PHILLIPS Alaska, Inc.
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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
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Table of Contents

4.3 Inspection

a. Techniques
   i. Manual Radiography (RT)
   ii. Real Time Radiography (RTR)
   iii. Tangential Radiography (TRT)
   iv. Ultrasonics (UT)
   v. Corrosion Rate Monitoring (CRM)
   vi. Below Grade Piping Specialty Inspection Techniques

b. Schedules

4.4 Mitigation - Chemical Inhibition

a. Optimization

4.5 Maintenance Pigging

a. Crude Gathering Lines
b. Wet Oil Lines
c. Produced Water Lines
d. Sea Water Lines
e. Mixed Water Lines

4.6 Data Management

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

a. Monitoring & Mitigation
b. Well Line Inspection
c. Cross-Country Line Inspection
d. External (Weld-Pack) Program
e. Below Grade Piping Program
f. Spills/Incidents

6.2 Year 2001 Forecast

a. Monitoring & Mitigation
b. Well Line Inspection
c. Cross-Country Line Inspection
d. External (Weld-Pack) Program
e. Below Grade Piping Program
f. Other

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).

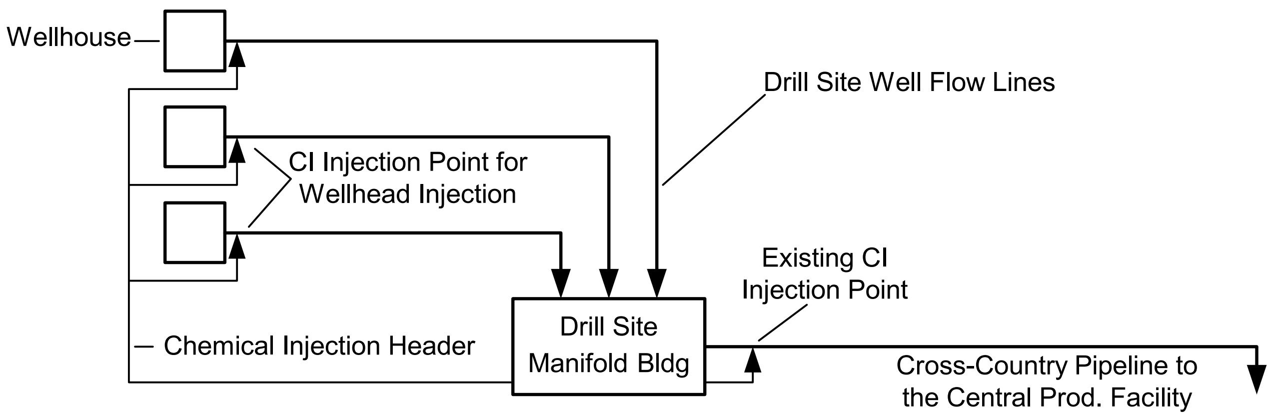
3.1.a. Production Lines

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^{o} 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 – 45º 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^{o} 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.

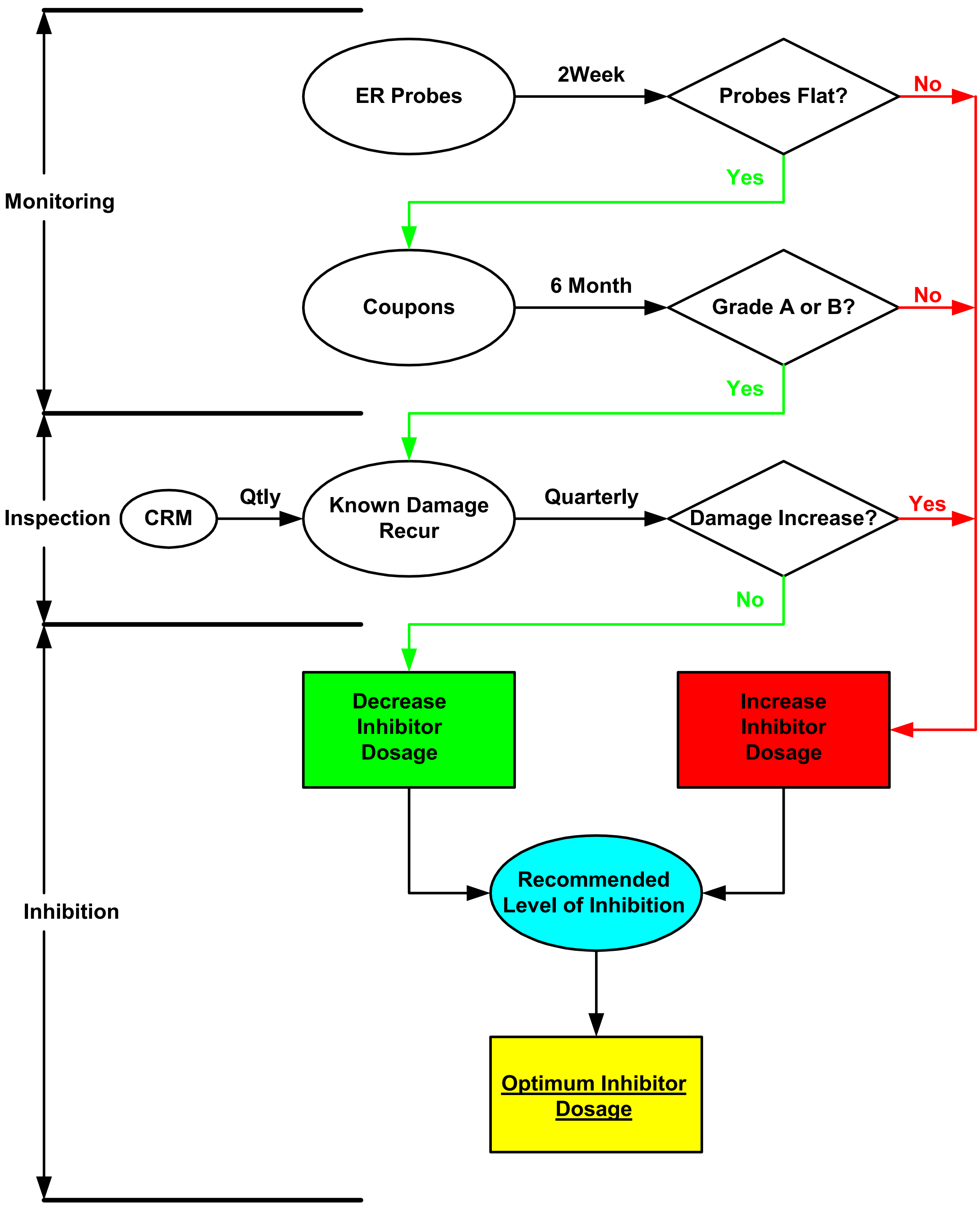
3) Direct inspection of the pipe wall with UT or RT is the only way to verify that the actual pipe wall is not corroding. If ER probes and corrosion coupons show no indication of corrosion activity, the pipe wall may still be corroding, but probably at a low rate. If a pipe is corroding at a low rate, 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 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 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: Year 2000	# of WPs Inspected by TRT: To Date	% of Total Inspected by TRT: Year 2000	% of Total Inspected by TRT: To Date	# of WPs that were TRT'd which required supplemental VT: Year 2000	# of WPs that were TRT'd which required supplemental VT: To Date	% of WPs that were TRT'd which required supplemental VT: Year 2000	% of WPs that were TRT'd which required supplemental VT: To Date	# of WPs VT'd and Refurbished: Year 2000	# of WPs VT'd and Refurbished: To Date	VT Backlog	Inspection Completion Goal (TRT)
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 2005
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 <u>approximately</u> 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.

6.2.c Cross-Country Line Inspection

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

- Decrease the amount of RTR inspection on cross-country lines, and significantly increase the amount of inspection on well lines, as noted above. Based on the relatively few numbers of repairs and damage increases in 2000, there should be no additional risk associated with this decrease in RTR coverage on the cross-country lines. Cross-country line RTR footage estimated for 2001 is <u>approximately</u> 10,000 feet.

- Develop and implement a risk-ranked Elbow Inspection Program, which should help increase the effectiveness of cross-country line RTR coverage. The purpose of this program is to identify higher-risk areas on a given line, taking into account flowing conditions and pipeline geometry's, so that more effective inspection schedules can be established.

6.2.d External (Weld-Pack) Program

- Complete inspection of remaining CC <u>Off-Pad</u> weld packs

- Inspect 20% of CC <u>On-Pad</u> and well line weld packs.

6.2.e Below Grade Piping Program

- Inspect approximately 100 road crossings using PTI/TWI

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

6.2.f Other

- Decision and execute 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 drill sites.

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