capable of finding evidence of both internal and external corrosion damage.

Results and Remedial Action:

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

Table 6. Results from the TWI inspections by service.

Service	Number of Cased Circuits Inspected	Incomplete or Inconclusive Results (I)	Number without any Significant Indications (N)	Number of Minor (Low) Anomalies (L)	Number of Minor to Moderate and Moderate Anomalies (M)	Number of Moderate to Severe and Severe Anomalies (S)
Oil	13	0	8	3	2	0
Other	114	26	47	34	7	0
Total	127	26	55	37	9	0

The 2005 TWI data indicated no new damage trends.

3.1.e (3) Results of Crossing Digs

After a revised risk assessment of the below-grade piping circuits that included water accumulation points, the number of below-grade piping circuits excavated was increased from eight in 2005 to 24 in 2006.

There were 24 below-grade circuits refurbished in 2005. Twenty-three circuits were excavated and one was replaced without excavation (cut and pulled through casing). Four of these circuits were considered repairs:

- Two repairs were made because of CUI damage only (West Trunk EOR at CPF1 and 1HPO at DS 1H pad). The EOR circuit was replaced and the 1HPO circuit was repaired with a pressure containing sleeve.
- One repair was made because of internal damage only (2KWI at 2H pad). This piping circuit was replaced by cutting and pulling the old pipe from the casing and pulling the new pipe into the casing.
- One repair was made because of a combination of CUI and internal corrosion damage (2KHBWI at the 2B pad crossing). This circuit was repaired with a pressure containing sleeve.
- Twenty of the excavated circuits inspected did not require de-rating, repair, or replacement because only minor or no corrosion damage was found.

For all twenty-four below grade circuits excavated in 2005, the insulation was refurbished and the pipe wrapped with Densyl tape to prevent further corrosion.

3.1.f Other Structural Concerns

Subsidence:

Existing Well Upgrade Program

- In 2005, four steel, conductor-mounted floor kits were installed in well houses at Drill Sites 1E, 2A, and 2Z. Well house floors are supported by the well conductor and provide table riser piping supports.
- In 2005, 17 heat tubes were installed at Drill Sites 1E, 2A, 2C, 2H and 3N. Heat tubes are used to keep the ground frozen or to re-freeze the ground where it has been thawed.

New Wells & Producer to Water Injection Well Conversions

- In 2005, 10 newly drilled wells at Kuparuk were installed with insulated conductors.
- In 2005, ten newly drilled wells had heat tubes installed. Of these 10 newly-drilled wells, two had floors with permanent pipe supports.
- In 2005, four existing producers converted to water injection wells or converted to jet pump lift already had insulated conductors and heat tubes and did not require a floor kit.

Wind-Induced Vibration:

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

During original development of the North Slope WIV program, secondary mode WIV failures were deemed highly unlikely and therefore mitigating measures for such events were not established. However, based on the unforeseen December 2004 secondary mode WIV failure on the DS3I 8" GL line, an effort to determine if secondary mode WIV is expected to be a fatigue threat to all the pipelines within the Kuparuk Wind Fan was sanctioned.

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

As a result of these analyses, up to 440 pipe spans will receive secondary mode WIV protection in 2006. More detailed evaluations will be completed once enhancements are completed to the WIV evaluation model to take into account broad-banded WIV events more typical of higher wind velocities.

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

- Well 2A-17 production well line leaked in March 2005 because of erosion in a two inch branch line off of the main six inch line at the 2nd elbow (lower) from the well head. The spill volume was less than one gallon of produced fluids and was confined to the well-house floor. No fluids contacted the tundra or the gravel pad. As such, it was determined to not be an ADEC reportable spill. This location is inspected on a regular basis during our well line interval survey. As a result of this leak all other erosion susceptible areas on this line were inspected and no additional erosion was found.

- Well 1G-09 water injection well line leaked in July 2005 because of a combination of internal under-deposit corrosion and CUI damage at a weld pack located in a saddle. The spill volume was determined to be 13 gallons. The spill was reported to ADEC. As a result of this leak the previous internal and external corrosion inspection records were reviewed. The review indicated that this line and the location of the leak had received regularly scheduled inspections within a time frame which should have detected the damage before the leak. As a result of this finding inspection records for several other lines and locations were reviewed under the inspection contractor's QA/QC program. This review resulted in tighter controls regarding RTR inspections of lines with high solid build-up and more coverage of CUI areas when found to be "Medium Wet."

- Drill site 2K water injection line leaked in March 2005 in the below-grade circuit at DS 2H pad because of internal corrosion damage. The spill volume was determined to be 51,198 gallons. The spill was reported to ADEC. As a result of the leak, a formal Failure Analysis that included ADEC and BP representatives was completed on this incident. Several enhancements to our monitoring, inhibition and inspection programs have been initiated based on this report.

- Drill site 2H warm-up line leaked in April 2005 under the 2H manifold building because of internal under-deposit corrosion in a dead-leg. The spill volume was less than one gallon of produced water confined to the pipe surface and the snow on top of the gravel pad. As such, it was determined not to be reportable to ADEC. This location was scheduled to be inspected under our "On-pad Deadleg Inspection Survey" in 2005. Unfortunately the leak occurred before our crews inspected it. We are confident that the damage would have been detected, and the location repaired before the leak, under our current inspection methods and procedures if the location had been scheduled earlier in the year. It should be noted that inspection of all piping similar to this at all drill sites was completed in 2005.

- Drill site 2U warm-up line leaked in December 2005 under the 2U manifold building. The same comments as noted in 2H (directly above) apply to this leak.

- The DS3J produced oil line leaked in October 2005 because of external corrosion at a weld pack located partially in a saddle. The spill of 16 gallons of produced fluids was reported to ADEC. There were three perforations in the weld pack area, with the heaviest corrosion located near the top of the pipe. Corrosion was noted around the entire circumference over two feet of the five-foot corrosion network. The 6 o'clock position of this particular location had been scanned with C-arm TRT (CTRT) in 2001 and determined to have no corrosion. CTRT is not strong enough to inspect the pipe through the saddle so the location would have been scanned right up to the saddle and then picked up again on the other side. The weld pack had been labeled as having CTRT inspection only. This failure has led the Corrosion Department to re-evaluate several aspects of its external corrosion program. Specifically, the layout and labeling guidelines have been reviewed and updated to assure that a CUI location will not be missed. Additionally, the weld pack inspection guidelines have been updated to include inspection of the upper portion of the pipe when medium or heavy wet insulation is detected at the six o'clock position or when a penetration exists in the outer jacket up high on the pipe (e.g., a branch connection, tear, etc.).

- No leaks were caused by subsidence in 2005.

Figures 8, 9, and 10 show the number of leaks and the volumes of leaks as a function of time. Figure 8 depicts the leaks caused by internal corrosion for the well lines. Figure 9 depicts the leaks caused by internal corrosion for the cross-country lines. Figure 10 shows the leaks caused by external corrosion for cross-country lines, well lines, and below-grade piping locations.

3.2 Year 2006 Forecast

3.2.a Monitoring & Mitigation

- Test additional inhibitor formulations.

- Continue to evaluate the biocide program and the maintenance pigging enhancements to the water injections systems.

- Increase biocide and maintenance pigging in the seawater system.

- Expand guideline for use of brush / disk combo cleaning pigs to CPF1 and CPF3.

3.2.b Well Line Inspection

Our recurring inspection program will continue in 2006. No in-service line will go longer than 10 years without some type of inspection.

3.2.c Cross-Country Line Inspection

Our recurring inspection program will continue in 2006. No in-service line will go longer than 5 years without some type of inspection.

Smart pigging is planned for the 30-inch sea water line from the STP to the CW skid.

3.2.d External (Weld-Pack) Program

Cross-country lines over tundra:

- Inspect approximately 3,950 cross-country line weld packs (based on seven lines) as part of our recurring inspection program. This includes CUI locations over tundra as well as on-pad.
- Inspect a minimum of 100 Tarn-style weld packs (insulation not touching the pipe) with TRT to continue to evaluate the efficacy of the design
- Inspect a minimum of 100 refurbished weld packs to continue to evaluate the performance of the Denso tape system.

Well lines:
Inspect approximately 1,500 well line corrosion-under-insulation locations (based on 130 lines) as part of our recurring inspection program.

3.2.e Below Grade Piping Program

- Continue our annual visual inspection of all (Priority 1, 2, and 3) cased lines. The appropriate GKA field department will be notified of any corrective actions early enough to complete clean out and re-inspection during the summer.
- Continue our recurring TWI inspection program of priority one cased lines.
- Excavate, inspect, refurbish, and repair (as necessary) fifteen to twenty-seven lines in cased crossings.
- Continue to work with TWI and ConocoPhillips R&D to refine inspection data reduction and interpretation.

3.2.f Other

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

4.0 Program Status Summary - WNS

4.1 Year 2005 Overview

4.1.a WNS Monitoring & Mitigation

Average general and pitting coupon corrosion rate data for Year 2005 are presented in Tables 7 and 8.

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

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average General Corrosion Rate, mpy (target=<3)	Number of Lines with Conformant General Corrosion Rates	Percent of Lines with Conformant General Corrosion Rates
Three-phase Production Cross-Country Lines	1	0.1	1	100
Seawater Cross-Country Lines	1	2.4	1	100
Seawater Injection Cross-Country Lines	0			
Production Well Flow Lines	29	0.5	28	96*
Seawater Injection Well Flow Lines	9	0.1	9	100

* *The one line with greater than 3 mpy CR was due to erosion*

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

Asset Group	Number of Lines with Coupons Analyzed	Coupon Average Pitting Corrosion Rate, mpy (target=<10)	Number of Lines with Conformant Pitting Corrosion Rates	Percent of Lines with Conformant Pitting Corrosion Rates
Three-phase Production Cross-Country Lines	1	2	1	100
Seawater Cross-Country Lines	1	1	1	100
Seawater Injection Cross-Country Lines	0*			
Production Well Flow Lines	29	1.8	28	96
Seawater Injection Well Flow Lines	9	4.7	9	100

* *NOTE: This coupon location is currently not accessible because of a new piping obstruction.*

4.1.b Well Line Inspection

In 2003, 33 three-phase production lines and 22 water injection lines were inspected; no damage was found.
In 2004, 18 three-phase production lines were inspected at direction changes; no damage was found.
In 2005, 32 well lines were inspected, no damage found.

4.1.b Cross-Country (CC) Line Inspection

2,900 ft of the CD2 produced crude CC line was inspected with RTR. No damage was identified.

4.1.d External (Weld-Pack) Program

No inspections for external corrosion were performed.

4.1.e Below Grade Piping Program

This section details the inventory and survey of below grade locations and the results of Specialty Testing. The plans for future inspections are given in section 4.2.e.

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

CPAI has 15 locations of below grade piping in the WNS, and 30 associated with WNS at GKA. These locations are cased lines at road or pad crossings.

Cased Lines

Inspection Status:
The annual visual survey of all the cased lines was conducted in 2005. The purpose of the survey was to identify, rectify, and report local conditions (e.g., debris found in casings and culverts, pipe insulation in contact with soil) that require remedial action.

Results and Remedial Action:
Of all the below-grade lines, two lines were found to have pipe in direct contact with soil and/or gravel/soil or debris in the casing. These two lines are considered to be "direct buried". Locations were excavated, evaluated and a request for waiver, contingent on a stringent inspection program, has been submitted to ADEC. The next inspection of the buried portions will be in 2009.

4.1.e (2) Results of Specialty Testing

No specialty testing was performed in the WNS in 2005. Of the 45 WNS below grade circuits, 10 are smart pigged with the remainder of the line. The remaining circuits will be inspected with TWI at their 10 year (max) interval even though they are externally coated.

4.1.e (3) Results of Crossing Digs

Two lines were excavated and are referenced in Results and Remedial Action above.

4.1.f Other Structural Concerns

Subsidence:

- No concerns identified.

Wind-Induced Vibration:

No problems identified in 2005.

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

- No leaks were caused by external corrosion in 2005.
- No leaks were caused by wind-induced vibration in 2005.
- No leaks were caused by internal corrosion in 2005.
- No structural or subsidence concerns were identified in 2005.

4.2 Year 2006 WNS Forecast

4.2.a Monitoring & Mitigation

- Pull coupons as scheduled
- Ensure new drill site development provides for adequate monitoring.

4.2.b Well Line Inspection

Inspect 15 lines, 15% of existing total for internal corrosion.

4.2.c Cross-Country Line Inspection

Obtain spot RT of CD1 PC line (on pad).

4.2.d External (Weld-Pack) Program

Cross-country lines over tundra:
No inspections planned.

Cross-country lines on pad:
No inspections planned.

Well lines:
TRT most likely locations for CUI on 20 lines.

4.2.e Below Grade Piping Program

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

4.2.f Other

Continue Alpine piping layout and piping information database development.

APPENDIX A
Glossary

Equipment Classification:

- **Well Line** – Pipe from the wellhead to the Drill Site manifold. For production wells, a well line handles the flow from a single well prior to commingling with fluids from other wells and transportation to the Central Processing Facility. For water injection wells, a well line handles the water flow going from a common manifold to a single wellhead.
- **Cross-Country Line** - Pipe from the Drill Site manifold to the Central Processing Facility (CPF).
- **Below-Grade Location** – That portion of a single pipeline, which crosses underneath a road or other earthen feature at a single location. The linear extent of the location consists of the length of pipeline between casing ends.

Service Definitions:

- **Three-phase Production** – Basic reservoir fluids (oil, water, and gas) produced from down hole through to the CPF. Typically sees changes in temperature and pressure only from reservoir changes and are essentially un-separated.
- **Seawater (SW)** – Water from the Beaufort Sea that has been treated at the Seawater Treatment Plant (STP). Note that seawater treatment at the Kuparuk STP consists of filtration, oxygen stripping using produced gas, and biociding.
- **Produced Water (PW)** – The water separated at the CPF from three-phase production
- **Mixed Water (MW)** – Produced water and seawater that have been commingled.
- **Gas** – Generic term for the different gas systems that transport dry (no liquids) gas between facilities. Includes fuel gas, artificial lift gas, and miscible Injectant.
- **Produced Oil** – The liquid hydrocarbon separated at the CPF from three-phase production

Inspection Terminology:

- **CRM** – Corrosion rate monitoring.
- **UT**- Ultrasonic testing
- **RT** – Radiographic testing
- **RTR** – Real time radiographic testing
- **TRT** – Tangential radiographic testing
- **PTI** – Profile Technologies Inc. (Electro magnetic inspection)
- **TWI** – The Welding Institute (Long range UT)\
- **KDR** – Known damage recur inspection
- **Leak** – Through-wall pipe damage that causes loss of product. Product volume may not be sufficient to be classified as a "spill".
- **Save** – When the Corrosion Group recommends a repair before a leak occurs.
- **Below Grade (priority 1)** – These are pipes with a higher probability and consequence of failure. In general they have larger diameters and higher pressures and would probably cause damage to the environment or cause safety concerns if they leaked.
- **Below Grade (priority 2)** – These are pipes with a lower probability or consequence of failure. In general, these have smaller diameters and lower pressures and would probably cause little, if any, environmental damage or safety concern if they leaked. Examples include un-insulated dry gas lines and flare lines.
- **Below Grade (priority 3)** – These are pipes with a low probability and consequence of failure. Examples include decommissioned pipes, pipes in fresh or fire water service and pipes constructed of corrosion resistant materials. In addition, they contain product that would cause little, if any, environmental damage or safety concern the pipe leaked.