Management Systems Review

2006 BPXA GPB OTL INCIDENTS

BP America Inc.
Final Report

March 2007

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Booz | Allen | Hamilton

BP AMERICA INC.
2006 BPXA GPB OTL INCIDENTS
MANAGEMENT SYSTEMS REVIEW

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I. PURPOSE AND SCOPE

BP America (BPA) management commissioned this project in light of the two leak incidents on the Prudhoe Bay Oil Transit Lines (OTL) in order to identify potential organizational, process, information systems, and governance issues that may have contributed to these incidents.

The purpose of this report is to assess the management systems, operational processes, and risk management approach for the OTL that were in effect prior to the leaks, and to assess their present state. The report also identifies potential non-technical root causes and contributing factors to the March and August 2006 leaks and subsequent actions. The report focuses on the management issues and does not attempt to identify or diagnose the technical causes of the corrosion that led to the leaks.

This report takes an independent view of BP's organization structure, processes, information systems, and management practices as they relate to the operation of the OTL. It does not include any analysis of other areas of BP's Alaska operations, and its conclusions are limited to the suitability of the management systems for the operation of the pipelines.

The scope of the analyses used in this report includes evaluation of the operational, safety, and management processes; information systems and reporting structure of operational and performance data; organization design and culture; and actions taken leading up to and immediately following the two leak incidents. In the course of these analyses, the Booz Allen Hamilton team reviewed the available reports and documents related to the operation of the OTL, conducted interviews of current and former management and field staff, and reviewed regulatory and industry standards. The Booz Allen team received the full cooperation of the BP staff in accessing information and during the interviews. This report's appendices provide a log of the reports reviewed and the interviews conducted.

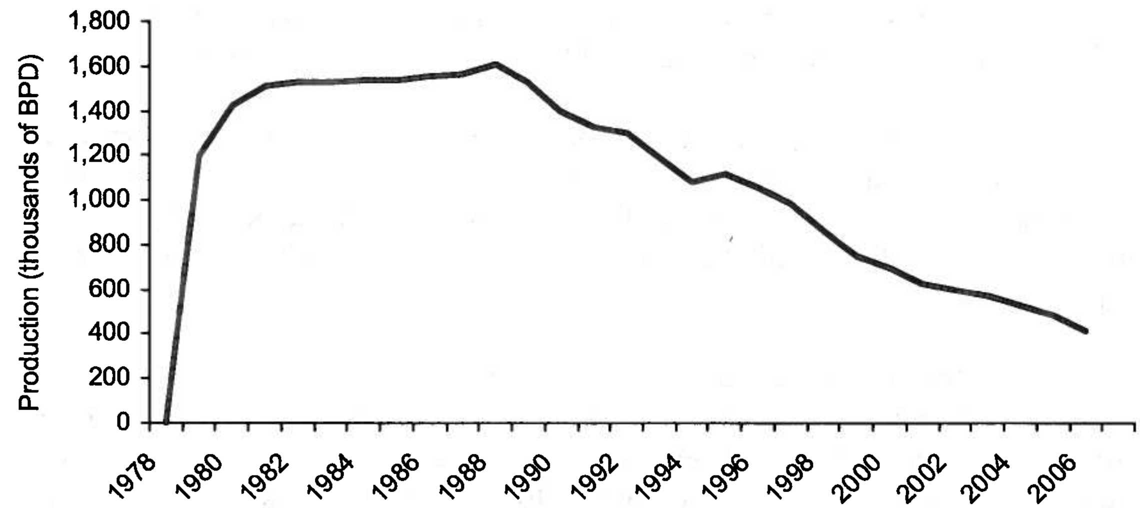
Given its aggressive timeframe of approximately 10 working weeks, this project was conducted on a "best efforts" basis. The report is based on the information available and the Booz Allen team's industry experience and professional opinion.

II. EXECUTIVE SUMMARY

Background

Greater Prudhoe Bay (GPB) is the largest producing oil and gas field in North America. It sits on the shores of the Beaufort Sea, over 200 miles north of the Arctic Circle. The field was discovered in 1968, and production commenced in 1977 with the opening of the Trans-Alaska Pipeline System (TAPS). GPB production peaked in 1989 at 1.5 million barrels of oil per day, and has since fallen by nearly 75 percent (see Exhibit ES-1). GPB currently includes approximately 39 well pads; 1,114 producing wells; 6 gathering centers; and 1,273 miles of pipeline. It is divided into two sections—the Western Operating Area (WOA) and the Eastern Operating Area (EOA).

Exhibit ES-1: GPB Production

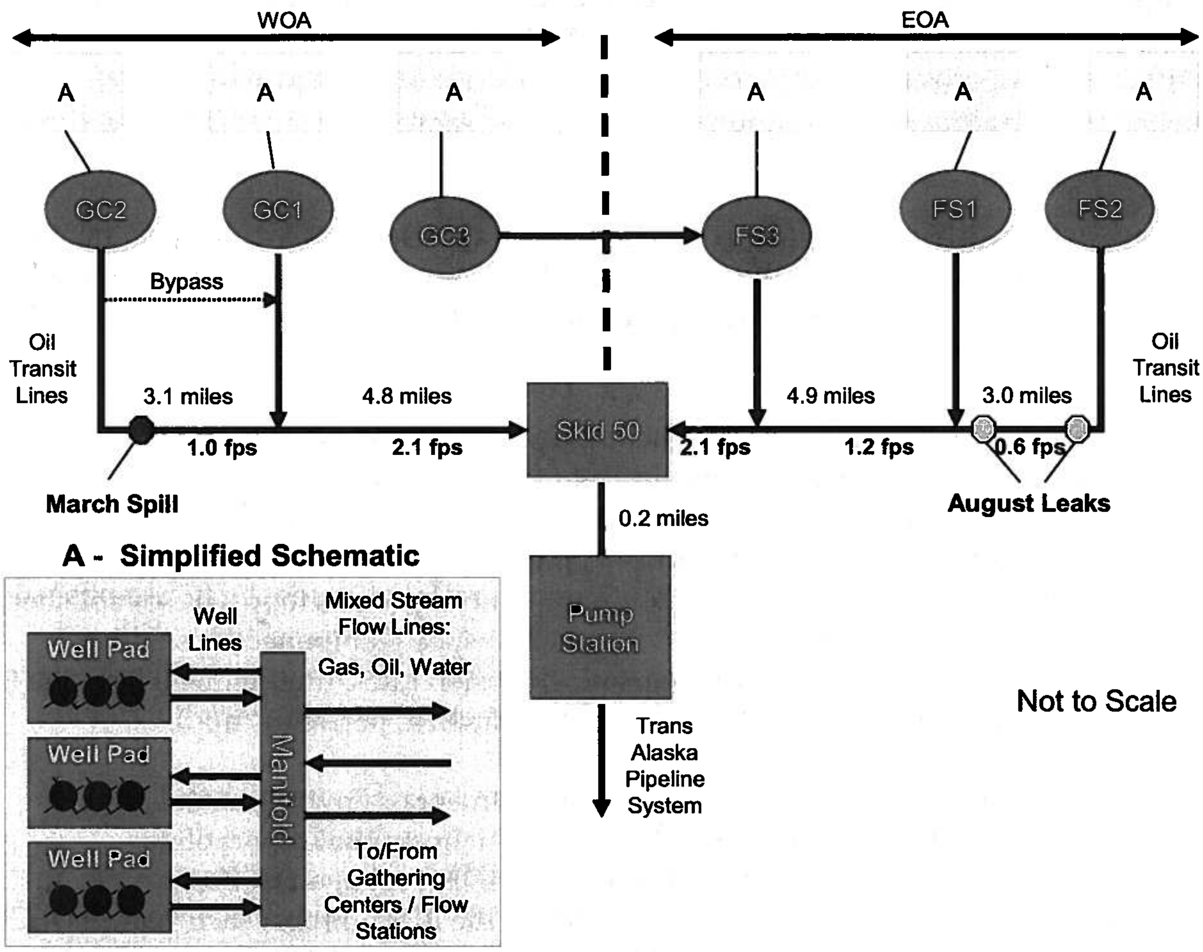


Source: BP Production Data

BP Exploration (Alaska) (BPXA) is a large, complex, and geographically dispersed organization, operating over 2,100 wells and employing over 2,100 people across more than 215,000 acres. BPXA has been the sole operator of GPB since BP acquired ARCO in 2000. Prior to that, ARCO Alaska Inc. (now ConocoPhillips Alaska, Inc.) operated the EOA. Although BPXA operates GPB, it is a minority owner at 26 percent. ExxonMobil and ConocoPhillips each own over 30 percent of GPB. Investments, annual budgets, and major operating decisions must be cleared with these Working Interest Owners (WIO).

GPB is a water drive reservoir with a gas cap; wells produce a mixed stream of oil, natural gas, and water. The combined stream moves from the well heads to the gathering centers (called flow stations in the EOA) in three-phase flow lines. The gathering centers separate the oil, gas, and water, and pass sales-quality crude to the oil transit lines (OTL), which bring it to the top of TAPS at Pump Station 1. By contract with the operator of TAPS, Alyeska, the flow that arrives at TAPS can contain a maximum of 0.35 percent basic sediment and water (BS&W). Exhibit ES-2 provides a schematic of the Prudhoe Bay Field.

Exhibit ES-2: Prudhoe Bay Oil Field Schematic



Source: FS-2 Oil Transit Line Spill, Prudhoe Bay Eastern Operating Area, August 6, 2006, Incident Investigation Report, January 31, 2007

As the field matured and production declined over time, flow composition changed. GPB now produces more viscous oil and much more water than it did in the past. The gathering centers currently process 10 times as much water as oil. Flow from the wells and manifolds is also less smooth, particularly as wells come on line, resulting in production upsets at the gathering centers. This pushes more BS&W into the OTL. Finally, flow rates through the OTL have declined significantly from their peak.

Throughout the 1990s and up to 2004, a period of relatively low oil prices, Alaska was under severe budget pressure from BP and the other WIO to deliver flat lifting costs (on the order of $2.00 per barrel), even as production volumes decreased. Cost pressures to operate an expensive field profitably led to an environment of repairing rather than replacing kit to keep production flowing while adhering to safety and environmental regulations.

Corrosion Management at BPXA

Corrosion is a constant challenge for oil field and pipeline operators. Corrosion management requires ingenuity, technical expertise, and resources, particularly in the hostile environment of Alaska's North Slope. Most of the 1,500 miles of pipe operated by BPXA is above ground; all of it is insulated to protect tundra permafrost from pipeline contents that are a minimum of 105 degrees Fahrenheit, and often exceed 140 degrees.

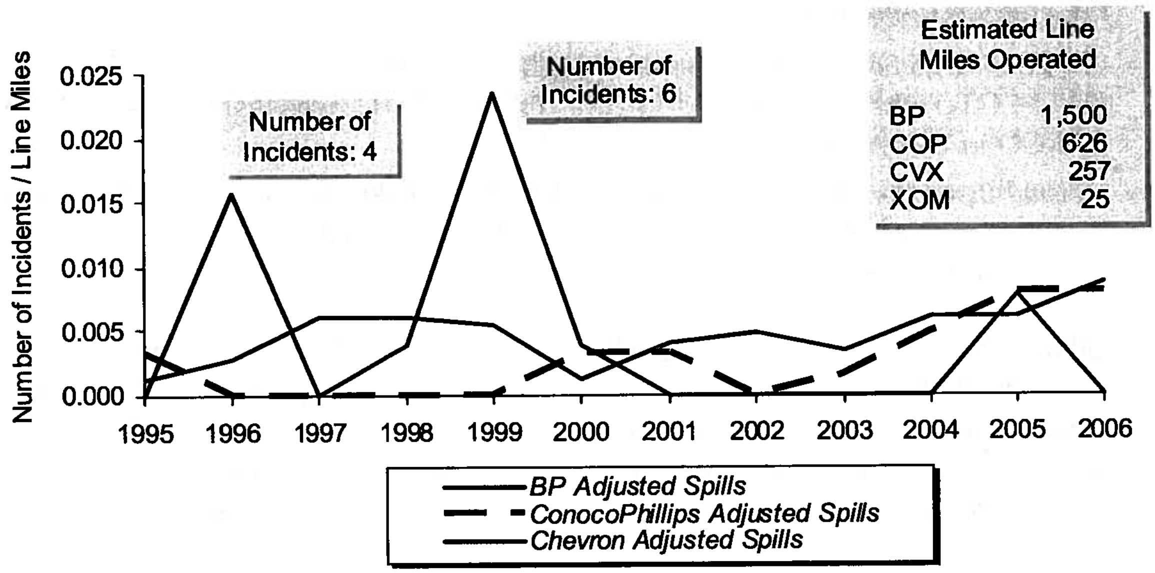
External corrosion under insulation (CUI) is a major issue, particularly at the over 300,000 pipe welds where water tends to collect. Internal corrosion is a function of what flows through the pipe; increased water, sediment and other corrosive elements result in greater corrosion risk.

In 1995, BPXA combined several functions into the Corrosion, Inspection, and Chemicals Group (CIC), which was responsible for the development and implementation of a comprehensive corrosion management strategy. The strategy was broadly risk-based, although it did not incorporate a formal risk assessment process. The strategy followed a control-inspect/monitor-control process loop. CIC established piping "fit-for-service" (FFS) criteria and routinely inspected pipe sections with a variety of techniques to monitor corrosion and corrosion rates. Internal wall loss due to corrosion had a target of less than or equal to 2 millimeters per year (mpy).

Since the ARCO acquisition, the Alaska Department of Environmental Conservation (ADEC) has required that BPXA submit an annual report of its commitment to corrosion monitoring. In addition, ADEC engaged Coffman Engineering Inc. to perform a third-party review of the BPXA report each year. ADEC did not indicate any dissatisfaction with either report or BPXA's conduct of corrosion management.

In general, the CIC program was effective. Exhibit ES-3 shows the number of corrosion-related spills over 1,000 gallons for the major Alaska pipeline operators, common sized by miles of pipeline. Given the extent of its pipeline network, BP's performance is not out of line with the other operators.

Exhibit ES-3: Corrosion-Related Spills per Line Mile



Note: 1) Spill data is counted for corrosion-related spills on oil production and transmission pipeline facilities, as reported by ADEC.
2) Line miles are estimated based on publicly available data. Unregulated pipeline miles for each company were estimated at the rate of 0.41 miles for each well identified by the Alaska Dept. of Natural Resources (the 0.41 ratio is calculated using BP's data). Regulated miles were identified in the 2006 Lease Compliance Monitoring Report of the Alaska State Pipeline Coordinator's Office.
3) BP includes ARCO data prior to acquisition; ConocoPhillips includes Phillips data prior to acquisition; Chevron includes Unocal data prior to acquisition.
4) ExxonMobil reported no corrosion-related spills for oil production or transmission pipeline facilities from 1995 to 2006.
Source: ADEC Spill Database, 1995 - 2006

The OTL were exempt from U.S. Department of Transportation (DOT) / Pipeline Hazardous Materials Safety Agency (PHMSA) regulation because they were low pressure, in-field, and did not traverse populated areas. The threat of internal corrosion in the OTL was generally considered to be low because water and gas had been removed at the gathering centers. In almost 30 years of operation, there were no incidents on the OTL or repairs for internal corrosion.

The CIC protocol for corrosion management of the OTL included inhibition and inspection:

- *Corrosion Inhibitors*, which also acted as a biocide, were regularly injected upstream of the OTL. Electrical resistance probes, which took readings of the corrosive potential of pipeline fluids every four hours, determined the required level of corrosion inhibitors.
- *Corrosion Coupons* were pulled on a three- to four-month frequency to confirm the efficacy of the corrosion inhibition system in the OTL. These were used to monitor corrosion rates, which had a target of no more than 2 mpy.
- *Ultrasonic Testing (UT) Inspection* was used to monitor internal corrosion by measuring wall loss. UT readings were taken across the entire circumference of

a one-foot length of pipe. Many locations were inspected repeatedly to check the amount of wall loss over time.

- *In-Line-Inspections (ILIs)* or "smart pigging" were performed on the OTL. The WOA OTL was smart pigged in 1998. The EOA OTL was last smart pigged by ARCO in 1991, but the results were invalid.
- *Visual Inspection* included walking the pipeline, drive-by, and flyover to check for evidence of leaks. Flyovers incorporated infra-red sensors in addition to visual examination.

In 2005, GPB conducted 59,494 inspections; analyzed 7,500 coupons; injected 2,660,000 gallons of chemical inhibitor; and ran 192 maintenance pigs and 3 smart pigs across its entire pipeline network. Alaska CIC was consistently regarded as "best in class" within BP ("world-class corrosion management for a world-class corrosion problem"). Its perceived success contributed to an internal sense of overconfidence.

There was reasonable and well-documented reluctance to pig the OTL because of potential and actual cost, lack of available senders and receivers, difficulty, disposal of BS&W, Alyeska concerns for disruption to TAPS, and potential for field shut-in since all production flowed through the OTL.

In the third quarter of 2004, four OTL locations indicated increased corrosion. As a result, the number of inspected locations was increased from 15 to 47 in 2005. The results from the 2005 inspection program showed seven locations with increased corrosion, but that were still well within FFS parameters. Consequently, 10 locations were put on 6-month inspection intervals (from 12-month intervals), and a smart pig was scheduled for 2006 for the entire line.

In summary:

- The OTL operated without incident or internal corrosion repair for 29 years
- BPXA had a comprehensive, ADEC approved corrosion management strategy that was conscientiously implemented
- The OTL were generally considered a low risk for internal corrosion, and years of inspection data supported this conclusion
- Based on the inspection regime in place, the OTL were well within fit-for-service criteria.

Incident Description

On March 3, 2006, an oil spill was discovered between flow stations GC-1 and GC-2 on the GPB WOA OTL. This spill was caused by an almond-size hole in the line as a result of pitting-type corrosion. The second leaks occurred on August 6 on the EOA OTL between Flow Station One (FS-1) and Flow Station Two (FS-2), as the line was being shut-in following a smart pig run that revealed a number of anomalies that were subsequently verified by UT and visual inspections.

Summary of Findings

The project identified a number of organizational, process, information system, and cultural causes that contributed to these two events. These findings are summarized below.

Corrosion and Integrity Management

- There was no formal, holistic risk assessment process for pipeline integrity. BPXA relied on inspection results and the experience and expertise within CIC to assess and manage corrosion risk.
- None of the risk assessment and risk management processes or tools in use at BPXA for pipelines explicitly addressed root cause ex ante. Root causes were well evaluated as part of the incident analyses ex post.
- Corrosion monitoring and control practices focused on known risks, based on lagging indicators.
- CIC's corrosion management strategy was developed in the late 1990s, and had not been substantially reviewed or revised until now, despite specific direction in a 2004 internal technical audit to do so.

Analysis and Conclusions

- CIC's corrosion management processes were relatively static and insensitive to changes in exogenous variables (e.g., flow rates, BS&W). There was no analysis of the potential effects of changing flow composition and rates on the OTL.
- CIC responded to indications of increased OTL internal corrosion with more UT inspection points and greater frequency, rather than a different inspection method (e.g., ILI) that might have yielded better insight.

Authority and Resources

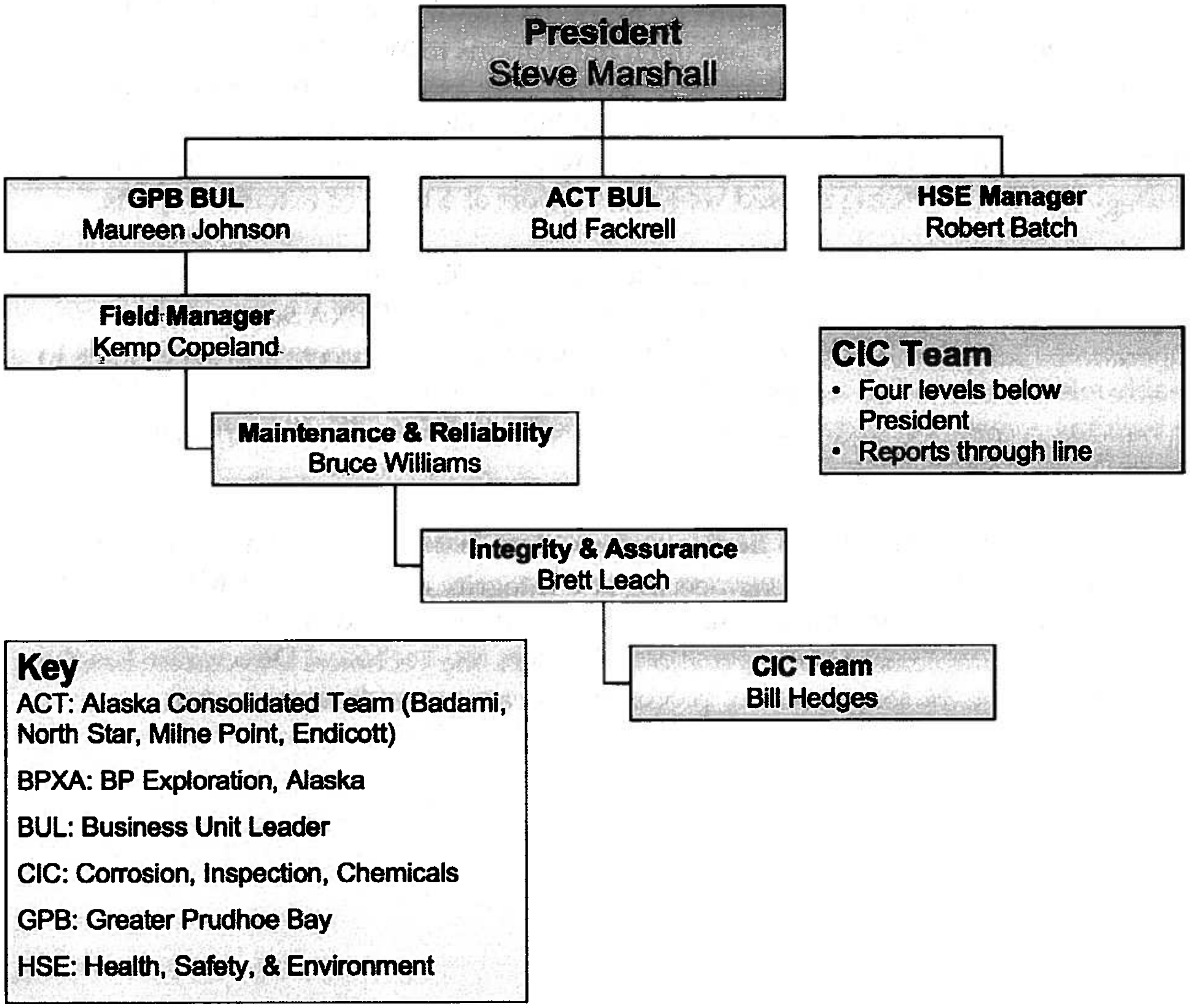
- There was no single owner of the OTL as a system. Accountability for them was divided geographically among the six GPB Area Managers. The Area Managers held CIC responsible for managing corrosion on the OTL.
- A number of key assurance processes (e.g., Audit, Management of Change) were not "closed loop" to ensure that required changes were truly implemented and documented.
- The information technology (IT) infrastructure was fragmented and weak, making data integration, analysis, and work flow difficult and actual infrastructure status opaque.
- BPXA had a deeply ingrained cost management ethic as a result of long periods of low oil prices, constrained budgets, and multiple cost/headcount reduction

initiatives. However, larger budgets alone would not have prevented these incidents without fundamental changes in corrosion and integrity management.

Internal Communications

- CIC made important project and activity tradeoff decisions to meet its budget targets. The budget development process provided little opportunity and no shared communication mechanisms (e.g., risk assessment methodology) for management to question these decisions.
- CIC was hierarchically four to five levels deep in the organization, limiting and filtering its communications with senior management. (See Exhibit ES-4)
- BPXA operated in vertical silos. There was minimal cross-functional communication and insufficient communication between slope operations and Anchorage.
- BPXA CIC operated in relative isolation. There was little sharing of technical knowledge or integrity management practices outside of Alaska, either within Exploration & Production (E&P) or across BP business segments.
- BPXA senior management tenure averaged roughly three years. This lack of continuity contributed to perceptions of disconnection between the Alaska Leadership Team and BPXA operating management and staff.
- BPXA senior management tended to focus on managing internal and external stakeholders rather than the operational details of the business, except to react to incidents.

Exhibit ES-4: 2006 BPXA Organizational Structure



Source: Letter from David Peattie to Admiral Thomas Barrett, U.S. DOT/PHMSA Administrator, September 12, 2006

BPXA has begun to address some of the issues and performance gaps identified in this project.

Since late 2004, major Operations and Maintenance (O&M) projects have been risk ranked in BARRS (Business Activity Risk Ranking System) as an input to the development of budgets. This provides the basis for more systematic management decisions regarding activities and resource allocation.

The entire context of BPXA operations has changed from harvest to growth with the plan for the "50-year future." The Renewal Program will redesign and replace much of the infrastructure to deliver this vision. Many of the historical resource constraints are being removed to facilitate this growth.

CIC Strategy & Planning (formerly "CIC Town") has been folded into the Technical Directorate, reporting directly to the Technical Director—two levels below the President of BPXA. The function has open requisitions to more than double its size, providing the resources to implement a rigorous risk assessment process and integrity management standard. CIC Field will also double in size, enabling it to extend the inspection regimen and reduce the outstanding backlog. The corrosion management strategy for BPXA is being revised with the support of a team of external experts.

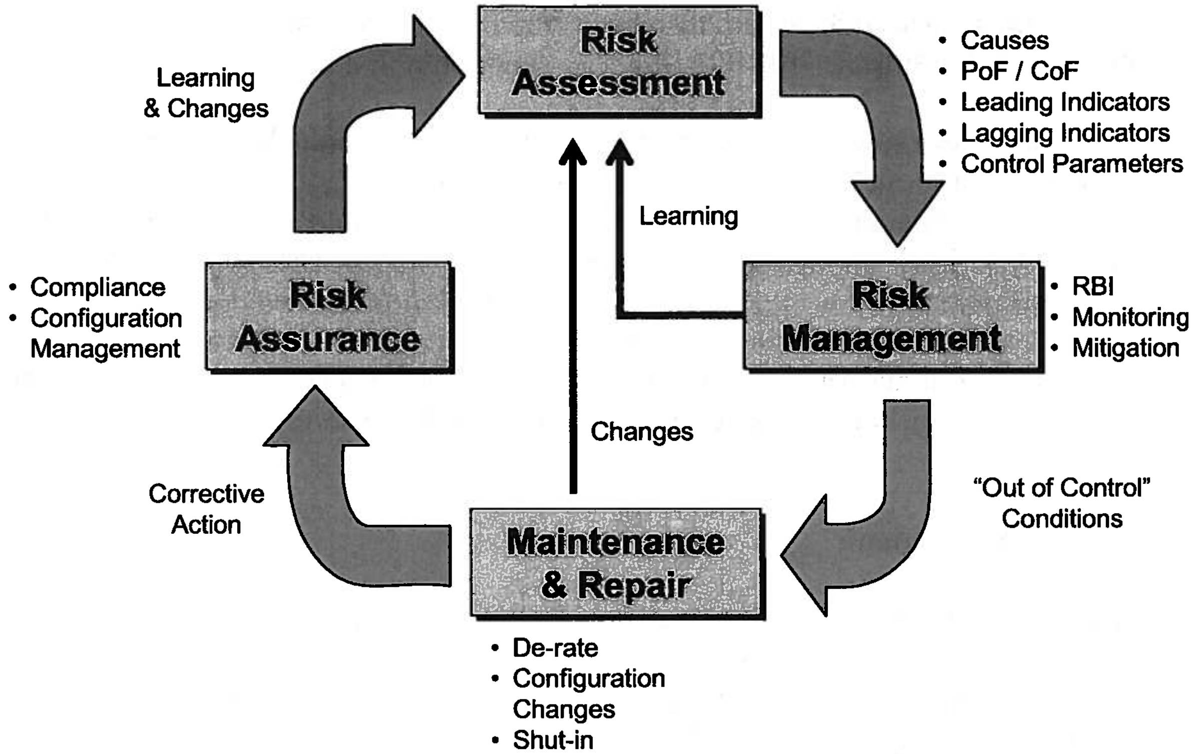
The Engineering Authority under the Technical Director constructed the first Risk Register in late 2006, providing a comprehensive picture of BPXA Safety and Operational Integrity (S&OI) issues. They are developing a process and set of tools to enable infrastructure risk assessment from the bottom up. This is an important first step in building a common understanding and shared vocabulary for managing integrity issues.

The Technical Directorate itself is charged with being an independent authority responsible for implementing engineering and integrity management (IM) standards and procedures. The Directorate will provide the audit check to ensure that the global IM standard is implemented in operations. As such, the Technical Directorate has the potential to close the loop on many processes that are currently open-ended.

Recommendations

An effective response to address the findings in this report would be to develop a comprehensive risk management process for pipeline integrity that includes risk assessment, risk management, maintenance & repair, and risk assurance as shown in Exhibit ES-5, and then implement it across the entire BPXA infrastructure.

Exhibit ES-5: Comprehensive Risk Management Process



The first priority is to respond to regulatory compliance directives in a timely manner. To avoid waste and further antagonizing regulatory authorities, BPXA should thoroughly coordinate its response internally, with BPA and with BP globally. This should be a managed process with single-point accountability for coordination and communication as well as transparency, both internal and external. A project office could be set up in the near term, ultimately evolving into a permanent office of regulatory affairs that would manage dealings with all of the regulators with an interest in BP's Alaska operations.

A second priority is to address the fundamental risk assessment and integrity management issues:

- Complete the revision to the corrosion management strategy and commence training for its implementation.

- Fully implement the Hazard and Risk Register. Task a joint CIC and Field Operations team with developing a field-wide risk register for pipeline integrity and corrosion issues.
- Develop and implement an integrity assurance process that links Field Operations with the Engineering Authority and CIC Strategy & Planning. The process should be a closed loop from identification and communication of issues to the Technical Directorate, to analysis, evaluation of options, implementation (e.g., shut in, de-rate, grant waiver), documentation, and follow-up. This model should also be applied to MOC more broadly, with an independent assurance function that can sanction non-compliance.

Stepping back from these specific, near-term recommendations, BPXA should take a broad perspective on how to identify and manage piping integrity risk in order to avoid "blind spots" or inadequate response to creeping change in the future. The Booz Allen team believes BPXA should significantly strengthen its risk assessment, risk management, and risk assurance processes and build a reinforcing system of data, knowledge, and experience that will enable it to be proactive rather than reactive to events. Risk assessment and risk management should be performed by cross-functional teams that bring together knowledge, expertise, and experience from "town," "field," and outside of Alaska.

Strengthen Risk Assessment

Without a rigorous and methodical approach that integrates risk assessment results into risk management and assurance activities, it will not be possible to have a truly effective integrity management program. There are certain key risk assessment areas that should be strengthened to fully utilize risk assessment data, in particular:

Design and implement a holistic risk assessment process.

BPXA should fully implement the Hazard and Risk Register. The process should be formal, methodical and documented. It should be a full-up risk assessment that addresses risk from a "systems" perspective and evaluates all parts of the kit including: Piping network; facilities; equipment/hardware; software; and normal and emergency operating procedures. The risk assessments should consider various sources of input including: Design, operating, and maintenance documents and drawings; audit, test, and inspection report findings; trended failure or problem areas; direct system observations; and, expert advice from on-site operating personnel. The validity of the risk assessment is contingent on facilitation by managers who are appropriately trained to verify that appropriate data is collected, analyzed, and synthesized for management reporting.

Conduct root cause analysis ex ante as part of risk assessment.

The risk assessment should clearly define each hazard risk scenario of concern so that managers have a good understanding of the actual risk. Identifying root causes should be an integral part of this process. Root causes need to be fully understood so that appropriate controls can be put into place. The risk assessment process should identify leading indicators of potential future problem areas that can be tracked as such.

Consider variable operating conditions and update the risk assessment whenever significant changes occur.

The aging kit and variable operating conditions can greatly impact risk. It is important to account for these variables as part of the risk assessment. Also, modifications, replacement, and repair of kit subsystems can impact risk, and any major change (hardware, software, or procedural) must be risk assessed. This means that the risk assessment is not a static document, but is updated as operations or conditions change.

Evaluate risk controls/corrective actions and ensure that they are adequate and in place.

Risk controls or corrective actions should be directly linked to resolving each hazard risk scenario. The risk assessment should include processes (i.e., inspection or testing) to validate that the controls adequately mitigate the hazard risk scenario and are verified to be viable.

Risk ranking should be formal and predefined, with clear risk acceptance criteria and rationale.

As part of the risk ranking, it is important that the risk assessment evaluate each hazard scenario for probability of occurrence and severity of consequences. The confluence of the two should be part of the formal risk ranking. It is critical that risk acceptance criteria are set by management before risk assessments are begun, and should be part of official policy. Documenting the risk acceptance rationale is important because it holds decision-makers accountable for how well risks are managed.

Enhance Risk Management

The BPXA risk management process should build on current successful programs. In addition to current and planned integrity and risk management activities, BPXA should implement the following actions:

Streamline critical risk data and make it comprehensible to senior management.

Decision-makers need relevant risk data to be able to best determine a course of action. Data should be comprehensive and sufficiently detailed to give leaders an understanding of the issues, but also clear and succinct so that critical risk messages are not lost. Senior leaders need both the current lagging indicators of integrity management and the leading indicators as determined by the risk assessments. The former will help focus attention on ensuring that mitigation strategies are effective. The latter will serve as early idicators of where future problems may arise, thus permitting rapid mitigation before they become serious.

Develop sustainable risk communication channels.

These channels should ensure that critical risk information reaches decision-makers in a reliable and timely manner. For senior managers to be held accountable for risk decisions, they need to receive timely and digestible risk data. The risk communication channels should be used to share important risk information, communicate key risk messages, and coordinate appropriate risk management strategies. Risk communication channels should horizontally link GPB organizations so that important risk data holders are able to share what they know and help devise appropriate risk-based responses. The communication channels must also work vertically, ensuring that front-line staff have a method to communicate important risk information to senior management.

Upgrade and integrate risk management information systems.

A risk-based inspection system (currently MIMIR) should be linked with a work order system that tracks PMPs (MAXIMO), a piping integrity system that manages the infrastructure, and a system that tracks proposed changes through closure (TRACTION). These systems should share common databases to eliminate duplication and ensure consistency. The risk based inspection system and change management systems should include tools for data analysis in order to assess trends and identify "creeping change" that may affect asset integrity. Analysis should be a regular feature of risk assessments and management reporting.

Assign single point accountability at the operating level for discrete piping systems and other infrastructure assets.

There should be clear line management ownership below the level of GPB Field Manager for the integrity and performance of infrastructure systems end-to-end. This will ensure that assets are appropriately monitored and that maintenance and assurance activities will not "fall through the cracks."

Strengthen Risk Assurance

The first job of an independent risk assurance and integrity management function (proposed for the EA) should be to strengthen the current assurance process, formalize key activities, and create an oversight and feed-back loop to ensure compliance.

Develop a formal risk-based assurance process.

At the heart of a formal risk-based assurance program is a robust, closed-loop audit process. The formal audit process should have two components: Audit, inspection/verification of current practices; and special audits based on high risk items identified in risk assessments. The first should be a continuation of current practices, but also include a close-loop tracking mechanism to ensure completion. The second should take the risk assessment/risk register results and use the high risk items to serve as leading indicators. These items would then form the basis of a "targeted" audit. This will permit BPXA to focus on emerging risk areas before they develop into crisis situations. As with the first component, the "targeted" audits should be closed loop with a verification piece that ensures corrective actions are adequate and in place.

Formalize the risk disposition process.

The Engineering Authority should continue with its plans to serve as the formal risk review and approval process owner. It is important to ensure that risk mitigation plans and corrective actions are put in place and that there is a formal independent review and approval process. Because asset and operational risk management must remain with line managers who own the risk, an independent assurance group should serve to verify that the risk has been appropriately dispositioned. All major changes should be risk reviewed and approved before action is taken.

Establish an escalation policy to ensure compliance.

A robust assurance program must include an escalation process that drives compliance with internal and external risk management requirements. If there are no consequences for non-compliance, there will be insufficient discipline in place to ensure that corrective actions and risk management strategies are implemented. An appropriate enforcement regime will make certain that this occurs. Furthermore, management should have metrics for asset integrity as part of their performance contracts to ensure an appropriate level of leadership attention.

BPXA has a large number of initiatives under way or planned. In addition to addressing the specific integrity issues arising from the leak incidents, BPXA has a long list of projects to undertake in the coming years:

- *Implementation of global IM standard* – process improvement
- *S&OI Six-Point Plan* – projects and process improvement
- *Reorganizations* – BPXA and GPB
- *Implementation of Operating Management System (OMS)* – process improvement
- *Implementation of Enterprise Risk Management (ERM)* – process improvement
- *Wedge* – major project
- *Major Projects* – 11 major projects identified
- *Mid-Stream Alaska*
- *Renewal*

Regulatory investigations and compliance will consume additional resources, particularly management time and attention. In addition, there are a number of open audit items that will require close-out.

Given the sheer number and complexity of initiatives planned, BPXA management should take the time to evaluate them holistically to identify prerequisites, redundancies, complements, and a critical path. It is unlikely that BPXA will be able to resource all of these initiatives simultaneously. A risk- and reward-based approach should be used to cull the list and establish priorities. Many aspects of ERM or OMS may be embedded in other initiatives. Portions of IM and OMS are likely to be redundant. If activities and tasks can legitimately be deferred, they should be. Renewal alone, in all of its aspects, could fully occupy much of the organization for many years.

BPXA should immediately reach out from Alaska to identify best practices for each of the risk management elements. There is a wealth of piping integrity risk management expertise in other regions of E&P (e.g., North Sea) as well as within R&M. For example, BP Pipelines (North America) regularly conducts HAZOPs as part of their risk assessments in GoM. Risk-based inspection procedures are also employed. BPXA should quickly adopt and then adapt the most effective processes and technologies available within BP, and then aspire to best practices, which are likely to reside in other industries, such as chemicals and nuclear power, or in high-reliability institutions like NASA or the nuclear U.S. Navy.

An important first step will be to establish the performance and process objectives of this initiative, and identify appropriate metrics for tracking and completion. These will determine pace and resource requirements.

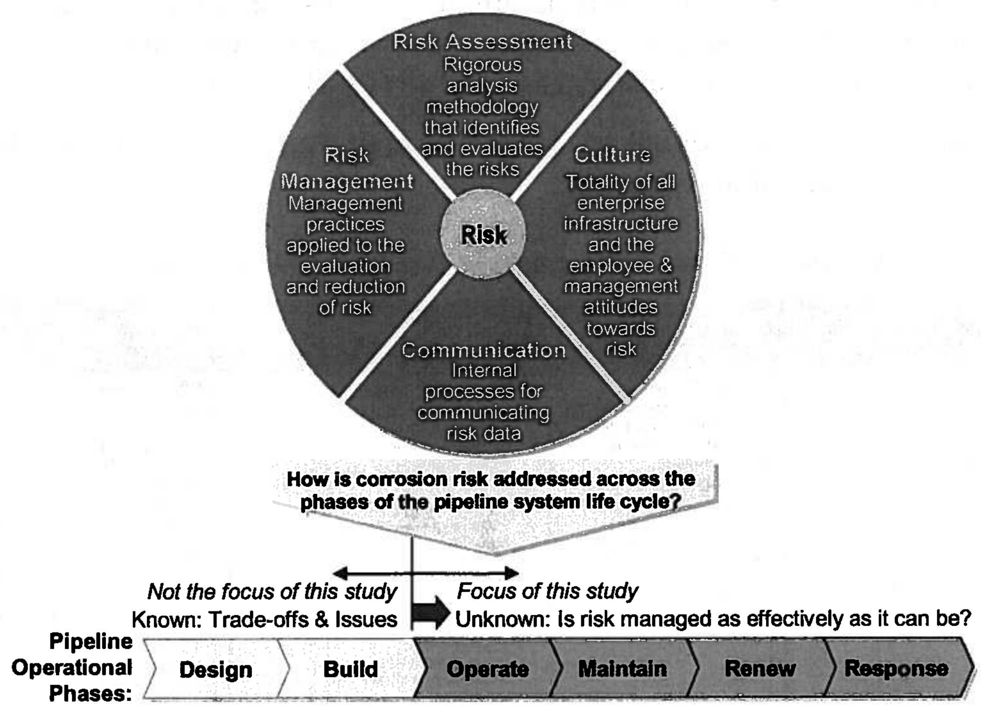
Coupled with the vision for a 50-year field, this set of initiatives presents a considerable challenge and a unique opportunity for the BPXA management team. The challenge and the opportunity are to revolutionize the way the field operates and performs. This is a long-term program that requires a long-term commitment from the senior team.

III. FRAMEWORK AND APPROACH

The objective of this project is to provide BP America (BPA) and BP Exploration (Alaska) (BPXA) senior management with an independent view of the causes that led to the March and August oil transit line (OTL) leak incidents with regard to organization, processes, and information technology. Booz Allen Hamilton conducted the project between November 13, 2006, and January 31, 2007, a period of approximately 10 working weeks. The Booz Allen team delivered a Preliminary Report after about 6.5 working weeks. Given the limited timeframe and the desire to provide objective insights, the team adopted an approach based on the following guiding principles:

- **Proven and tested**: Booz Allen applied an assessment framework that the firm has used in other high-risk enterprises. The framework examines four dimensions of the management of corrosion risk: How are risks assessed? How are risks managed? How are risks communicated? What is the organizational culture when managing risks? As depicted in Exhibit 1, the Booz Allen team applied this framework to several steps in the activity set for the OTL (operate asset, maintain asset, renew asset, and respond to events).

Exhibit 1: Booz Allen Assessment Framework



Source: Booz Allen Hamilton

- **Structured**: To efficiently build a fact base and identify causes, the Booz Allen team followed a structured and proven approach.

General Description of Approach	
1) Develop detailed framework and template	▸ Develop detailed framework wheel and assessment template from leading risk practices ▸ Focus framework on operational risk management of corrosion issues ▸ Review and concurrence by BP ▸ Identify key required data elements, interviewees, and documentation ▸ Set up interview meetings
2) Gather key data elements	▸ Interview cross-section of managers and staff ▸ Review relevant documents ▸ Where appropriate observe operations ▸ Apply framework wheel to each applicable lifecycle phase ▸ Document results in detailed template
3) Conduct pipeline scenario tree	▸ Interview stakeholders to validate scenario tree ▸ Leverage Booz Allen risk experts ▸ Identify key BP stakeholders to provide input
4) Synthesize data, complete gap analysis and develop final report	▸ Gather all relevant data and complete assessment templates ▸ Review scenario tree for relevant data ▸ Compare BP operational procedures with internal standards ▸ Conduct gap analysis ▸ Write final report

- **Fact-based**: The team used a template to compile and organize a fact base against the various elements of the framework, including the gap between BPXA practices and commonly accepted practices (i.e., protocol element), and regulatory references. The ranking reflects the team's assessment of the gap from ○ (Does not exist) to ● (Exists and fully implemented).

  Exhibit 2 presents an example of this template. Appendix 7 contains the complete assessment template.

Exhibit 2: Booz Allen Sample Assessment Template

Item	Protocol/Element	Global BP Standard	GPB Procedure and practice (Source cited)	Fact-Based Findings (Source Cited)	Ranking	Regulatory Approach/Practice (CFR or PHMSA)	Changes Since the Incidents
1.2	The risk assessment process uses a holistic, "systems" approach (including facilities, equipment, procedures, environment) to evaluate pipeline network risks	GP 43-17 4.2.c Risk Management Process	BP Group Engineering Technical Practice guidance call for integration of the Group MAR process and linkages to the Environmental & Social Impact Assessment (ESIA) processes, leveraging pipeline integrity and safety assurance programs that are complementary to a holistic approach to corrosion risk management.	▸ No evidence was found that risk assessment processes use a predictive and holistic systems-based approach ▸ There are corrosion response campaigns (e.g., CRM, CMP, FIP, ERM) that are inspection-based *(Inspection Contractor)* ▸ Localized risks are determined by prescriptive Fit-for-Service standards *(GPB CIC Team Leader, GPB Area Managers)*	○	RMPS IV.1.1 risk management program should include physical boundaries, all life cycles impacted within those boundaries, and the full breadth of analyses	The methodology development effort of the Pipeline Assessment and Intervention Team (PAIT) is planned to incorporate a systems approach to integrity risk assessment, including operations, business, and external risk factors *(PXA Technical Director)*

The fact base was assembled via site visits, interviews with key stakeholders, and reviews of internal and publicly available documents. (Appendices 3 and 4 provide the complete lists of interviews and documents.)

- **Balanced**: During the course of the assessment, the Booz Allen team made every effort to acknowledge both the positive and the negative practices to provide an objective view of BPXA corrosion management practices before and after the incidents.

This report comprises four work products.

1. The completed assessment template of dimensions of corrosion risk management
2. The timeline from 1995 to the present of significant events at BPXA and relevant data trends
3. The scenario tree for the March and August leak incidents
4. The report narrative, which draws on the template and timeline to document the key findings of the project

Interviews were restricted to current and former BP employees and contractors. The Booz Allen team did not interview any state or federal regulators, investigators, legislative representatives, working interest owners (WIO), or other outside stakeholders, nor did we extensively review regulatory issues.

BPXA management provided ready access to all documents requested. All interviewees were cooperative and made themselves available on short notice during a busy time of year.

Booz Allen conducted the project on a "best efforts" basis. The Booz Allen team members applied their experience and professional judgment when assessing BPXA performance against the risk management dimensions captured in the template. Booz Allen based all findings on the information available—which, while comprehensive, is unlikely to be exhaustive.

The purpose of the project was to assess the effectiveness of BPXA's management systems, organization, processes, information technology, and risk management approach as they related to the two spill incidents; document findings; and suggest areas for improvement. The project's aim was not to make findings related to legal compliance. As a result, this report and Booz Allen's findings are not intended for use in legal proceedings to which BP is or may become a party. Booz Allen made no attempt to develop evidence that would be legally admissible or to draw conclusions about compliance with legal standards. In our findings, we are neither making objective determinations nor acting in a role comparable to finder of fact in a legal proceeding. For example, interviews were not taken under oath, and documents and emails were taken at face value. For these and other reasons, the information that we evaluated reflects varying degrees of ambiguity and interpretation on our part. In conducting this project, we did not consider it necessary to resolve all factual ambiguities encountered.

Our findings should not be construed as suggesting or determining that any particular individual, whether a BPXA employee, contractor, manager, corporate-level manager, or BP board member, failed to meet any applicable legal standard, was negligent, committed wrongful or tortuous conduct, or breached any duties owed to the company or its stakeholders. Any such finding or determination is outside of the scope of this project. We would note, however, that during the course of this project, Booz Allen Hamilton saw no information to suggest that any BP employee or contractor acted in anything other than good faith.

Many of these dimensions warrant further investigation to develop fit-for-purpose recommendations addressing the gaps identified and issues raised throughout the course of this project.

IV. CONTEXT

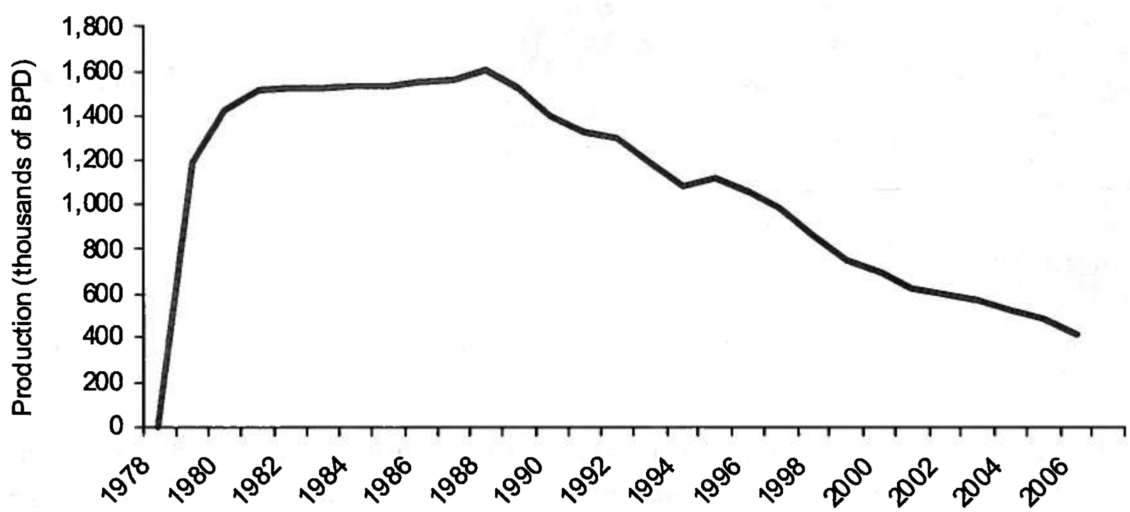
Summary: Greater Prudhoe Bay (GPB) is a large, complex operation with over 1,200 miles of pipelines.[1] The 30-year-old operation was managed through its maturity in the 1980s and decline in the 1990s, and has just recently been given new life as oil and gas prices encourage further development. During the last 10 years, the operation has come under cost pressure, which has resulted in several reorganizations and a propensity to repair rather than replace assets as needs arise. Over this same period, BP has focused on managing the risk on the upstream pipeline systems as they have historically proven to be highly susceptible to corrosion, while the OTL were considered to be low risk.

Assets and Operations Description

BPXA manages over 2,000 wells and approximately 1,500 total miles of piping systems in active North Slope operation. GPB is segregated into the East Operating Area (EOA) and the West Operating Area (WOA). Each area has three gathering centers (called flow stations in EOA). GPB operations include approximately 39 well pads; 1,114 wells; and 1,273 miles of pipeline.[4]

The Prudhoe Bay oil field was discovered in 1968, and production commenced with the opening of the Trans-Alaska Pipeline System (TAPS) in 1977. The Prudhoe Bay field produced more than 1.5 million barrels of oil per day at its peak in 1989, and has since declined to approximately 0.5 million barrels per day, as shown in Exhibit 3.[2]

Exhibit 3: GPB Production

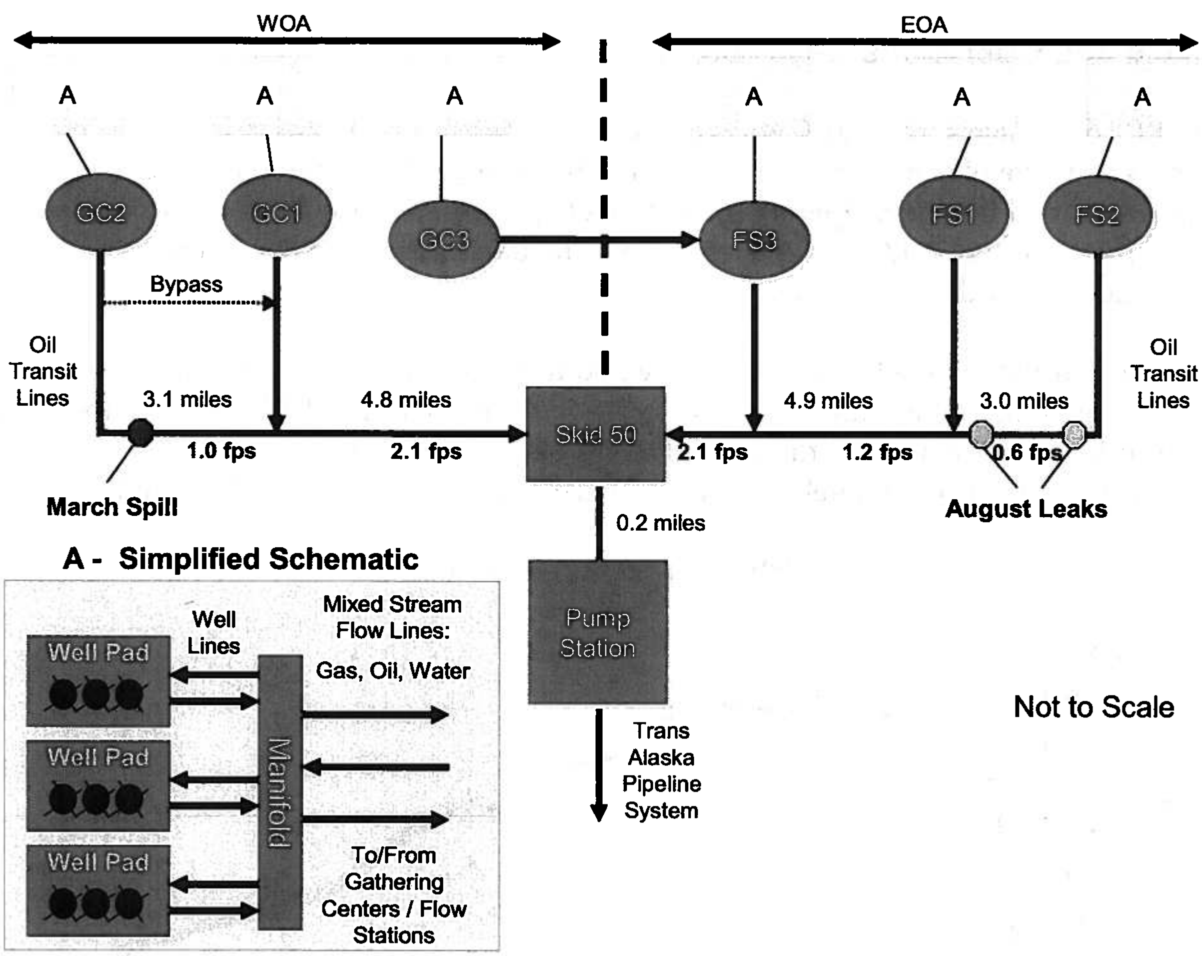


Source: BP Production Data

Prudhoe Bay is a water drive reservoir with a gas cap—thus, gas and water are produced along with the oil. The gas and water, along with additional sea water, are injected back into the ground through injection pipelines to maintain reservoir pressure and dispose of the produced water and gas.

Exhibit 4 presents a schematic of the oil field. The wells produce a mixed stream of gas, oil, and water. The manifold combines the well streams and directs the oil to the gathering centers. The gathering centers split the gas, water, and oil, producing a sales-quality product for the oil transit lines. These oil transit lines (16 miles of 30 and 34 inch pipe) provide the last stage of product transfer to TAPS.[3]

Exhibit 4: Prudhoe Bay Field Schematic



Source: Prudhoe Bay Pipelines Schematic, FS-2 Oil Transit Line Spill, Prudhoe Bay Eastern Operating Area, August 6, 2006, Incident Investigation Report, January 31, 2007

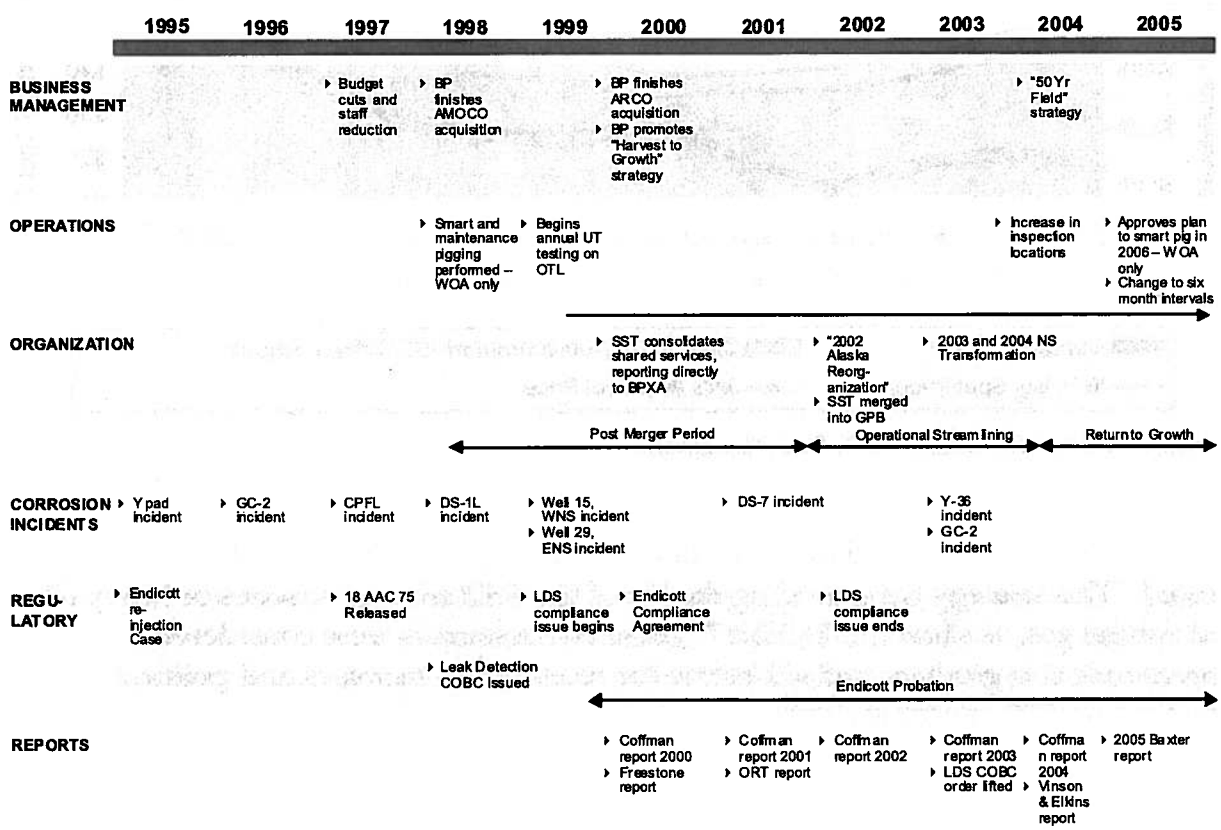
When BP acquired ARCO in April 2000, BP was required to sell part of its interest in the Prudhoe Bay reservoir. As part of meeting that requirement, the GPB unit was created through a consolidation of the interests of BP, ARCO, ExxonMobil, and Phillips. Prior to the consolidation, BP had full ownership of the oil located in WOA, and ARCO owned the EOA assets. Additionally, BP owned a minority interest in the gas located in

WOA, while ExxonMobil owned the balance. BP sold a portion of its oil assets to Phillips, and also sold a share of its oil interests to ExxonMobil in exchange for an increased equity position in WOA gas (BP's position increased from 13.8 to 26.5 percent). GPB ownership is currently split as BP (26.4 percent), ExxonMobil (36.4 percent), ConocoPhillips (36.1 percent), and other parties (1.1 percent). Despite having a minority ownership, BP remains the operator of the GPB unit.[5]

Brief History of the Asset

Exhibit 5 presents a timeline of the key events over the 11 years leading up to the spills in March and August of 2006.

Exhibit 5: Key Events Timeline (1995-2005)



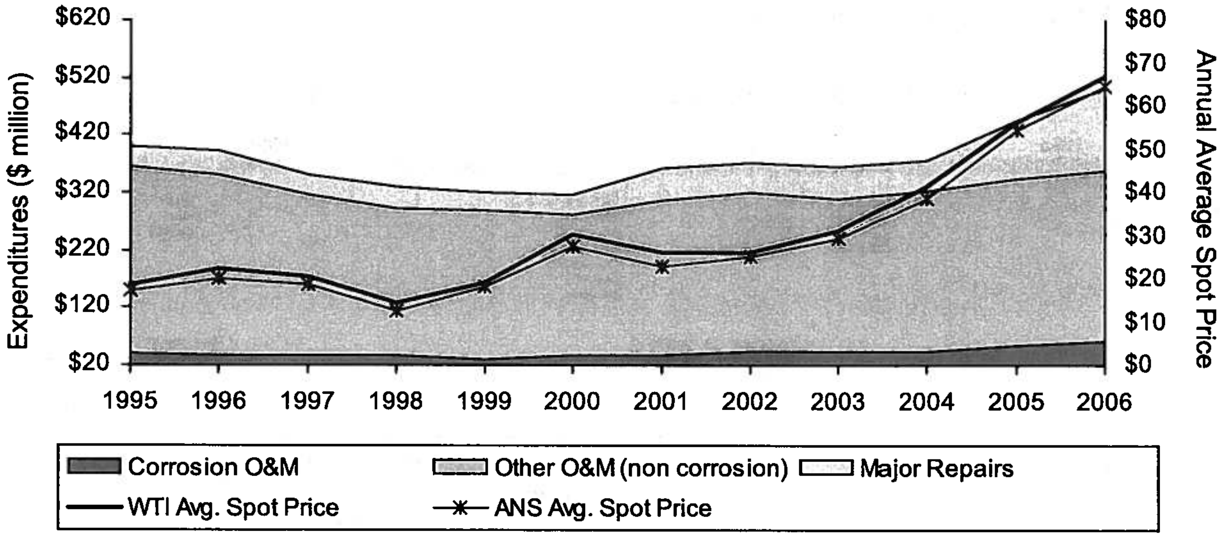
Source: ADEC incident database from Web site; Interviews: Senior Attorney - HSE and Regulatory, BPXA President, GPB BUL; Cited reports; BPXA Organization charts

Business Management

GPB operations commenced in the 1970s with the development of the Prudhoe Bay field by BP and ARCO. The field began commercial production in 1977 with the first flow of TAPS. Production grew through the 1980s, until finally peaking in 1989 at 1.5 million barrels per day. During this period, the oil industry experienced a deep price decline to approximately $10 per barrel with a small recovery to the high teens. In the

1990s, the field transitioned into decline as prices hovered in the $15 to $25 range. Budgetary constraint characterized this period as the field tried to manage costs down in conjunction with the continued decline in production (see Exhibit 6). Staff reductions were made in 1999 (Design Change), 2002 (Anchorage overhead), and again from 2003 to 2004 when the Transformation Project examined lowering lifting costs by $0.40 per barrel by reducing the amount of high-cost labor on the North Slope.[6]

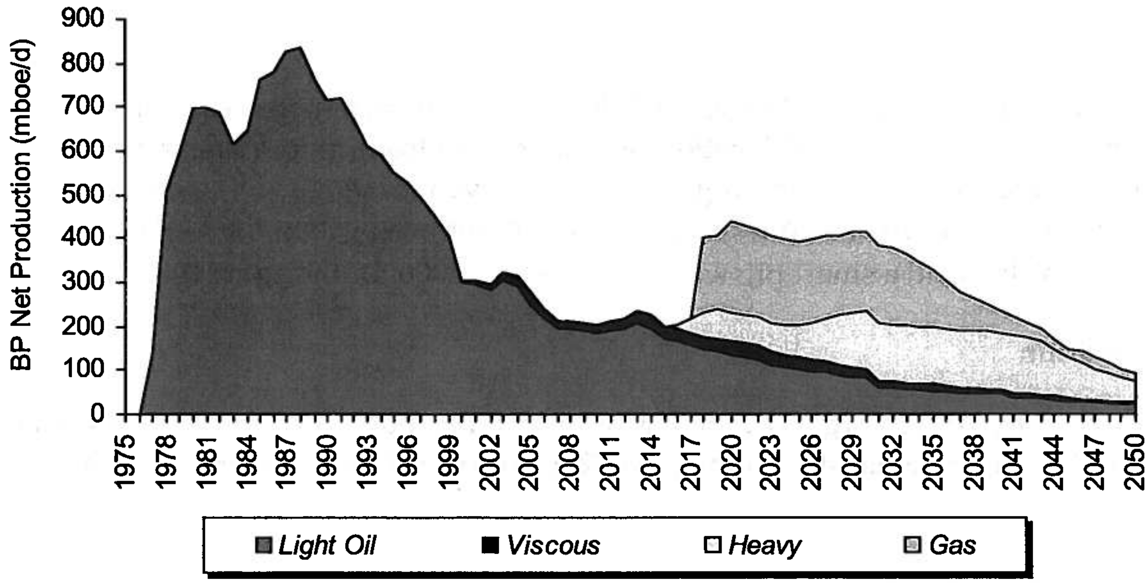
Exhibit 6: Operations and Maintenance, Corrosion, and Major Repairs Spend vs. Oil Prices



Sources: BPXA Financial Data, NYMEX, Booz Allen analysis

As oil prices continued to rise in 2003 and 2004, the "50-Year Field" strategy was created.[7] This strategy for extending the life of the field relies on viscous or heavy oil and natural gas, as shown in Exhibit 7. These two resources were considered uneconomical to produce and sell before the recent price increases and political emphasis on U.S. energy security.

Exhibit 7: Forecast Production



Source: BPXA "50 Year Plan" internal announcement

The "50-Year Field" strategy has shifted focus from cost management to renewal in order to ensure that the infrastructure at Prudhoe Bay will be sufficient for the long-term future of the field. The dramatic increases in major repairs in the 2004 to 2005 expenditure levels, shown in Exhibit 6, reflect part of this renewal effort.

Operations

The internal corrosion inspection and management program included a variety of approaches such as maintenance and smart pigging, coupons, visual inspection, ultrasonic testing (UT) inspection, and chemical injection. The following provides a summary of the OTL corrosion management operations.

In 1997, the WOA OTL were de-rated to 500 psig maximum allowable operating pressure (MAOP) due to corrosion on the Skid 50 bypass line. As a result of this corrosion, the entire WOA was de-rated to this level (the lowest MAOP), and a determination to smart pig the WOA was made.[8]

The WOA OTL underwent maintenance and smart pigging in 1998. Results showed moderate internal and external corrosion. The WOA OTL were next scheduled for smart pigging in eight years (in 2006).[9] In 2005, pigging costs for both the WOA and EOA pipelines were included for the 2006 budget.[10]

Following the 1998 pigging, regular ultrasonic testing (UT) was added to the OTL inspection regime beginning in 1999. These tests were conducted at specified locations along the pipeline based on the results of the 1998 pigging, and the data were captured and trended to monitor the rate of corrosion by the amount of wall loss. Between 1998 and 2003, there were no significant changes in corrosion observed from the ultrasonic testing.[11]

In the third quarter of 2004, four OTL locations indicated increased corrosion. As a result, the number of inspected locations was increased from 15 to 47 in 2005. The results from the 2005 inspection program showed seven locations with increased corrosion. This led to 10 locations being put on 6-month inspection intervals (from 12-month intervals), and a smart pig was scheduled for 2006 for the entire line.[12]

Organization

Since 1998, BPXA's organization has progressed through three phases: Post merger (1998 to 2002), operational streamlining (2002 to 2004), and return to growth (2004 to 2006).

Post Merger (1998 to 2002)

The BPXA organization underwent a series of high-level restructuring moves after the Amoco and ARCO mergers from 1998 to 2000. Initial post-merger consolidations brought together disparate support functions to capture operational synergies.

In 2000, Shared Services Technical (SST) group consolidated functions such as corrosion inspection, well operations, and drilling support, also reporting directly to the President of BPXA in 2000. SST was subsequently absorbed under GPB in 2002.[13]

Likewise, other support and geographical functions were combined:

1. Health, Safety, and Environment (HSE) was made a direct report to the President of BPXA in 1999.
2. Eastern North Slope (ENS) and Western North Slope (WNS) operations were merged in 2002 under Alaska Consolidated Team (ACT)
3. Legal, Audit, and Tax Management joined other functional offices such as Finance and IT under Commercial Business Support (CBS) in 2000.
4. Some functions moved out of Alaska altogether, such as Alaska Exploration (AEX), which was consolidated in Houston when new exploration in Alaska was stopped.

In 2002, the BP Alaska Strategic Performance Unit (SPU) was created, with Steve Marshall as its President. The SPU combined the various business units (BUs) under its umbrella to provide more scale and scope to cross-Alaska operations and to free the BUs to operate more strategically, rather than focus entirely on delivering operating results.

Operational Streamlining (2002 to 2004)

After the high-level reorganizations, individual BUs reorganized their mid-level offices. These second-tier restructurings reduced mid-level managers' spans of control, but also pushed functions like Corrosion, Inspection and Chemical (CIC) down another reporting level within BPXA.

During the 2002 to 2004 period, a series of reorganization projects focused on streamlining business operations and cutting costs:

1. The 2002 Alaska Reorganization reduced Anchorage overhead functions.
2. Transformation projects in 2003 and 2004 aimed to reduce North Slope costs, rationalize support functions, and transfer some activities to Anchorage.
3. The internal audit function was transferred from the segment (BPXA) to the region (BPA).

The Transformation projects made organizational changes in lower levels of BPXA, restructuring the operating area managers' teams and the lines of reporting in operations support functions like CIC.

From 2002 to 2004, BPXA employee headcount decreased by 65 (or 5 percent). However, the loss of BP employees was buffered by an 88-percent increase in agency contractors (from 104 to 196). The net effect was to increase total headcount by two percent.[14]

Return to Growth (2004 to August 2006)

After the two previous rounds of organizational change, there were very few structural changes from 2004 until after the March 2006 incident. The organization began to expand again, in line with its new business objectives.

Over the past two years, BPXA has clearly resumed its growth. The growth is occurring primarily in BP employees, rather than agency contractors. From 2004 to 2006, total headcount increased 20 percent—275 BP employees (21 percent higher) and 26 agency contractors (13 percent higher).[15]

Since 1999, BPXA has reorganized several times, undertaken several change programs, and had considerable senior management turnover. Table 1 shows the number of people who were new to BPXA senior management and GPB roles since the prior year, and the total number of positions at that level. Only 2 people who were in BPXA senior management roles in 2000 were still in those roles in 2006: the head of HR, and the BUL for Gas.

Table 1: Management Turnover (1999-2006)

Year	BPXA Senior Management		GPB Senior Management	
	New Since Last Year	Total Positions	New Since Last Year	Total Positions
2000	2	12	N/A	N/A
2001	6	14	N/A	N/A
2002	5	13	5	10
2003	1	10	2	7
2004	4	9	2	6
2005	1	10	2	5
2006	1	10	3	7

Source: BPXA Organization Charts, 1999-2006

Incidents

The timeline in Exhibit 5 shows the corrosion-related incidents resulting in spills in excess of 1,000 gallons from the mid 1990s to 2006. The incidents show that corrosion was an active integrity issue in GPB operations, and that the OTL had not had a spill or leak issue. Table 2 summarizes each of the listed incidents.

Table 2: Corrosion-Related Incidents (1995-2006)

Date	Name	Location	Description
Nov 7, 1995	Y pad incident	Y pad behind Well 7	12,600 gallons of seawater were spilled onto the reserve pit at Y Pad behind Well 7. The incident was closed with ADEC on December 4, 1995.
Apr 17, 1996	Gathering Center #2 (GC-2) incident	GC-2	A corrosion-related incident involving 1,075 gallons of crude and produced water occurred in West Prudhoe Bay. A final report was issued August 21, 1997, and the incident was closed with ADEC on October 2, 1997.
Nov 15, 1997	CPF1 incident	CPF1 in Kuparuk	3,030 gallons of produced water were spilled at the ARCO-operated area between CPF1 and the Flare Pit. The incident was closed with ADEC on December 5, 2000.
Oct 6, 1998	DS-1L incident	Drill Site 1-L in Kuparuk	There was a 10,500-gallon spill of produced water in ARCO-operated territory within Kuparuk. The spill occurred at a transmission pipeline facility.
Jun 10, 1999	Well 29, ENS incident	Drill Site 14, Well 29	There was a corrosion-related incident in the ARCO-operated section of the North Slope. A flowline blowout occurred at Drill Site 14, spilling 5,107 gallons of produced water and 1,277 gallons of crude oil. The flowline had developed a hole at the edge of a gravel pad of Well 29. Most of the spill was contained on the gravel, although a fine spray landed on the tundra.
Jul 23, 1999	Well 15, WNS incident	West North Slope in Kuparuk	There was a 6,300-gallon spill from the Produced Water Injection line at Well 15 in ARCO-operated territory. The incident was closed with ADEC on December 5, 2000.
Feb 19, 2001	DS-7 incident	Drill Site 7	A blowout occurred at Drill Site 7, spilling 5,345 gallons of seawater. A "No Further Action" decision was issued on March 7, 2001.
May 25, 2003	GC-2 incident	GC-2	A 1,681-gallon produced water spill occurred at GC-2 in West Prudhoe Bay. The incident was quickly closed with

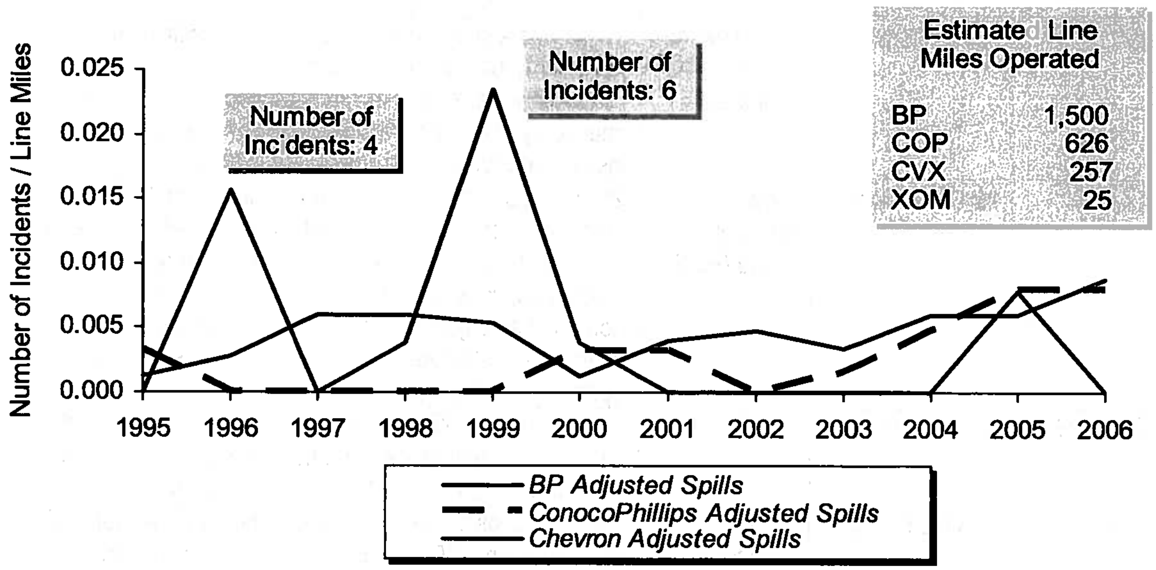
Date	Name	Location	Description
			ADEC on June 9, 2003.
May 27, 2003	Y-36 incident	Y-36 flowline between GC-2 and CG1	There was a significant corrosion-related spill at the Y-36 flowline. 1,500 gallons of crude oil and 4,500 gallons of produced water spilled onto the access road. The spill was caused by external corrosion beneath the flowline's insulation, which was subsequently repaired.
Mar 2, 2006	Mar OTL incident	Flowline between GC-1 and GC-2	267,000 gallons of crude oil were spilled. The 34-inch diameter oil transit pipeline had a quarter-inch hole caused by internal corrosion. The spill was found to have impacted 1.93 acres, consisting mainly of frozen tundra and also a portion of an adjacent frozen lake. The incident garnered international attention and led to extensive scrutiny of BP's operations in Alaska.
May 24, 2006	DS-11 incident	Drill Site 11	There was a 1,050 gallon release of seawater from Drill Site 11 in EOA to tundra impoundment and gravel pad. The incident was resolved with ADEC on June 26, 2006.
Aug 6, 2006	Aug OTL incident	Oil Transit Line for Flow Station 2	Internal corrosion on the oil transit line for Flow Station 2 resulted in an 8,358-gallon spill of crude oil. The incident sparked a shut-in of Prudhoe Bay oil field for 43 days, reducing the flow of all North Slope oil by 400,000 barrels a day.

Source: ADEC Spill Database, 1995-2006

These earlier incidents occurred on the upstream pipelines, or those pipelines that handle gas and liquids between the gathering centers and the wellheads as well as the gas compression and seawater systems. These pipelines handle materials that are more corrosive than the finished oil that was transported in the OTL. These incidents help explain much of management's focus and expenditure on the upstream pipelines and corrosion under insulation (CUI) that gave rise to these incidents. Prior to 2006, there were no corrosion-related incidents on the OTL.

Exhibit 8 shows the number of corrosion-related spills per estimated pipeline mile in Alaska as reported by the Alaska Department of Environmental Conservation (ADEC). The number of incidents reported for BP is consistent with that of other primary operators in Alaska.

Exhibit 8: Number of Corrosion-Related Spills per Line Mile



Note: 1) *Spill data is counted for corrosion-related spills on Oil Production and Transmission Pipeline facilities, as reported by ADEC.*
2) *Line miles are estimated based on publicly available data. Unregulated pipeline miles for each company were estimated at the rate of 0.41 miles for each well identified by the Alaska Dept. of Natural Resources (the 0.41 ratio is calculated using BP's data). Regulated miles were identified in the 2006 Lease Compliance Monitoring Report of the Alaska State Pipeline Coordinator's Office.*
3) *BP includes Arco data prior to acquisition; ConocoPhillips includes Phillips data prior to acquisition; Chevron includes Unocal data prior to acquisition.*
4) *ExxonMobil reported no corrosion-related spills for Oil Production or Transmission Pipeline facilities from 1995 to 2006.*

Source: ADEC Spill Database, 1995-2006

Regulatory

BPXA operates under numerous and sometimes overlapping regulatory jurisdictions and authorities. Specific to the operation of the pipelines and more specifically the OTL, BP operates under the jurisdiction of the following governing bodies:[16]

- U.S. Department of Transportation (DOT) Pipeline Hazardous Materials Safety Agency (PHMSA)
- U.S. Environmental Protection Agency (EPA)
- Bureau of Land Management (BLM) for onshore leases
- U.S. Coast Guard (USCG)
- Alaska Department of Environmental Conservation (ADEC)
- Alaska Oil and Gas Conservation Commission (AOGCC)
- Alaska Department of Natural Resources (ADNR) Division of Oil and Gas
- Occupational Safety and Heath Administration (OSHA)
- Alaska Occupational Safety and Health Administration (AKOSH)

PHMSA and ADEC are the critical regulators for corrosion and integrity issues—and thus, are the focus of this discussion.

PHMSA Regulations and the OTL

PHMSA has regulatory authority over common carrier transportation pipelines and high-pressure lines. The agency also has jurisdictional authority to regulate to the wellhead, if they so desired. Large-diameter, low-stress, in-field pipelines are part of an exemption granted in 1969.

49 Code of Federal Regulations (CFR) Part 195 is the section of the federal regulations that addresses all pipeline safety. Under 49 CFR Part 195.2, BPXA's OTL are low-stress pipelines as they operate at less than 20 percent of the specified minimum yield strength. Under exception 49 CFR Part 195.1, federal hazardous liquid pipeline safety regulations do not apply to onshore, low-stress pipelines that are located in rural areas, do not transport highly volatile liquids, and are outside of a waterway currently used for commercial navigation.

Currently, PHMSA is proposing regulations that would bring the OTL under its regulatory control as the agency invokes a large-diameter, low-pressure pipeline through an Unusually Sensitive Area (USA) clause.[17] Comments on the proposed rules were due by November 6, 2006. At the time of this writing, the final regulation has not been issued. The impact of the OTL falling under CFR 195 is requirements for inspections, leak detection system, damage prevention, training for abnormal conditions, and public education requirements.

ADEC Regulations

Alaska Administrative Code 18 Part 75 (18 AAC 75) addresses oil and other hazardous substances pollution control. Sections 055 and 080 specifically address pipeline transmission. The key aspects of the regulations mandate a working leak detection system, the ability to stop the leak within an hour, and inspection and testing requirements. [18]

When the Charter Agreement with Alaska was signed after the ARCO acquisition, the state placed an additional requirement for a performance management system to monitor corrosion. Under this program, BP is required to meet and confer with ADEC and the other operators, report annual progress as a minimum, and consult with ADEC regarding various technologies and practices that could be improved.

Significant Regulatory Events

ADEC: In January 2002, a Compliance Order by Consent (COBC) was issued to close a long-standing compliance issue with a leak detection system that began in 1999.

In March 2003, after $150,000 in fines paid to ADEC for out-of-compliance lines, BP was able to close out this COBC by installing and testing an approved leak detection system on the OTL. There was an additional COBC in 2001 related to spill response classifications and training. This COBC included a $10,000 fine to BP where non-compliance was identified over a short period (2 to 3 months).

EPA: As a result of a hazardous substance violation in 1995, the EPA fined BXPA and required changes to its operating procedures by installation of a comprehensive environmental management system (EMS). As part of the settlement of this issue, BPXA was on probation for five years.

PHMSA: As a result of the recent spills, PHMSA has issued three Corrective Order Amendments (COAs) to BPXA this year requiring more comprehensive inspections of the company's North Slope pipelines and pigging of the OTL.

Outside Reports

From 1995 to 2006, a series of outside reports were commissioned to review BP's corrosion management program and related activities. Generally, these reports were complimentary of BP's corrosion management programs and technical capabilities. Later reports in 2003 highlighted issues of internal corrosion; however, CUI remained a focus. Table 3 summarizes the findings of these reports.

Table 3: Summary Findings of Corrosion Management Reviews

Date	Timeline Reference	Report Title	Summary Findings
2000	Coffman Report	Corrosion Monitoring of Non-Common Carrier North Slope Pipelines, Technical Analysis of BP Exploration (Alaska) – Commitment to Corrosion Monitoring	▸ Corrosion was lowest level in 12 years ▸ CUI suggested as the cause of leaks in 2000
2000	Freestone Report	Global Operation Integrity Assurance Review, GPB B.U.	▸ Difficulty in characterizing the extent and likelihood of failure due to CUI ▸ More effective resource planning is required ▸ Need to confirm resource requirements – especially in support skills like Process, Facility and Electrical/Instrumentation
2001	Coffman Report	Corrosion Monitoring of Non-Common Carrier North Slope Pipelines, Technical Analysis of BP Exploration (Alaska) – Commitment to Corrosion Monitoring	▸ Internal corrosion for cross-country and well lines was "clearly being controlled" ▸ External corrosion identified as most significant risk
2001	Operations Review Team Report	Review of Operational Integrity Concerns at Greater Prudhoe Bay	▸ Management did not effectively communicate how worker concerns were being incorporated in the decision-making process ▸ Management was forced to make decisions based on incomplete data because

Date	Timeline Reference	Report Title	Summary Findings
			management systems did not capture and track key data ▸ The organization did not clearly assign accountability for delivery of operational integrity ▸ Increased external corrosion monitoring was recommended ▸ Budget pressure over last 10 years had been imposed on them by GPB owners
2002	Coffman Report	Corrosion Monitoring of Non-Common Carrier North Slope Pipelines, Technical Analysis of BP Exploration (Alaska) – Commitment to Corrosion Monitoring	▸ Internal corrosion for cross-country and well lines was "clearly being controlled" ▸ External corrosion identified as most significant risk
2003	Coffman Report	Corrosion Monitoring of Non-Common Carrier North Slope Pipelines, Technical Analysis of BP Exploration (Alaska) – Commitment to Corrosion Monitoring	▸ Isolated areas of internal corrosion were found ▸ External corrosion identified as an ongoing priority
2004	Vinson & Elkins Report	Report of BPXA Concerning Allegations of Workplace Harassment from Raising HSE Issues and Corrosion Data Falsification	▸ Incorporating HSE incidents as performance metrics on contractor management had potential side effect of creating pressure to not report incidents ▸ Report did not uncover any evidence to suggest falsification of corrosion inspection data ▸ A complete audit of the corrosion program was recommended in light of the accusations
2005	Baxter Report	BPXA Corrosion Management System Technical Review (Report #5001-104)	▸ Current corrosion strategy needs updating to reflect long-term business strategy ▸ Planning and budgeting should shift from flat lifting costs to consider lifecycle implications of corrosion management ▸ Development and implementation of succession program for key positions ▸ Further development of internal communications regarding corrosion management ▸ A technical review should be performed to complement the existing inspection and mitigation program

Sources: BPXA, ADEC, Booz Allen analysis

V. DESCRIPTION OF THE CORROSION MANAGEMENT SYSTEM THROUGH MARCH 2, 2006

Summary: As of March 2, 2006, corrosion issues were managed by a governance model, dedicated organization, a set of processes, and supporting information systems. Prior to 2004, the general consensus was that BPXA had a robust corrosion management system in place, although related management systems (EMS and HSE) exhibited some deficiencies mostly related to documentation and compliance with processes.[1] In 2005, an internal audit highlighted a number of management system deficiencies in the areas of corrosion strategies, planning and budgeting, resource management, and internal communication.[2]

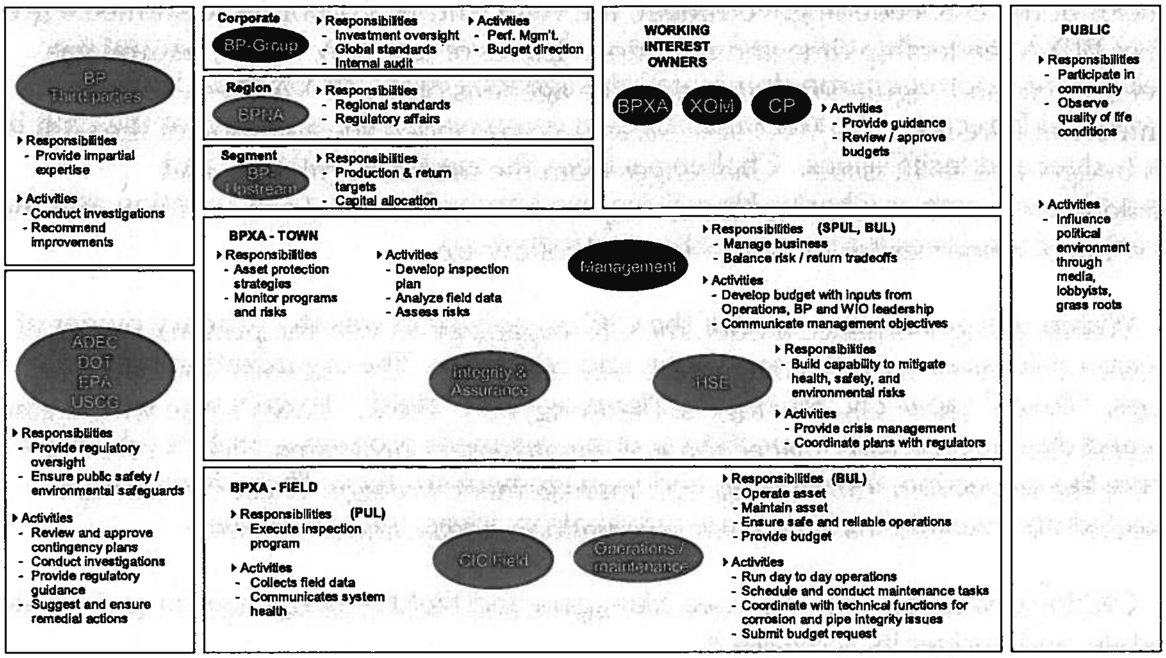
The following sections discuss various aspects of BPXA's corrosion management system.

Governance Model Overview

GPB is one of several, and by far the largest, BU under the BPXA SPU. Within this BU, Field Operations constitute the primary performance unit (PU). Consistent with the BP governance model, performance contracts are used to govern the BUs and PUs. Both the BULs and PULs are given significant autonomy to deliver against these performance contracts.[3]

BPXA operated in an environment with multiple internal and external stakeholders, as illustrated in Exhibit 9. Although a number of outside parties had varying levels of control and oversight, responsibility for maintaining and operating the assets rested predominantly in the Field organizations.

Exhibit 9: Governance Model



Source: Booz Allen analysis

Within BP's corporate reporting structure, management received information from North Slope operations and forwarded updates to BP America and BP global headquarters in London at weekly, monthly, quarterly, and annual intervals. The annual planning process was used to establish performance goals and operating budgets, which were then translated into objectives for the BUs and the PUs.[4]

Since BPXA ran all North Slope operations, the budgeting and planning process included the additional step of obtaining authorization from the other WIO, ExxonMobil and ConocoPhilips. The WIO collectively arrived at operations and maintenance (O&M), Operating CAPEX, and major repair budgets based on top-down direction and initial submissions. BPXA provided the WIO with quarterly updates in addition to the annual budget development process.[5]

Beyond the WIO, BPXA also interfaced with state and federal regulators such as ADEC, the U.S. DOT, and EPA.[6]

In addition, BPXA's governance model included periodic reviews, audits, or both. These could be conducted by other BP entities or by outside third parties. These groups collected data and interviewed all levels of the BPXA organization and provided recommendations to address areas for improvement.[7]

Other significant stakeholders included the greater public, varying from local communities to national media to international non-governmental organizations. They were capable of influencing the political and business environments.

Managing relationships with external stakeholders such as the State of Alaska, agencies of the U.S. Federal government, the WIO, and BP corporate consumed a great deal of BPXA leadership time and attention. Issues of taxation, leases, natural gas development, and regulation dominated the agendas of the BPXA President and Commercial Director. The WIO and Alyeska commanded the attention of the GPB BUL with budget and tariff issues. Challenges from the media, regulators, and whistleblowers such as Charles Hamel required immediate and full attention and the allocation of resources for investigation and follow-up.

Within this governance model, the CIC organization was the primary owner of corrosion risk assessment, management, and assurance. The organization had two groups, "Town" (now CIC Strategy & Planning) and "Field." Town's role was to assess risks and design corrosion inspection and management programs. Field's role was to execute the inspection, monitoring, and management strategy. These two groups interacted on a weekly basis to share information, ideas, and problems.[8]

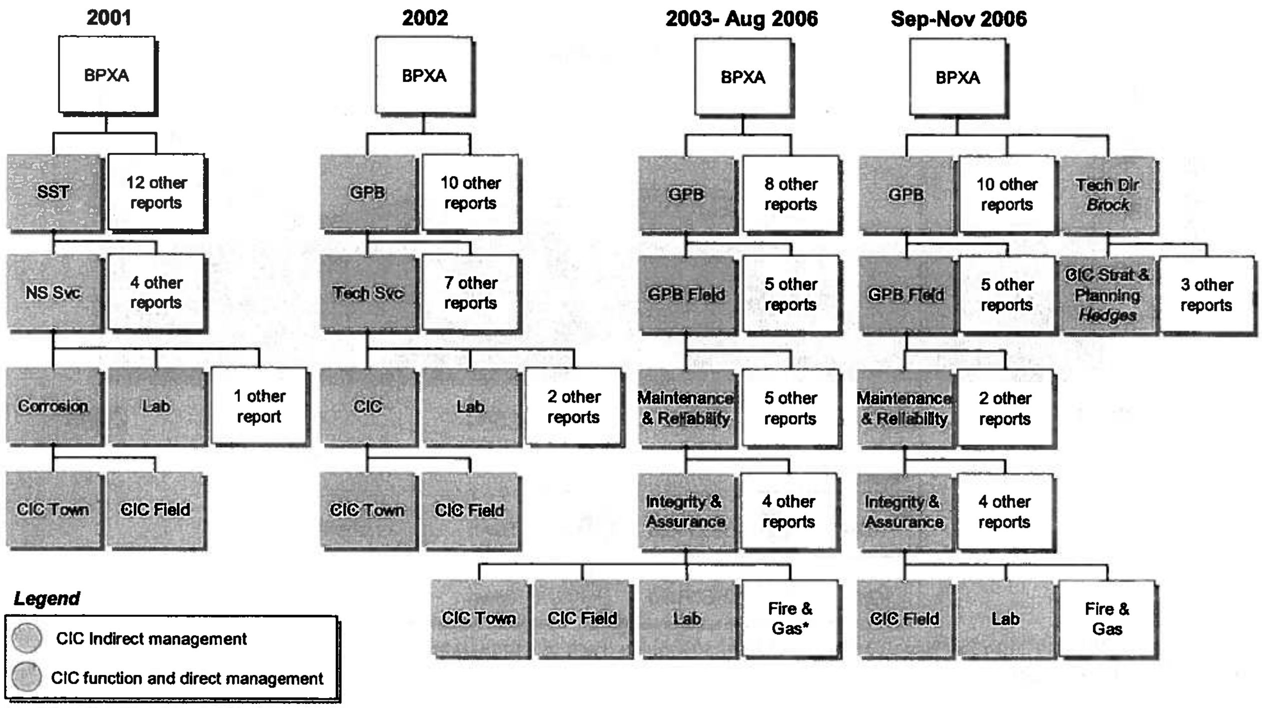
CIC Field worked with the Area Managers and Field management to coordinate, schedule, and budget its activities.[9]

CIC Town was also responsible for assurance. It was to ensure that the inspection, management, and abatement activities were performed according to plan and policy. It was responsible for reporting issues up through Field management as needed.

Corrosion Management Organization

The CIC function has evolved over time. CIC first appeared as a distinct entity in 1995, called "Plant Inspection." Beginning in 2001, CIC appeared as part of the the SST function. In 2002, the SST function was moved under GPB. In 2003, CIC was moved further down in the organization under the Operations Support department, as illustrated in Exhibit 10.[10]

Exhibit 10: CIC Evolution in BPXA

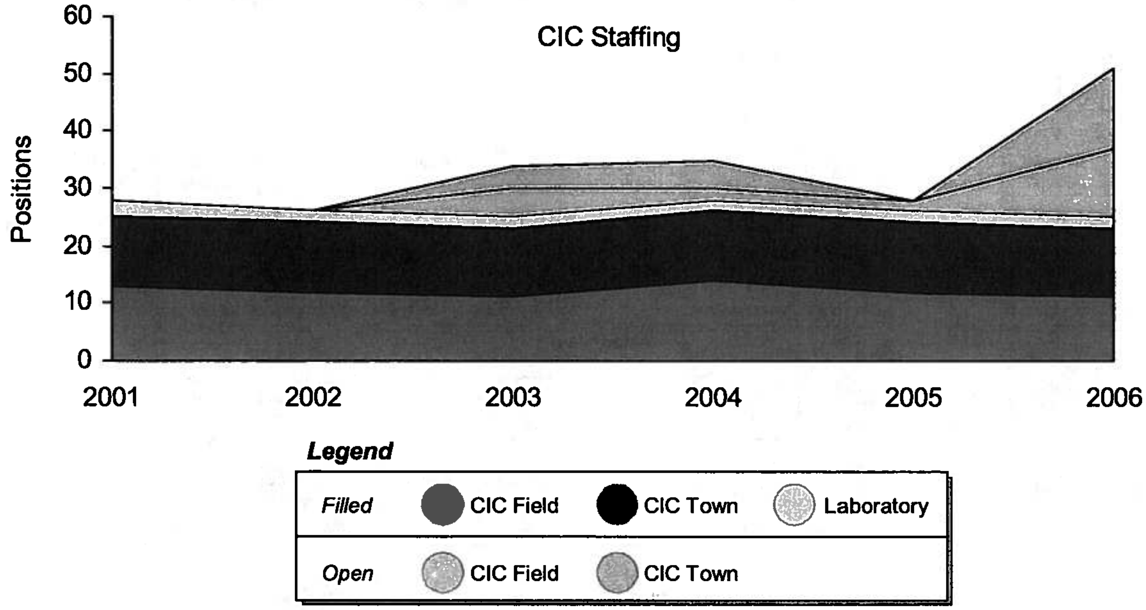


Notes: 1) Assistants not included in number of reports
2) Fire & Gas added in 2005
Source: Booz Allen analysis

CIC remained at this reporting level from 2003 until August 2006. The manager who had run the CIC function since its inception was moved out of his role in 2004; his replacement arrived in July 2005. In 2004, the leadership structure was changed to create a CIC Town manager. Both Fire and Gas and CIC report to the Integrity and Assurance function under Field Maintenance and Reliability.[11]

The staffing of the CIC functions remained fairly stable since the ARCO integration in 2001 (see Exhibit 11). When unfilled staffing needs were first tracked in 2003, their number fluctuated between one and nine. After the March 2006 event, open CIC positions increased monthly from 2 to a high of 30. After restructuring the CIC functions in September 2006, the open positions stabilized with 19 open needs in CIC Strategy & Planning and 14 in CIC Field.

Exhibit 11: CIC Manpower Positions

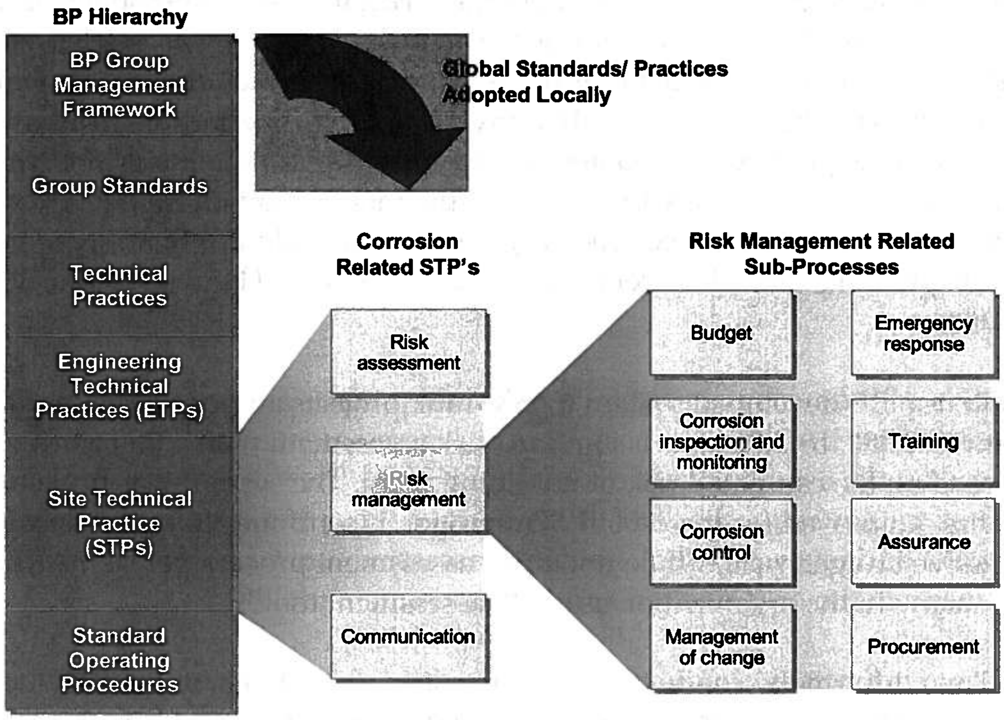


Note: Prior to 2003, BP did not have a position control system to track open positions
Source: Booz Allen analysis

Key Processes

BP has a formal hierarchy of policies, processes, and procedures to ensure alignment between the Group management framework and the standards, practices, and procedures used throughout the organization (see Exhibit 12). For the purposes of this study, we focused on GPB practices pertaining to corrosion management.[12]

Exhibit 12: BP Hierarchy of Policies, Processes and Procedures



Source: Booz Allen analysis

Risk Assessment

There are formal and informal risk assessment processes at BPXA. Formal risk assessment approaches include the Hazard and Operability Studies (HAZOP), Major Accident Risk (MAR), Major Accident Hazard Assessment (MAHA), and Business Activity Risk Ranking System (BARRS). The informal processes include individual risk assessments and historical trends performed by both Field and Town CIC groups.

HAZOP studies were performed on all facilities that contained processes that fall under the BPXA Process Safety Management (PSM) program as defined in the BPXA PSM Application Element Administrative procedure. These HAZOP studies focused on personnel safety and were conducted on operations only within facilities; operations outside of the defined facilities were not covered.[13]

From 2003 to 2004, driven by the PS/IM standard, a risk assessment of the GPB PU using the MAHA process was conducted by the Emerald Consulting Group, a third-party consultancy. MAHA is a qualitative evaluation technique used to identify major hazards that have the potential for catastrophic loss of facility, major loss of life, irreparable damage to the environment, and/or damage to corporate reputation. Risks are evaluated using a 5-by-5 probability versus consequence risk-ranking matrix.[14]

As required by the new BP Global IM Standard, a risk assessment was performed in 2005 on the Alaska SPU using the MAR process. In preparation for this, Emerald

Consulting Group revalidated the 2003/2004 MAHA register to use as an input to the MAR study. The MAR process evaluated potential risk to on-site personnel, off-site personnel, and the environment. Consequence analysis software was used to predict the severity of events, and industry data (or BPXA specific historical data when available) were used to estimate frequency. The MAR process only evaluated the resultant output of the event from the generic list of potential scenarios identified; it was not concerned with the causes of these scenarios. Output from the model provided F-N curves—a curve showing the cumulative frequency (F) of incidents and number of people harmed (N)—and weighed the identified scenarios for risk ranking.[15] The report was delivered in March 2006.

BARRS is a BP-developed system to risk-rank projects and operating budget items larger than $100,000. BARRS uses a standard risk assessment matrix to prioritize projects based on the estimated risk of not doing them. The system was implemented in 2004, and first employed for the 2005 BPXA budget. It continues to be enhanced with each successive budget cycle. While not a risk assessment process per se, BARRS is viewed by many in the organization as a risk assessment tool.[16]

CIC Town informally conducted corrosion risk assessments of the BPXA pipeline infrastructure; there was no formal risk assessment process or tool employed. These assessments were performed idiosyncratically based on technical expertise, knowledge of conditions, inspection trend data, and historical experience. High-pressure lines, two- and three-phase flow lines, seawater lines, and produced water lines were identified as higher risk for internal corrosion than the OTL, which carried sales-quality crude. External corrosion, particularly CUI was widely regarded as the greatest corrosion risk on the North Slope. While these assessments were often thorough, they were not holistic, formal, or rigorous.[17]

Risk Management

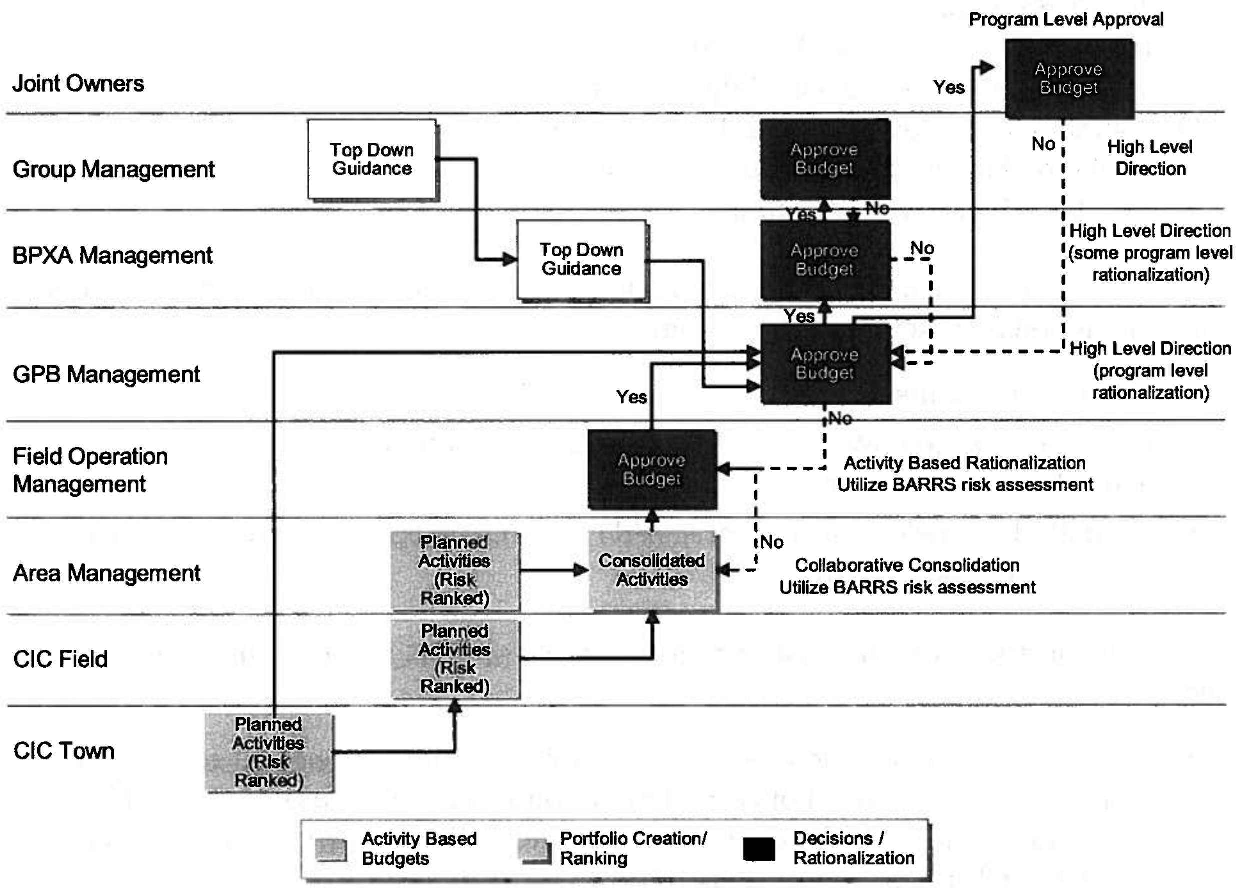
The risk management processes included a variety of activities to incorporate the planning, execution, and assurance of corrosion risk management. These processes include budgeting, corrosion inspection and monitoring, corrosion control, training, management of change, emergency response, assurance, and procurement.

Budgeting

The overall budgeting process combined a strong top-down target with a bottom-up, activity-based process. The Area Managers and CIC Field groups developed requests for their planned activities based on workload and expected expenditures (e.g., equipment replacement). Prioritization of requested activities then took place at the Area Manager level. This area budget was then taken to the Field level where GPB Field-level rationalization and prioritization took place. The Field-level budget was then proposed to the GPB leader. Budget direction from the Group, BPXA, and the WIO were then applied to the requested budget from Field. Top-down targets were considered sacrosanct and were rarely exceeded.

Since 2004, the prioritization and rationalization effort used BARRS to assess large (over $100,000) O&M and CAPEX projects. The prioritization of funding for CIC activities was coordinated between the Town and Field CIC groups and the Area Managers. The revised budget was then approved successively up to GPB management and the WIO. This approved budget was then submitted to BPXA. Exhibit 13 illustrates the various steps of the process.[18]

Exhibit 13: Budget Process



Source: Booz Allen analysis

Corrosion Inspection and Monitoring

Management of corrosion in North Slope oilfield pipeline systems followed a general control-inspect/monitor-control process loop. Monitoring and control process distinctions existed in how internal and external corrosion issues are addressed. Overall, the approach and focus on particular subsystems and locations was prescriptive and tended to remain static over time.[19]

Corrosion inspection and monitoring procedures were directed by what is now CIC Strategy & Planning in Anchorage. Routine inspection activities and inspection campaigns were carried out by the Integrity Management team (CIC-Field) under the GPB Field Management/Maintenance organization. CIC integrity management concentrated on monitoring piping sections with predetermined inspection evaluation and piping "fit-for-service" criteria. CIC maintained and adjusted these criteria periodically. By categorizing and assessing inspection results ("A" through "F"), CIC determined and initiated needed corrective actions and/or further inspections. [20]

The inspection categories for allowable wall loss were:

A - 0% or no damage
B - 0% to 20% allowable wall thickness loss
C - >20% to 40% allowable wall thickness loss
D - >40% to 60% allowable wall thickness loss
E - >60% to <80% allowable wall thickness loss
F - 80% to 100% allowable wall thickness loss, or not fit for service.

For piping segments, given the current segment ratings, monitoring and inspection focused mainly on assessment of three elements:

- Time since last inspection
- Estimated average wall thickness of pipe segment based on last and prior inspection information
- Estimated corrosion rates experienced since last inspection, based on time and corrosion coupon readings.

The CIC protocol for corrosion management of the OTL included inhibition and inspection techniques:

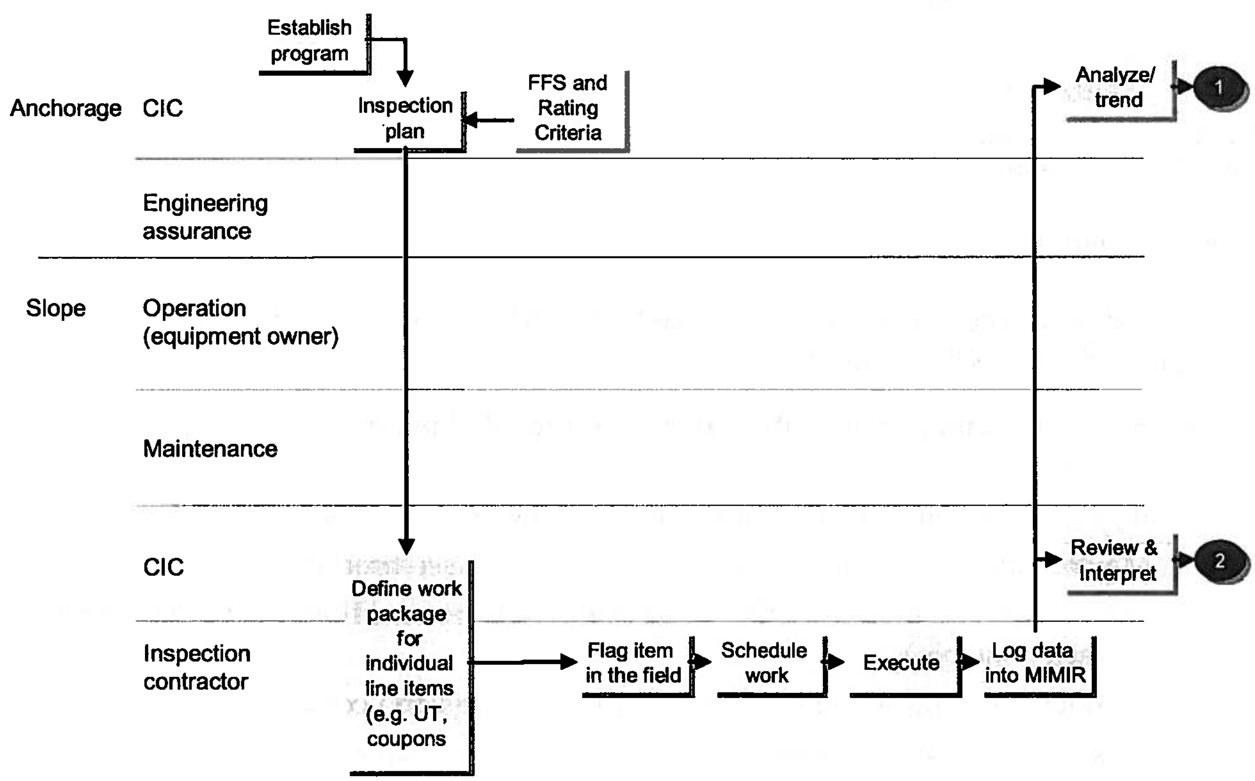
- *Corrosion inhibitors,* which also act as a biocide, were injected upstream of the OTL regularly. The level of corrosion inhibitor required was determined by electrical resistance (ER) probes, which took readings of the corrosive potential of pipeline fluids every 4 hours.
- There were *corrosion coupons* that were pulled on a 3- to 4-month frequency to confirm the efficacy of the corrosion inhibition system in the OTL. These were used to monitor the corrosion rate, which had a target of no more than 2 millimeters per year (mpy).
- *UT inspection* was used to monitor internal corrosion on the OTL because they were almost entirely above ground. UT readings were taken across the entire circumference of a one-foot length of pipe.
- *In-line inspections (ILIs)* or "smart pigging" was performed periodically on the OTL. The WOA OTL were smart pigged in 1998; the EOA OTL were last smart pigged by ARCO in 1991, but the results were invalid.

In 2005, GPB conducted 59,494 inspections; analyzed 7,500 coupons; injected 2,660,000 gallons of chemical inhibitor; and ran 192 maintenance pigs and 3 smart pigs across the entire North Slope pipeline network.[21]

CUI was a significant risk, particularly at the 300,000 locations where pipe sections were welded ("weld packs"). External inspections for CUI were performed primarily using radiographic testing (RT). Locations where corrosion was indicated were scheduled for visual inspection, which entailed removal of the insulation.

Pipe interior and exterior wall inspections on the North Slope were performed by contract inspectors, licensed to appropriate levels to conduct UT and RT inspections. Contractors followed a set work program, with locations pre-defined. Within the contract terms, CIC had some flexibility to adjust locations or add inspection points. Any significant redirection was initiated by a change order from CIC Town in the form of a Special Project Request (SPR). Exhibit 14 illustrates the corrosion inspection process.[22]

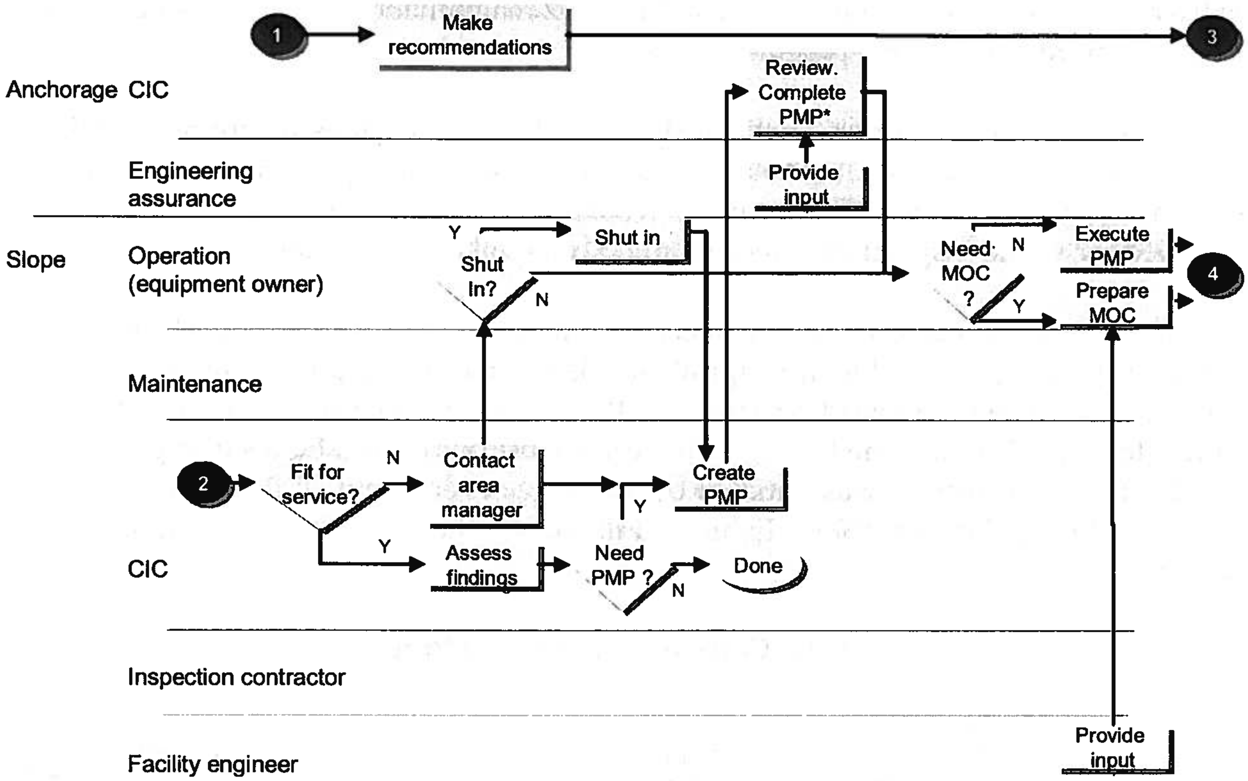
Exhibit 14: Corrosion Inspection Process



Source: Booz Allen analysis

If inspections or other observations indicated piping was not fit for service, or if conditions indicated the pipe section integrity was at risk for any reason, a Piping Modification Process (PMP) was developed with recommended scheduled or immediate actions. Exhibit 15 illustrates the PMP.[23]

Exhibit 15: Corrosion Management



*Note: *With completion schedule*
Source: Booz Allen analysis

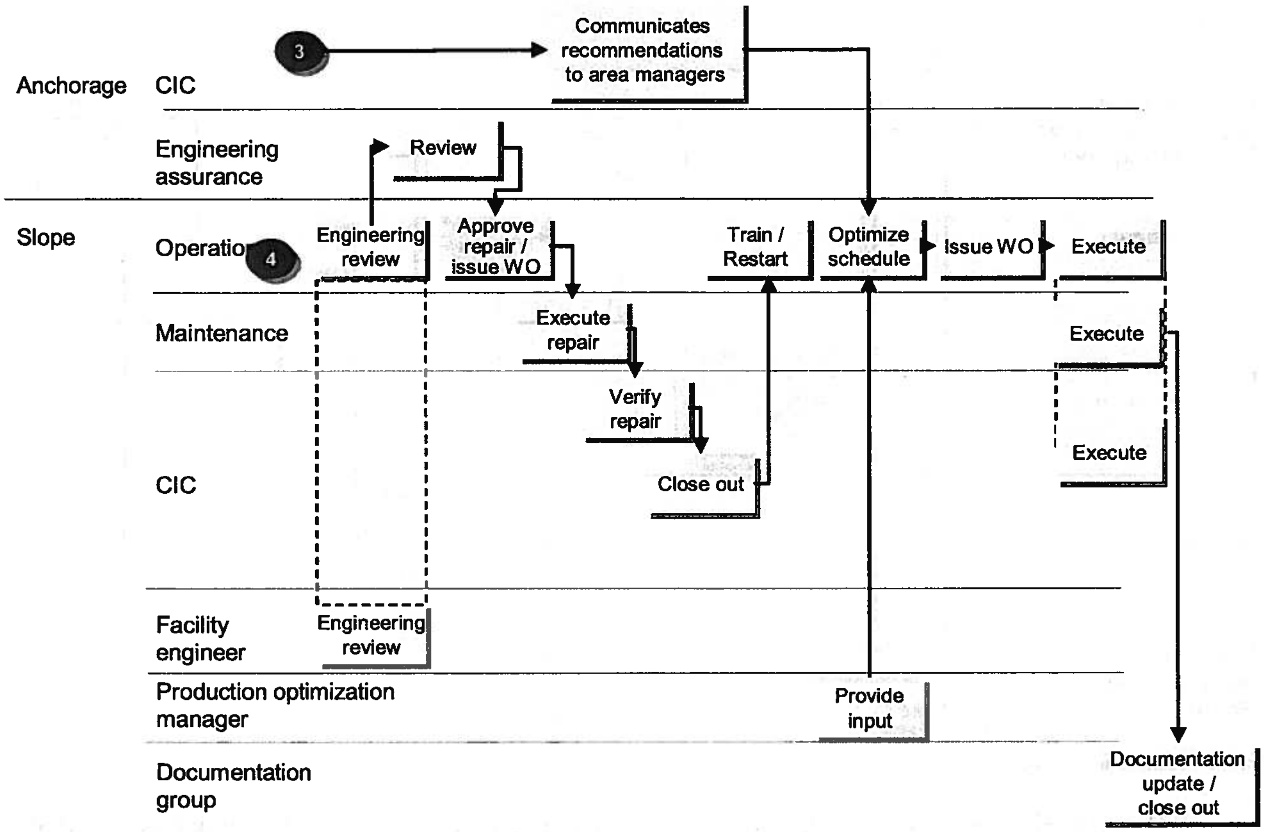
Corrosion Control

The corrosion control approach utilized for North Slope production and transit piping includes six basic measures: [24]

- Separation and removal of water and sediment at manifold and oil processing facilities
- Injection of chemicals to inhibit corrosion and bacterial action
- Maintenance of adequate flow rates to minimize sedimentation
- Mechanical sediment cleaning and removal by internal flow device (cleaning or maintenance pig)
- Maintenance and repair of external pipe coatings and coverings
- Execution of PMP-driven repairs.

CIC planned maintenance and repair work based on inspection results, Integrity Management standards, engineering orders, and inputs from the Pipeline Assessment Team. CIC finalized PMPs in process, and developed work packages in consultation with Field Operations and the Engineering Authority. For a PMP, CIC followed up on implementation and inspection of completed work. Exhibit 16 illustrates the process for the implementation of corrosion control measures.[25]

Exhibit 16: Corrosion Management (Cont'd.)



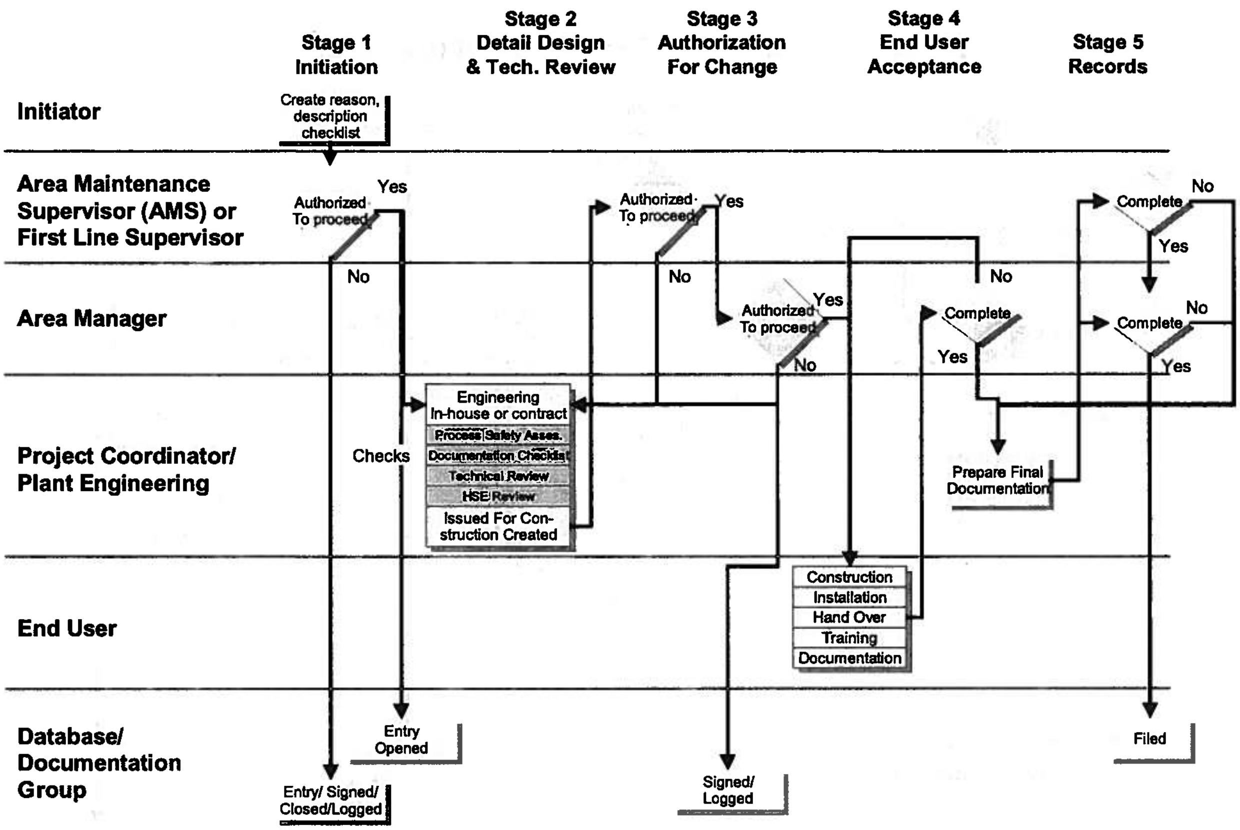
Source: Booz Allen analysis

Management of Change

Management of Change (MOC) was the process used to manage and account for changes to any project plan, system, management process, or operational practice. For the pipelines, MOC was used to track changes in piping configuration or piping performance limits. In the case of a PMP that could not be accomplished in the prescribed manner by the prescribed deadline, an MOC was developed and approved to either provide an alternate solution or de-rate the pipe section. De-rating could lower the fit-for-service threshold, re-establishing the section as fit for service at reduced operating pressures and flows. In effect, a reduction in operating capacity was a tradeoff for added time before the section must be repaired or shut in.[26]

BPXA had a formal "Technical Management of Change Process" procedure manual. Included in this manual were guidelines for proceeding with an emergency change, a temporary change, or a permanent change. Exhibit 17 outlines the permanent change process. An MOC database was maintained, including copies of all relevant files.[27]

Exhibit 17: Management of Change Process



Source: Booz Allen analysis

Although the closure of each MOC was dutifully documented, the process did not provide a feedback loop to update institution-wide knowledge and keep track of every change (e.g., extent of pipe de-rating across the network), and there was no re-inspection to validate that the documents accurately reflected the final physical changes.

Emergency Response

The Area Manager was a major decision maker in the process of taking appropriate actions to prevent and mitigate a discharge of oil from components under the manager's responsibility. The Area Manager was involved in all decisions concerning the potential release of oil and in approving steps to defuse a potential situation. The emergency response process included emergency shut-in, internal and external notification, and spill containment:

- *Emergency Shut-in:* The loss of pipeline integrity and/or emergency conditions on site or at connecting pipelines may require emergency shut-in to lower the pressure in the pipe and minimize environmental damage and product loss.

- *Internal Notification:* Spills are identified as Tier I, II, or III depending on their size. The chain of command to notify internally is well established with levels of authority defined based on the magnitude of the spill.
- *External Notification:* Spill notification to external agencies is facilitated differently depending on the size of the spill. Notifications for a Tier I spill are handled by the GPB Incident Commander. Notifications for Tier II and Tier III spills are handled by the GPB Environmental Team Leader.[28]
- *Spill Prevention:* Personnel safety and safe handling procedures for fluid transfer protocol follow the best management practices of North Slope Operations including information on the use of drip liners and fuel transfer guidelines, procedures, and checklist.

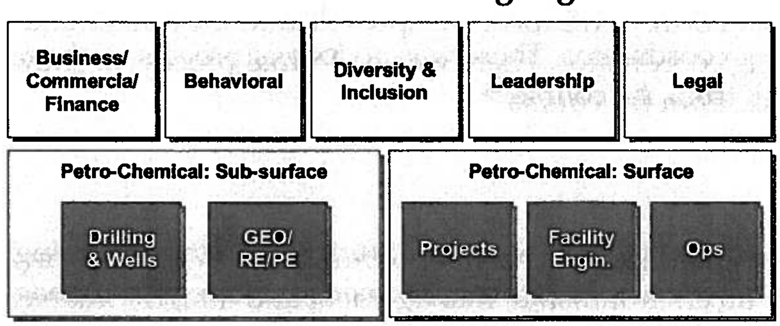
The incident management organization structure was depicted in the GPB Oil Discharge Prevention Contingency Plan and the BPXA Incident Management Manual. The Incident Management Team (IMT) structure for BPXA was identified by name, position, and function. The North Slope IMT included positions typically found in an Incident Command System, with the exception of the Information Officer, Liaison Officer, and Finance Section, which are provided by Anchorage.[29]

Training

BPXA had a variety of relevant training programs available to technical and field staff. These programs were reviewed on an annual basis. Capability gaps were identified through a learning needs assessment process and classes were targeted to fill the identified gaps. Responsibility for establishing the curriculum was segmented among the HSE group for compliance-specific training and the Staff Development and Deployment Network (SDDN) and Area Managers for managerial and technical training. Individual supervisors were responsible for ensuring staff attended the identified training. The Learning and Organizational Development team administered all training.

Non-HSE training was split into seven segments, as shown in Exhibit 18. Each segment had a "Champion" responsible for content and leadership. Both petrochemical segments also had a SDDN identified in addition to the champion.

Exhibit 18: BPXA Training Segments



Source: Booz Allen analysis

Two types of classes within the non-HSE training framework were critical as they relate to corrosion issues. Both classes were offered through the "Petro-Chemical: Surface" training sub-curriculum. The first was risk management training offered in the "Projects" sub-category, and the other was integrity management/PSIM training offered through the "Ops" sub-category.

- ***Risk Management Training:*** In 2006, risk management training was offered through the course "Managing Risks in Projects." It was based on global BP's professional generalist program. Twenty-seven staff members from BPXA attended the class in 2006. The focus was on managing project risk, but also covered all of the critical areas of effective risk management, including identification, assessment, response, risk control, and risk learning. An outside vendor instructed the course, which was previously offered in 2004 to BPXA staff. *Note: A "Risk Analysis Toolkit" course was also offered in 2006; however, this class was focused on business risks (offered through the business segment) and the spreadsheet-based tools to quantify them.* [30]
- ***Integrity Management Training:*** In 2006, an "Integrity Management Fundamentals" workshop was offered to BPXA employees. The vendor was Det Norske Veritas (DNV), who was also the contractor responsible for the development of the BP Global IM standard. Twenty-two BPXA staff members attended the workshop, which covered all of the basic elements of the Global BP standard including accountabilities, competencies, risk assessment, change management, corrosion management, and performance standards. Integrity management training was planned in both 2003 and 2005, but classes were never scheduled. A "Corrosion Basics" training class was offered in 2005 that included some elements of integrity management. [31]

The HSE department administered HSE training for both BP staff and contractors. Each position had a structured HSE training matrix, identifying required courses, to ensure compliance and certification at critical positions. The HSE training curriculum focused on process and personal safety and emergency response.[32]

All training was tracked via a database contained in Virtual Training Assistant (VTA, on BPXA intranet). VTA included information on the course, instructor, attendees, and a brief course description. Each participant was requested to fill out a "Training Feedback Form." This form was provided to the trainer and the HR department training coordinator. There was no formal process to show the champions or SDDNs feedback from the course.[33]

Assurance

Assurance was handled by a number of functions. When focusing on corrosion, and more broadly on environmental management and integrity management, a number of entities were involved, including Group Internal Audit, Group Compliance and Ethics, and the HSE Management Group. Until 2003, Internal Audit was embedded in BPXA. Since then, it has been centralized at the Group level. Internal Audit established audit programs based on enterprise-level risks or in response to specific events (e.g., whistle blower). Since 2000, Internal Audit has conducted a number of audits in Prudhoe Bay:[34]

- 2001: *Operational Review Team,* triggered by management concerns on employee feedback
- 2002: *Getting HSE Right* (followed by a self assessment in 2005), Group wide initiative
- 2003: *Alaska HSE Compliance Review,* conducted at the request of the Group General Auditor
- 2005: *BPXA Corrosion Management System Technical Review,* triggered by a whistle blower (followed by a subsequent assessment in 2006 after the March leak).

The Group Compliance and Ethics conducted periodic audits of the Process Safety Management OSHA regulation (this was previously handled by Internal Audit until 2003). The PSM audits took place in 2002 and 2006. The BPXA HSE Management Group ensured the compliance of the environmental management system with the ISO 14001 standard. External audits (performed by DNV) and internal audits were conducted on a yearly basis.[35]

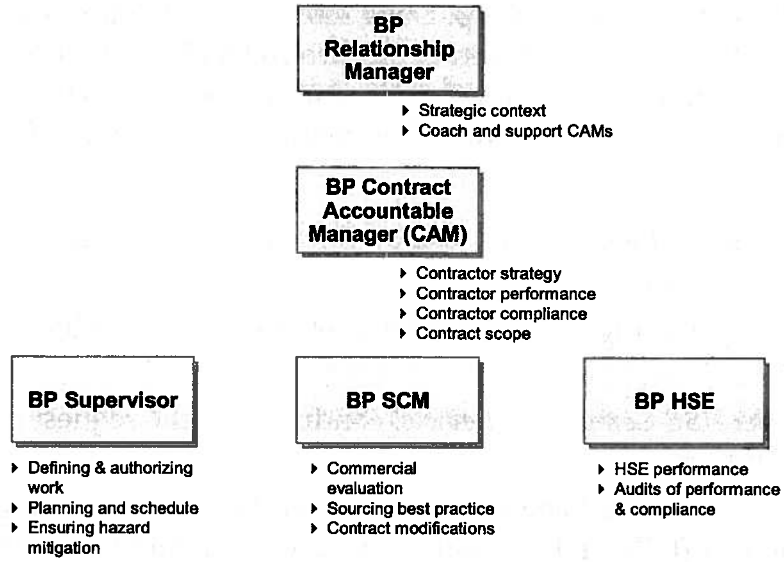
In addition to these audits, ADEC mandated external reviews of the BPXA Commitment to Corrosion Monitoring report by a third party (Coffman Engineering Inc.) on a yearly basis starting in 2000. With the exception of the Coffman audits and the 2005 Baxter report, the majority of the external reviews did not address corrosion management issues directly, but rather indirectly via environmental and health and safety management systems.[36]

The close-out of corrective actions was based on a self-verification/self-assurance model where the business was responsible for implementing and tracking (in the TRACTION system) the corrective actions.[37]

Procurement

Since BP employed extensive contractor support for operations, there was a formal process for selecting and managing contractors. Roles and responsibilities were clearly laid out in a contract oversight manual, and best practices were also available.[38] Exhibit 19 presents an overview of the roles and responsibilities.

Exhibit 19: Contractor Governance



Source: Booz Allen analysis

Safety risk and process safety management were handled through a standard HSE contract clause. This clause contained detailed information on HSE compliance responsibilities, training, and reporting. There were also clauses on auditing both compliance and HSE performance. Each contractor was required to produce an HSE plan for each contract that provided details of how they would manage HSE and the training plan for the contract employees. Contractors were required to use the TRACTION database for incident and compliance reporting. It was also typical for contracts to have HSE performance incentives.[39]

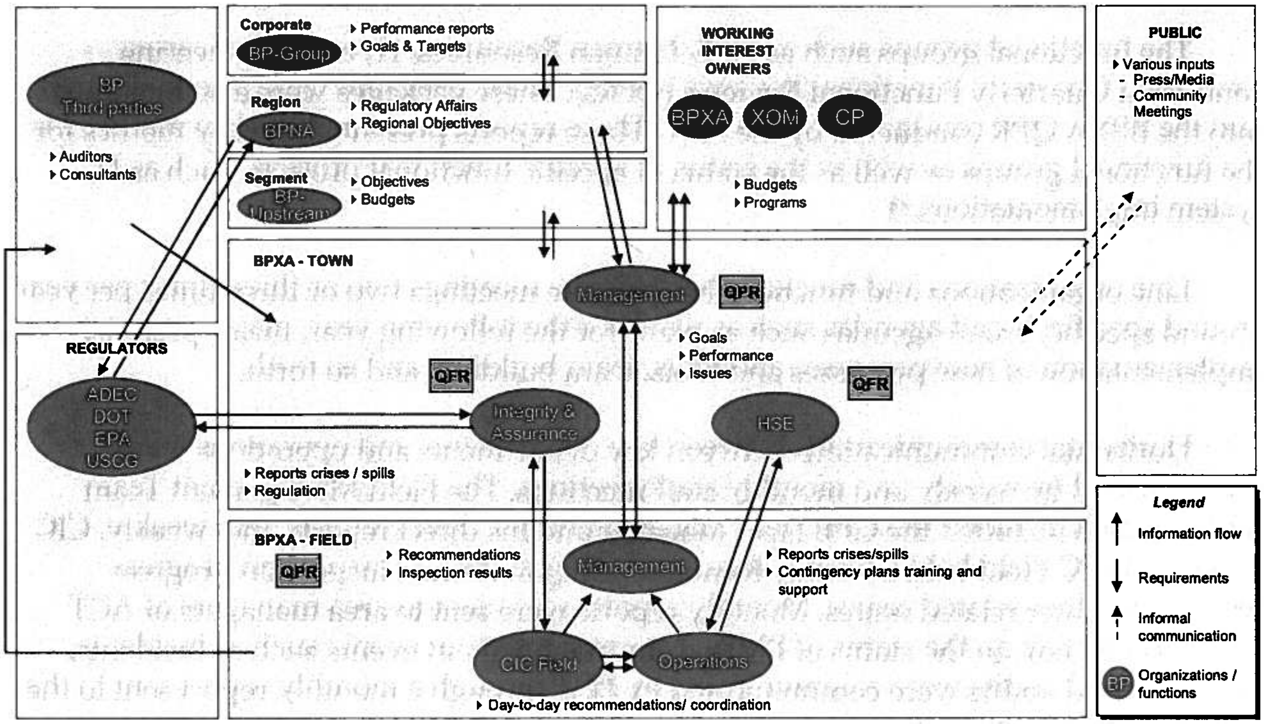
Communications

BP's communications structure included a complex network of internal and external stakeholders who provided and received information regarding the operations of the GPB unit as well as environmental and integrity issues.

Internal

Information flowed between the BPXA Field organizations and BPXA Anchorage organizations through a series of formal and informal reports and meetings. External communications occurred primarily at the BPXA Anchorage level, with the notable exception of communications with regulators who had direct communication with the Field. BPXA Anchorage also provided the primary conduit for operational, risk, and financial information to the Group and Regional organizations within BP, as well as to the WIO. Exhibit 20 provides a high-level diagram of these interactions.[40]

Exhibit 20: Information Flow Diagram



Source: Booz Allen analysis

BPXA had both vertical and horizontal communications, with formal reporting on the vertical dimension. Most of the horizontal communications occurred through scheduled meetings.

Vertical communications were carried out within the BPXA operations by a combination of monthly, quarterly, and annual reports and meetings. GPB communicated key information with respect to operations, integrity, health, safety, and environmental metrics for Prudhoe Bay to the Alaska Leadership Team (ALT) on a monthly basis through the Group Financial Operations (GFO) report.[41]

BPXA prepared Quarterly Performance Review (QPR) packages to guide the review meetings. This QPR package was sent to the BP Group office in London, and contained information on financials, human resources, operations, annual plan milestones, major and strategic project status, safety issues, renewals, and integrity management, as well as an incident summary.[42]

Each element of the line organization (PU and BU) conducted QPRs. Ideally, PU and BU QPRs were held before the BPXA QPR so that a comprehensive view of the Alaska operation could be rolled up for review by the ALT. The packages prepared by the line organizations summarized the financials, human resource, operations metrics, annual plan milestones, major and strategic project status, safety issues, renewals, integrity management, and incidents much as the BPXA QPR prepared for the Group office.[43]

The functional groups such as HSE, Human Resources, IT, and Engineering conducted Quarterly Functional Reviews (QFRs). These packages were also integrated into the BPXA QPR conducted by the ALT. These reports presented the key metrics for the functional groups as well as the status of specific functional projects, such as IT system implementations.[44]

Line organizations and functions held off-site meetings two or three times per year around specific, broad agendas such as plans for the following year, major projects, implementation of new processes and tools, team building, and so forth.

Horizontal communications between key departments and operations were accomplished by weekly and monthly staff meetings. The Field Management Team (FMT), which included the GPB Field Manager and his direct reports, met weekly. CIC Town and CIC Field held a weekly formal meeting to discuss inspection progress results and other related issues. Monthly reports were sent to area managers of ACT and Prudhoe Bay on the status of PMPs. Information about events such as incidents, HAZOPs, and audits were communicated by HSE through a monthly report sent to the managers of all groups in GPB.

In addition to the scheduled meetings, ad hoc meetings were conducted to discuss various projects and issues as needed by operations, CIC, and other stakeholders.

External (Regulator)

A large number of agencies with overlapping jurisdictions regulated BP's Alaska operations. The principal regulators of pipeline operations were ADEC, U.S. DOT/PHMSA, EPA, AOGCC, and Alaska DNR.[45]

The BPXA Vice President, External Affairs maintained a formal relationship matrix that identified primary responsibility for contact by each ALT member. In this de jure model, the Vice President, HSE had the relationships with the Commissioner of ADEC and the Alaska Director of EPA. The GPB BUL was responsible for the relationships with the Chairman and Commissioner of AOGCC. The President of BPXA had the relationship with the Commissioner of Alaska DNR.

Structured and formal communications came in the form of compliance documents (e.g., Corrosion Management Annual Report to ADEC, Spill Response Plan to PHMSA), responses to inquiries, compliance orders and responses (e.g., PHMSA Corrective Action Order of March 15, 2006), inspections and reports, comments on proposed regulations and regulatory changes, and formal hearings.[46]

The de facto distributed relationship management model did not always match the formal matrix. For example, because Mid-Stream Alaska (MSA) controlled the bulk of the U.S. DOT-regulated pipelines, the MSA BUL managed the relationship with the U.S. DOT. Similarly, the HSE manager handled the relationship with EPA. The GPB BUL managed the relationships with Alaska DNR and the AOGCC, and the Senior Attorney, HSE and Regulatory, managed the relationship with ADEC as a result of long-standing personal friendships and professional interactions.[47]

Since the March 2006 incident, many regulatory relationships have become strained. U.S. DOT/PHMSA has become very aggressive in their treatment of the OTL. The U.S. DOT has also complained that BPXA has abused the risk assessment provisions of the controlling regulations, and that the camps are, in fact, population centers and pipelines in their proximity are subject to regulation. The U.S. DOT has also asked that BPXA provide a single point of contact for regulatory matters.[48]

Information Technology Infrastructure

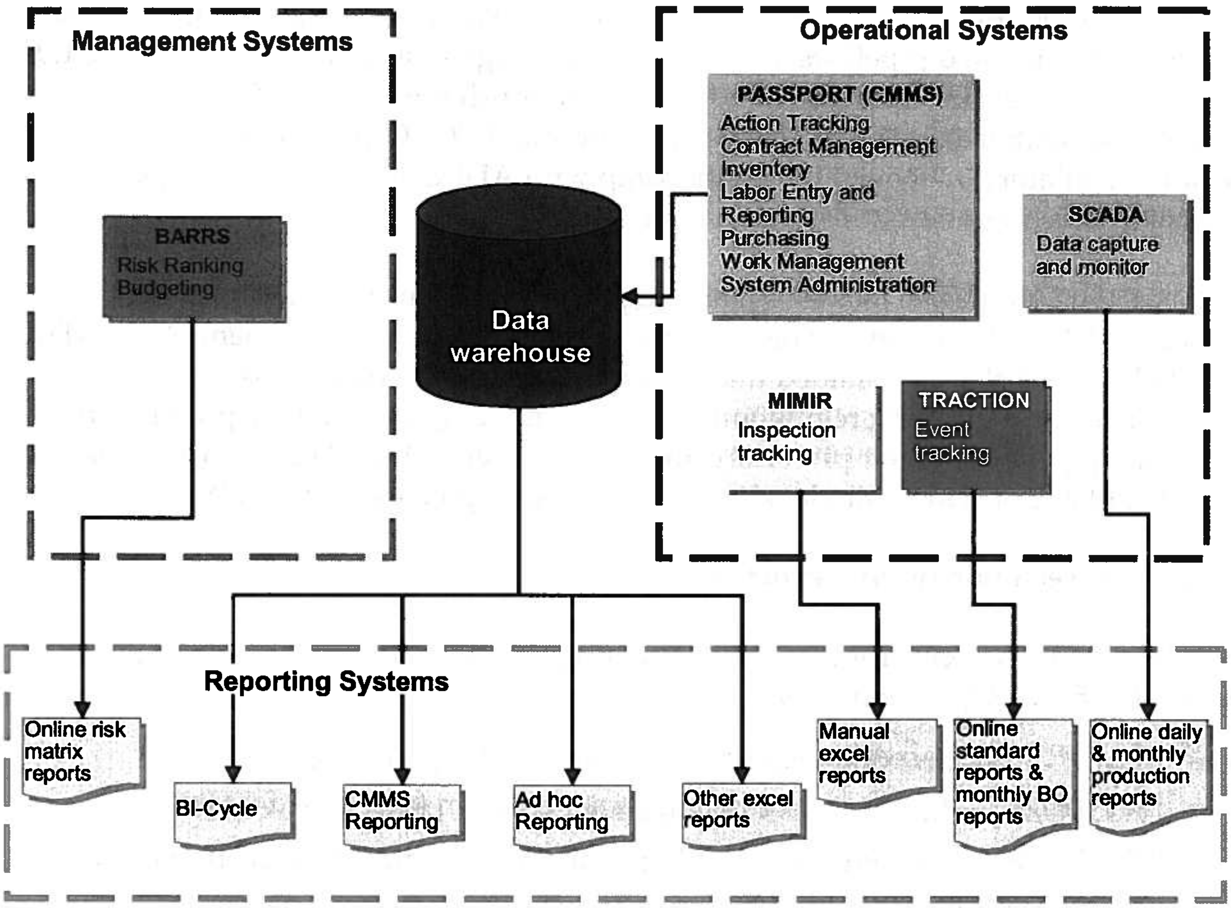
The primary systems for planning, executing, and tracking corrosion and integrity issues at the BPXA Operations were:

- *MIMIR* – The corrosion inspection data system for pipelines
- *PASSPORT* – The local work management system (also called CMMS)
- *TRACTION* – A system used by BP globally to store and track events such as incidents, audits, and HAZOP
- *SCADA* – A performance operating system that does live data monitoring, operation, and optimization of pipelines, meters, wells, etc.
- *BARRS* – A project risk ranking system for budget development.

Architecture

As shown in Exhibit 21, BP's software systems were largely disconnected and did not share information. There were a variety of technologies, vendors, and architectures used across the organization, making it difficult to create an integrated system for reporting and management. The use of manual processes for data loading and data manipulation increased the probability of data inconsistency. There was no single interface to access all available reports, thereby limiting a broad view of the risk level. A small number of standard reports forced management to make special requests for analyses and trends.[49]

Exhibit 21: BPXA Systems Architecture



Source: BPXA Business Applications Diagram

BARRS (Business Activities Risk Ranking System) was an Oracle-based Web tool. BARRS replaced a manual Microsoft Excel system and came on-line the first quarter of 2006. It was used for the generation of the FY 2007 Operations CAPEX and major repair budgets. Specifically, BARRS was used for projects over $100,000; items less than $100,000 were incorporated in the general budget process and were not risk ranked.[50]

BPXA used the work management software PASSPORT. This was an old system, also referred to as CMMS (Computer Maintenance Management System). Use of PASSPORT had declined as work was performed outside of the system. As a result, it was not a 100-percent reliable source for work completion.

MIMIR was the main system used by CIC. It was an in-house, custom-built repository for managing inspection information on pipelines, tanks, vessels, wells, etc. MIMIR had been in use since 2001, and there were plans to integrate data such as pressure and temperature from the SCADA system. Brio, a third-party reporting tool, was used to create reports and draw charts from MIMIR data. Most of these were ad hoc or custom queries that needed a dedicated resource to create them. Reports to management were generated after manual data loading and analysis using Microsoft

Excel. MIMIR was a stand-alone database that was not integrated with any other system at BPXA.[51]

TRACTION was a Web-based application that runs on an Oracle database. BPXA could create reports from the TRACTION database using a third-party reporting tool called Business Objects. Standard reports, such as the "Spill Report," "Incident Summary," and "Action Items Report," were readily available in the TRACTION system. Management did not have direct access to any of the analytical reports, but monthly reports were generated by the HSE team and emailed to them.[52]

The SCADA system was used in BPXA operations to collect real-time data from pipelines, meters, wells, and other infrastructure components. The Eastern Optimization Center (EOC) monitored the SCADA system around the clock, and worked with the area operators to manage the GPB system. As part of this effort, the EOC also monitored the system for alarms that could signal system failures, out-of-tolerance conditions, and leaks. Daily, monthly, and quarterly production reports were generated, which could be accessed online.[53]

Reporting

Some standard reports and a number of ad hoc reports were generated from the existing databases and data warehouses. Off-the-shelf tools such as Brio, Business Objects, and Business Information Cycle (BI-Cycle) were used by to generate analytical reports. In addition to these tools, the use of Microsoft Excel for analysis and reporting was extensive.[54]

TRACTION had a set of standard reports for incidents, spills, injuries, action items, etc., which could be accessed through BP's intranet. The HSE team generated a monthly report with trends and metrics, which was distributed to all managers. The BI-Cycle reporting system provided reports on root cause analysis of equipment failures, usage patterns of equipment, work order status, and other work-order related information.

At the request of management, ad hoc reports for corrosion inspections and their status were created using Brio within the MIMIR system. Reports for tracking the status of PMPs were manually generated by CIC Town using Microsoft Excel and made available for download by the CIC Field and area managers through the intranet. These Excel reports provided different presentations such as open PMPs and overdue PMPs.[55]

Online.NET was used to create reports from BARRS. Field managers and area managers had access to these via the intranet. Summary information from MIMIR, TRACTION, BARRS, and the PMP reports were included in QPRs.[56]

VI. INCIDENT ANALYSIS

Summary: Our root cause analyses of the March 2nd and August 6th incidents highlight a number of corrosion assessment and management system shortfalls when dealing with evolving operating conditions leading to increased risk levels. These include:

1. The established risk assessment processes and practices were not adequate to detect and address new risks due to evolving operating conditions.
2. The budgeting process did not provide sufficient visibility into risk tradeoffs to senior management.
3. Established corrosion monitoring and control practices focused on known risks, based on lagging indicators.
4. The lack of strong assurance processes (e.g., open-loop process, self-verification model) led to poor compliance with some corrosion management practices and created inertia in implementing third-party recommendations.
5. Internal communication was lacking to effectively manage corrosion risk.
6. Disconnected information systems did not provide easy visibility into corrosion-related data.
7. The OTL were not covered by a formal PSM process.

Although the March 2 and August 6 spills had many common process failures, there were some differences.[1] Analysis of each was important to determine their individual and common causes and uncover any system-wide management infrastructure weaknesses that contributed to the events.

To do this, the Booz Allen team conducted an incident analysis. The first step was to identify the sequence of events that led up to each spill. Deconstructing the sequence of events enabled the team to more fully understand the precursor and ancillary events that contributed to the spills. A scenario tree analysis was then performed on each spill. The scenario tree structure provided a systematic process to identify root causes. (Appendix 4 provides a generic scenario tree.) The next step was to map scenario tree results to BP risk-related processes that had an impact on corrosion management. This mapping illustrated how well BP risk-related activities functioned. The final step was to expand the analysis through a risk management diagnostic to identify and evaluate GPB systemic weaknesses that could have affected corrosion risk management.

Discussion of Spill Incidents

March 2, 2006 Spill

A well pad operator driving the GC-2 to GC-1 line discovered the March spill. He immediately notified the appropriate authorities. A Code Black was called in and the line was shut in and depressurized. Table 4 chronologically lists key March event actions and consequences.[2]

Table 4: March Spill Events

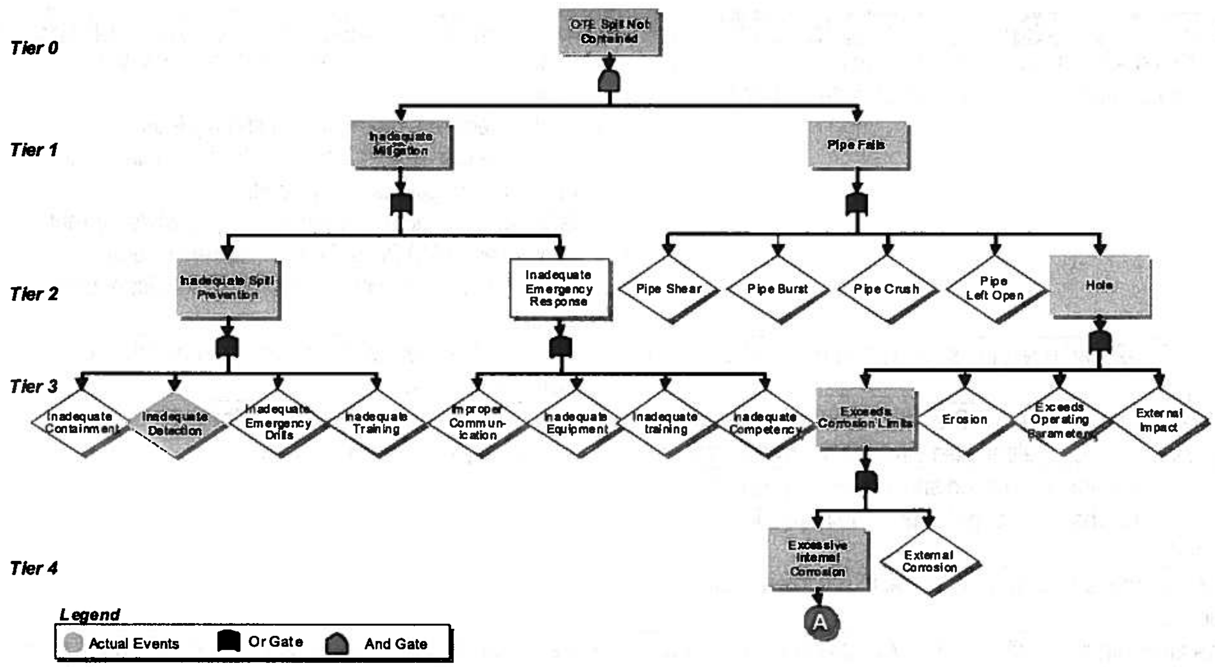
Relevant Actions	Observations/Comments
4/2/2006 GC-2 well pad operator drives the GC-2 and GC-1 line segment and notices the smell of hydrocarbons	▸ Leak was not identified by operations parameter changes ▸ Leak detection system did not identify leak ▸ It was not determined when the leak actually started; estimation suggests 5 days earlier ▸ GC-2 to GC-1 design rated at 740 psi, while current de-rating was to MAOP of 500 psi, current operating pressure of 61-91 with no history of significant pressure spikes
Notified GC-2 lead operator, security guard, and GC-2 area manager	▸ Operator followed SOP requirements and did not investigate alone
Following notification, the GC-2 area manager and well pad operator drive the pipeline, also smelling the hydrocarbons	▸ Area manager and pad operator followed BPXA emergency response protocols
GC-2 manager found an open snow cave with liquids running off of what he thought was the third pipeline in from the road	
GC-2 manager called in a Code Black (emergency spill response)	
BPXA immediately notified ADEC, Alaska Dept. of Natural Resources, North Slope Borough, and EPA	▸ Key external stakeholders (esp. regulators) are notified
GC-2 manager and others thought that they identified the source at Y/P large diameter flow line and called to immediately shut in pads	▸ Spill response shut-in process is performed ▸ Leak was not identified by operational changes ▸ Leak detection system did not identify leak
Produced water lines from GC-1 were shut in. The GC-2 area manager called to shut in GC-2	
Mobile Command Center (MCC) arrives at the scene	▸ MCC sets up unified command structure ▸ 3 separate teams arrive through MCC: incident response team, business resumption team, and incident investigation team
Affected wells are shut in	
GC-2 to GC-1 and transit oil to GC-1 shut in	
Alaska Clean seas mobilized	▸ BPXA emergency procedures initiated
GC-2 transit line confirmed at 0 pressure and the leak stopped	▸ Clean up activities commence
Emergency removal operations started	
ADEC representative arrives on the scene	

Source: Booz Allen analysis; GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report; Interviews: GC-2 Area Manager, HSE Crisis Manager, GPB CIC Team Leader, CIC Head, HSE Program Manager, Production Optimization Leaders (Slope), CIC S&P Engineer, Mid-Continent PUL

March 2 Scenario Tree Discussion

Exhibits 22a and 22b highlight in yellow the actual events and their precursors that led up to the March 2 spill. The uncolored boxes indicate other typical scenarios that could lead up to an uncontained spill (i.e., not indicative of what may or may not be relevant to BPXA). While these incident-specific scenario trees are comprehensive with regard to the March and August spills, they are not exhaustive. Appendix 4 provides a generic scenario tree.

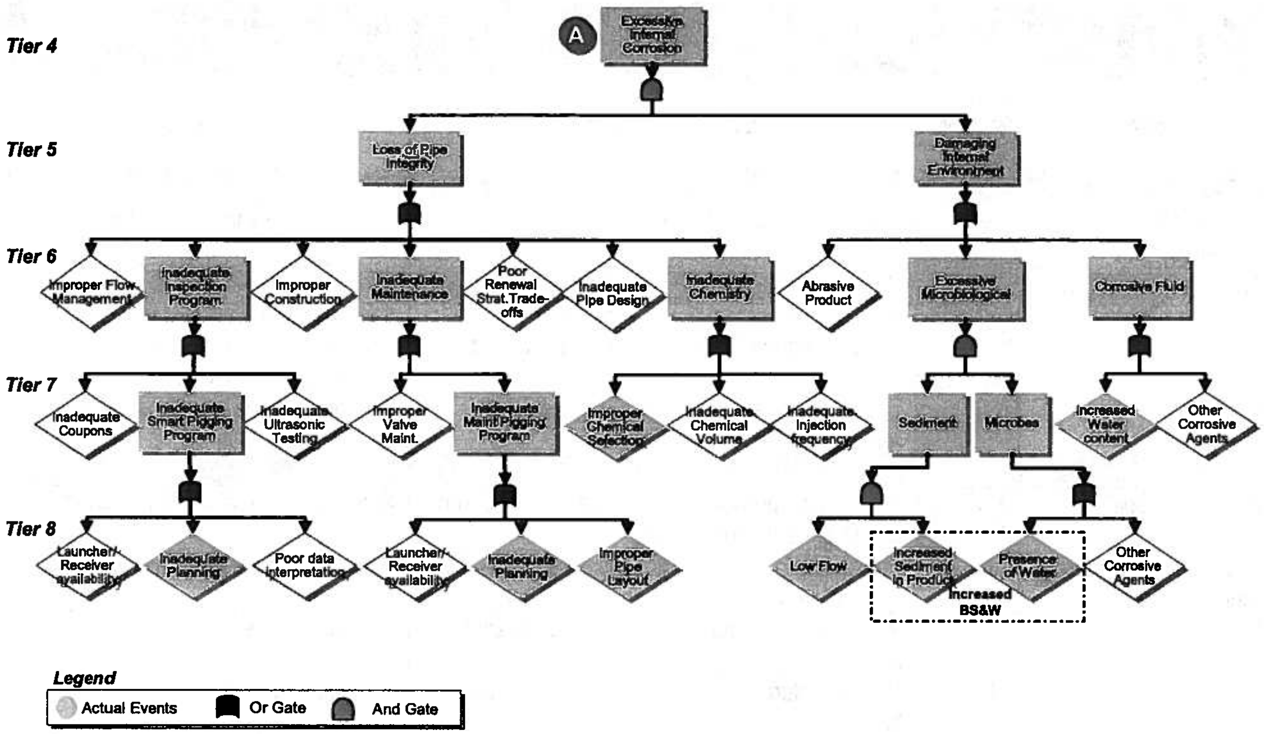
Exhibit 22a: March Scenario Tree (1/2)



Note: Scenario tree is comprehensive, but not exhaustive

Following the yellow boxes from top to bottom illustrates the event path that occurred around March 2 that led to the spill. An *OTL Spill Not Contained* is the actual spill event that required an emergency response. The March 2 tree decomposes the top event into the precursor events and their root causes, illustrating how the spill transpired. Table 5 summarizes the root causes of the March spill event. Table 6 lists the events that led to the top event.

Exhibit 22b: March Scenario Tree (2/2)



Source: Booz Allen analysis; GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report; Interviews: GC-2 Area Manager, HSE Crisis Manager, GPB CIC Team Lead, CIC Head, FS-2 Area Managers, FS-1 Area Manager, HSE Program Manager, Production Optimization Leaders (Slope), CIC S&P Engineer, MSA Delivery Manager, GPB Field Manager, M&R Manager, Mid-Continent PUL

Table 5: March Incident Root Causes

Summary of March 2 Incident Root Causes	
Pipe Integrity Root Causes: ▶ Inadequate (leak) detection ▶ Inadequate Smart Pigging Program planning ▶ Improper chemical selection ▶ Inadequate maintenance pigging planning ▶ Improper pipe layout	**Damaging Internal Environment Root Causes:** ▶ Low flow ▶ Increased sediment in product ▶ Presence of water (carrying microbes) ▶ Increased water content (creating corrosive fluid)

Source: Booz Allen analysis

Table 6: March Scenario Tree Table

March Scenario Tree (August events are the same)			
Item	**Root Cause Event**	**Event Description**	**Impact**
TIER 0			
OTL Spill Not Contained	Yes	Defines top event of interest	Clearly defines the focus of analysis
TIER 1			
Inadequate Mitigation	Yes	Preventative and prescriptive plans and actions do not adequately mitigate the effects of a spill	Increases the likelihood that a minor leak escalates into a major (catastrophic) incident
Pipe Fails	Yes	Describes the activities that could physically damage the pipe, resulting in a spill	Increased risk that large quantities of product could spill
TIER 2			
Inadequate Spill Prevention	Yes	Includes the proactive actions that can be taken to contain leak/prevent spill	Spill quickly escalates out of control
Inadequate Emergency Response	No	Spill mitigation is degraded because emergency and local staff did not respond adequately	Spill expands beyond initial incident levels
Pipe Shear	No	Pipe is severed (cut or separated due to external action)	Creates large spill
Pipe Burst	No	Pipe is ruptured (e.g., overpressure, hydraulic hammer)	Creates large spill
Pipe Crush	No	External physical action destroys the pipe section	Creates large spill
Pipe Left Open	No	Pipe is open to environment (e.g., valve left open)	Creates large spill
Hole	Yes	Pipe is breached through pipeline wall	Creates spill
TIER 3			
Inadequate Containment	No	Spill is released into the environment (e.g., leaks through pipe sleeves)	Spill footprint and consequence increase
Inadequate Detection	Yes	Leak was not detected promptly	Spill footprint and consequence increase
Inadequate Emergency Drills	No	Operators not adequately practiced in emergency shut down (in simulated emergency conditions)	Spill footprint and consequence increase
Inadequate Training	No	Operators are not adequately trained in preventing spills	Increases incident risk
Improper Communication	No	Communications protocols and channels are misunderstood or do not perform adequately	Enhances the potential for making the spill consequences worse
Inadequate Equipment	No	Proper emergency equipment not available or does not function	Makes spill mitigation difficult and could escalate severity of spill
Inadequate Training	No	Staff not adequately trained in emergency response	Makes spill mitigation difficult and could escalate severity of spill
Inadequate Competency	No	Area staff do not have the skill sets to appropriately respond to an emergency	Makes spill mitigation difficult and could escalate severity of spill
Exceeds Corrosion Limits	Yes	Corrosion exceeds design standards to the point of breach or insufficient for designated MAOP	Creates potential for wall breach (hole, rupture, etc.)
Erosion	No	Agents within product (e.g., sand) erode internal wall surfaces	Creates potential for wall breach (hole, rupture, etc.)
Excessive Operating Parameters	No	Designated operating parameters exceed pipe design (e.g., excessive pressure from hydraulic hammer)	Creates potential for wall breach (hole, rupture, etc.)

March Scenario Tree (August events are the same)			
Item	**Root Cause Event**	**Event Description**	**Impact**
External Impact	No	Hole is created by equipment operators (e.g., pipe puncture from backhoe activities)	Creates potential for wall breach (hole, rupture, etc.)
TIER 4			
Excessive Internal Corrosion	Yes	Pipe inner wall corrosion exceeds acceptable/safety levels	Creates potential for wall breach (hole, rupture, etc.)
External Corrosion	No	External corrosion reduces wall thickness (e.g., CUI)	Creates potential for wall breach (hole, rupture, etc.)
TIER 5			
Loss of Pipe Integrity	Yes	Pipe integrity is compromised	Increases risk of catastrophic failure (especially of common cause failures)
Damaging Internal Environment	Yes	Transported product stream contains corrosives, erosives, or other harmful substances	Creates environment for general and localized corrosion/erosion
TIER 6			
Inadequate Inspection Program	Yes	Inspection program does not adequately identify and/or verify that key integrity risks are mitigated	Increases likelihood of a major incident
Inadequate Chemistry	Yes	Chemical additives do not perform as planned/desired	Increases corrosion rate beyond program design or expectations
Inadequate Maintenance	Yes	Maintenance program does not sufficiently address wear and breakage on system	Increases likelihood of a leak or spill
Improper Construction	No	Construction did not meet design parameters (e.g., poor welds)	Lowers actual system capabilities below operating design
Poor Renewal Strategy Tradeoffs	No	Repair/replace decisions do not adequately address useful life of assets	Lowers actual system capabilities below operating design
Inadequate Pipe Design	No	Pipe design does not address operating parameters	Increases risk for leak, rupture, or spill
Improper Flow Management	No	Pipe flow rates do not conform to design parameters (e.g., low flow rates leave sediment in the pipe system)	Increases sediment and microbial build up
Abrasive Product	No	Pipe stream contains excessive particulates	Creates conditions for erosion
Excessive Microbiological	Yes	Internal environment contains excessive microbes	Increases corrosion risk
Corrosive Fluid	Yes	Internal fluid contains corrosive elements	Increases corrosion risk
TIER 7			
Inadequate Smart Pigging Program	Yes	Smart pigs are not used appropriately	Reduces visibility into pipeline corrosion and corrosion rates
Inadequate UT/Coupons	No	NDE programs are not adequately managed	Reduces visibility into corrosion rates/nature of stream
Improper Chemical Selection	Yes	Chemical selection does not produce the desired effect	Increases corrosive qualities of internal pipeline environment
Inadequate Chemical Volume	No	Injected chemical volumes insufficient to produce the desired effect	Increases corrosive qualities of internal pipeline environment
Inadequate Injection Frequency	No	Chemicals not injected into the process frequently enough	Increases corrosive qualities of internal pipeline environment
Inadequate Maint. Pigging Program	Yes	Maintenance pigs are not used appropriately or at needed frequency	Increases corrosive qualities of internal pipeline environment
Improper Valve Maintenance	No	Valve maintenance does not ensure all valves function properly	No effect on corrosion rates
Sediment	Yes	Sediment levels in pipe reduce effectiveness of corrosion management program	Increases corrosive qualities of internal pipeline environment
Microbes	Yes	Active microbe levels in pipeline exceed acceptable levels	Increases corrosive qualities of internal pipeline environment

March Scenario Tree (August events are the same)			
Item	**Root Cause Event**	**Event Description**	**Impact**
Increased Water Content	Yes	Water content exceeds design parameters	Increases corrosive qualities of internal pipeline environment
Other (e.g., corrosive agents)	No	Additional corrosive elements are present in stream	Increases corrosive qualities of internal pipeline environment
TIER 8			
Launcher/Receiver Availability (Smart Pigging Program)	No	Pig launchers, receivers are inoperable or do not exist	Reduces ability to pig lines and execute pigging plan and identify corrosion problems
Inadequate Planning (Smart Pig)	Yes	Pigging locations, frequency, or strategy is inadequate	Reduces ability to pig lines and execute pigging plan and identify corrosion problems
Poor Data Interpretation (Smart Pig)	No	CIC misinterprets smart pig results	Causes missed corrosion trends or hot spots
Launcher/Receiver Availability (Maintenance Pigging Program)	No	Pig launchers, receivers, and slug catchers are inoperable or do not exist	Reduces ability to pig lines and increases corrosive qualities of internal pipeline environment
Inadequate Planning (Maintenance Pig)	Yes	Pigging locations, frequency, strategy, or basic sediment and water (BS&W) management is inadequate	Reduces ability to pig lines and increases corrosive qualities of internal pipeline environment
Improper Pipe Layout	Yes	Piping layout contains constraints on running pigs or catching sediment	Reduces ability to pig lines and increases corrosive qualities of internal pipeline environment
Low Flow	Yes	Flow rates are not sufficient to move BS&W through pipeline	Increases corrosive qualities of internal pipeline environment
Increased Sediment in Product	Yes	Sediment levels exceed operating design parameters	Increases corrosive qualities of internal pipeline environment
Presence of Water	Yes	Water content exceeds operating design parameters	Increases corrosive qualities of internal pipeline environment
Other (Microbes)	No	Pipeline stream contains additional microbial or corrosive elements	Increases corrosive qualities of internal pipeline environment

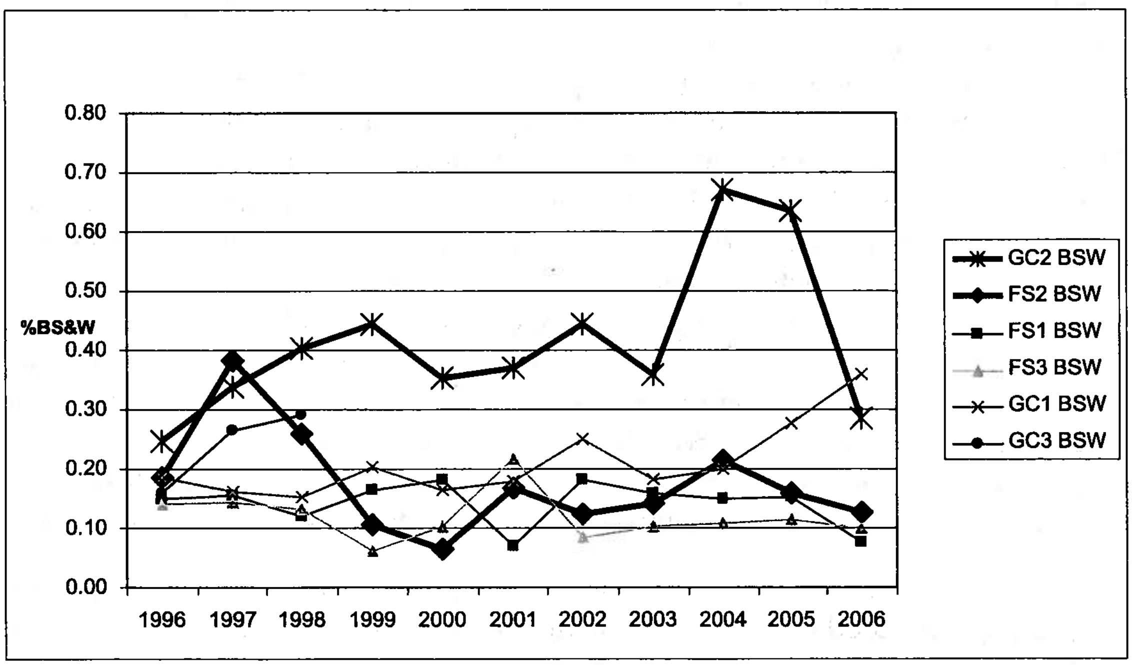
Source: Booz Allen analysis; GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report; Interviews: GC-2 Area Manager, HSE Crisis Manager, GPB CIC Team Lead, CIC Head, FS-2 Area Managers, FS-1 Area Manager, HSE Program Manager, Production Optimization Leaders (Slope), CIC S&P Engineer, MSA Delivery Manager, GPB Field Manager, M&R Manager, Mid-Continent PUL

The March spill resulted from a physical OTL wall failure (due to internal corrosion) and slow spill detection.[3] Prior to the spill discovery, the OTL leak detection system signaled alarms various times, days, and weeks, prior to the incident.[4] Area engineers investigated earlier leak alarms, but never found evidence of a leak.[5] No evidence indicated that area engineers modified their work procedures based on the large number of "false" leak detections.[6] Area operators, subsequently supported by the BP investigation analysis, indicated that the leak detection system was too sensitive to the significant variability in flow rates to be able to accurately detect a leak.[7] Based on the amount of liquid spilled and the size of the hole, the BP investigation indicated that the leak had probably started five days before it was discovered. This estimated spill rate would have been below the one-percent tolerance of the leak detection system. The

BP investigation was not able to determine whether any of the leak alarms truly indicated the actual leak. [8]

The scenario tree illustrates how internal corrosion created the hole that led to the spill. Two critical events occurred that led to the creation of the pipe hole—a corrosive internal fluid environment coupled with a pipe integrity program that did not adequately manage those risks.[9] Fluid composition had been changing over the last five years without adequate change in corrosion management.[10] In particular, in September 2005, coupon sampling and inspection found increased corrosion in the OTL[11] However, this corrosion was not readily connected to the new fluid content regime—there was no systematic way to process this information.[12] The increase in water production and process upsets created a more corrosive fluid. In addition, lower well head flows, combined with increased sediment content in the fluid, allowed more sediment to remain in the OTL, especially in pipe bends and elbows. Sediment remaining in the OTL probably harbored microbiological growth, resulting in increased corrosion and significant pitting.[13] Analysis to determine the precise corrosion mechanism is ongoing. Exhibit 23 shows the increase in BS&W between GC-2 and GC-1.

Exhibit 23: Annual Average BS&W Levels



Source: GPB Field Optimization Group, TAPS Performance Manager

Inadequate smart pigging program planning is listed as a root cause event, because a smart pigging program would have identified the pitting problems in the OTL. This is evident from the results of the post-incident smart pig runs, which identified several locations with pitting problems that had not been identified by UT inspections.[14]

The last WOA OTL smart pig inspection was conducted in 1998. Because the OTL were deemed "low risk," they were not scheduled for another smart pig inspection until 2006.[15] Likewise, no maintenance pigging had been performed since 1998. Pigging the OTL was "off the radar."[16] The EOA was last pigged by ARCO in 1991.[17]

For a variety of reasons, there was resistance to pigging. These reasons included the costs, the availability of launchers and receivers, concern over a stuck pig affecting production, resistance from Alyeska, and the lack of an easy way to trap BS&W before entering TAPS. Senior managers did not have insight into these pigging issues because the information was reported at a high level and in a rolled-up format.[18]

Several factors combined to accelerate corrosion in the OTL. The increased presence of water and sediment combined with low flow rate created favorable conditions for microbacterial corrosion to occur. Furthermore, experimentation with emulsion breakers to handle viscous and heavy oil may have reduced corrosion inhibitor carryover.[19]

August 6, 2006 Spill

The August 6 spill was very similar to the March incident. Although the BP forensic investigation has not been completed, it is important to review the August events to understand the risk management processes in place. The March event produced the U.S. DOT requirement to smart pig the entire OTL.[20] Smart pig data on the EOA OTL showed an approximate 80-percent allowable wall loss in some locations.[21] The Flow Station 2 (FS-2) area manager, CIC, and Engineering Authority reviewed the data, spoke with the pipeline vendor, and subsequently decided not to shut-in.[22] While removing external insulation, CIC discovered some stains. A decision to shut in the pipe was made. During the process of shutting in the pipe, an active leak was discovered.[23] Once the spill was discovered, a Code Black was called in. Because the internal incident investigation report is still in draft form and not available for team review, the information in Table 7 was developed based on interviews with the various FS managers and technical staff and the CIC Slope team leader and inspectors. These events are very similar to the earlier March incident with two significant exceptions:

- There was a decision to continue operating the EOA OTL even though smart pigging indicated a loss of 80-percent allowable wall thickness.[24] The decision to operate the EOA continued until spotting was discovered in the insulation, at which point the decision to shut-in the EOA was made.
- The August event had a pressure spike in the OTL system that might have contributed to the spill initiation and severity.[25] Review of the shut-in actions taken indicate that the emergency shut-in procedures were inadequate to avoid blocking out the FS-2 to FS-1 line while the Crude Oil Topping Unit (COTU) was still operating.[26]

Table 7: GPB August Spill Events

Relevant Actions	Observations/Comments
Because of the March event, a corrective action was ordered by the U.S. DOT to smart pig all of the OTL	▸ Although two sides of slope are separate OTL, March corrosion failure mode gave concern to ensure all OTL were robust
In late July, the OTL were maintenance pigged and then smart pigged	▸ First maintenance pig since 1998 on the WOA and earlier on the EOA, generated approximately 55 barrels of BS&W
Smart pig results found 16 anomalies in 12 locations of the EOA with 80% allowable loss of wall thickness in some cases	▸ Because of significant wall thickness loss, it was important to discuss mitigation strategies with CIC ▸ Typically, CIC approves continued operation or the need for PMP actions ▸ The Engineering Authority was consulted and gave permission to operate without a PMP
8/4 results were discussed with CIC	
FS-2 area manager requested Engineering Authority approval to continue operating	
Based on vendor consultations, the Engineering Authority authorized to continue operations at a nominal 70 psi	▸ Typical operating pressures are 70-90 psi ▸ Highest pressure spike ever recorded was 200 psi (occurred twice) ▸ Shut-in controls are set at 240 psi
No PMP was written because the operating pressure was well below the MAOP	▸ Even with 80% allowable wall thickness loss, the pipe could be operated because of the perceived large margin of safety
8/6 insulation removed so that UT could be conducted	▸ Based on the oil spotting (not an active leak), FS-2 manager decides to shut-in the line and depressurize ▸ CIC supports Code Black call
Removing insulation, a 10x16 inch discoloration (oil spotting) on the insulation was found	
FS-2 area manager decided to take the pipeline and plant down, starting by depressurizing the line	
FS-2 area manager and CIC slope team leader agreed to declare a Code Black	
Code Black declaration occurred during shift change-over	
FS-2 area manager communicates with COTU and request they shut down	▸ When COTU starts their shut-in process, it first must go through a cool down ▸ Cool down requires blocking just the suction line but leaving the residual line open to bleed the pressure ▸ COTU and FS-2 had different meanings for the term "shut-in;" for FS-2, it meant that the plant is not flowing product; for COTU, it meant start the cool-down process and then later reduce the pressure
COTU confirms plant shut-in (however, interviews indicate that COTU uses the term "shut-in" once the cool-down process begins)	
COTU blocks suction line but leaves residual line open as part of its cool-down procedure	
FS-2 area manager unaware that COTU shut-in designation really indicates cool down and not complete plant shut-in	▸ Because FS-2 area manager thinks that COTU is shut down, he does not know that COTU is still pumping into the OTL ▸ Because FS-2 area manager believes that there is no flow from COTU into the OTL, he blocks FS-1 ▸ Now the system is closed loop with COTU still pumping between blocked FS-2 and FS-1
FS-2 requests FS-1 line blocked	
MCC set up at site of "oil spotting"—leak site 1	▸ Pressure spike measured at approximately 160 psi ▸ Although MCC set up at site 1, Veco employee reports leaks at sites 2 and 3
Active leak is found—leak site 2	
Pipe fails and leaks oil—Site 3	

Source: Booz Allen analysis; GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report; Interviews: GC-2 Area Manager, HSE Crisis Manager, GPB CIC Team Lead, CIC Head, FS-2 Area Managers, FS-1 Area Manager, HSE Program Manager, Production Optimization Leaders (Slope), CIC S&P Engineer, MSA Delivery Manager, Field Manager, M&R Manager, Mid-Continent PUL

August 6 Scenario Tree Discussion

The March and August scenario trees are very similar because corrosion and integrity management are relatively uniform across the slope. This section focuses discussion on the unique scenario events and event paths particular to the August spill. As shown in Exhibits 24a and 24b, the events of the August incident follow the same path as the March incident with the following exceptions:

- August scenario tree does not have an *Inadequate Detection* event.
- August scenario tree does include *Incomplete Training*, whereas the March does not.

Table 8 summarizes the August incident root causes. Table 9 describes the unique events that contributed to the August spill.

Exhibit 24a: August Scenario Tree (1/2)

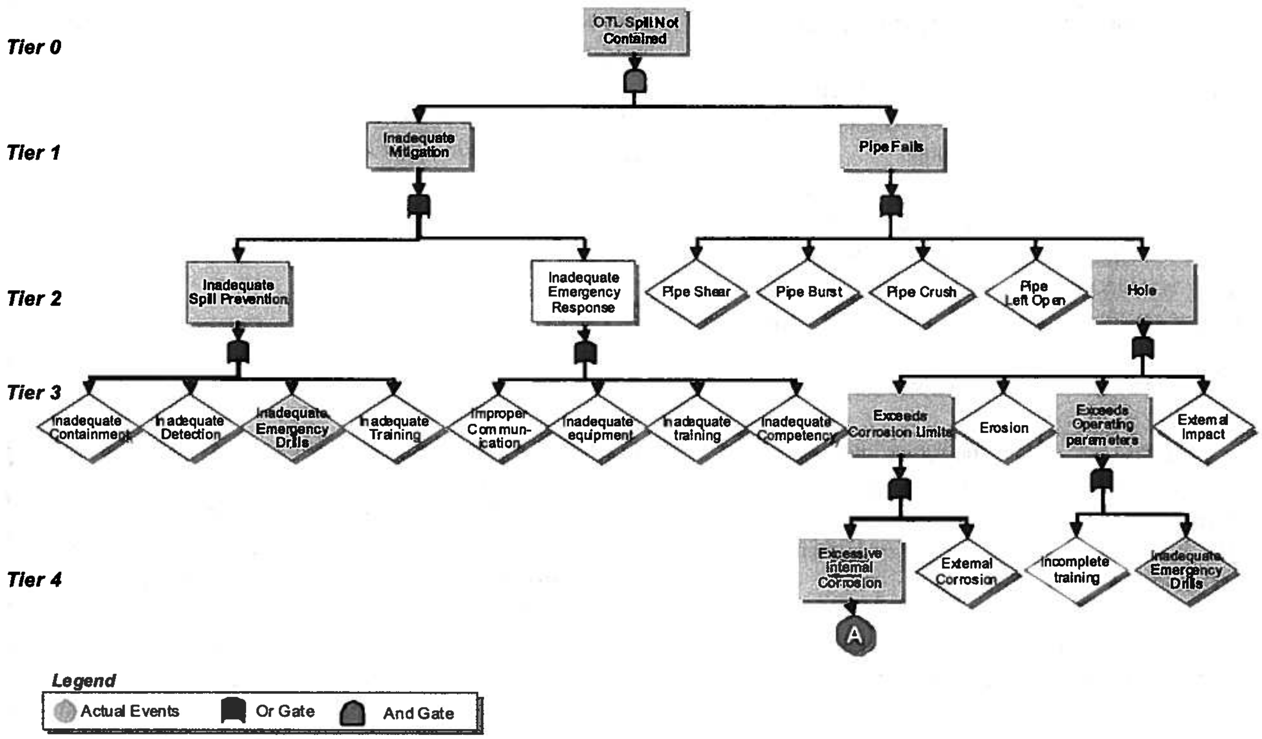
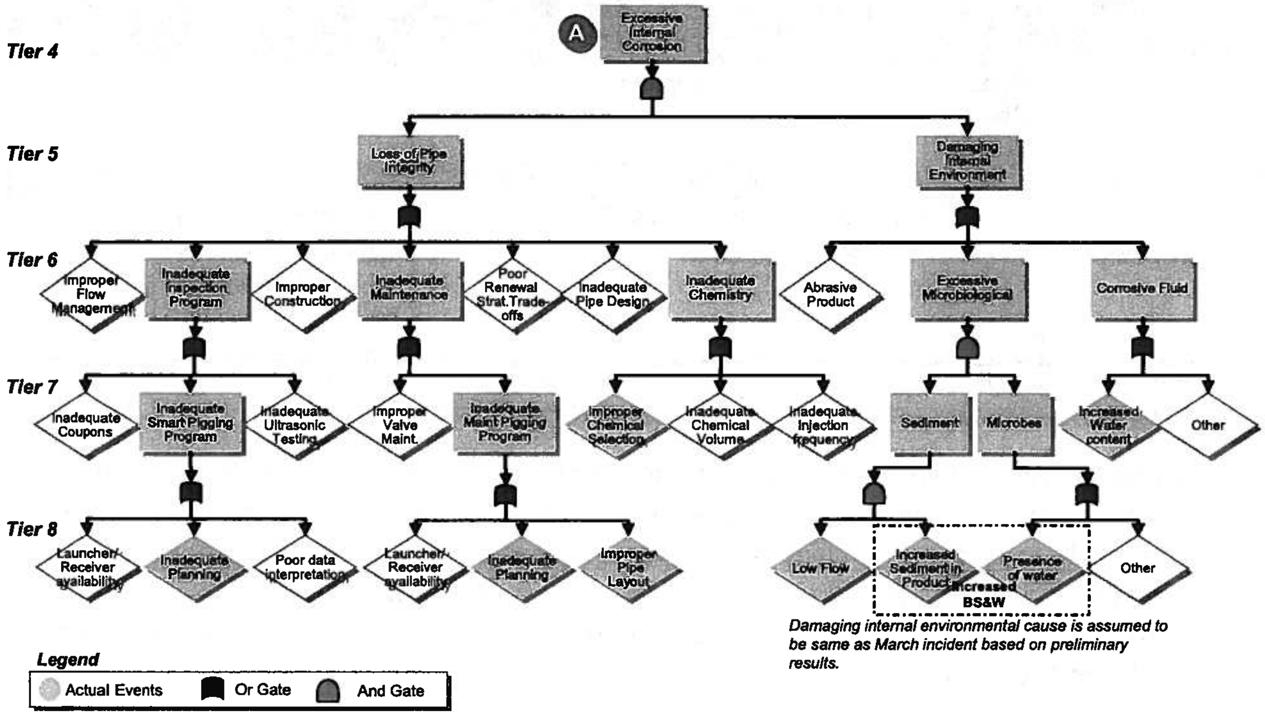


Exhibit 24b: August Scenario Tree (2/2)



Source: Booz Allen analysis; GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report; Interviews: GC-2 Area Manager, HSE Crisis Manager, GPB CIC Team Lead, CIC Head, FS-2 Area Managers, FS-1 Area Manager, HSE Program Manager, Production Optimization Leaders (Slope), CIC S&P Engineer, MSA Delivery Manager, Field Manager, M&R Manager, Mid-Continent PUL

Table 8: Summary of August Incident Root Causes

Summary of August 6 Incident Root Causes	
Pipe Integrity Root Causes:	**Damaging Internal Environment Root Causes:**
▶ Incomplete training (emergency drills)	▶ Exceeds operating parameters
▶ Inadequate Smart Pigging Program planning	▶ Low flow and increased sediment in product
▶ Improper chemical selection	▶ Presence of water (carrying microbes)
▶ Inadequate maintenance pigging planning	▶ Increased water content (creating corrosive fluid)
▶ Improper pipe layout	

Source: Booz Allen analysis

Table 9: August Scenario Tree Table

August Scenario Tree (Only August-unique events indicated here)			
Item	**Root Cause Event**	**Description**	**Impact**
TIER 4			
Inadequate Emergency Drills	Yes	Operators not adequately practiced in emergency shut down	Leak is exacerbated by increase in operating pressure caused by flawed shut-in (e.g., excessive pressure from hydraulic hammer from blocked-in lines)

Source: Booz Allen analysis; Interviews: HSE Crisis Manager, FS-2 Area Managers, FS-1 Area Manager, HSE Program Manager, CIC S&P Engineer, MSA Delivery Manager, Field Manager, GPB M&R Manager

Adequate training significantly influences how well area engineers can react to an emergency situation, especially one that exceeds normal operating conditions. There is an indication that emergency drill training was not practiced as part of the spill prevention program. This possibly affected the reaction time of the operators to shut-in the OTL from FS-2 to FS-1, and the necessary coordination to depressurize, cool down, and shut down the COTU.[27]

As the Table 8 timeline indicates, the FS-2 area manager and COTU manager had different understandings of the COTU emergency shut down process.[28] Although the COTU plant had been shut down several times over the 2006 summer, it had always been in a planned and well-controlled manner.[29] This is significant because during normal shut-down procedures, the FS-1 block valve is not blocked in until confirmation that COTU pressure (as well as any residual FS-2 pressure head) has been bled to 0 psi. During the August incident, this step was not taken.[30] Neither the FS-2 nor COTU managers understood at the time that the COTU, FS-2, and FS-1 were in a closed-loop configuration.[31]

The closed-loop situation did not allow the COTU to adequately bleed pressure before blocking in the FS-1 block valve. FS-2 and FS-1 area managers stated that it appeared to them that the residual pressure spike reached approximately 160 psi. It is unknown if this pressure spike initiated the leak or only contributed to a leak already in progress. However, at a minimum, the pressure spike increased the spill flow rate.

Discussion of Systemic Management Challenges

It is possible to have insight into the systemic management challenges that currently face GPB. The scenario tree analysis root causes can be evaluated against GPB corrosion risk management processes to determine how effectively GPB processes mitigate corrosion risk. Results serve as the basis to further investigate and understand how general management practices in place at the time of the incidents affected risk.

GPB Corrosion Management Processes that Had an Impact on the March 2nd and August 6th Incidents

To understand the corrosion management causes that led to the incidents, it is important to first identify key GPB processes that impact corrosion risk management. The March and August incident root cause tables serve as the baseline. The selection of GPB control processes for review is based on applying the four key risk template areas. Each process is then evaluated against the scenario tree results documented in their root cause tables. Relevant GPB risk-related corrosion management processes are mapped to March and August root causes in Exhibit 25. The key GPB processes that heavily influenced the events that led up to the March and August incidents, as described in scenario tree results, are illustrated across the top of the exhibit. Scenario tree incident root causes (listed in the columns) are mapped directly to the GPB processes that influence corrosion risk.

The major GPB processes in the exhibit are Risk Assessment, Risk Management, Communications, and Culture. Under Risk Management, there are five sub-processes that address the planning and execution of the overall risk management process. Within the Communications process, there are two primary sub-processes. The first is the Internal Communications mechanisms and processes that capture how the organization shares information across functions and up through the management levels. Within the Culture process, there is a distinction drawn at BPXA between HSE and integrity management (IM). At BPXA, HSE relates primarily to personnel safety, while IM is considered a separate issue and process.

Exhibit 25: GPB Control Processes for March and August Incidents

GPB Control Processes									
		Risk Management					Communications		Culture
Root Causes	Risk Assessment	Budgeting	Corrosion Inspection & Monitoring	Corrosion Control	Emergency Response	Assurance	Internal (vertical & horizontal)	IT Systems	HSE vs. IM
Inadequate (leak) detection [March only]					X				
Incomplete training (August only)					X				
Inadequate smart pigging program planning		X	X			X			
Inappropriate chemical selection				X					
Inadequate maintenance pigging planning				X		X	X		

GPB Control Processes									
		Risk Management					Communications		Culture
Root Causes	Risk Assessment	Budgeting	Corrosion Inspection & Monitoring	Corrosion Control	Emergency Response	Assurance	Internal (vertical & horizontal)	IT Systems	HSE vs. IM
Improper pipe layout				X					
Low flow and increased sediment in product	X		X			X	X	X	X
Presence of water (carrying microbes)	X		X			X	X	X	X
Increased water content (creating corrosive fluid)	X		X			X	X	X	X

Source: Booz Allen analysis

Risk Assessment

Key Finding: Although BPXA has various risk assessment methodologies, none of them evaluate OTL corrosion risk in a holistic and methodical way (e.g., process is not sensitive to exogenous variables).[32]

Reference to Scenario Tree Root Causes (March 2 and August 6): Low flow and increased sediment in product, presence of water (carrying microbes), and increased water content (creating corrosive fluid).

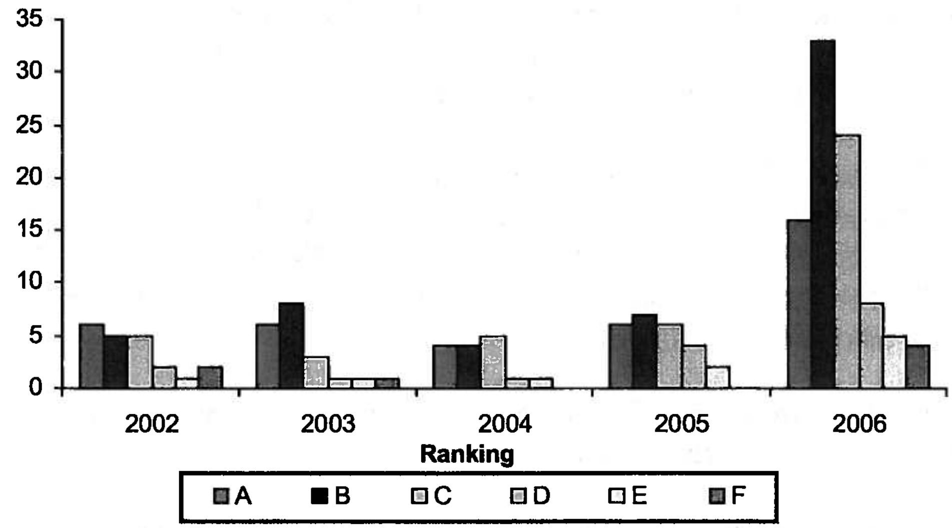
Finding Discussion:

The risk assessment process is a critical factor for corrosion risk management. This is because a methodical, systems-based risk assessment process not only identifies key production threats but also serves to collate critical corrosion risk management data that must be evaluated and acted upon by appropriate levels of management.

Interviews indicated that GPB CIC (Town and Slope), Area Managers, and Optimization managers believed that the MIMS PMP/MOC inspection process was how corrosion risk was managed. The results of the inspection process led CIC to believe that the OTL were not a high corrosion risk (see Exhibit 26). This belief was re-enforced by the fact that the OTL had not experienced any incidents in the past.[33]

Further, the lack of a single owner of the OTL for operations, management, and integrity inhibited a systemic view of the risks associated with the changing operating environment and its impact on the corrosion program. Area Managers did not feel that they owned the corrosion management issues on their segment of the OTL, and relied solely on CIC to ensure that corrosion was managed on their piece of the system.[34] This view effectively orphaned the OTL as CIC and Area Managers were focused on higher-risk assets.

Exhibit 26: OTL Inspection Results



Source: MIMIR report

Although GPB operated the MIMS process and used the OSHA PSM standard, there was no formal, methodical, network systems-based and closed-loop risk assessment process in place that addressed OTL corrosion risks at the time of the incidents.[35] The BPXA PSM Application Element Administrative procedure (see Appendix 1 of the procedure document) used a flow diagram to test and determine whether a process should fall under the BPXA PSM program and have a HAZOP performed. According to this flowchart and discussions with FS and GC managers, CIC Slope and Town leadership, and GPB senior managers, the OTL did not require coverage under the PSM procedure because it is neither a facility nor a process within a facility.[36]

As a result, the risk assessment process/practice in place at the time of the incident failed to capture and analyze changes in and their impact on exogenous variables such as lower flow rates, increased water content, and increased sedimentation.

Risk Management – Budgeting

Key Finding: Process did not provide transparency on the risk tradeoffs at the senior management level and was largely driven by top-down targets.[37]

Reference to Scenario Tree Root Causes (March 2 and August 6): Inadequate smart pigging program planning.

Finding Discussion:

Interviews with various CIC representatives indicated that top-down budget targets provided a "budget box" into which activities, materials, and projects had to fit.

The top-down budgets came from three sources – BP Segment, WIO, and BPXA. This top-down element was driven by a desire to run a profitable operation in a high-cost environment, holding lifting costs flat even as production declined substantially. Bottom-up selection of corrosion management projects was made within the technical organization and at the Field level. The list of projects was rolled up and presented to GPB management with limited visibility on the selection rationale.

In 2004, the BARRS tool was implemented to assist the organization in prioritizing projects and making the necessary budgetary tradeoffs. BARRS was used strictly to assist in the bottom-up budgeting process to help rank the relative importance of projects. Prior to the launching of BARRS in 2004, this was done ad hoc through the force of a project manager's persuasion.

Budget pressure eventually led to de-scoping some projects and deferring others. For example, the plan to run a smart pig in the OTL was dropped in 2004 and 2005.[38]

Staffing levels within CIC offer further evidence of the impact of budget constraints on corrosion management activity. A CIC manager request in 2005 to increase the staffing of CIC Town by three full-time equivalents (FTEs) was declined.[39] After the incidents, CIC has 19 open positions in Anchorage and 14 open positions on the North Slope.[40]

2006 ALT Performance Contracts included metrics for recordable injury frequency (RIF) as the only explicit target for risk management. Other metrics had implicit risk elements, such as operating efficiency and production, but the only metric specifically linked to integrity risk was the integrity spend (Gross Opex) target for the GPB Field Manager. There were a few integrity-related milestones, but these related to the implementation of the IM standard.[41]

Risk Management – Corrosion Inspection and Monitoring

Key Finding: CIC corrosion inspection and monitoring systems were static and insensitive to changes in exogenous variables.[42]

Reference to Scenario Tree Root Causes (March 2 and August 6): Inadequate smart pigging program planning, low flow, increased sediment in product, presence of water (carrying microbes).

Finding Discussion:

The Inspection and Monitoring program was at the heart of the Corrosion Management System (CMS), and the primary method to evaluate corrosion risk. The CMS process was static even though product composition changed over the last few years. The CMS did not change the inspection and monitoring regime for the OTL.

Corrosion in the OTL was monitored via coupons and ultrasonic thickness testing which were effective for measuring progress of general wall loss, but not appropriate for localized phenomena like pitting corrosion. In 2004, inspection results indicated an increase in corrosion at four locations on the OTL. CIC did not identify a need to modify the inspection regime other than to add inspection points (from 15 to 47) and increase frequency at 10 locations (from 12-month intervals to 6-month intervals). The *GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report* documented that the WOA OTL had not been smart pigged since 1998 and were planned to be pigged in 2006. This was within the range of analytically defined smart pigging frequency given the estimated rate of allowable wall loss. The EOA had not been smart pigged since 1991.[43]

The combination of the belief that OTL were low risk despite changing operating conditions (re-enforced by the results from traditional inspections) and the risk associated with pigging them contributed to CIC placing a low priority on smart pigging the OTL.[44]

Risk Management – Corrosion Control

Key Finding: Practices do not adapt to evolving operating conditions and are not always followed.[45]

Reference to Scenario Tree Root Causes (March 2 and August 6): Inadequate maintenance pigging, improper pipe layout, improper chemical selection.

Finding Discussion:
Corrosion control methods were the product of the understanding of the corrosion risks and corrosion rate (based on inspection results). The corrosion strategy spelled out the various methods to control corrosion. This strategy was established before the merger with ARCO in 1999, and had not been updated since. As a result, GPB and CIC failed to account for evolving operating conditions of the OTL.[46]

The failure to maintenance pig the OTL was an example of the lack of adaptability in the corrosion control methods. The presence of sediment in the OTL was known by Field Operations and CIC. The pig run in 1998 produced 2 yards of waste.[47] The Operations Review Team (ORT) report included some concerns about sediments; the 2002 COBC acknowledged the presence of sediment. In 2001, the presence of BS&W interfered with the implementation of the ADEC-mandated leak detection system. However, the belief that the lines were low risk (established corrosion monitoring techniques did not detect the pitting corrosion) combined with the risks of maintenance pigging these lines (e.g., pushing sediment into TAPS, "sticking" the pig and halting production, etc.), led the technical organization to decide to defer the maintenance pig.

There is some evidence of a lack of rigorous feedback loops. For example, the *GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report* and FS and GC area manager discussions indicated that an inappropriate mix of inhibitor chemicals may have diminished their positive effects. The problem was detected during the March 2nd accident investigation and not by the corrosion monitoring processes. The technical interactions of the emulsion breaker, corrosion inhibitor, and sediment are not fully understood, but corrosion inhibitor carryover was reduced in the OT-21 line.[48]

Risk Management – Emergency Response

Key Finding: The leak detection system was not adequate to contain a spill in time. The emergency shut-in procedures lack clarity and enforcement.[49]

Reference to Scenario Tree Root Causes: Inadequate leak detection (March 2), incomplete training (August 6).

Finding Discussion:

The leak detection system in place as of March 2, 2006, did not provide ample warning of the leak. Per ADEC requirements, the system was designed to detect leaks that would signal a loss in excess of one percent of the system segment volume over 24 hours.

The leak detection system was based on a flow measurement system that calculated the system inputs from a series of turbine and sonic meters, and subtracted system deliveries to calculate a volumetric balance for the system. If the measured inputs exceeded the measured deliveries over a time interval, the system created an alarm. The measurement system was sensitive to a number of variables including variations in flow rates. The frequent fluctuations in flow rates in the OTL often caused the leak detection system to create alarms. System operators would investigate the alarms per procedure and identify any abnormal readings. The leak detection system experienced several such false alarms during the week preceding March 2nd.[50]

Given the ADEC leak detection threshold of 1 percent over 24 hours, it is not certain whether, under the best circumstances, a system calibrated to these levels would have created an alarm given a small, slow leak such as the leak in the WOA line.

The GPB Oil Discharge Prevention Plan contains personnel safety and safe handling procedures for fluid transfer protocol and follows practices that have been compiled from sections of the Alaska Safety Handbook (1998). However, these procedures did not specifically address emergency shut-in procedures for GPB Field components. Interviews with FS and GC area managers and emergency response personnel indicated that there seemed to be some uncertainty as to who had authority over discharge prevention programs and training requirements. The August incident illustrates how failure to communicate COTU emergency shut-down procedures may have exacerbated the spill.[51]

Risk Management – Training

Key Finding: The training for emergency shut-in procedures incorporates individual process and procedure drills; however, it does not include system-wide shut-in drills in simulated emergency situations that incorporate all potential participants.

Reference to Scenario Tree Root Causes (March 2 and August 6): Inadequate emergency shut-in drills. The miscommunication between the pipeline operators and COTU operators resulted in a spike in line pressure, which may have contributed to the size and severity of the incident.

Finding Discussion:

Operations personnel are trained and drilled in shut-in and other emergency procedures. However, these drills are typically done in isolation and under controlled conditions. The drills do not typically involve personnel from other areas or locations. Communication issues such as those experienced during the shut-in of the EOA OTL were never covered.[52]

Risk Management – Assurance

Key Finding: The assurance processes are open loop and lack the leverage of material consequences for non-compliance. Most third-party assessments/audits were focused on HSE functions and other non-integrity GPB processes.[53]

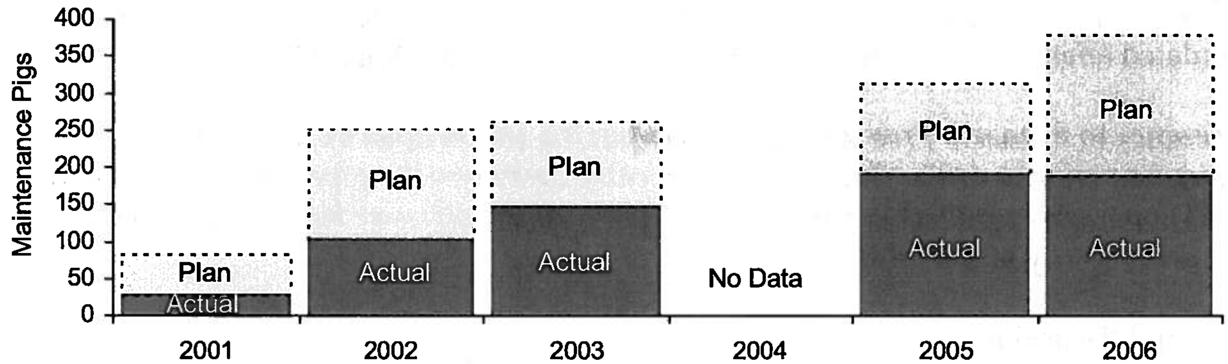
Reference to Scenario Tree Root Causes (March 2 and August 6): Inadequate smart pigging program planning, inadequate maintenance pigging, low flow and increased sediment in product, presence of water (probably carrying microbes), increased water content.

Finding Discussion:

Remediation of audit and assessment findings (internal, EMS, HSE) relied on a self-verification model where the business was responsible for implementing corrective actions. In addition, the consequences for not complying with processes and practices were not clear. The absence of third-party verification and sanction led to long delays in implementation, administrative documentation of close-out even though remedial actions were not actually taken, or simple non-compliance. For example, the ORT recommendations dealing with employee concerns were administratively closed by 2003, but are now being revisited. Another example was the recommendations from the 2005 *BPXA Corrosion Management System Technical Review*, which were not implemented after a full year.

The lack of rigorous closed-loop processes translated, in some instances, into non-compliance with corrosion control methods. For example, the maintenance pigging activity exhibited a chronic backlog (see Exhibit 27).

Exhibit 27: Prudhoe Bay Maintenance Pigs



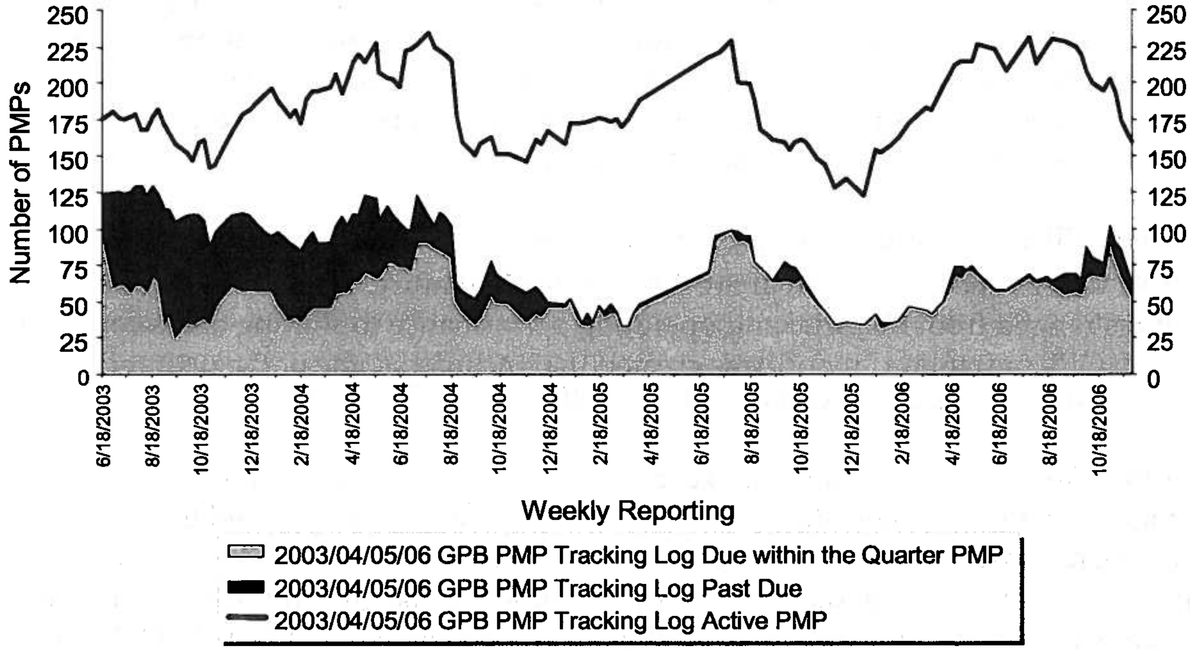
Percentage Complete					
2001	2002	2003	2004	2005	2006
Overall: 35%	**Overall: 42%** EOA: 39% WOA: 43%	**Overall: 56%** EOA: 80% WOA: 46%		**Overall: 61%** EOA: 64% WOA: 56%	**Overall: 50%** GC1: 62% GC2: 38% GC3: 5% FS1: 63% FS2: 41% FS3: 64% LPC: 59% Oil Transit: 91%

Note: Maintenance pig were not run on the OTL prior to the leak
Source: Booz Allen analysis; CIC Status Tables (1996-2006)

There were many possible reasons for the chronic backlog, including lack of availability of the pig launchers/receivers, shortage of operators, etc. From a management system standpoint, the key finding is that the absence of feedback loops has allowed known, suboptimal situations to persist over time.

In contrast to the maintenance pig situation, the PMP was a formal and closed-loop process where CIC verified that serious issues (e.g., F ranked inspections) were followed up. As a result, the level of compliance with the recommended schedule was dramatically different and had notably improved since the PMP tracking results were shared with London beginning in November 2004, as shown in Exhibit 28.[54]

Exhibit 28: 2003/04/05/06 GPB PMP Tracking Log



Source: PMP Yearly Status 2003, 2004, 2005, 2006

With the exception of the yearly Coffman Engineering report and the 2005 *BPXA Corrosion Management System Technical Review,* corrosion issues were not the direct focus of audits and assessments outside of GPB. However, the absence of formal follow-up or lack of compliance with established processes were identified during various audits related to EMS and HSE. For example, a review of the PSM Audits (2000, 2002), EMS External Audits (1998 to 2003, 2005), and EMS Internal Audits (1998, 2000 to 2003, 2005) indicated a migration of findings from process formalization to process compliance and control. The number of action items identified in these audit reports (an average of 20 per year) clearly shifted from lack of formal processes (1998 to 2001) to lack of compliance with established processes. Similarly, the internal audit conducted in 2003 highlighted the reliance on "good people, experience, and history," rather than formal processes.[55]

Communications – Internal

Key Finding: Risk-related vertical and horizontal communications do not elevate critical risk data to senior leadership and, in some cases, preclude the efficient exchange of information related to corrosion.[56]

Reference to Scenario Tree Root Causes (March 2 and August 6): Poor maintenance pigging, low flow and increased sediment in product, presence of water (probably carrying microbes), increased water content (creating corrosive fluid).

Finding Discussion:

Vertical Communications: Interviews with senior BPXA and GPB management indicated that there was an open communication channel but no formal process that regularly reported on risk. The Alaska weekly email, Alaska weekly performance report, and monthly report from the SPU Performance Analyst to ALT provided opportunities to report, but did so only by exception.[57]

The QPR was a formal, quarterly meeting that had a standing agenda of common items as well as agenda items that are more topical in nature. Issues raised at the meetings ranged from financial and operating performance to staffing and safety issues. For each QPR, a standard report was created that included some of the operations metrics such as the details and status of the PMPs and spill incidents.

Other key information related to corrosion such as the pigging statistics, inspection statistics and summary, and status of MOCs would typically be reported to management through ad hoc meetings or reports, but not included in the standing QPR agendas or through the standard QPR reports. Although the QPR reports captured any significant anomalies, they did not typically address pipeline integrity risk. HSE safety and risk issues were reported, but only as they related to workplace safety.

The QPR reports did address integrity issues, but only from the perspective of tracking dollars spent to plan. The technical intricacies related to the assessment of the risks would have been difficult to translate for a management review due to a lack of common language and shared risk assessment framework.[58]

In addition, the organizational structure at the time of the spills affected corrosion risk management. Because CIC was hierarchically four levels down from senior leadership, corrosion risk management had less visibility.[59]

As a result, the technical evaluation of corrosion risk was not effectively challenged by senior management to fully understand the tradeoffs made within CIC and at the Field Operation level. This ultimately led to a "normalization of deviance" where risk levels gradually crept up due to evolving operating conditions.

Horizontal Communications (Cross Functional): Horizontal communications took place through the Wednesday meetings between the CIC Town and CIC Field groups. These meetings covered inspection issues and occasionally included ad hoc risk implication discussions.

The PMP was the primary corrosion risk communication channel between CIC and Operations. PMPs communicated the condition and recommended remediation of F-ranked pipe segments. The PMP Tracking Sheet and the PMP Yearly Report tracked PMP closure status. These communications were focused on reporting activity, and were not investigative in nature. For example, Field Operations had detected the presence of H_2S (an indication of increased bacteria level) downstream of GC-2 prior to the spills, but had not shared this with CIC.[60]

At the time of the incidents, the OTL did not fall under the responsibility of a single manager, but were managed by all Area and Optimization Managers, according to geographic boundary. This might have contributed to the OTL not receiving a proper level of attention for corrosion issues, despite the fact that the Field managers met regularly to discuss tactical issues.[61]

Communications – IT Systems

Key Finding: There is no single IT system that integrates all corrosion risk data, thus inhibiting a holistic view.[62]

Reference to Scenario Tree Root Causes (March 2 and August 6): Low flow and increased sediment in product, presence of water (probably carrying microbes), increased water content (creating corrosive fluid).

Finding Discussion:
Given the current IT architecture, there was no single corrosion and risk management knowledge management system that could provide an integrated view of risk assessment, operations, maintenance, inspection, and system changes. MIMIR, the PMP system, TRACTION, CMMS/PASSPORT, and BARRS all contained elements of the corrosion management system, but were not linked through direct connections or a data warehouse that could provide a multi-faceted view of the program to management.[63]

Another aspect of these IT systems was the difficulty in data query. Review of the data systems indicated that it can be very difficult to sort and query key risk data. For example, the MIMIR system did not have a robust set of useful risk reports that could help analysts trend the leading indicators to target key corrosion risks. This not only potentially obscured relevant risk data, but also made it difficult to synthesize the information for reporting to senior BPXA managers.

Culture

Key Finding (HSE and IM): There is a scope gap between HSE and IM programs in corrosion risk management.[64]

Reference to Scenario Tree Root Causes (March 2 and August 6): Decreased flow and increased sediment in product, and increased water content (creating corrosive fluid).

Finding Discussion:

The interaction between HSE and IM was an important dynamic at the time of the incidents. Conversations with HSE and CMS staff and managers (both on the slope and in town), along with HSE's *PSM Application Element Administrative* procedures, state that HSE PSM activities are strictly focused on workplace safety, process safety (as it relates to personnel safety), and environmental safety. The OTL, which did not include any processes or direct links to personnel safety, were not evaluated with the PSM procedures. Likewise, the CMS program, which did apply to the OTL, focused only on integrity management issues. At the time of the incidents, there was a gap in coverage between these two disciplines. Because HSE focused on workplace safety and not network integrity, its MAR and MAHA reports did not consider corrosion issues on the OTL.[65] These risk assessment approaches might have identified the changing risk profile of the OTL created by the changing operating conditions.

The CMS IM program did conduct a successful inspection and monitoring program on the OTL early in their life. However, because no leading risk indicators or root causes were studied, when the product composition changed, it was not flagged as an important corrosion management issue. This led to an increase in corrosion risk on the OTL that ultimately precipitated the two incidents.

A detailed risk assessment process that reviewed this issue holistically could have been engendered from the MAR and MAHA if either of them used a more complete systems-network-based risk assessment approach, with particular emphasis on causal analysis (i.e., what specific root causes impact successful corrosion management). Although HSE and IM did interact on a frequent basis, neither took ownership of this particular risk.[66]

Other GPB Corrosion Management Process Issues That Had No Apparent Impact on the March 2nd and August 6th Incidents

Management of Change/Configuration Management

Key Findings: The MOC process is not closed loop, thus creating the opportunity to drop critical risk data.[67]

Finding Discussion:

Change (and configuration) management was an important aspect of corrosion risk control. Review of the MOC form and the BPXA Technical Management of Change Process document stated that whenever a material change was made in process, hardware, vendor, or procedures, an MOC must be completed. Most (but not all) MOCs were tracked through the CMMS work management program, but only if a work order was written. Because an MOC can be created by anyone but is typically closed out by the Area Manager's staff, the MOC did not have a clear owner. There was no formal feedback loop that ensured that the MOC action was appropriately implemented.[68]

For example, interviews with GC and FS area managers indicated that there may be a number of hardware drawings that are not fully documented under configuration control. This is a concern because as systems are modified, it is more difficult to accurately assess the change in risk if their configuration is not controlled. The change management processes become more important as time passes, especially with an aging kit. If equipment drawings do not reflect the true as-built condition, there is added risk (that may be unknown to the operator) because of the lack of understanding of the system configuration.[69]

Although the MOC process did require a process safety assessment (*BPXA PSM Application Element Administrative*), this risk focus was on personnel safety and did not formally assess the fit-for-purpose of the change itself. In some cases, for large modifications of the facility or plant, a HAZOP may be led by HSE. No evidence was found that indicated that a risk assessment was performed on OTL MOCs or PMPs.[70]

Communication – Regulator

Key Finding (Regulator): At the time of the incidents, BPXA had strong and positive relationships with Alaska and federal regulators. However, communication was idiosyncratic and not coordinated.[71]

Finding Discussion:

A large number of agencies with overlapping jurisdictions regulated BP's Alaska operations. The principal regulators of pipeline operations were ADEC, U.S. DOT/PHMSA, EPA, AOGCC, OSHA, and Alaska DNR. According to interviews, BPXA had a very positive relationship with Alaska and federal regulators. Structured and formal communications came in the form of compliance documents (e.g., Corrosion Management Annual Report to ADEC, Spill Response Plan to PHMSA), responses to inquiries, compliance orders and responses (e.g., PHMSA Corrective Action Order of March 15, 2006), inspections and reports, comments on proposed regulations and regulatory changes, and formal hearings.[72]

The BPXA Vice President, External Affairs maintained a formal relationship matrix that identified primary responsibility for contact by each ALT member. In this de jure model, the Vice President, HSE had the relationships with the Commissioner of ADEC and the Alaska Director of EPA. The GPB BUL was responsible for the relationships with the Chairman and Commissioner of AOGCC. The President of BPXA had the relationship with the Commissioner of Alaska DNR.

The de facto distributed model in place at the time of the incidents did not precisely match the formal relationship matrix. For example, because MSA controlled the bulk of the U.S. DOT-regulated pipelines, the MSA BUL managed the relationship with the U.S. DOT. Similarly, the HSE manager handled the relationship with EPA. The

GPB BUL managed the relationships with Alaska DNR and the AOGCC, and the Senior Attorney, HSE and Regulatory, managed the relationship with ADEC. However, these relationships were unique to individuals and not formally coordinated. The Senior Attorney acted as a de facto coordinator of regulatory communications because he had extensive and long-standing relationships with state and federal regulators.[73]

Summary

Overall, the corrosion management system exhibited a set of strengths and weaknesses summarized in Table 10. The details are provided in Appendix 7.

Table 10: BPXA Management Assessment Template Summary

Corrosion Management Elements	Strengths	Weaknesses
Risk assessment	▸ MAR/MAHA risk assessment process is a strong process that addresses high hazard system risk ▸ HAZOPs performed for GPB facilities with HSE focus on personnel and process safety	▸ Does not provide a system-wide view of the potential risk due to lack of formal process and tools ▸ Does not include detailed causal analysis ▸ Risk results are very high level and not easily actionable ▸ Static risk assessment does not address evolving conditions over time (e.g., effect of sediments in the line, increased water content —HAZOPs not conducted on pipeline)
Risk management	▸ BARRS ranks project risk of O&M and Cap Ex project ▸ PMP/MOC primary processes to control and manage corrosion risk ▸ Structured training program ▸ Robust emergency response capabilities ▸ Robust process for incident/accident reporting	▸ Budgets and funding largely based on affordability (vs. necessity) and were not supported by an analytical process to prioritize risk. Senior management incentives based on cost and production ▸ Majority of inspection and monitoring activities focused on areas considered high risk with a robust monitoring program—lack of clear ownership of the OTL ▸ Lack of corrosion control focus on leading indicators to anticipate potential vulnerability that can turn to high risks ▸ Lack of internal audit mechanisms to ensure follow through with corrective actions. ▸ Open-loop MOC process ▸ Lack of IT integration of corrosion-related data
Communications	▸ Robust PMP process between CIC and operations to manage repair on high-risk areas ▸ Good relationship with regulator at the time of the accident	▸ Lack of formal channel to communicate corrosion risks to upper management—risk/production tradeoffs happen at the lower level in the organization. Critical risk data can be lost in the "noise" of data ▸ External: Interaction with regulators not coordinated (locally and nationally)

Corrosion Management Elements	Strengths	Weaknesses
Culture		▸ Lack of ownership of the process safety of the OTL ▸ Gap in scope between HSE and IM activities

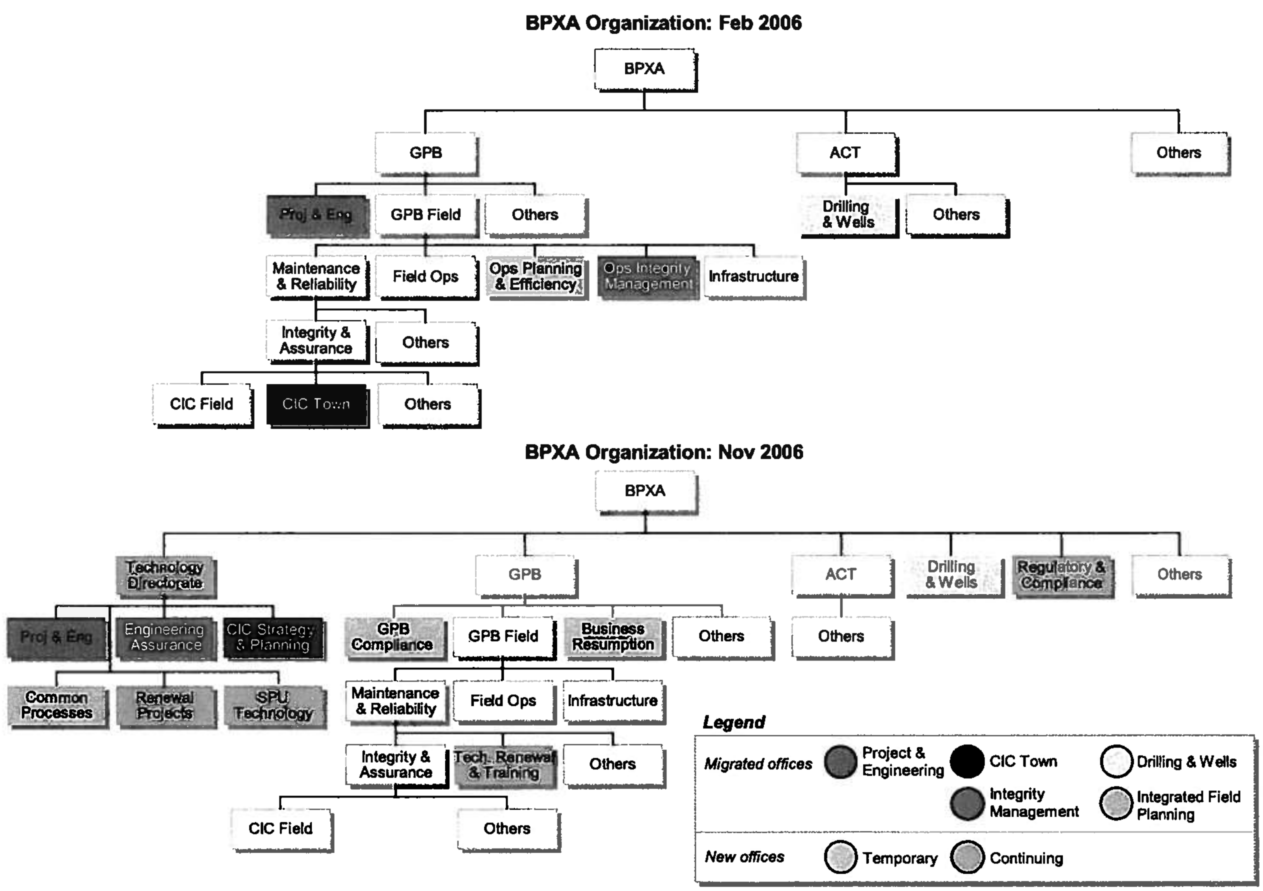
Source: Booz Allen analysis

VII. ANALYSIS OF CHANGES SINCE MARCH 2

Organization

Prior to the August 2006 event, BPXA began restructuring its organization to address some of the issues that contributed to the March 2006 incident.[1] BPXA created two new, high-level organizations to address the need for increased accountability and management focus—the Technology Directorate and the office of Regulatory Affairs and Compliance (see Exhibit 29). Other reorganizations also occurred within GPB, such as the restructuring of Field Operations, and some of them still in process.

Exhibit 29: BP Organization Chart Changes



Source: Booz Allen Hamilton analysis

The office of Regulatory Affairs and Compliance, reporting to the BPXA President, has the objective of establishing a regulatory affairs program in Alaska that interfaces effectively with BP America's businesses and ensures robust compliance and ethics.[2]

The Technology Directorate brings together a number of existing, dispersed GPB engineering functions and several new capabilities. Its creation is recognition that complex engineering issues need centralized coordination, greater visibility, and oversight, with a direct functional report into BPXA's President. Forming the Technology Directorate is also a key element identified in BP's Global Integrity Management Technical Practice Manual. The Technology Directorate comprises:[3]

1. *Projects and Engineering:* Moving over from GPB, with the addition of new engineering offices to run IM; Automation, Fire & Gas (AF&G); Pipeline; and Special projects.
2. *Engineering Authority:* Creates accountability for coordinating IM implementation and conducts SPU-wide risk management for BPXA. (The SPU Risk Management staff have yet to be hired.)
3. *CIC Strategy & Planning:* Moves the CIC Town office out of GPB, enabling more independent management of corrosion and inspection programs. Elevating it three levels in the organization also increases its ability to communicate key corrosion risks to senior management. (The CIC Field organization remains in GPB's Integrity and Assurance office.)
4. *Common Processes:* Elevates Operations Planning and Efficiency out of GPB Field Operations, allowing greater coordination of integrated Field planning and BARRS management.
5. *Renewal Projects:* New office to focus on strategic renewal of North Slope infrastructure, in line with the 50-Year-Field growth plan.
6. *SPU Technology:* New office to focus on keeping BPXA on the forefront of technology, addressing challenges in extracting heavy and viscous oil (still to be staffed).

In addition to the migration of these functions out of the organization, GPB made a few minor adjustments to its structure after the March incident. First, it created two short-term entities to handle issues related to the 2006 pipeline incidents—a Business Resumption Manager and a GPB Compliance Program. Second, it created a Technician Renewal and Training function within Maintenance and Reliability to focus on improving and verifying technician training.[4]

Beyond the changes made in the last quarter of 2006, GPB Field Operations plans to restructure its North Slope organization 2007. The primary aim is to assist GPB Field Operations with additional administrative and management support, allowing Area Managers to focus on more network-wide, strategic issues facing North Slope assets and production:[5]

1. Reduce the direct reports of the GPB Operations head by consolidating the 21 direct reports to 14 (primarily area managers).
2. Create an Operations Excellence function, reporting to GPB Field Operations, to manage a full field view of slope planning and drive process improvements identified by the Technology Directorate.

3. Create additional administrative support through a GPB Field staff manager and convert the single Integrity Assurance manager position to two slope-based shifts.

With reduced supervisory workload, the Area Managers are expected to integrate activities, track and mitigate risks, coordinate product delivery, meet cost targets, and run area teams, which matrix functional organizations (e.g., HSE, Drilling and Wells) with GPB Operation activities.

Key Processes (Corrosion Management Process and Approach)

Since the OTL leak events, there has been increased management attention and inquiry surrounding pipeline system integrity, corrosion risk assessment, and corrosion risk management. To address immediate corrective issues, there have been organizational changes, various investigations, and several task force activities. Although a comprehensive retooling of corrosion risk management has not yet occurred, the following key process changes have been planned and initiated:

- Risk assessment and prioritization
- Risk management (maintenance, inspection, repair, and renewal)
- Accountability
- Budgeting and resources.

Risk Assessment and Prioritization

After the March spill, the Pipeline Assessment and Intervention Team (PAIT) was created to develop a holistic pipe corrosion risk assessment approach, blending industry experience with various pipeline risk assessment models. [6] The team was led by a pipeline engineering integrity advisor from outside Alaska, and included two pipeline engineers from the WIO. The PAIT developed a screening process for well lines, flowlines, and distribution pipelines that would provide an objective, auditable basis for ranking the relative probability of failure (PoF) from internal and external corrosion. The methodology would determine the state of the infrastructure and recommend actions for each segment or section, such as:

- Shut in immediately
- Initiate immediate replacement
- Replace in three years, or
- Continue to monitor.

Primarily using information contained in the MIMIR database, the PAIT risk assessment scored piping sections based on condition and degradation rate. After identifying the critical pipe sections based on the calculated score, a process was begun to assess the strategic implications of pipe shut in and/or replacement (cost, production disruption, etc.). The risk assessment approach developed by the PAIT provides a new formalization and refinement of the process that had been applied from time to time (ad hoc) by CIC staff. PAIT recommended that CIC follow the PAIT process going forward.

Risk Management

Risk management processes to maintain, inspect, repair, and renew pipelines have not changed appreciably since the 2006 spill events, in spite of significant process issues with inspection follow-up (e.g., growing CUI backlog), work backlog accounting, an outmoded CMMS, and continued shortfalls in achieving maintenance pigging plans. Efforts to resume North Slope production have contributed to these backlogs in 2006. However, there have been significant steps taken in pipeline replacement and initiation of updates to Site Technical Practices and Engineering Technical Practices (to make them both consistent slope-wide and more tailored to Alaska-specific conditions).

Holistic risk management is still a work in progress. The Technology Directorate's Engineering Authority is responsible for developing a Risk Register, which should assimilate a comprehensive ranking of all risks faced by the SPU. Risks are measured against severity of consequence and probability of occurrence, ranking them within this matrix. Activities to address risks will be linked to their relative rankings.[7]

The Engineering Authority is in the process of consolidating known risks from a variety of existing sources, including the PAIT, MAHA, and MAR analyses. The first BPXA high-level risk matrix (November 2006) did not fully reflect the internal corrosion risks associated with the OTL, listing CUI as the highest corrosion risk.[8]

Relevant activities that address these corrosion risks include:

- A 10-year pipeline replacement program, including a budgeted, planned, and initiated program for replacement of the OTL over two years
- The selection and implementation of a new, more effective piping leak detection system (awaiting ADEC approval).

However, key steps remain to be completed:

- Codified risk management processes
- Risk policies
- Integrated rankings across all systems
- Detailed causal analysis of high-risk items
- Accountability for executing risk mitigating actions
- Expectations on acceptable completion dates
- Key process indicators (KPI)

- Methods to verify that accomplished activities have mitigated the identified risks.

Accountability

"Ownership" of the OTL has been partially clarified since the 2006 incidents. Area Managers are now responsible for the OTL asset from their facility to the next Area Manager's facility, or Skid 50 if the line does not connect into another Area Manager's facility (even if that line has already crossed into the geographical region of the next Area Manager). The consolidation of GPB assets under fewer managers also makes accountability easier, with fewer divisions between geographical regions. However, a division still remains with CIC, which "owns" corrosion management of the pipeline and the area managers who "own" the OTL asset.[9]

Budgeting and Resources

Additional resources are needed to support BPXA's 50-Year-Field strategy and for renewal efforts associated with the 2006 OTL incidents. Both budget and manpower allocations have been increased for 2007 onward.[10]

Current BPXA staffing requirements estimate 2,403 positions, up 26 percent from the 1,913 estimated needs in March 2006. Specifically, the Technical Directorate has over 65 open technical positions. CIC Strategy & Planning and CIC Field authorizations are expanding by 29, an increase of 116 percent. Additionally, GPB Operations plans to increase its staff by approximately 65 employees, or roughly 12 percent.

Capital spending in BPXA is accelerating due to the 50-Year-Field and renewal projects associated with the 2006 OTL incidents. Projected CAPEX increases in 2007 are of 12 percent to $685 million. The budget is projected to further grow over the years, hitting $1.389 billion in 2010, for an overall combined annual growth rate of 23 percent. Similarly, GPB's O&M budget was projected up from $358 million in 2006 to $395 million, an increase of 10 percent.

Information Technology Infrastructure

BPXA has already taken steps to create a new Business Intelligence system that integrates data from the different functional systems to enable better reporting capabilities. Phase I of the project, which provides access to standardized reporting to all budget owners on a daily basis, started in September 2006 and is scheduled to be completed by the first quarter of 2007. There are projects in the pipeline to replace the existing work order management system CMMS with MAXIMO, the BP standard.[11]

Communications

There were no significant differences found in existing communication relationships or media. However, some report and meeting agendas are being recalibrated to better focus management attention on risks.

Specifically, the QPR now has a major section focused on safety and operational integrity (S&OI). The Technology Directorate has taken the lead in compiling an initial risk assessment across BPXA, in line with the BP North America-wide recommendations from the Texas City incident.[12]

There are plans to roll out more reports internal to BPXA. For example, BULs plan to have quarterly performance updates with their performance units, where they can discuss issues with more formality and depth than occurred prior to 2006.[13]

It is not immediately apparent whether there are any issues associated with CIC communication between the Field inspectors and the Strategy & Planning engineers. Although splitting the CIC Strategy & Planning function creates a more independent and elevated voice, a continual and productive dialogue between execution and planning functions remains crucial (despite reporting up through different ALT managers).[14]

VIII. COMPARISON WITH TEXAS CITY INCIDENT

On March 23, 2005, the BP refinery in Texas City, Texas, experienced an explosion and fire in the Isomerization unit. As the result of this accident, 15 people were killed and over 170 were injured.

The standard for any comparison with the incident at Texas City is The Report of the BP U.S. Refineries Independent Safety Review Panel, the "Baker Panel Report." The report was released in late January 2007, and was not available to the Booz Allen team at the time of this project.

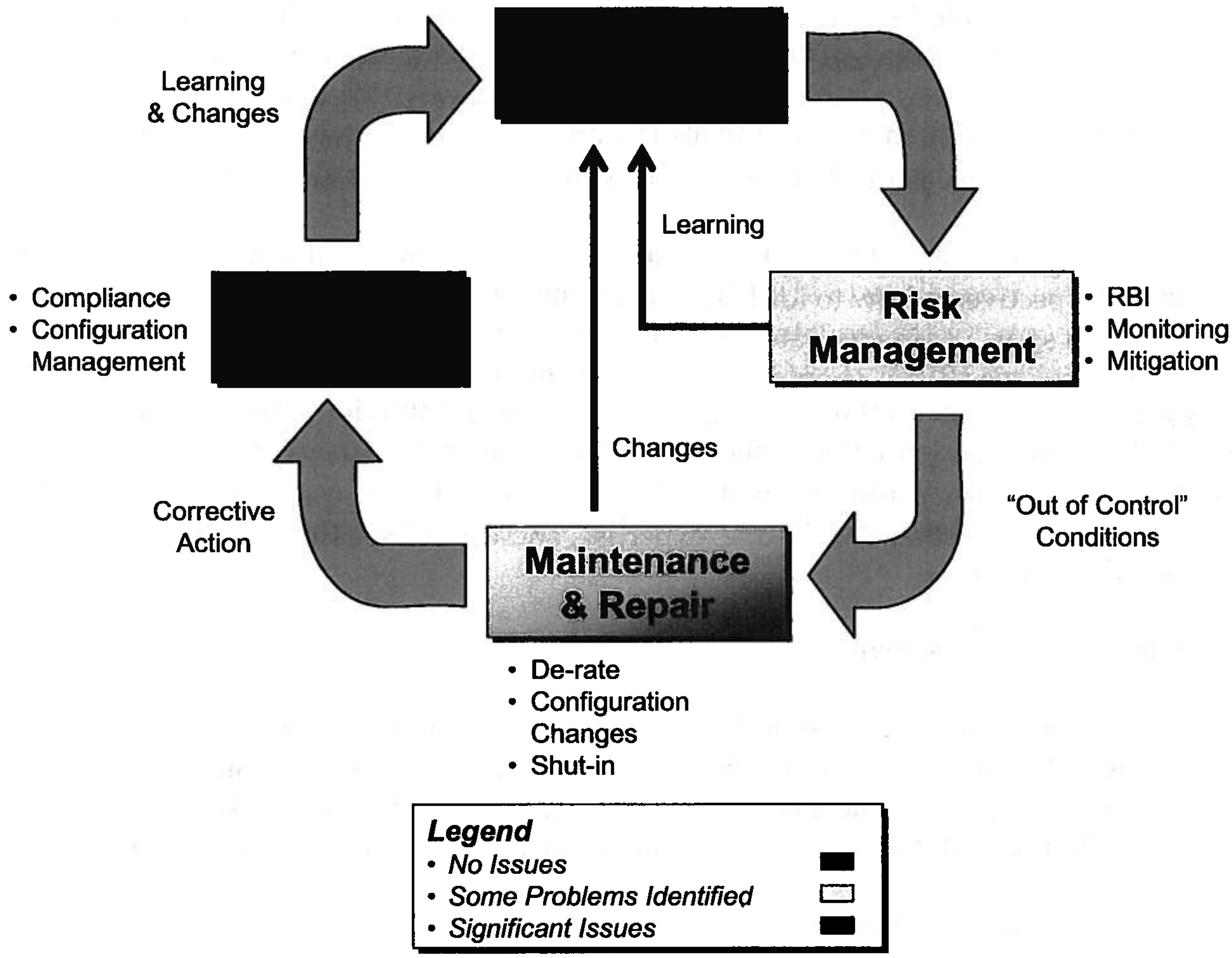
The Booz Allen team was provided with the BP internal Fatal Accident Investigation Report, Isomerization Unit Explosion Final Report, Texas City, Texas, USA, dated December 9, 2005. This "Mogford Report" was to be used exclusively as a basis of comparison with the Alaska incidents.

While the "Mogford Report" is an extremely thorough and comprehensive incident analysis, it lacks the third-party independence of the "Baker Panel Report." Since comparisons with the Alaska incidents will inevitably be made against the "Baker Panel Report," the Booz Allen team felt unable to deliver to the requisite standards of quality and independence that would give such analysis value to BP America management in addressing issues shared by the incidents. BP America senior management agrees with this assessment. Consequently, no comparison with the findings of the "Mogford Report" are presented here.

IX. THE WAY FORWARD – RECOMMENDATIONS

An effective response to address the findings in this report would be to develop a comprehensive risk management process for pipeline integrity that includes risk assessment, risk management, maintenance & repair, and risk assurance as shown in Exhibit 30, and then implement it across the entire BPXA infrastructure. The colors reflect the conclusions of the Booz Allen team based on the findings of the project.

Exhibit 30: Comprehensive Risk Management Process



The first priority is to respond to regulatory compliance directives in a timely manner. To avoid waste and further antagonizing regulatory authorities, BPXA should thoroughly coordinate its response internally, with BPA and with BP globally. This should be a managed process with single-point accountability for coordination and communication as well as transparency, both internal and external. A project office could be set up in the near term, ultimately evolving into a permanent office of regulatory affairs that would manage dealings with all of the regulators with an interest in BP's Alaska operations.

A second priority is to address the fundamental risk assessment and integrity management issues:

- Complete the revision to the corrosion management strategy and commence training for its implementation.
- Fully implement the Hazard and Risk Register. Task a joint CIC and Field Operations team with developing a field-wide risk register for pipeline integrity and corrosion issues.
- Develop and implement an integrity assurance process that links Field Operations with the Engineering Authority and CIC Strategy & Planning. The process should be a closed loop from identification and communication of issues to the Technical Directorate, to analysis, evaluation of options, implementation (e.g., shut in, de-rate, grant waiver), documentation, and follow-up. This model should also be applied to MOC more broadly, with an independent assurance function that can sanction non-compliance.

Stepping back from these specific, near-term recommendations, BPXA should take a broad perspective on how to identify and manage piping integrity risk in order to avoid "blind spots" or inadequate response to creeping change in the future. The Booz Allen team believes BPXA should significantly strengthen its risk assessment, risk management, and risk assurance processes and build a reinforcing system of data, knowledge, and experience that will enable it to be proactive rather than reactive to events. Risk assessment and risk management should be performed by cross-functional teams that bring together knowledge, expertise, and experience from "town," "field," and outside of Alaska.

Strengthen Risk Assessment

Without a rigorous and methodical approach that integrates risk assessment results into risk management and assurance activities, it will not be possible to have a truly effective integrity management program. There are certain key risk assessment areas that should be strengthened to fully utilize risk assessment data, in particular:

Design and implement a holistic risk assessment process.

BPXA should fully implement the Hazard and Risk Register. The process should be formal, methodical and documented. It should be a full-up risk assessment that addresses risk from a "systems" perspective and evaluates all parts of the kit including: Piping network; facilities; equipment/hardware; software; and normal and emergency operating procedures. The risk assessments should consider various sources of input including: Design, operating, and maintenance documents and drawings; audit, test, and inspection report findings; trended failure or problem areas; direct system observations; and, expert advice from on-site operating personnel. The validity of the risk assessment is contingent on facilitation by managers who are appropriately trained to verify that appropriate data is collected, analyzed, and synthesized for management reporting.

Conduct root cause analysis ex ante as part of risk assessment.

The risk assessment should clearly define each hazard risk scenario of concern so that managers have a good understanding of the actual risk. Identifying root causes should be an integral part of this process. Root causes need to be fully understood so that appropriate controls can be put into place. The risk assessment process should identify leading indicators of potential future problem areas that can be tracked as such.

Consider variable operating conditions and update the risk assessment whenever significant changes occur.

The aging kit and variable operating conditions can greatly impact risk. It is important to account for these variables as part of the risk assessment. Also, modifications, replacement, and repair of kit subsystems can impact risk, and any major change (hardware, software, or procedural) must be risk assessed. This means that the risk assessment is not a static document, but is updated as operations or conditions change.

Evaluate risk controls/corrective actions and ensure that they are adequate and in place.

Risk controls or corrective actions should be directly linked to resolving each hazard risk scenario. The risk assessment should include processes (i.e., inspection or testing) to validate that the controls adequately mitigate the hazard risk scenario and are verified to be viable.

Risk ranking should be formal and predefined, with clear risk acceptance criteria and rationale.

As part of the risk ranking, it is important that the risk assessment evaluate each hazard scenario for probability of occurrence and severity of consequences. The confluence of the two should be part of the formal risk ranking. It is critical that risk acceptance criteria are set by management before risk assessments are begun, and should be part of official policy. Documenting the risk acceptance rationale is important because it holds decision-makers accountable for how well risks are managed.

Enhance Risk Management

The BPXA risk management process should build on current successful programs. In addition to current and planned integrity and risk management activities, BPXA should implement the following actions:

Streamline critical risk data and make it comprehensible to senior management.

Decision-makers need relevant risk data to be able to best determine a course of action. Data should be comprehensive and sufficiently detailed to give leaders an understanding of the issues, but also clear and succinct so that critical risk messages are not lost. Senior leaders need both the current lagging indicators of integrity management and the leading indicators as determined by the risk assessments. The former will help focus attention on ensuring that mitigation strategies are effective. The latter will serve as early idicators of where future problems may arise, thus permitting rapid mitigation before they become serious.

Develop sustainable risk communication channels.

These channels should ensure that critical risk information reaches decision-makers in a reliable and timely manner. For senior managers to be held accountable for risk decisions, they need to receive timely and digestible risk data. The risk communication channels should be used to share important risk information, communicate key risk messages, and coordinate appropriate risk management strategies. Risk communication channels should horizontally link GPB organizations so that important risk data holders are able to share what they know and help devise appropriate risk-based responses. The communication channels must also work vertically, ensuring that front-line staff have a method to communicate important risk information to senior management.

Upgrade and integrate risk management information systems.

A risk-based inspection system (currently MIMIR) should be linked with a work order system that tracks PMPs (MAXIMO), a piping integrity system that manages the infrastructure, and a system that tracks proposed changes through closure (TRACTION). These systems should share common databases to eliminate duplication and ensure consistency. The risk based inspection system and change management systems should include tools for data analysis in order to assess trends and identify "creeping change" that may affect asset integrity. Analysis should be a regular feature of risk assessments and management reporting.

Assign single point accountability at the operating level for discrete piping systems and other infrastructure assets.

There should be clear line management ownership below the level of GPB Field Manager for the integrity and performance of infrastructure systems end-to-end. This will ensure that assets are appropriately monitored and that maintenance and assurance activities will not "fall through the cracks."

Strengthen Risk Assurance

The first job of an independent risk assurance and integrity management function (proposed for the EA) should be to strengthen the current assurance process, formalize key activities, and create an oversight and feed-back loop to ensure compliance.

Develop a formal risk-based assurance process.

At the heart of a formal risk-based assurance program is a robust, closed-loop audit process. The formal audit process should have two components: Audit, inspection/verification of current practices; and special audits based on high risk items identified in risk assessments. The first should be a continuation of current practices, but also include a close-loop tracking mechanism to ensure completion. The second should take the risk assessment/risk register results and use the high risk items to serve as leading indicators. These items would then form the basis of a "targeted" audit. This will permit BPXA to focus on emerging risk areas before they develop into crisis situations. As with the first component, the "targeted" audits should be closed loop with a verification piece that ensures corrective actions are adequate and in place.

Formalize the risk disposition process.

The Engineering Authority should continue with its plans to serve as the formal risk review and approval process owner. It is important to ensure that risk mitigation plans and corrective actions are put in place and that there is a formal independent review and approval process. Because asset and operational risk management must remain with line managers who own the risk, an independent assurance group should serve to verify that the risk has been appropriately dispositioned. All major changes should be risk reviewed and approved before action is taken.

Establish an escalation policy to ensure compliance.

A robust assurance program must include an escalation process that drives compliance with internal and external risk management requirements. If there are no consequences for non-compliance, there will be insufficient discipline in place to ensure that corrective actions and risk management strategies are implemented. An appropriate enforcement regime will make certain that this occurs. Furthermore, management should have metrics for asset integrity as part of their performance contracts to ensure an appropriate level of leadership attention.

BPXA has a large number of initiatives under way or planned. In addition to addressing the specific integrity issues arising from the leak incidents, BPXA has a long list of projects to undertake in the coming years:

- *Implementation of global IM standard* – process improvement
- *S&OI Six-Point Plan* – projects and process improvement
- *Reorganizations* – BPXA and GPB
- *Implementation of Operating Management System (OMS)* – process improvement
- *Implementation of Enterprise Risk Management (ERM)* – process improvement
- *Wedge* – major project
- *Major Projects* – 11 major projects identified
- *Mid-Stream Alaska*
- *Renewal*

Regulatory investigations and compliance will consume additional resources, particularly management time and attention. In addition, there are a number of open audit items that will require close-out.

Given the sheer number and complexity of initiatives planned, BPXA management should take the time to evaluate them holistically to identify prerequisites, redundancies, complements, and a critical path. It is unlikely that BPXA will be able to resource all of these initiatives simultaneously. A risk- and reward-based approach should be used to cull the list and establish priorities. Many aspects of ERM or OMS may be embedded in other initiatives. Portions of IM and OMS are likely to be redundant. If activities and tasks can legitimately be deferred, they should be. Renewal alone, in all of its aspects, could fully occupy much of the organization for many years.

BPXA should immediately reach out from Alaska to identify best practices for each of the risk management elements. There is a wealth of piping integrity risk management expertise in other regions of E&P (e.g., North Sea) as well as within R&M. For example, BP Pipelines (North America) regularly conducts HAZOPs as part of their risk assessments in GoM. Risk-based inspection procedures are also employed. BPXA should quickly adopt and then adapt the most effective processes and technologies available within BP, and then aspire to best practices, which are likely to reside in other industries, such as chemicals and nuclear power, or in high-reliability institutions like NASA or the nuclear U.S. Navy.

An important first step will be to establish the performance and process objectives of this initiative, and identify appropriate metrics for tracking and completion. These will determine pace and resource requirements.

Coupled with the vision for a 50-year field, this set of initiatives presents a considerable challenge and a unique opportunity for the BPXA management team. The challenge and the opportunity are to revolutionize the way the field operates and performs. This is a long-term program that requires a long-term commitment from the senior team.

X. APPENDICES

APPENDIX 1 PROJECT TERMS OF REFERENCE

DRAFT 20 November 2006

Terms of Reference
for a Review for BP Relating to the Alaska Pipeline Matter

Booz Allen Hamilton (the "Firm") will conduct a factual investigation for BP, as requested by the President of BP America Inc. (BP America), into certain issues related to the corrosion management program at Prudhoe Bay, including the GC-2 and FS-2 spills and the August 6, 2006 decision to shut down the Prudhoe Bay Operating Area because of corrosion issues ("Alaska Pipeline Matter") in order to render advice to BP America and BP Alaska Inc. (BP Alaska) and their respective current managements and to other members of the BP Group ("BP Group Companies").

The scope of the Firm's investigation will focus on an external review of the following issues relating to the Alaska Pipeline Matter and have particular regard to root causes, key skills gaps, the appropriateness or otherwise of the organisation, information transparency, relationships with regulators, behaviours and culture, lessons learned, and actual or potential parallels with root causes of the Texas City Refinery incident in March 2005 ("Texas City Incident").

<u>Corrosion and Integrity Management</u>
In light of the BP Alaska's previous management's approach and responses to, and handling of, corrosion and integrity management processes in relation to the Alaska business including actions (or lack of actions) to detect, prevent or correct corrosion in the Prudhoe Bay oil transit lines and other related problems, assess the appropriateness of current responses and management of problems, and relationships with regulators, joint venturers, and other parts of the BP Group prior to and upon announcement of corrosion and other issues.

<u>Analysis and Conclusions</u>
In light of the Alaska Pipeline Matter, assess appropriateness of BP Alaska's management's current handling of any corrosion warning signals and actions taken or not taken in response to those signals.

<u>Authority and Resources</u>
In light of the Alaska Pipeline Matter, assess whether BP Alaska's management and employees hold appropriate authority, accountability and resources to manage corrosion issues.

<u>Internal Communication</u>
In light of the Alaska Pipeline Matter, assess the state of future communication capabilities within, to or from BP Alaska's management.

This engagement is separate from the work of other individuals and firms advising BP Group Companies on the Alaska Pipeline Matter and as the case may be the Texas City Incident. Regarding the actual Alaska Pipeline Matter, BP America will use reasonable endeavours to make the factual work product prepared by other individuals/firms involved in matters related to the Alaska Pipeline Matter and the Texas City Incident available to the Firm for its use, where appropriate, in this engagement.

The Firm will provide its report to the President of BP America Inc. The target date for completion of the review and the final report of the Firm's findings is 31 January 2007.

APPENDIX 2 ENDNOTES

I. Purpose and Scope

No endnotes

II. Executive Summary

No endnotes

III. Framework and Approach

No endnotes

IV. Context

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17. PHMSA Web site, Federal Register, Vol. 71, No. 172, September 2006

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V. Description of the Corrosion Management System Leading to March 2

1. "2000 to 2004 Coffman Reports," PSM Audit Reports (2000, 2002), EMS External Audit Reports (1998-2003, 2005), and EMS Internal Audit Reports (1998, 2000-2003, 2005)

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3. BP Global Management Framework "Greenbook"

4. Interviews: BPXA President, BPXA Commercial Director

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14. Interview: MAR/MAHA Coordinator, 2004 Emerald Consulting Group Major Accident Hazard Analysis for Greater Prudhoe Bay Performance Unit 2006, Major Accident Hazard Analysis 2005 Update and Register Development, 2005 Guidance on Practice for Major Accident Risk Process, 2006 Major Accident Risk Assessment of Alaska Business Unit
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16. Interviews: GPB Field Manager, GPB Area Managers, GPB Commercial Manager, Integrated Field Planning Lead; BARRS Introduction PowerPoint; BARRS database Excel spreadsheets
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20. Ibid.
21. Ibid.
22. Ibid.
23. Ibid.
24. Ibid.
25. Ibid.

26. Interviews: GPB Area Managers, GPB Production Optimization Leaders

27. Interview: GPB Engineering Document Group Manager; BPXA "Technical Management of Change Process," November 2004

28. Interviews: BPXA Talent Manager, BPXA Operations SDDN Manager; "BPXA Development Guide for Supervisors"

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46. Ibid.

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16. Interview: CIC S&P Engineer

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19. "GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report"

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60. PMP Tracking Sheet and the PMP Yearly Report; Interviews: GPB CIC Team Leader, CIC Head, CIC Engineering (S&P), FS-2 Area Manager, Mid-Continent PUL

61. Interviews: GPB Area Managers

62. CMMR database; TRACTION database; MIMIR database; BARRS spreadsheet (Excel); MAHA/MAR documents; Interviews: MIMIR Manager, Commercial Manager, FS-2 Area Manager, HSE Program Manager, MAHA/MAR Coordinator, GPB CIC Team Leader, CIC Head

63. Ibid.

64. Interviews: GPB CIC Team Leader, CIC Head, HSE Program Manager, HSE Analyst, Technical Director, Optimization Managers

65. MAHA/MAR documents, PSM Element Application, Interviews: GPB CIC Team Leader, CIC Head, HSE Program Manager, HSE Analyst, Technical Director, Optimization Managers

66. Ibid.

67. BPXA Technical Management of Change Process document, November 2004, MIMIR database, CMMR, PMP Tracking Sheet; Interviews: GPB CIC Team Leader, CIC Head, CIC Engineering (S&P), Optimization Managers, FS-1, FS-2, and GC-2 Area managers

68. Ibid.

69. BPXA Technical Management of Change Process document, November 2004; MIMIR database; CMMR; PMP Tracking Sheet; Interviews: GPB CIC Team Leader; CIC Head; CIC Engineering (S&P); Optimization Managers; FS-1, FS-2, and GC-2 Area managers

70. BPXA Technical Management of Change Process document, November 2004; MIMIR database; CMMR; PMP Tracking Sheet; Interviews: GPB CIC Team Leader, CIC Head, CIC Engineering (S&P), Optimization Managers, GPB Area Managers

71. Interviews: Senior Attorney (HSE and Regulatory), VP Regulatory and Compliance, GPB BUL

72. Corrosion Management Annual Reports; Spill Response Plan to PHMSA, Corrective Action Order March 15, 2006; Interviews: Senior Attorney (HSE and Regulatory), VP Regulatory and Compliance

73. Interviews: Senior Attorney (HSE and Regulatory), VP Regulatory and Compliance, HSE Program Manager, GPB BUL

VII. Analysis of Changes Since March 2

1. Interviews: BPXA President, GPB BUL, GPB Field Ops Manager, email from BPXA President – June 2006, BPXA Organization Charts 2004-2006

2. Interview: BPXA VP for Regulatory and Compliance

3. Interview: BPXA Technical Director; BP Global "Integrity Management Standard" November 2005

4. Interviews: BPXA Engineering Process Manager, GPB Field Ops Manager

5. Interview: GPB Field Ops Manager

6. BPXA "Pipeline Assessment and Intervention Team," July 2006; Interviews: BPXA Engineering Process Manager, E&P Technology Group Engineer (Member of PAIT Team)

7. "Hazard and Risk Register Creation," December 2006; Interviews: BPXA Technical Director, BPXA Engineering Authority

8. "Hazard and Risk Register Creation," December 2006; Interviews: BPXA Engineering Authority, BPXA Integrity Manager

9. Interview: GPB Field Manager; GPB Organization Charts 2006

10. BPXA Group Financial Outlook, Interview: Commercial Manager GPB

11. Interview: BPXA Business Information Manager

12. Interview; Commercial Manager GPB

13. Interviews: BPXA Commercial Director, GPB Commercial Manager

14. Interview: CIC Head

VIII. Comparison with Texas City Incident

No endnotes

IX. The Way Forward – Preliminary Recommendations

No endnotes

APPENDIX 3 INTERVIEW LIST

Title	First Name	Last Name	Initial Interview Date	Follow-Up Interview Date
Operations Lead - Applications Team	Terri	Adkins	12/1/2006	
HR- Data Management	Shelly	Allen	11/28/2006	
BPXA Commercial Manager	Belal	Atiiyah	11/15/2006	
HSE Program Manager	Bob	Batch	11/15/2006	
Group Engineering Director	John	Baxter	11/27/2006	
Director of Public Affairs	Daren	Beaudo	12/14/2006	
BPXA Human Resources Director	Sandy	Beitel	11/21/2006	
CIC Chemical Engineer	Tim	Bieri	12/7/2006	
Strategy & Planning Manager	Damian	Bilbao	12/5/2006	
Former GPB Field Manager	George	Blankenship	11/17/2006	
President BP Pipelines (Alaska)	Albert	Bolea	11/17/2006	
Resource Planning Manager	Florian	Borowski	12/7/2006	
PAIT - Materials Engineer	Chase	Breidenthal	12/6/2006	
Technical Director	Tony	Brock	11/21/2006	
Senior Attorney, HSE and Regulatory	Randal	Buckendorf	11/17/2006	12/14/2006
Production Optimization Leader	Mike	Bulkavatz	11/29/2006	
Business Information Manager	Tom	Bundy	11/28/2006	
Former HSE Program Manager	Gary	Campbell	11/17/2006	
Mid-continent Performance Unit Leader, North America Gas & Investigation Team Leader	Bryant	Chapman	11/29/2006	
GPB Field Manager	Kemp	Copeland	11/15/2006	
GPB CIC Team Lead	Gary	Crawford	11/29/2006	
CIC Integrity Analyst	Doug	Czechowicz	12/7/2006	
HSE Analyst	Shannon	DeMarco	11/28/2006	
Accuren Contractor - CIC Inspector	Kevin	Deutsch	12/6/2006	
PSCM Material Team Lead	Mike	Dong	11/20/2006	
GPB Infrastructure Manager	Neil	Dunn	11/29/2006	
Flow Station Maintenance	Chris	Dye	11/29/2006	
Compliance and Ethics Leader	Phil	Dziubinski	11/16/2006	
GPB Compliance Program Manager	John	Ennis	11/16/2006	
Sr. Financial Analyst	C. Drais	Farnham	12/4/2006	12/6/2006
Former GPB Technical Services Director	Nancy	Foust	11/15/2006	
HR Talent Manager	Alice	Galvin	12/1/2006	
Consultant - ECP	Billie	Garde	11/16/2006	
Former BPXA Commercial Director	Alastair	Graham	12/19/2006	
HSE Assurance Manager	Leslie	Griffith	12/12/2006	
CIC Head	Bill	Hedges	11/15/2006	12/14/2006
BPXA Engineering Authority	Corey	Herod	11/21/2006	12/20/2006

Title	First Name	Last Name	Initial Interview Date	Follow-Up Interview Date
Fmr GPB Business Unit Leader	Tim	Holt	11/30/2006	
GPB Business Unit Leader	Maureen	Johnson	11/17/2006	
Gas Performance Unit Leader	Ken	Konrad		
Motor Maintenance - Field Crew	Marc	Kovac	11/30/2006	
Integrity Management Coordinator	Bob	Krenzelok	12/14/2006	
GPB Operations Manager	John	Kurz	11/30/2006	
Senior Corrosion Engineer	John	Kuzma	11/21/2006	
Reliability and Performance Planning	Jerry	Larsgaard	11/20/2006	
Reliability & Perf. Plng Mgr	Jerry	Larsgaard	11/20/2006	11/28/06 12/21/06
BPXA Integrity Management Lead	Dan	Lebsack	11/21/2006	12/5/2006
President, BPXA	Steve	Marshall	12/7/2006	
FS-1 Area Manager	Adrian	McCaa	11/29/2006	
Former GPB Field Manager	Neil	McCleary	11/30/2006	
Managing Attorney	Brad	McKim	12/13/2006	
BP North America Audit Head	Kerr	McLaren	12/7/2006	
Former COO TNKBP	Larry	McVay	12/15/2006	
HSE Manager	Mark	Merrill	11/28/2006	
MAHA/MAR Coordinator	Candice	Miller	12/19/2006	
Integrated Field Planning Lead	Guy	Mofley	11/29/2006	
Group Vice President	David	Peattie	11/28/2006	
GPB CIC Team Lead	John	Phillips	12/18/2006	
CIC S&P Engineer	Tim	Pine	12/6/2006	12/7/2006
GPB Engineering Document Group Manager	Sandy	Reimer	12/14/2006	
FS-2 Area Manager	Chris	Rhoads	11/30/2006	
MSA Delivery Manager	Mike	Rocereta	11/20/2006	
Technical Discipline Group Team Lead	Susan	Shaw	11/29/2006	
Maximo/PASSPORT Team Lead	Tim	Shortridge	12/20/2006	
CIC Integrity Analyst	Kip	Sprague	11/20/2006	12/5/2006
Vice President, Regulatory Affairs and Compliance	Sandy	Stash	12/20/2006	
Corrosion Engineer	Randy	Sulte	12/19/2006	
HSE Crisis Manager	Ed	Thompson	11/28/2006	
GC3 Maintenance Operator	Glenn	Trimme	11/29/2006	
Production Optimization Leader	Hal	Tucker	11/29/2006	
Operating Procedures Coordinator	Doug	VanWingerden	12/6/2006	
SDDN Operations Manager	Janice	Vosika	12/13/2006	
Commercial Vice President	Angus	Walker	11/16/2006	
FS-2 Area Manager	Bob	Walker	11/29/2006	
GPB M & R Manager	Bruce	Williams	11/21/2006	
PSIM Mgr & Engineering Authority	George	Williamson	11/21/2006	

APPENDIX 4 DOCUMENT LIST

Item	Document Title	Date Received	Source
Audits (Internal / External)			
1.1	Alaska Transit Pipeline Technology Review 10th-12th April 2006	11/14/2006	Sandy Stash
1.2	Internal Audit - BPXA Corrosion Management System Technical Review Final Report	11/14/2006	Sandy Stash
1.3	People Assurance Survey	11/14/2006	Sandy Stash
1.4	People Assurance Survey	11/14/2006	Sandy Stash
1.5	People Assurance Survey Results Email from Steve Marshall	11/14/2006	Sandy Stash
1.6	Review of Operational Integrity Concerns at Greater Prudhoe Bay (ORT Report)	11/14/2006	Sandy Stash
1.7	Freestone Report	11/14/2006	Phil Dzubinski
1.8	Alaska Transit Pipeline Technology Review 10th-12th April 2006	11/14/2006	Brad McKim paper copy of Baxter
1.9	BPXA Corrosion Management System Technical Review	11/14/2006	Brad McKim paper copy of Baxter rpt
1.10	ORT Genesis Documents (emails, notes, etc.)	11/14/2006	Phil Dzubinski
1.11	GPB Management Response to ORT report	11/14/2006	Phil Dzubinski
1.12	GPB ORT Team Progress Update presentation	11/14/2006	Phil Dzubinski
1.13	2006 People Assurance Survey	11/14/2006	Sandy Bietel
1.14	Global Integrity Assurance Review - GPB Bav B.U. (Freestone Report)	11/20/2006	Brad McKim
1.15	2005 Internal EMS Audit	12/12/2006	Leslie Griffiths
1.16	BPXA 5-year Forecast Environmental Audits	12/12/2006	Leslie Griffiths
1.17	Conducting Environmental Requirement Compliance	12/12/2006	Leslie Griffiths
1.18	Draft 2006 BPXA EMS Audit	12/12/2006	Leslie Griffiths
1.19	Environmental Audit Program Overview (Tier 1 Doc)	12/12/2006	Leslie Griffiths
1.20	2002 External gHSEr Audit GPB	12/12/2006	Leslie Griffiths
1.21	2004 External gHSEr Audit ACT	12/12/2006	Leslie Griffiths
1.22	2005 gHSEr Audit Self Assessment TRACTION Report	12/12/2006	Leslie Griffiths
1.23	2000 PBU gHSEr Final Report	12/12/2006	Leslie Griffiths
1.24	Exec Summary GPB gHSEr Report	12/12/2006	Leslie Griffiths
1.25	ACT gHSEr Audit Report, June 28, 2004	12/12/2006	Leslie Griffiths
1.26	GPB 2002 Final gHSEr Audit Report	12/12/2006	Leslie Griffiths
1.27	2000 GPB PSM Audit TRACTION Report	12/12/2006	Leslie Griffiths
1.28	2002 GPB PSM Audit TRACTION Report	12/12/2006	Leslie Griffiths
1.29	2006 GC&E Alaska Closing Meeting Summary	12/12/2006	Leslie Griffiths
1.30	2002-2003 GPB PSM Internal Assessment Report	12/12/2006	Leslie Griffiths
1.31	PSM Process Safety Information Element Administrative Procedure	12/12/2006	Leslie Griffiths
1.32	2001 ORT Audit TRACTION Report	12/12/2006	Leslie Griffiths

Item	Document Title	Date Received	Source
1.33	IM Audit Protocol Elements	12/12/2006	Leslie Griffiths
1.34	Alaska HSE Compliance Review, BP Internal Audit, Feb 27, 2003	12/13/2006	Kerr McLaren
1.35	Alaska HSE Compliance Review - Executive Briefing, BP Internal Audit, Feb 28, 2003	12/13/2006	Kerr McLaren
1.36	Alaska HSE Compliance Review - Executive Briefing, BP Internal Audit, March 3, 2003	12/13/2006	Kerr McLaren
1.37	HSE/OI Compliance Assurance - Progress Report	12/13/2006	Kerr McLaren
1.38	Alaska 4QPR HSE & Integrity Management Update	12/13/2006	Kerr McLaren
1.39	Audit Report of 2004 Major Accident hazard Analysis (MAHA)	12/12/2006	Leslie Griffiths
1.40	PSM Audit Protocol	12/14/2006	Leslie Griffiths
1.41	2005 Internal EMS Audit	12/14/2006	Leslie Griffiths
1.42	1998 Internal EMS Audit	12/14/2006	Leslie Griffiths
1.43	1999 Internal EMS Audit	12/14/2006	Leslie Griffiths
1.44	2000 Internal EMS Audit	12/14/2006	Leslie Griffiths
1.45	2001 Internal EMS Audit	12/14/2006	Leslie Griffiths
1.46	2002 Internal EMS Audit Northstar	12/14/2006	Leslie Griffiths
1.47	2002 Internal EMS Audit ACT	12/14/2006	Leslie Griffiths
1.48	2002 Internal EMS Audit BPXA-wide	12/14/2006	Leslie Griffiths
1.49	2002 Internal EMS Audit GPB	12/14/2006	Leslie Griffiths
1.50	2003 Internal EMS Audit	12/14/2006	Leslie Griffiths
1.51	2005 Internal EMS Audit	12/14/2006	Leslie Griffiths
1.52	1998 External EMS Audit	12/14/2006	Leslie Griffiths
1.53	1999 External EMS Audit	12/14/2006	Leslie Griffiths
1.54	2000 External EMS Audit	12/14/2006	Leslie Griffiths
1.55	2001 External EMS Audit	12/14/2006	Leslie Griffiths
1.56	2002 External EMS Audit	12/14/2006	Leslie Griffiths
1.57	2003 External EMS Audit North Slope	12/14/2006	Leslie Griffiths
1.58	2003 External EMS Audit Endicott	12/14/2006	Leslie Griffiths
1.59	2004 External EMS Audit	12/14/2006	Leslie Griffiths
1.60	2005 External EMS Audit	12/14/2006	Leslie Griffiths
1.61	2000 Internal Surveillance Audit	12/14/2006	Leslie Griffiths
1.62	Internal Audit - BPA SPU EAMS Project Review	12/20/2006	Tim Shortridge
1.63	Email regarding Final EAMS Project Review	12/20/2006	Tim Shortridge
COBC			
2.1	ADEC Leak Detection COBC Correspondence Log '98-'03	12/1/2006	Randal Buckendorf
2.2	BP Exploration (Alaska) Inc. ADEC	12/1/2006	Randal Buckendorf
2.3	Closure of COBC No. 02-138-10 BPXA, GPB, ADEC Plan No. 014-CP-5079	12/1/2006	Randal Buckendorf
2.4	COBC for BPXA, GPB, ADEC Plan No. 014-CP-5079	12/1/2006	Randal Buckendorf
2.5	COBC Monthly Status Report, Nov 2002	12/1/2006	Randal Buckendorf

Item	Document Title	Date Received	Source
2.6	COBC, Dept of Env. Conservation v. BPXA, Consent Order No. 02-138-10	12/1/2006	Randal Buckendorf
2.7	COBC Monthly Status Report, Consent Order No. 02-138-10 Oct 2002	12/1/2006	Randal Buckendorf
2.8	COBC Monthly Status Report, Consent Order No. 02-138-10 Sept 2002	12/1/2006	Randal Buckendorf
2.9	COBC Monthly Status Report, June and July 2002	12/1/2006	Randal Buckendorf
2.10	COBC Monthly Status Report, Consent Order No. 02-138-10 July 2002	12/1/2006	Randal Buckendorf
2.11	COBC Monthly Status Report, Consent Order No. 02-138-10 June 2002	12/1/2006	Randal Buckendorf
2.12	COBC, Dept of Env. Conservation v. BPXA, Consent Order No. 02-138-10 Copy of Check	12/1/2006	Randal Buckendorf
2.13	Economic Benefit Calc Relating to Draft COBC Addressing Possible BPXA C-Plan Violations at GPB BU	12/1/2006	Randal Buckendorf
2.14	Draft COBC COBC Addressing Possible BPXA Violations of ADEC Leak Detection Req at GPB	12/1/2006	Randal Buckendorf
2.15	Application of Renewal of the BPXA GPB Oil Discharge and Contingency Plan , ADEC Plan Number 014-CP-5079, RFI	12/1/2006	Randal Buckendorf
2.16	Application of Renewal of the BPXA GPB Oil Discharge and Contingency Plan , ADEC Plan Number 014-CP-5079, ADEC Engineering Review	12/1/2006	Randal Buckendorf
2.17	COBC No. 01-124-40-1858 BPXA, EOA, Contingency Plan 984-CP-4104	12/1/2006	Randal Buckendorf
2.18	COBC, Dept of Env. Conservation v. BPXA, COBC No 01-124-40-1858	12/1/2006	Randal Buckendorf
2.19	COBC, Dept of Env. Conservation v. BPXA, COBC No 01-124-40-1858 Copy of Check	12/1/2006	Randal Buckendorf
2.20	COBC for BPXA EOA, Order No 10-124-40-1858	12/1/2006	Randal Buckendorf
2.21	BPXA Pipeline Leak Detection for the GPB, EOA and WOA	12/1/2006	Randal Buckendorf
2.22	Pipeline Leak Detection BAT Review GPB and GPMA BPXA	12/1/2006	Randal Buckendorf
2.23	Pipeline Leak Detection Information GPB BPXA	12/1/2006	Randal Buckendorf
2.24	Pipeline Leak Detection Information GPB BPXA follow up	12/1/2006	Randal Buckendorf
2.25	BPXA Proposed Leak Detection on the GPB EOA and WOA Crude Oil Transmission Pipeline Systems; Oil Discharge and Contingency Plan Number 984-CP-4138 and 984-CP-4129 (12/07/2000)	12/1/2006	Randal Buckendorf
2.26	BPXA Proposed Leak Detection on the GPB EOA and WOA Crude Oil Transmission Pipeline Systems; Oil Discharge and Contingency Plan Number 984-CP-4138 and 984-CP-4129 (01/12/01)	12/1/2006	Randal Buckendorf

Item	Document Title	Date Received	Source
2.27	Leak Detection System Info Submittal, ADEC Plan No 984-CP-4129 GPB WOA Oil Discharge Prevention And Contingency Plan (ODPCP)	12/1/2006	Randal Buckendorf
2.28	Amendment to the BPXA, GPB WOA, Oil Discharge Prevention and Contingency Plan, Date Sept 1998, ADEC Plan No 984-CP-4129, RFAI	12/1/2006	Randal Buckendorf
2.29	WOA and EOA/GPMA Crude Oil Transmission Pipelines, Pipeline Leak Det. BAT Amendment Condition No 8 of 99 CER-4335 and 00 CER- 4336	12/1/2006	Randal Buckendorf
2.30	Amendment to the BPXA, GPB WOA, Oil Discharge Prevention and Contingency Plan, Date Sept 1998, ADEC Plan No 984-CP-4129, Sufficient for Review, Notice to Publish	12/1/2006	Randal Buckendorf
2.31	ARCO/EOA - BP/WOA - GPB McIntyre Crude Oil Transmission Pipelines Proposed Leak Detection	12/1/2006	Randal Buckendorf
2.32	ADEC Letter - Nov 5, 1999 Status of Conditions of Approval GPB WOA Oil Spill Contingency Plan	12/1/2006	Randal Buckendorf
2.33	Status of Conditions of Approval for BPXA GPB Alaska Oil Discharge Prevention and Contingency Plan (984-CP-4129) (Nov 5, 1999)	12/1/2006	Randal Buckendorf
2.34	EOA/WOA and GPMA Crude Oil Transmission Pipelines Proposed Leak Detection BAT Analysis (Oct 15, 1999)	12/1/2006	Randal Buckendorf
2.35	Alternative Compliance Schedule Crude Oil Transmission Pipelines (Jan 28, 1999)	12/1/2006	Randal Buckendorf
2.36	OASIS Environmental-ADEC Leak Detection RFP	12/1/2006	Randal Buckendorf
2.37	RFI: BPXA, PB BU, WOA, Oil Discharge Prevention and Contingency Plan, Dated Sept 1998, ADEC Plan No 984-CP-4129	12/1/2006	Randal Buckendorf
Corrosion Management (Policies, Programs, Procedures, Compliance/Reports)			
3.1	BP OTL Technical Paper (Bill Byrd Report)	11/14/2006	Sandy Stash
3.2	EOA/WOA Corrosion Inspection Timeline	11/14/2006	Sandy Stash
3.3	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2004	11/14/2006	Sandy Stash
3.4	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2003	11/14/2006	Sandy Stash
3.5	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2002	11/14/2006	Sandy Stash
3.6	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2001	11/14/2006	Sandy Stash
3.7	BPXA Corrosion Data Integrity Assessment	11/14/2006	Sandy Stash
3.8	Corrosion Management System Element - Monitoring	11/14/2006	Sandy Stash
3.9	Corrosion Management System Element - Mitigation	11/14/2006	Sandy Stash
3.10	Corrosion Management System Element - Inspection	11/14/2006	Sandy Stash
3.11	Corrosion and Process Monitoring Techniques	11/14/2006	Sandy Stash
3.12	Weight Loss Coupons and Probes	11/14/2006	Sandy Stash

Item	Document Title	Date Received	Source
3.13	Corrosion and Structural Related Spills and Incidents	11/14/2006	Sandy Stash
3.14	2002 Corrosion Monitoring and Inspection Goals	11/14/2006	Sandy Stash
3.15	Data Tables (Migration Corrosion Procedures of two lines in Prudhoe Bay)	11/14/2006	Sandy Stash
3.16	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2000 Draft	11/14/2006	Sandy Stash
3.17	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2000	11/14/2006	Sandy Stash
3.18	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2001 Draft	11/14/2006	Sandy Stash
3.19	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2002	11/14/2006	Sandy Stash
3.20	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2003	11/14/2006	Sandy Stash
3.21	Corrosion Monitoring of Non-Common Carrier - North Slope Pipelines 2004	11/14/2006	Sandy Stash
3.22	Corrosion Documentation Collected for Congress (Black Binder)	11/14/2006	Sandy Stash
3.23	AFE review concerning pigging	11/14/2006	Sandy Stash
3.24	Corrosion testing history - OTLs, Pigging, Q&A (Looks like a congressional report)	11/14/2006	Sandy Stash
3.25	Corrosion Under Insulation (CUI) budget discussion (External Corrosion)	11/14/2006	Sandy Stash
3.26	HSE 1838 Reduction of Coupon Pulling Crews	11/14/2006	Sandy Stash
3.27	HSE 1888 Procedures not being updated	11/14/2006	Sandy Stash
3.28	CIC independence discussion email (Faust and Wollam)	11/14/2006	Sandy Stash
3.29	Budget reduction email trail	11/14/2006	Sandy Stash
3.30	Richard Wollam's input to Business Assurance Process	11/14/2006	Sandy Stash
3.31	Budget adjustments long email trail	11/14/2006	Sandy Stash
3.32	Corrosion Management System Technical Review Action Items	11/14/2006	Sandy Stash
3.33	Budget Discussion Email trail	11/14/2006	Sandy Stash
3.34	BPXA Maintenance Pigging Presentation	11/14/2006	Sandy Stash
3.35	Vinson & Elkins Allegations Review	11/14/2006	Sandy Stash
3.36	PAIT - Pipeline Assessment and Intervention Team Presentation July 18, 2006	12/5/2006	Susan Shaw
3.37	PAIT Translation Methodology - Dec 1, 2006	12/5/2006	Kip Sprague
3.38	PAIT Assessment Matrix - July 2006	12/5/2006	Kip Sprague
3.39	CIC Corrosion Mitigation Procedures- Issue Date April 10, 1997	12/6/2006	Leslie Griffiths
3.40	CIC Corrosion Monitoring Procedures- Issue Date June 18,1996	12/6/2006	Leslie Griffiths
3.41	CIC Facility Piping Integrity Program- Issue Date June 18, 1996	12/6/2006	Leslie Griffiths
3.42	CIC Field Piping Integrity Program- Issue Date June 6, 1996	12/6/2006	Leslie Griffiths

Item	Document Title	Date Received	Source
3.43	BPXA CIC In-line Inspection Validation and Verification- July 15, 2003	12/6/2006	Leslie Griffiths
3.44	CIC Boiler and Pressure Vessel Integrity	12/7/2006	Leslie Griffiths
3.45	CIC Coating and Linings Inspection Program	12/7/2006	Leslie Griffiths
3.46	CIC Plant Inspection Program	12/7/2006	Leslie Griffiths
3.47	Corrosion/Erosion Management	12/7/2006	Leslie Griffiths
3.48	BPXA Install GPB Pig Launcher & Receiver Facilities Survey	12/7/2006	Tim Pine
3.49	PMP Process Binder	12/7/2006	Tim Pine
3.50	Piping Summary	12/7/2006	Tim Pine
3.51	Evaluation and Repair of Corroded Piping Systems SPC-PP-00090	12/7/2006	Tim Pine
3.52	Erosion/Corrosion Management Guidelines, EFOP OM-29	12/7/2006	Leslie Griffiths
3.53	Field Operating Procedure Development, EFOP OM-06	12/7/2006	Leslie Griffiths
3.54	Maintenance Pigging Log Sheet WOA, snapshot	12/7/2006	Tim Pine
3.55	Pigging Schedule and Comments EOA, snapshot	12/7/2006	Tim Pine
3.56	Corrosion Management Meeting Agenda/Action Item Examples	12/14/2006	Tim Pine
3.57	Status Tables	12/7/2006	Tim Pine
3.58	Corrosion Inhibitor Data	12/13/2006	Tim Bieri
3.59	BPXA GPB Pipeline Inspection & Integrity Overview	12/7/2006	Tim Pine
3.60	PMP Tracking Log	12/7/2006	Tim Pine
3.61	PMP Purpose and Process presentation Oct 2006	12/7/2006	Tim Pine
3.62	PMP Process Flow Diagram	12/7/2006	Tim Pine
3.63	PMP Status Report 12_6_06	12/7/2006	Tim Pine
3.64	PMP Yearly Status 03 04 05 06	12/7/2006	Tim Pine
3.65	Pigging Data Review and Action Process 9-06	12/7/2006	Tim Pine
3.66	Corrosion Management Strategy for DOT reg Pipelines, June 2006	12/7/2006	Leslie Griffiths
3.67	Sample PMP Inspection Report - PMP 06-422	12/7/2006	Tim Pine
3.68	CIC Weekly Meeting Summary - 12/9/06	12/13/2006	Tim Pine
Financial Data			
4.1	O&M and Capital Budgets	11/17/2006	Belal Atiyyah & Mark Dennehy, rec'd PJ Hurst
4.2	GPB Operations Production Cost and HSE Performance	11/17/2006	Phil Dzubinski
4.3	BAH - 0606GPB FLC 2001 - 2007 (FMT 061306 rev 1)	12/4/2006	Drais Farnham
4.4	BAH - 0806GPB 2001-06 MR Ops Capex Category Summary	12/4/2006	Drais Farnham
4.5	BAH - 0205Budgets XOM	12/4/2006	Drais Farnham
4.6	BAH - FCM10 Perf Sum GPB Combined 2002-12	12/4/2006	Drais Farnham
4.7	BAH - FCM10 Perf Sum GPB Combined 2003-12	12/4/2006	Drais Farnham
4.8	BAH - FCM10 Perf Sum GPB Combined 2004-12	12/4/2006	Drais Farnham
4.9	BAH - FCM10 Perf Sum GPB Combined 2005-12	12/4/2006	Drais Farnham
4.10	BAH - FCM10 Perf Sum GPB Combined 2006-10	12/4/2006	Drais Farnham
4.11	BAH - FCM10XL Perf Sum by Seg 01-12	12/4/2006	Drais Farnham

Item	Document Title	Date Received	Source
4.12	1106GPB Belal Request	11/30/2006	Belal Atiyyah
4.13	EOA Operating Costs (1995-2000) - Tab A	12/4/2006	Drais Farnham
4.14	WOA Lifting Costs 1995 - Tab H	12/4/2006	Drais Farnham
4.15	WOA Lifting Costs 1996 - Tab I	12/4/2006	Drais Farnham
4.16	WOA Lifting Costs 1997 - Tab J	12/4/2006	Drais Farnham
4.17	WOA Lifting Costs 1998 - Tab K	12/4/2006	Drais Farnham
4.18	WOA Lifting Costs 1999 - Tab L	12/4/2006	Drais Farnham
4.19	WOA Lifting Costs 2000 - Tab M	12/4/2006	Drais Farnham
4.20	Prudhoe Bay Unit WOA Budget Status Report (December 1995)	12/6/2006	Drais Farnham
4.21	Prudhoe Bay Unit WOA Budget Status Report (December 1996)	12/6/2006	Drais Farnham
4.22	Prudhoe Bay Unit WOA Budget Status Report (December 1997)	12/6/2006	Drais Farnham
4.23	Prudhoe Bay Unit WOA Budget Status Report (December 1998)	12/6/2006	Drais Farnham
4.24	1999 BP Exploration Investment Details (dated 1-20-2000)	12/6/2006	Drais Farnham
4.25	Prudhoe Bay Unit Budget Status Report (December 2000)	12/6/2006	Drais Farnham
4.26	BAH - 0806GPB prod & cost history (Drais)	12/7/2006	Drais Farnham
HSE (Policies, Programs, Procedures, Compliance/Reports)			
5.1	Greater Prudhoe Bay - Discussion Group Preparation	10/23/2006	Chris Fitch
5.2	Greater Prudhoe Bay - Leadership Team Presentation	10/30/2006	Cory Shelton
5.3	Greater Prudhoe Bay - Results by Workgroup	11/14/2006	Cory Shelton
5.4	BPXA Compliance Agreement EPA Case 99-0139-00	11/14/2006	Randall Buckendorf
5.5	North Slope Environmental Field Handbook	11/20/2006	Sandy Halliwill
5.6	Alaska Safety Handbook 2006	11/20/2006	Sandy Halliwill
5.7	BPXA HSE Management System Tier 2 Procedure "Contractor HSE Training Requirements"	11/20/2006	Sandy Halliwill
5.8	BP MIA and HIPO Summary '02-'06 (Major Incident Reports)	12/1/2006	Leslie Griffiths
5.9	Surface Facility Safety Design/Process Haz Analysis (CRT-PI-00001 Rev 1)	12/4/2006	Leslie Griffiths
5.10	GPB Field Management HSE Leadership Meeting Notes/Addenda, Nov. 16, 2006	12/6/2006	Leslie Griffiths
5.11	PSM Application Element Administrative Procedure	12/6/2006	Leslie Griffiths
5.12	PSM Compliance Audits Element Administrative Procedure, Doc No. UPS-US=AK=ALL=ALL=HSE-DOC-0038-2	12/6/2006	Leslie Griffiths
5.13	PSM Contractors Administrative Procedure, Doc No. UPS-US-AK-ALL-ALL-HSE-DOC-003414-2	12/6/2006	Leslie Griffiths
5.14	PSM GPB Covered Processes ID	12/6/2006	Leslie Griffiths
5.15	PSM Definitions Element Administrative Procedure	12/6/2006	Leslie Griffiths
5.16	PSM Hot Work Administrative Procedure	12/6/2006	Leslie Griffiths

Item	Document Title	Date Received	Source
5.17	PSM Incident Investigation Element Administrative Procedure, Doc No: UPS-US-AK-ALL-ALL-HSE-00317-2	12/6/2006	Leslie Griffiths
5.18	PSM Management of Change Summary Procedure	12/6/2006	Leslie Griffiths
5.19	PSM Mechanical Integrity Element Administrative Procedure, Doc No: UPS-US-AK-ALL-ALL-HSE-DOC-00207-2	12/6/2006	Leslie Griffiths
5.20	PSM Operating Procedures Element Administrative Procedure	12/6/2006	Leslie Griffiths
5.21	PSM Organizational Management of Change Procedure, Doc No: UPS-US-AK-ALL-ALL-HSE-DOC-00049-2	12/6/2006	Leslie Griffiths
5.22	PSM Pre-Start-Up Safety Reviews Procedure, Doc No: UPS-HS-AK-ALL-ALL-HSE-DOC-00313-2	12/6/2006	Leslie Griffiths
5.23	PSM Process Safety Information Element Administrative Procedure	12/6/2006	Leslie Griffiths
5.24	PSM Restart Procedures for Planne and Emergency/Unplanned Shutdowns	12/6/2006	Leslie Griffiths
5.25	PSM Trade Secrets Element Administrative Procedure, Doc No: UPS-US-ALL-ALL-HSE-DOC-00316-2	12/6/2006	Leslie Griffiths
5.26	PSM Training Element Administrative Procedure	12/6/2006	Leslie Griffiths
5.27	2002-2006 BPXA Historical Spill Report v1	12/6/2006	Leslie Griffiths
5.28	2002-2006 NS Spill Data Criteria	12/6/2006	Leslie Griffiths
5.29	Updated BPXA Process for Raising Worker Concerns	12/6/2006	Leslie Griffiths
5.30	BPXA EMS Top Management Review, Feb 3, 2005	12/7/2006	Leslie Griffiths
5.31	BPXA EMS Top Management Review, Feb 3, 2005	12/7/2006	Leslie Griffiths
5.32	2006 EMS Top Management Review	12/7/2006	Leslie Griffiths
5.33	Management Reviews EMS Screenshot	12/7/2006	Leslie Griffiths
5.34	Outcome of Management Review Screenshot	12/7/2006	Leslie Griffiths
5.35	Field Action Safety Team (Charter)	12/7/2006	Leslie Griffiths
5.36	GPB Audit and Assessment Program	12/7/2006	Leslie Griffiths
5.37	GPB HSE Management Plan	12/7/2006	Leslie Griffiths
5.38	GPB Leak Detection Monitoring and Response Procedure	12/7/2006	Leslie Griffiths
5.39	ACT HSE Management Program	12/7/2006	Leslie Griffiths
5.40	ACT Internal Environmental Communication Procedure	12/7/2006	Leslie Griffiths
5.41	ACT Abnormal Operations Definition	12/7/2006	Leslie Griffiths
5.42	HSE Management Program: Reduce Injuries to Workers	12/7/2006	Leslie Griffiths
5.43	NFOP HSE-84 ERA Task Risk Assessment Form	12/7/2006	Leslie Griffiths
5.44	NFOP HSE-84 ERA Task Risk Assessment No. 4 Environmental Concerns	12/7/2006	Leslie Griffiths
5.45	GPB East PHA link Screenshot	12/7/2006	Leslie Griffiths
5.46	HSE Technical Competency Assessment Manual Screen Shot	12/7/2006	Leslie Griffiths
5.47	Task Hazard Assessment Procedures	12/7/2006	Leslie Griffiths
5.48	Task Hazard Assessment GPB Form	12/7/2006	Leslie Griffiths
5.49	Task Hazard Assessment GPB Checklist	12/7/2006	Leslie Griffiths
5.50	Getting HSE Right Elements Presentation	12/7/2006	Leslie Griffiths
5.51	GPB gHSEr Exec Summary Report	12/7/2006	Leslie Griffiths

Item	Document Title	Date Received	Source
5.52	2005 gHSEr Self Assessment for GPB	12/7/2006	Leslie Griffiths
5.53	ACT gHSEr Audit Report, June 28, 2004	12/7/2006	Leslie Griffiths
5.54	GPB gHSEr Audit Report, July 12 2002	12/7/2006	Leslie Griffiths
5.55	BPXA Hazard Communication Program	12/7/2006	Leslie Griffiths
5.56	BPXA Incident and Action Tracking Procedure	12/7/2006	Leslie Griffiths
5.57	Major Accident Risk Process GP 48-50	12/7/2006	Leslie Griffiths
5.58	HSE Communication Form	12/13/2006	Leslie Griffiths
5.59	BPXA Major Accident Hazard Assessment (MAHA) Report for GPB 1/28/05	12/19/2006	Candice Miller
5.60	BPXA Major Accident Hazard Assessment (MAHA) Report for ACT	12/19/2006	Candice Miller
5.61	BPXA Major Accident Hazard Assessment (MAHA) Report for ACT with attachments	12/19/2006	Candice Miller
5.62	MAHA action item TRACTION Report 9/14/05	12/19/2006	Candice Miller
5.63	BPXA Major Accident Hazard Assessment (MAHA) 2005 Update and Register Development	12/19/2006	Candice Miller
5.64	BPXA 2006 Register of Top Hazards	12/19/2006	Candice Miller
5.65	Major Accident Risk Assessment of ABU Final Report March 2006	12/19/2006	Candice Miller
5.66	Alaska Risk Calculator for All Facilities	12/19/2006	Candice Miller
5.67	MAR March 2006 Action Items	12/19/2006	Candice Miller
5.68	Email PAIT input clarification	12/19/2006	Chase Briedenthal
Incident Investigations (Third Party, Regulatory, Public Affairs)			
6.1	GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report	11/14/2006	Sandy Stash
6.2	Report for BPXA Concerning Allegations of Workplace Harassment from Raising HSE Issues and Corrosion Data Falsification - Final as redacted for Congressional Production	11/14/2006	Sandy Stash
6.3	Report of Investigation - Revisions to Coffman Engineering Report: BP Exploration INC - Commitment to Corrosion Monitoring Year 2000	11/14/2006	Sandy Stash
6.4	Alaska State Legislature Letter to Lord Browne	11/14/2006	Sandy Stash
6.5	BP Response Letter to Alaska State Legislature Letter to Lord Browne	11/14/2006	Sandy Stash
6.6	BP Americans Documents Delivered to The House Energy and Commerce Committee - Subcommittee on Oversight and Investigations	11/14/2006	Sandy Stash
6.7	US House of Rep. Letter to Robert Malone regarding investigation	11/14/2006	Sandy Stash
6.8	Letter to DOT Pipeline and Haz Mat Safety Admin - Clarification of Requirements and Request for Info	11/14/2006	Sandy Stash
6.9	GJ Subpoena - Interviewee List	11/14/2006	Sandy Stash
6.10	Report for BPXA Concerning Allegations of Workplace Harassment from Raising HSE Issues and Corrosion Data Falsification - Final as redacted for Congressional	11/14/2006	Sandy Stash

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	Production		
6.11	Anchorage Daily News Article: "No fine for BP in past spill" (Y-36 Spill Reference)	11/30/2006	Google Search
6.12	Incident Investigation Manual (Sept 2001)	12/4/2006	Leslie Griffiths
6.13	Injury Incident Reporting Sequence Guide	12/4/2006	Leslie Griffiths
6.14	Official ADEC Spill Data 01Dec2006	12/1/2006	ADEC
IT/Systems			
7.1	BPXA Business Applications Architecture	11/28/2006	Tom Bundy
7.2	TRACTION Monthly reports for Management	11/28/2006	Shannon Dmarco
7.3	BARRS Introduction	11/29/2006	Guy Mofley
7.4	Business Intelligence Design	12/4/2006	Tom Bundy
7.5	TRACTION action tracking system guide	12/13/2006	Shannon Dmarco
7.6	Hints and Tips for TRACTION Users	12/13/2006	Shannon Dmarco
Maintenance & Repair (Policies, Programs, Procedures, Compliance/Reports)			
8.1	Email of Smart Pigging Schedule for the next 4 years	11/14/2006	Sandy Stash
8.2	Prudhoe Bay Oil Transit Lines Pigging Program	11/14/2006	Sandy Stash
8.3	Prudhoe Bay Oil Transit Lines Pigging Program - Enhanced Pipeline Surveillance and Response Plan	11/14/2006	Sandy Stash
8.4	Prudhoe Bay Oil Transit Lines Pigging Program - EOA Oil Transit Line Mechanical Integrity and Pigging Plan Risk Assessment	11/14/2006	Sandy Stash
8.5	Gamma Ray Attenuation Scanning Project - Internal Pipeline Density Inspection	11/14/2006	Acuren
8.6	Repair Activities	11/14/2006	Sandy Stash
8.7	CGF and LPC VOC Leak Detection, Repair, and Reporting Procedure	12/7/2006	Leslie Griffiths
8.8	Cross Country Pipeline Procedures	12/7/2006	Leslie Griffiths
8.9	Defeated Alarms/Safety Devices Procedure	12/7/2006	Leslie Griffiths
8.10	Review Process - Safety Critical Work Orders	12/7/2006	Leslie Griffiths
8.11	BPXA Maintenance KPIs - Nov 06	12/21/2006	Jerome Larsgaard
Operations (Policies, Programs, Procedures, Compliance/Reports)			
9.1	Monitoring Program Techniques	11/14/2006	Sandy Stash
9.2	Mitigation Program Techniques	11/14/2006	Sandy Stash
9.3	Inspection Program Techniques	11/14/2006	Sandy Stash
9.4	Inspection Monitoring Techniques	11/14/2006	Sandy Stash
9.5	Internal and External Inspection	11/14/2006	Sandy Stash
9.6	BP Group Technical Pipeline Practices	11/15/2005	Mike Rocereta
9.7	Integrated Field Planning Common Process Opportunity Alignment Risk Ranking Update (BARRS)	11/30/2006	Guy Mofley
9.8	BARRS Data (Introduction, definitions, user ops)	11/30/2006	Guy Mofley
9.9	The Field View: Operations Excellence and Renewal	12/1/2006	Sandy Beitel
9.10	North Slope Pipelines Spec CRT-PP-00002	12/4/2006	Leslie Griffiths
9.11	Mech Piping Process & Mechanical Design Spec SPC-PI-00001	12/4/2006	Leslie Griffiths

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9.12	Utility Line Class - All Lines SPC-PP-00015	12/4/2006	Leslie Griffiths
9.13	North Slope Pipeline Design SPC-PP-00031	12/4/2006	Leslie Griffiths
9.14	BPXA DOT Integrity Management Program Manual September 2005	12/5/2006	Phil Dziubinski
9.15	BPXA Integrity Management Implementation-DRAFT Minimum Requirements 26-Nov-06	12/5/2006	Dan Lebsack
9.16	IM Standard 2006 Implementation in E&P	12/6/2006	Leslie Griffiths
9.17	CPS Cardox CO2 System Procedure	12/7/2006	Leslie Griffiths
9.18	CPS Safety Procedure SF-209 Power Generation	12/7/2006	Leslie Griffiths
9.19	CPS Risk Assessment Procedure	12/7/2006	Leslie Griffiths
9.20	CPS SCADA Operating Data Procedure	12/7/2006	Leslie Griffiths
9.21	CPS Administrative Procedure AD-106 Rev1 Compliance Inspections	12/7/2006	Leslie Griffiths
9.22	Winter Spill Prevention	12/7/2006	Leslie Griffiths
9.23	FS@ DOT Pipeline Emergency Shutdown	12/7/2006	Leslie Griffiths
9.24	MCD 04-003 Operations Guidelines for Keeping E-Book, Traccess and MOC data current	12/7/2006	Leslie Griffiths
9.25	MCD 98-032 Procedure Development Guideline	12/7/2006	Leslie Griffiths
9.26	MCD 99-034 PSM Operation Procedure Self Assessment and Annual Certification	12/7/2006	Leslie Griffiths
9.27	Northstar Pipeline Company DOT Operations, Maintenance, and Emergency Response (OMER Manual)	12/7/2006	Leslie Griffiths
9.28	Pig the Endicott Pipeline procedure	12/7/2006	Leslie Griffiths
9.29	Renewal Project Activities & Timeline	12/6/2006	Doug VanWingerdon
9.30	Renewal SOP Estimated costs	12/6/2006	Doug VanWingerdon
9.31	Renewal SOP Project Scope of Work	12/6/2006	Doug VanWingerdon
9.32	Renewal Project 12-2006	12/6/2006	Doug VanWingerdon
9.33	Compliance matrix screen shots	12/7/2006	Leslie Griffiths
9.34	Guidance on Practice for Pipeline Assessment, Rehabilitation, and Change of Use	12/12/2006	Leslie Griffiths
9.35	External Communications Procedure (Tier 1 Doc)	12/12/2006	Leslie Griffiths
9.36	Internal Communications Procedure (Tier 1 Doc)	12/12/2006	Leslie Griffiths
9.37	Legal and Other Requirements Procedure (Tier 2)	12/12/2006	Leslie Griffiths
9.38	Hazard and Risk Register Creation: Report for BPXA Inc. 70018378-2	12/20/2006	Corey Herod
9.39	GPB Risk Management (Risk Register Matrices)	12/20/2006	Corey Herod
9.40	Prudhoe Bay Pipelines Schematic	11/17/2006	Katharine Fontaine
Organization (Structure, Governance, Initiatives, Performance Management)			
10.1	Alaska Consolidated Team Business Unit	11/14/2006	Sandy Stash
10.2	Work Plan and Guide for Performance Metric Reporting	11/14/2006	Sandy Stash
10.3	Facilities Schematic	11/14/2006	Sandy Stash

Item	Document Title	Date Received	Source
10.4	BPXA Organization Chart 1999	11/14/2006	Sandy Stash
10.5	BPXA Organization Chart 2000	11/14/2006	Sandy Stash
10.6	BPXA Organization Chart 2001	11/14/2006	Sandy Stash
10.7	BPXA Organization Chart 2002	11/14/2006	Sandy Stash
10.8	BPXA Organization Chart 2003	11/14/2006	Sandy Stash
10.9	BPXA Organization Chart 2004	11/14/2006	Sandy Stash
10.10	BPXA Organization Chart 2005	11/14/2006	Sandy Stash
10.11	BPXA Organization Chart Jan 2006	12/4/2006	Shelley Allen
10.12	BPXA Organization Chart Feb 2006	12/4/2006	Shelley Allen
10.13	BPXA Organization Chart Mar 2006	12/4/2006	Shelley Allen
10.14	BPXA Organization Chart Apr 2006	12/4/2006	Shelley Allen
10.15	BPXA Organization Chart May 2006	12/4/2006	Shelley Allen
10.16	BPXA Organization Chart Jun 2006	12/4/2006	Shelley Allen
10.17	BPXA Organization Chart Jul 2006	12/4/2006	Shelley Allen
10.18	BPXA Organization Chart Aug 2006	12/4/2006	Shelley Allen
10.19	BPXA Organization Chart Sep 2006	12/4/2006	Shelley Allen
10.20	BPXA Organization Chart Oct 2006	12/4/2006	Shelley Allen
10.21	BPXA Organization Chart Nov 2006	12/4/2006	Shelley Allen
10.22	11-06 Org Data.xls	12/4/2006	Shelley Allen
10.23	060100 JR Data.xls	12/4/2006	Shelley Allen
10.24	06291998ALL.xls	12/4/2006	Shelley Allen
10.25	AAI Acq.xls	12/4/2006	Shelley Allen
10.26	ALT Summary Staffing&4cast 7-2-03.xls	12/4/2006	Shelley Allen
10.27	Jun 2004 Alaska Region Monthly PU Summary Report	12/4/2006	Shelley Allen
10.28	Jun 2005 Alaska Region Monthly PU Summary Report	12/4/2006	Shelley Allen
10.29	Jun 2006 Alaska Region Monthly PU Summary Report	12/4/2006	Shelley Allen
10.30	Sep 2006 Alaska Region Monthly PU Summary Report	12/4/2006	Sandra Beitel
10.31	2006 Strategic Workforce Plan (Draft)	12/4/2006	Florian Borowski
10.32	10-3-06 Demographics.xls	12/4/2006	Sandra Beitel
10.33	Business Unit/Carrier Functional Demographic Charts	12/4/2006	Florian Borowski
10.34	2006 Operations Excellence & Renewal Report	12/4/2006	Sandra Beitel
10.35	Transformation Vision (April 2, 2003)	12/4/2006	Sandra Beitel
10.36	Organizational Announcements (April 15, 2004)	12/4/2006	Sandra Beitel
10.37	Organizational Announcements (June 4, 2004)	12/4/2006	Sandra Beitel
10.38	Tier III Organizational Announcements (June 30, 2004)	12/4/2006	Sandra Beitel
10.39	Alaska MI Report - Sep GFO	12/4/2006	Damian Bilbao
10.40	Alaska SPU Planfest Deepdive Nov 15, 2006 Final Set	12/4/2006	Damian Bilbao
10.41	Alaska Weekly Production (Nov 26, 2006)	12/4/2006	Damian Bilbao
10.42	Alaska Weekly Report (Nov 29, 2006)	12/4/2006	Damian Bilbao
10.43	Alaska SPU 2006 3QPR Pre-read DKP	12/4/2006	Damian Bilbao
10.44	Alaska SPU 2004 2QPR (May 04)	12/5/2006	Damian Bilbao
10.45	Alaska SPU 2005 4QPR (29 Nov 05)	12/5/2006	Damian Bilbao
10.46	Alaska SPU October 2006 QPR(lite)	12/5/2006	Angus Walker
10.47	Alaska SPU 2006 Annual Plan & Performance Contracts	12/5/2006	Angus Walker
10.48	Canspec Sample Contract (BPXA Contract 5535)	12/5/2006	Sandy Halliwill
10.49	VECO Sample Contracts (BPXA Contract 4458 and 2561)	12/5/2006	Sandy Halliwill

Item	Document Title	Date Received	Source
10.50	NALCO Sample Contracts (BPXA Contract 627)	12/5/2006	Sandy Halliwill
10.51	Professional Recognition Programme (PRP overview video)	12/5/2006	Sandy Bietel
10.52	Variable Pay Plan (VPP) performance binder (1998 - 2005)	12/5/2006	Sandy Bietel
10.53	Addendum to the Charter for Development	12/5/2006	Randall Buckendorf
10.54	E & P Annual Organizational Review 2006	12/5/2006	Sandy Bietel
10.55	EPC Annual Organization Review 2005	12/5/2006	Sandy Bietel
10.56	BP Management Framework 2004	12/5/2006	Sandy Stash
10.57	BP versus Alyeska Management Systems	12/5/2006	Dan Lebsack
10.58	Contractor Performance and Relationship Management Accountabilities	12/6/2006	Leslie Griffiths
10.59	Contractor Oversight: Contract Accountable Manager (CAM) Roles, Responsibilities, and Selection Criteria Overview doc 4.4.6.3	12/6/2006	Leslie Griffiths
10.60	Contractor Oversight: Environmental Compliance and EMS Evaluation Procedure doc 4.4.6.4	12/6/2006	Leslie Griffiths
10.61	BP Global HSSE Compliance Framework (Project Emerald)	12/6/2006	Leslie Griffiths
10.62	E&P Supplier Performance Management Common Process	12/6/2006	Leslie Griffiths
10.63	Technical Management of Change Process	12/7/2006	Leslie Griffiths
10.64	BPXA Management of Change Website Screenshot	12/7/2006	Leslie Griffiths
10.65	Technical Management of Change Forms	12/7/2006	Leslie Griffiths
10.66	Management of Change Procedure for Chemical Changes	12/7/2006	Leslie Griffiths
10.67	AES QPR	12/7/2006	Neil Dunn
10.68	BPXA As Built Drawing Procedure	12/12/2006	Leslie Griffiths
10.69	GPB Long Term Strategy Study, May 2001	12/13/2006	Belal Atiyyah
10.70	BPXA Engineering Drawing/Document Requirements	12/13/2006	Leslie Griffiths
10.71	Annual Performance Review - John Ennis 2004	12/19/2006	Sandra Beitel
10.72	Annual Performance Review - Brett Leach 2003	12/19/2006	Sandra Beitel
10.73	Annual Performance Review - Brett Leach 2004	12/19/2006	Sandra Beitel
10.74	Annual Performance Review - Bruce Williams 2003	12/19/2006	Sandra Beitel
10.75	Annual Performance Review - Bruce Williams 2004	12/19/2006	Sandra Beitel
10.76	Annual Performance Review - Bruce Williams 2005	12/19/2006	Sandra Beitel
10.77	Job Description - Ops Integrity Mgr 2003	12/19/2006	Sandra Beitel
10.78	Job Description - CIC Team Leader 2004	12/19/2006	Sandra Beitel
10.79	Job Description - Managed Services Mgr 2001	12/19/2006	Sandra Beitel
10.80	Job Description - GPB Ops Manager 2005	12/19/2006	Sandra Beitel
10.81	Job Description - HSE Mgr 2003	12/19/2006	Sandra Beitel
10.82	E-mail of 2006 BPXA Reorganization Plan	12/19/2006	Sandra Beitel
Emergency Response			
11.1	Crisis Management Framework Information Pack	12/1/2006	Ed Thompson

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11.2	GPB Contingency Plan (Response and Prevention)	12/1/2006	Ed Thompson
11.3	Alaska Clean Seas Tech Manual (Three Volumes)	12/1/2006	Ed Thompson
11.4	BPXA Incident Management System Manual	12/1/2006	Ed Thompson
11.5	Oil Discharge Prevention and Contingency Plan Endicott Ops and Badami Development Area Amended Dec 2003	12/1/2006	Leslie Griffiths
11.6	Oil Discharge Prevention and Contingency Plan MPU Revised Aug 2004	12/1/2006	Leslie Griffiths
11.7	Oil Discharge Prevention and Contingency Plan NorthStar Ops March 2002	12/1/2006	Leslie Griffiths
11.8	Endicott Emergency Notification and Response Plan	12/1/2006	Leslie Griffiths
11.9	GPB Emergency Notification and Response Plan	12/1/2006	Leslie Griffiths
11.10	Northstar Emergency Notification and Response Plan	12/1/2006	Leslie Griffiths
11.11	MPU Emergency Notification and Response Plan	12/1/2006	Leslie Griffiths
11.12	Badami Emergency Notification and Response Plan	12/1/2006	Leslie Griffiths
11.13	Contingency Plan Approval Letters	12/1/2006	Leslie Griffiths
11.14	2006 Quarterly ER Drill Schedule GPB WOA/EOA Facilities, Camps, Shops, Offices	12/6/2006	Leslie Griffiths
11.15	Pipeline Emergency Shutdown: Badami Sales Oil Line, Proc No. BPL-11	12/6/2006	Leslie Griffiths
11.16	CFP Gas Plant Emergency Shutdown PSMOP, DCD 98-088	12/6/2006	Leslie Griffiths
11.17	Pipeline Emergency Shutdown: Emergency Shutdown of MPU Oil Sales Pipeline, Proc No. DCD 04-021	12/6/2006	Leslie Griffiths
11.18	Pipeline Emergency Shutdown: CFP Keor Pipeline Emergency Shutdown, Proc No. DCD 01-034	12/6/2006	Leslie Griffiths
11.19	First Responder Environmental Bulletin	12/7/2006	Leslie Griffiths
11.20	Course Spec: HAZWOPER 2: First Responder Ops (Lvl2) - Initial	12/7/2006	Leslie Griffiths
11.21	Flow Station 1 Pipeline Company DOT Operations, Maintenance, and Emergency Response (OMER) Manual	12/7/2006	Leslie Griffiths
11.22	Flow Station 2 Pipeline Company DOT Operations, Maintenance, and Emergency Response (OMER) Manual	12/7/2006	Leslie Griffiths
11.23	GPB ERT Communications Procedure	12/7/2006	Leslie Griffiths
11.24	GPB Fire Department Org Statement	12/7/2006	Leslie Griffiths
11.25	ERT Training Program Procedure	12/7/2006	Leslie Griffiths
11.26	Spill Prevention Checklist	12/7/2006	Leslie Griffiths
11.27	GPB NGL DOT Operations, Maintenance, and Emergency Response (OMER) Manual	12/7/2006	Leslie Griffiths
11.28	Winter Spill Prevention GPB	12/7/2006	Leslie Griffiths
11.29	Sample ESD Procedures	12/6/2006	Doug VanWingerdon
11.30	RCRA Emergency Contact List	12/7/2006	Leslie Griffiths
11.31	Spill Prevention and Response Compliance Matrix Example	12/7/2006	Leslie Griffiths

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Human Resources			
12.1	Transformation Vision Presentation (April 2, 2003)	12/1/2006	Sandy Bietel
12.2	Organizational Announcements Presentation (April 15, 2004)	12/1/2006	Sandy Bietel
12.3	Organizational Announcements Presentation (June 4, 2004)	12/1/2006	Sandy Bietel
12.4	Tier III Organizational Announcements Presentation (June 30, 2004)	12/1/2006	Sandy Bietel
12.5	2006 Strategic Workforce Plan	12/1/2006	Sandy Bietel
12.6	Surface Career Atlas	12/13/2006	Janice Vosika
Training			
13.1	GPB GC-1 Training Matrix	12/4/2006	Leslie Griffiths
13.2	Endicott Training Matrix	12/4/2006	Leslie Griffiths
13.3	GPB Corrosion Training Matrix	12/4/2006	Leslie Griffiths
13.4	GPB FS-1 Training Matrix - SIP	12/4/2006	Leslie Griffiths
13.5	Contractor HSE Training Requirement	12/4/2006	Leslie Griffiths
13.6	HSE Training Procedure	12/4/2006	Leslie Griffiths
13.7	Milne Point HSE Training Matrix	12/4/2006	Leslie Griffiths

APPENDIX 5 GENERIC SCENARIO TREE

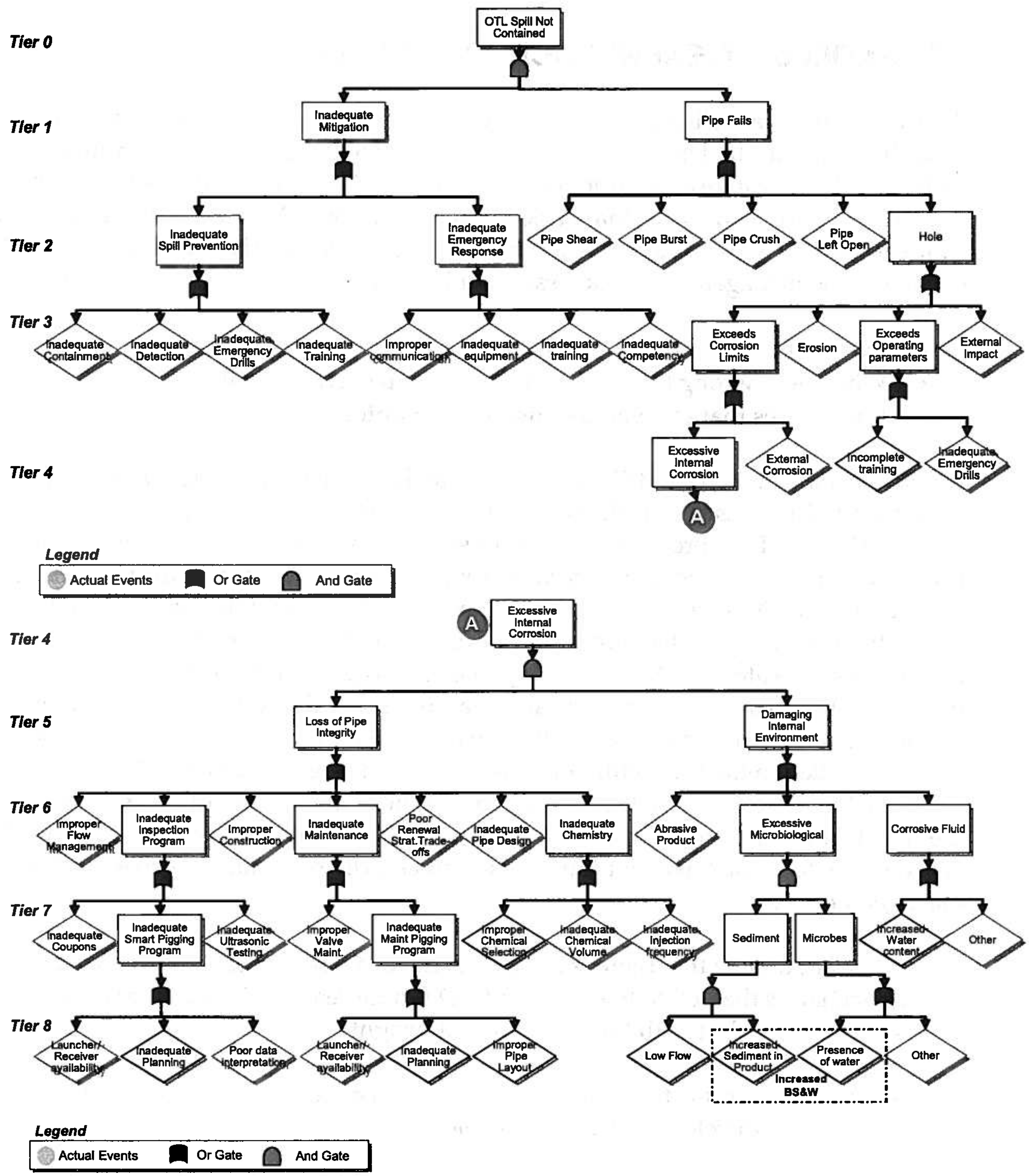
A scenario tree is a well-practiced safety and risk engineering evaluation tool that describes activities that can lead to an incident. The top event of the scenario tree is defined as the negative event under consideration. Through a set of AND and OR gates, the top event is decomposed into various event scenarios. Analysis of the scenario tree yields important activity relationships that can help describe the root causes of the top event and the management weaknesses that led to the event. In particular, it describes:

- Events that led to the top event
- What went wrong to actually enable the top event to occur
- Root causes that allowed the top event to unfold.

The sequencing of AND and OR gates indicate the robustness of the management system and illustrates how well the system is protected from the top event. AND gates indicate that all of the precursor events must occur for the next higher level event to take place—the system is robust because several events must occur for the next level fault to develop. Numerous OR gates in succession imply that the system is not very robust because if any of the faults listed occur, the top event will unfold. A long string of OR gates indicates that there is little protection to prevent the top event from occurring. The diamond shape indicates that there are additional decomposed events that lead to the diamond event but that are not further analyzed. These events are not further detailed in the tree, either because they are not relevant to the March 2nd or August 6th leaks, or because they are discussed more thoroughly in the text following the tree. Dotted lines next to events indicate that there may be other faults that could also contribute to the top event (but are not necessarily germane to corrosion risk management per se).

It is important to note that there is no single scenario tree that can accurately represent specific scenarios that led to the top events. Different teams might create trees with different structures but with the same level of insights.

In an attempt to describe the typical scenarios that can lead to a pipeline leak, a generic scenario tree was developed (see figures below).



Generic Scenario Tree Discussion

The top undesired event is *OTL spill not contained.* Taking this top event, one can decompose the events that can lead to the spill incident. The top event takes place if *pipe fails* AND *inadequate (spill) mitigation* actions are performed. The AND gate indicates that both events must transpire for the top event to unfold.

Inadequate mitigation occurs if either *inadequate spill prevention* occurs OR *inadequate emergency response* is performed after the leak commences. The *inadequate spill prevention* can take place if any one or combination of the following events occur: *inadequate containment* (the spill escapes into the environment), OR *inadequate* (leak) *detection,* OR *inadequate* (operational procedures) *SOP,* OR *inadequate training.*

Inadequate emergency response occurs if *inadequate communication* (emergency responder and area managers) occurs, OR *inadequate equipment* is deployed as part of the emergency response (e.g., inadequate spill fighting hardware), OR *inadequate training* (both area and emergency responder staff are poorly trained on how to respond to a spill), OR *inadequate competency* (area staff do not know how to respond to emergency actions).

Pipe fails can take place if any of the following events occur: *pipe shear,* OR *pipe burst,* OR *pipe crush,* OR *pipe left open* (i.e., valve left open), OR *hole* (an opening in the pipe wall). A *hole* occurs if pipe *exceeds* (acceptable) *corrosion limits,* OR pipe *erosion,* OR *exceeds operating parameters* (e.g., pipe overpressure), OR pipe hole created by *external impact.* The hole *exceeds corrosion limits* occurs by either *excessive internal* (pipe) *corrosion,* OR *external* (pipe outer wall) *corrosion. Exceeds operating parameters* occurs by either *inadequate training* (e.g., emergency shutdown) OR *inadequate SOP.*

For *excessive internal corrosion* to appear, two events must occur: *loss of pipe integrity* OR a *damaging internal environment* (internal pipe products). *Loss pipe integrity* is predicated on *inadequate* (pipe) *inspection program,* OR *inadequate chemistry* (chemical management of pipe fluids), OR *inadequate maintenance* (activities), OR *improper construction* (of piping systems), OR *poor renewal strategy trade offs* (decision-making of OTL system or subsystem renewal options), OR *poor pipe design* (the pipe is not adequately designed for its intended purpose), OR *improper flow management* (normal day-to-day fluid management of flow rates and pressure).

Inadequate inspection program will occur if the *smart pigging program* is inadequate, OR *UT/coupons* (and other inspection techniques) are inadequate. *Inadequate smart pigging program* occurs because of (pig) *launcher and receiver availability (lack of),* OR *inadequate planning* (pig planning), OR *poor data interpretation* (misunderstanding of pigging data).

Inadequate chemistry (management) takes place if *chemical selection* is inadequate, OR there is *inadequate chemical volume* injection, OR there is (inadequate chemical) *injection frequency. Inadequate maintenance* actions are predicated on an *inadequate maintenance pigging program,* OR an *improper valve maintenance,* OR *other* maintenance action. Similar to *inadequate smart pigging program, inadequate maintenance pigging program* occurs because of pig *launcher/receiver availability,* OR *inadequate* (pigging program) *planning,* OR *improper pipe layout.*

A damaging internal environment occurs because of an *abrasive product,* OR *excessive microbiological,* OR *corrosive fluid. Excessive microbiological* takes place if there is *sediment* AND *microbes. Sediment* occurs with *low* (well head) *flow,* AND *excessive sediment in product. Microbes* will exist if there is a *presence of water* OR *other* factors.

The generic scenario tree is not intended to be a representation of either of the two incidents. The generic scenario tree's primary purpose is to identify the GPB processes and management infrastructure that can result in an uncontained spill. This is especially important because improving corrosion risk management only vertically through GPB organizations—especially only within CIC—does not ensure that another spill can be prevented. The quantity and diversity of events illustrates the importance of a risk-based approach, which evaluates the entire system and is implemented as a broad and holistic risk management approach to corrosion management.

APPENDIX 6 ACRONYM LIST

AAC	Alaska Administrative Code
ACT	Alaska Consolidated Team
ADEC	Alaska Department of Environmental Conservation
AEX	Alaska Exploration Team
AF&G	Automation, Fire & Gas
ALT	Alaska Leadership Team
BARRS	Business Activity Risk Ranking System
BLEVE	Boiling Liquid Expanding Vapor Explosion
BPNA	BP North America
BPXA	BP Exploration Alaska
BS&W	Basic Sediment and Water
BU & BUL	Business Unit and Business Unit Leader
CAM	Contract Accountable Manager
CAPEX	Capital Expense
CBS	Commercial Business Support
CIC	Corrosion, Inspection and Chemical
CMMS	Computer Maintenance Management System
CMS	Corrosion Management System
COA	Corrective Order Amendments
COBC	Compliance Order By Consent
CoF	Consequences of Failure
COTU	Crude Oil Topping Unit
CUI	Corrosion Under Insulation
DOT	U.S. Department of Transportation
EA	Engineering Authority
EMS	Environmental Management System
ENS & WNS	Eastern and Western North Slope
EOA and WOA	East and West Operating Area
EOC	Eastern Operations Center
EPA	U.S. Environmental Protection Agency
ERM	Enterprise Risk Management
ETP	Engineering Technical Practice
FS-1	Flow Station Number 1
FTE	Full Time Equivalents (Staffing)
GC-1	Gathering Center Number 1
GFO	Group Financial Outlook
GPB	Greater Prudhoe Bay
HAZOP	Hazardous and Operability Study
HR	Human Resources
HSE, HSSE	Health, Safety, (Security), Environment
ILI	In Line Inspection
IM	Integrity Management
IMT	Incident Management Team
KPI	Key Performance Indicator (Key Process Indicator)
LTO	License To Operate

Acronym List (Continued)

MAHA	Major Accident Hazard Assessment
MAOP & PSIG	Maximum Allowable Operating Pressure
MAR	Major Accident Risk
MCC	Mobile Command Center
MIMIR	Mechanical Integrity Management Inspection Report
MIMS	Mechanical Integrity Management System
MOC	Management of Change
MSA	Mid-Stream Alaska
MT	Magnetic Flux
NDE	Non-Direct Evaluation
O&M	Operation and Maintenance
ODPCP	Oil Discharge Prevention and Contingency Plan
OMS	Operating Management System
Opex	Operating Expenses
ORT	Operations Review Team
OSHA	Office of Safety and Hazards Analysis
OTL	Oil Transit Lines
PAIT	Pipeline Assessment and Intervention Team
PBU	Prudhoe Bay Unit
PHMSA	Pipeline Hazardous Materials Safety Agency
PMP	Piping Modification Process
PoF	Probability of Failure
PSIM	Process Safety Integrity Management
PSM	Process Safety Management
QPR	Quarterly Performance Review
RBI	Risk Based Inspection
RIF	Reportable Injury Frequency
RT	Radiographic Testing
SCADA	System Control And Data Acquisition
SCM	Supply Chain Management
SDDN	Staff Development and Deployment Network
SO&I	Safety and Operational Integrity
SOP	Standard Operating Procedures
SPMcp	Supplier Performance Management Common Practice
SPR	Special Project Request
SPU	Strategic Performance Unit
SST	Shared Services Technical
STP	Site Technical Practice
SYMS	Specified Minimum Yield Strength
TAPS	Trans Alaska Pipeline System
USA	Unusually Sensitive Area
UT	Ultrasonic Testing
WIO	Working Interest Owners
WTI	West Texas Intermediate

Appendix 7 - Template

Development of the Corrosion Risk Management Template

A corrosion risk management template was created to serve as an analytical framework on which to determine the efficacy of BPXA's corrosion risk management at the time of the two 2006 spills. The intent of the template process was not only to identify critical corrosion risk issues that affect OTL integrity, but also to document those findings in a fact-based fashion. At the time of the two incidents, the OTL was not under any formal PHMSA regulations. Because of this, and to ensure that all appropriate corrosion risk management areas were properly evaluated, a template was developed based on applicable risk management elements found in complex systems.

The template has been used in various high risk industries and served as the safety risk management review methodology for the Special Commission of Inquiry (SCOI) into the 2004 Waterfall rail accident in Sydney, Australia. The SCOI was a formal public inquiry into the rail accident and required that the review methodology be comprehensive, fact-based, with well documented findings. The template, and its corresponding results, were independently reviewed by outside risk experts and formally introduced as evidence into the SCOI proceedings. The template (as modified for the BPXA evaluation) was based on these sources:

- Center for Chemical Process Safety. *Guidelines for Hazard Evaluation Procedures.* New York: American Institute of Chemical Engineers
- U.S. Department of Defense. *Military Standard System Safety Program Requirements.* Mil-Std 882C, 1993.
- U.S. Occupational Safety and Health Administration, *Voluntary Protection Program.* 1996
- U.S. National Aeronautics and Space Administration (NASA). NSTS 1700.7B - Safety Policy and Requirements for Payloads Using the Space Transportation System (STS). 1999.
- U.S. Department of Transportation. Federal Transit Administration. *Handbook for Transit Safety and Security Certification.* DOT-FTA-MA-90-5006-02-01. 2002
- American Public Transit Association (APTA) *Manual for the Development of Rail Transit System Safety Program Plans,* 1999
- ISO 9001: 2000
- Qantas Airways system safety audit process
- BlueScope Steel *Occupational Health and Safety Management System* McCormick, N.J., *Reliability and Risk Analysis: Methods and Nuclear Power Applications.* London, UK: Academic Press, 1981
- Bahr, N.J. *System Safety Engineering and Risk Assessment: A Practical Approach.* London, UK and New York City, US: Taylor and Francis, 1997.

Data that were gathered through site visits , document reviews, and staff and manager interviews were assembled and documented with the template. This tool was the primary method for managing the disparate pieces of information and collating them into meaningful corrosion risk management subject areas. The template documents procedures and practices performed at the time of the two incidents. Where applicable, information regarding changes since then are noted.

Item

A unique tracking item number for each protocol/element

Protocol/Element

Risk management item (taken from the sources cited above) as applicable for complex systems referring specifically to internal corrosion and integrity of piping systems.

Global BP

Standard to address most relevant element (may not always apply to corrosion and piping)

GPB Procedure

Any relevant procedure to address element and will acknowledge whether or not it currently applies to piping systems.

Findings

Application of procedures or practices (where there are no formal procedures) and their adequacy

Ranking

●	◕	◑	◔	○
Formal, adequate procedure and practices in place	There is an adequate procedure in place but only partially followed	There is an inadequate procedure in place but an adequate practice is followed	No procedure in place with a partially adequate practice followed	No procedure or practice in place

Appendix 7 — Template

Item	Protocol / Element	Global BP Standard	GPB Procedure (Source Cited)	Findings (Sources Cited)	Ranking	Regulatory Approach/Practice (CFR or PHMSA)	Post-Incident Changes
1.0 RISK ASSESSMENT							
RISK ASSESSMENT PROCESS							
1.1	There is a formal, methodical, and documented process that identifies, evaluates and tracks risks	GP 43-17 1.0 Scope	Existing formal risk assessment processes include: • HAZOP: Process applied to facilities but not piping. • MAR: Process focused on impact of an incident – not on the root causes. • MAHA: Process addressed the probability and severity of an incident. It is used only on facilities not piping. • BARRS: Risk ranked new O&M and capex projects over $100,000. • Incident investigations: Identified and evaluated risks through causal analysis, ex post. *MAR/MAHA Coordinator, GPB Area Managers, BPXA Technical Director BARRS Introduction PowerPoint, Integrated Field Planning Lead, BARRS data base excel spread sheets)*	• No formal, holistic risk assessment process for pipeline integrity. • CIC informally assessed pipeline corrosion and integrity risks based on individual experience and technical expertise. • Area Managers informally assessed pipeline integrity risks under their control. • Inspection results were collected and tracked in MIMIR. • HSE focused on personnel safety not on process safety, including integrity management. *(BPXA HSE manager, GPB CIC Team Leader, CIC Head, GPB Area Managers)*	◐	RMPS IV	Teams formed to define and implement improved IM and risk assessment processes as part of the S&OI, OMS and IM initiatives and to develop new corrosion management strategy (CMS). A Risk Register is under development, (based on the MAR process) led by the Engineering Authority within the Technical Directorate. *(BPXA Engineering Authority, CIC Head, MAR/MAHA Coordinator), "Hazard and Risk Register Creation/DNV report Dec. 2006)*

1.0 RISK ASSESSMENT

Item	Protocol/ Element	Global BP Standard	GPB Procedure (Source Cited)	Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
1.2	The risk assessment process uses a holistic, "systems" approach (including facilities, equipment, procedures, environment) to evaluate pipeline network risks	GP 43-17 4.2.c. Risk Management Process	• See Item 1.1	• Formal processes were not holistic and only focused on pieces of the kit (e.g. HAZOP, MAR and MAHA did not address piping, BARRS only evaluated projects but did not evaluate network-wide impacts). • Piping risk assessment was based entirely on inspection results. • Localized risks associated with internal corrosion were measured by prescriptive Fit-for-Service standards, inspection results A- F. • CIC integrity analysts informally developed Equipment Life Forecasts as time permitted. *(GPB Area Managers, MARA/MAHA Coordinator, BPXA Technical Director, GPB CIC Team Leader)*	◔	RMPS IV.1.1	The methodology development effort of the Pipeline Assessment and Intervention Team (PAIT) evaluated probability of infrastructure failure based on MIMIR data. *(BPXA Technical Director, PAIT Materials Manager)*
1.3	There is a formal, documented process that evaluates risk controls (or corrective actions), ensuring the control is adequate and in place	GP 43-17 5.9 Risk Evaluation	The procedures to evaluate risk control included. • Inspection. • Fit for service analysis. • Management of Change. *(GPB CIC Team Leader GPB Area Managers))*	• PMP formally documented the process. It included CIC/Town, Engineering Technical Authority, and Area Manager review and approval. CIC inspectors conducted follow-up inspection to validate corrective action for closure. • MIMIR tracked A-F inspection results and PMP follow-up date. However, the PMP was tracked in separate spreadsheet system. • Risk control procedures were followed but not critically evaluated in light of changing operating conditions (i.e. increased corrosion in OTL, increased BS&W, lower flow rates). *(GPB Area Managers, GPB CIC Team Leader, Inspection Contractor, BPXA Engineering Authority, BPXA Technical Director)*	◔	RMPS IV.2.2	

1.0 RISK ASSESSMENT

Item	Protocol/ Element	Global BP Standard	GPB Procedure (Source Cited)	Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
1.4	Risk controls (or corrective actions) are tracked to closure, give adequate rationale of how closed, and regularly trended	GP-43-17 6.e & f Risk Mitigation	See Item 1.3	• The PMP process formally tracked PMPs in MIMIR until closeout (including verification inspections to ensure corrective actions, pipe de-rating, or production process changes were implemented). • Inspections were followed up by subsequent inspection results and FFS analyses (e.g. volume corrosion inhibitor vs. corrosion rate) by CIC. • Other processes relied on self assurance. There was no formal follow up by the issuer of corrective actions. For example, MOC was not a closed-loop process. *(MIMIR data bas, PMP 06-422, GPB Area Managers, ADEC report)*		RMPS IV.2.3	
1.5	Risk assessments are performed whenever significant changes (both hardware and procedural) are made to operations	GP 43-17 7.b Risk Mitigation	Procedures existed that required that major changes were evaluated: • The MOC process had to be followed for any change in hardware, software, or procedure, etc. (including pipeline). • HAZOPs were required for major hardware change in facilities.	• MOC process was followed for any changes. • However, the MOC did not include conducting formal risk assessments or risk ranking. No process to capture changes in the operating environment and assess their impact on pipeline integrity or corrosion was found. • HAZOPs were conducted on all facility modifications. However, HAZOPs did not evaluate pipeline. *(GPB Area Manager, HSE Program Manager, HSE Assurance Manager, HSE Program Manager)*		RMPS IV.1.2	

1.0 RISK ASSESSMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure (Source Cited)	Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
1.6	Hazard severity and event probability (either quantitative or qualitative) are risk assessed	GP43-17 5.8 Risk Estimation	The existing processes included: • MAR: Quantitative analysis that assessed hazard severity and event probability. • MAHA: Qualitative process that evaluated hazard severity and event probability. • HAZOPs did evaluate severity and probability.	• MAR was based on historical probabilities but was not applied to piping systems. • MAHA focus was on facility and not piping systems. • Neither MAR nor MAHA conducted causal analysis. • HAZOPs were performed only on facilities and not piping systems. *(GPB CIC Team Leader)*		RMPS IV.1.3 & 4	PAIT evaluated piping probability of failure. All severities were categorized as high.
1.7	Hazards and causes are identified in risk assessments	GP 43-17 5.5 Threat Identification	See Item 1.6.	• MAHA and MAR identified the hazard events associated with their risk assessments. • MAR did not include causal analysis. • MAHA did conduct some causal analysis. • HAZOPs did conduct causal analysis. • MAR, MAHA, and HAZOPs were not performed on piping systems. *(GPB Area Managers, GPB CIC Team Leader, MAR/MAHA Coordinator)*		RMPS IV.1.2	New Risk Register process will incorporate MAHA, MAR, HAZOPS, Pipe inspection, and other inputs. *(BPXA Technical Director, BPXA Engineering Authority)*
1.8	The risk assessment process states whether risks should be eliminated, controlled, or accepted with or without attendant contingency plans		• No formal procedures or guidance found on this topic.	• Ad-hoc practices existed. For example: Joint decision between CIC and asset owner to repair, replace, de-rate, etc. *(PMP 06-422, GPB CIC Team Lead, GPB Area Managers, BPXA Technical Director)*		RMPS IV.2.2	The Engineering Authority will determine the disposition of known integrity risks.

1.0 RISK ASSESSMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure (Source Cited)	Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
1.9	Risk ranking is formal and pre-defined, and risk prioritization protocols are in place	GP 43-17 5.10 & 4.1 Risk Acceptance Criteria	• MAR, MAHA, and HAZOPs do have risk ranking based on probability and severity. • BARRS process risk ranks proposed Capex and (>$100K) projects.	• MAR, MAHA, HAZOPs were not performed on piping. • BARRS was not a risk assessment process. • Inspection results were ranked A-F (least to most severe). *(CIC Manager, MIMIR reports; GPB Commercial Manager)*	◔	RMPS IV.1.5	PAIT ranked infrastructure probability of failure. Risk Register will formally evaluate and rank all risks.
1.10	Risk assessments consider audits, testing, and incident reports	GP 43-49 5.8.g Risk Manage-ment	• There were regular audits (e.g., Baxter), testing (inspection), and incident reporting (e.g., CUI).	• Risk assessments (MAR, MAHA) did not appear to formally consider audits, testing, and incident reports. • BPXA did not have a formal risk register or frequency/severity matrix for pipelines. • Audits, testing, inspection and incidents were inputs into the informal CIC risk assessment processes. *(HSE Program Manager, MAR/MAHA coordinator, GPB Technical Director)*	◔	RMPS IV.1.1	
1.11	Risk assessments are conducted by appropriately trained staff	GP 43-17 5.3 Formu-lation of risk assess-ment teams	HAZOP, MAR, MAHA included training programs. *(Virtual Training Assistant (VTA)*	• Existing processes were not applied to pipelines. • Informal CIC risk assessments were performed by internal experts. *(CIC Head, CIC Analyst, SDDN Operation Manager)*	◔	RMPS II.1	

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
RISK POLICY							
2.1	There is a defined integrity risk policy and objectives that align appropriately with other organizational policies	BP's Manage-ment Framework (2004)	• Risk policy was clearly defined in the BP Alaska Safety Handbook, with individual and supervisory responsibilities identified. • Annual ADEC "Commitment to Corrosion Monitoring" report contained BPXA's corrosion integrity management policies and procedures. *(Alaska Safety Handbook 2006, "BPXA Commitment to Corrosion Monitoring" reports)*	• The risk policy was aligned with other organizational policies through performance contracts which set and measured personal safety metrics. • As a practical matter, the generic risk policy applied to corrosion and integrity management of piping systems. • BPXA executed their commitment to corrosion monitoring. *(Alaska Safety Handbook 2006; 2006 ALT Performance Contracts, "BPXA Commitment to Corrosion Monitoring" reports)*	◕	RMPS III	

2.0 RISK MANAGEMENT

Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.2	There are checks and balances in place that ensure integrity risk policy and standards are implemented and are regularly reviewed	GP 43-49 5.8.h Risk Manage-ment	• Internal audits ensured that risk policy and standards were implemented. • CIC Town monitored CIC Field operations for commitment to corrosion integrity management. • ADEC commissioned an annual independent review of the Commitment to BPXA Corrosion Monitoring report (Coffman).	• BPXA executed regular internal and external audits and verified compliance. • ADEC regularly monitored BPXA regulatory compliance. • Corrosion, and more broadly integrity management related issues fell under the scope of a number of auditing protocols, including internal audits, Process Safety Management (PSM) and Environmental management system (EMS). • Group Internal audits were triggered based on enterprise-wide risk levels (e.g., business, financial, operational) or specific events (e.g., whistle blower, noncompliance). • Implementation of corrective actions was not always timely or complete (e.g., Baxter recommendations 2005). *(BPNA Audit Head, Baxter 2005 Report, HSE Assurance Manager, Green Book, PSM audit protocols)*	◕	RMPS II.1	Engineering Authority will be responsible for integrity management risk assurance. *(BPXA Technical Director)*
2.3	There are sufficient staff to support the risk management program	GP 43-17 4.2.c Risk Manage-ment Process	• Corrosion risk management consists of: inspection, monitoring, and mitigation. These tasks are carried out by contract employees in the field. *(Resource Planning Manager, CIC Strategy & Planning Manager)*	• There was an inspection backlog for internal and external corrosion monitoring. • Prior to the March incident CIC had between 2-9 open positions between 2003 and 2005. • In July 2006, CIC had 33 open positions. *(CIC Strategy & Planning Manager, CIC S&P Engineer; GPB M&R Manger; GPB Corrosion Training Matrix, 2006 BPXA Organization Charts)*	◑	RMPS III.1.2	There are 29 open positions in CIC, as of Jan. 2007. *(CIC Strategy & Planning Manager, BPXA Organization Charts – 2006)*

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.4	There is sufficient funding in place to support risk management programs	GP 43-49 4.2.b.6 Funding PIMS (RM is an element)	• Annual CIC budget was reviewed and approved by GPB Area Managers, GPB Field Manager, GPB BUL, and WIO. *(BPXA Commercial Manager,, GPB Area Managers)*	• CIC budgets increased each year since 2000 (CAGR ~ 4.3%). • See Item 2.3. *(1995 – 2006 Budgets; GPB Commercial Manager, Group Engineering Director, CIC Head, GPB CIC Team Leader, Black Binder 3.29, 3.31, 3.33, BPXA Corrosion Management System Technical Review (Report #5001-104)*	◑	RMPS III 1.1	See Item 2.3.
2.5	There are effective means for making senior managers accountable for risk issues	GP 43-17 8.c Document. & Monitoring	• BP used performance contracts for all management down to "Band D," the PU level. Performance contracts incorporated a wide variety of metrics and milestone objectives, including safety and integrity. *(2004 BP's Management Framework, aka. Green Book)*	• Senior managers had performance contracts that included HSE requirements (RIF targets). Some also included integrity expenditure objectives or milestones toward implementation of new IM standard. • 2006 performance contracts reviewed did not have explicit objectives for asset integrity. *(GPB Commercial Manager 2006, QPRs, 2006 ALT Management Performance Contracts).*	◑	RMPS I.5	

2.0 RISK MANAGEMENT

Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
ROLES AND RESPONSIBILITIES							
2.6	Risk management hierarchical roles and responsibilities (especially for asset managers) are clearly delineated, with appropriate filtering, throughout the enterprise to ensure a thorough understanding and action to manage risks		• Corrosion management, strategy, operations, and enforcement were the responsibility of CIC. • Area Managers were accountable for all of the assets within their geographic boundaries. • Accountability for the GPB assets resided with the GPB Field Manager. *(2004 BP Management Framework; 1999-2006 BPXA Organization Charts GPB Operations Manager, GPB Commercial Manager, GPB Area Managers)*	• There were ambiguities concerning accountability for the OTL. The OTL crossed the geographic boundaries of all six area managers. • Area Managers believed that CIC was responsible for corrosion management of the OTL. *(GPB Area Managers, GPB CIC Team Leader, GPB Field Mgr.; CIC Head, , 2001 Review of Operational Integrity Concerns at Greater Prudhoe Bay)*	◑	RMPS I.5	Area Manager accountability for OTL has been clarified. *(GPB CIC Team Leader, BPXA Engineering Authority, GPB Field Manager)*
2.7	There are effective means in place to ensure that risk owners understand the risks they own.	GP 43-49 5.6.b Roles and Responsi-bilities.	• Inspection results were primary method for communicating piping integrity risks to asset owners. *(CIC Strategy & Planning Manager, GPB Area Managers)*	• By policy, only "F" ranked inspections and/or PMPs were communicated to Area Managers for action. • Inspection results "A" through "E" were not communicated to Area Managers. *(GPB Area Managers)*	◑	RMPS I.5	

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.8	Where appropriate, position descriptions and performance contracts clearly delineate mechanical integrity risk roles, responsibilities, and metrics	GP 43-48 11.7.1 Gen.	• Position descriptions for many roles (e.g., CIC, Area Managers) were not available. • Performance contracts were established annually for Alaska Leadership Team (ALT) members, which included performance metrics based on position roles and responsibilities. *(BPXA Commercial Manager, 2006 ALT Performance Contracts)*	• Not all staff positions had formal position descriptions. They were created for positions advertised for external hiring. Of position descriptions which were available, mid-level managers had varying levels of integrity risk roles, responsibilities and metrics. • Performance contracts for senior and mid-level managers had personnel safety target metrics. There were no explicit metrics for Mechanical integrity or environmental. performance. *(GPB Commercial, BPXA HR Director, GPB Area Managers; 2006 ALT Performance Contracts; 2005 Operations Integrity Manager performance review; GPB Ops Manager, GPB HSE Manager, CIC Team Leader, Ops Integrity Manager position descriptions)*	◔	RMPS I.5	

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.9	There are cross-functional committees or teams that address mechanical integrity issues	GP 43-48 11.1.2.b	• Incident investigation teams were cross functional ex post. *(CIC Head, GPB CIC Team Leader, Corrosion Management Meeting Agenda and Action Items)*	• Corrosion Management Meetings/conference calls occurred on a weekly basis between CIC "town" and CIC "slope". Asset owners were invited to participate. These meetings discussed working issues specific to integrity management, corrosion, inspection, and HSE. • Area Managers assembled cross functional team ad hoc for MOC. • Broader cross-functional committees designed to address mechanical integrity were not found. *(CIC Head, GPB CIC Team Leader, Corrosion Management Meeting Agenda and Action Items)*		No Available Standard	PAIT was a cross functional team that assessed failure risk of piping systems in 2006.
2.10	Mechanical integrity cross-functional committee or team findings and corrective actions are communicated to senior managers, tracked to closure, and trended		• Incident investigation findings were communicated to senior management. *(Various QPRs, GPB BUL, HSE Program Manager)*	• Neither the GC-2 nor the FS-2 incident investigation reports made recommendations and therefore there were no corrective actions to track. • No evidence of ex ante committee or team process to address mechanical integrity. *(Various QPRs, GPB BUL, HSE Program Manager, GPB CIC Team Leader, CIC Head)*		RMPS 1.5	PAIT made recommen-dations which were communicated to management.

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
TRAINING AND EDUCATION							
2.11	Personnel are adequately trained (including refresher) to fulfill their risk management roles and responsibilities		• Corrosion inspection, monitoring, and mitigation were performed by certified contract employees. *(BPXA Talent Manager, BPXA Operations SDDN Manager)*	• The majority of CIC Town staff were degreed corrosion engineers. • There was no evidence of refresher training. • A "Corrosion Basics" training class was offered in 2005 that included some elements of integrity management, but was not comprehensive (e.g. lack of risk assessment training). *(GPB Corrosion Training Matrix, BPXA Integrity Management Fundamentals, BPXA Talent Manager, BPXA Operations Manager, SDDN Manager)*	◑	RMPS II.1	
2.12	There are processes in place that review the effectiveness of training and update programs as necessary		• Training programs were reviewed annually.	• During this review, capability gaps were identified through a learning needs assessment process and then courses were targeted to fill those gaps. All staff were required to fill out a training feedback form at the completion of a training course – copies were provided to training coordinator and instructor. This information was retained in the Virtual Training Assistant. • Because training was not always directly linked with identified corrosion risks, effectiveness was difficult to accurately measure. *(Development Guide for Supervisors, training feedback form, BPXA HR Talent Manger and SDDN Operations Manager)*	◑	No Available Standard	

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
MANAGING RISKS							
2.13	ALT is aware of risk management issues	GP 43-49 5.8.h Risk Manage-ment	• BPXA's governance model included periodic reviews and audits, conducted either by BP Internal Audit or 3rd parties (e.g. Coffman Engineering). • QPR provided a forum for ALT to review corrosion and integrity management issues.	• Internal audit process findings were presented to ALT (e.g. 2002 *HSE right* report Ref. 2002AK010 distributed to BPXA Management and VP HSE, 2005 *EMS Audit Report* presented to GPB Field Manager, 2005 BPXA *Corrosion Management System Technical Review* distributed to GVP E&P, GVP technology and BPXA management). • Information related to corrosion was shared with ALT during QPRs but was highly summarized as part of M&R presentations. *(Source: 2006 Q1, Q2 QPR presentations)*		RMPS I.5	Technical Director, as member of AL:T will present more integrity risk information. Risk Register will consolidate risk issues at ALT level.
2.14	ALT is actively managing risk and risk management issues	GP 43-06 6.6 Risk Manage-ment	• QPRs were the forum for ALT managers to understand and discuss risk issues. • In general, critical operational risks were elevated to the ALT level at the discretion of the PU and BU management. *(GC2 Area Manager, GPB BUL, BPXA President, BPXA Commercial VP)*	• Risks were elevated and discussed at the senior level on a formalized basis using the QPR reports and meetings. • Internal OTL corrosion risks were not discussed at ALT level. • BU/PU and technical functions has delegated responsibilities for managing risk. • ALT intervened in the case of extraordinary business risks or in response to incidents. *(QPR reports, interviews: BPXA President, BPXA Commercial Vice President)*		RMPS I.5	Technical Director, as member of ALT will regularly assess and disposition integrity risks. *(BPXA Organization Chart – 2006)*

2.0 RISK MANAGEMENT

Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.15	There is a, formal process for risk disposition	GP 43-49 Annex B Single Point of Account-ability	• The PMP/MOC process was the formal corrosion risk and integrity management system.	• Once a PMP/MOC designation was given, it was assigned a risk owner. • CIC Slope and the Area Manager agreed on a planned course of corrective action. *(CIC Head, GPB CIC Field Team Leader, GPB Production Optimization Leaders, Area Managers, Technical Director, Review of PMP 06-422)*		RMPS IV.2.2	Engineering Authority will be responsible for integrity management assurance. *(BPXA Technical Director, BPXA Engineering Authority)*
2.16	Risk acceptance and rationale is documented and signed by senior executives	GP 43-17 8.a. Document.	• No formal process was found that documented senior executive risk acceptance.	• Typically risk acceptance and rationale were documented and signed at the CIC/ Area Manager levels and were not escalated to senior managers. *(CIC Head, GPB CIC Team Leader, Area Managers BPXA President)*		RMPS IV.2.2.1	See Item 2.16.
2.17	There is a formal configuration management control process in place (which includes review and approval of changes that affect risk)	GP 43-06 6.6 Risk Manage-ment	• Configuration Management was a formalized process covered under the "BPXA Engineering Drawing/Document Requirements Procedures/ Guidelines", "BPXA As Built Drawing Procedure", and "Technical Management of Change Process".	• Configuration Management process was structured and formal, working as indicated in the procedure manuals. • There was no formal verification to ensure drawings reflected "as-built". *(Area Managers, BPXA Engineering Authority, GPB Field Manager)*		RMPS IV.2.2	
2.18	There is a clearly defined process and procedure for management of change	GP 43-06 6.6.3 & GP 43-49 5.8.f. & 5.14	• Management of change was a formalized process covered under a "Technical Management of Change Process" procedure manual. There was a formal project for updating documentation in the MOC process.	• Management of change process was structured and formal, working as indicated in the procedure manual. • There was no assurance process to verify corrective actions had been implemented. *(Technical Management of Change Process, GBP Engineering Document Group Manage, Area Managers)*		RMPS III.1.3	

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
INTERNAL INSPECTIONS							
2.19	There is a documented, methodical and formal inspection process		• CIC had a formal and methodical process as documented in the Commitment to Corrosion Monitoring report *(CIC Head, GPB CIC Team Leader, GPB Area Managers, GPB Field Manager, Annual Corrosion Monitoring report to ADEC)*	• CIC was responsible for corrosion inspection and monitoring. Routine inspection activities and inspection campaigns were carried out by the Integrity Management team (CIC-Field) under the GPB Field Management/Maintenance organization. • Contractors performed most inspections including smart pigging, coupon monitoring, UT, RT and visual. • CIC integrity management concentrated on monitoring piping sections with predetermined inspection evaluation and piping "fit-for-service" criteria. *(CIC Head, GPB CIC Team Leader, GPB Area Managers, GPB Field Manager, 2005 BPXA Corrosion Management System Technical Review, Annual Corrosion Monitoring report to ADEC).*	●	RMPS I.5	
2.20	The inspection program is risk-focused		• The CIC inspection program focused on pipeline corrosion rates and was risk focused. *(Commitment to Corrosion Monitoring report)*	• Inspection regime was based on known risk. These risks were formulated from historical inspection data determined from wall loss for piping and corrosion rate for coupons. • Inspection regime did not incorporate changes in operating conditions that could affect risk (e.g. BS&W, lower flow rate, change in product composition). *(CIC Head, GPB CIC Team Leader, Annual Corrosion Monitoring report to ADEC, GPB M&R Manager)*	◑	API Recommended Practice 580, Risk Based Inspection	New CMS strategy is being developed.

2.0 RISK MANAGEMENT

Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.21	There is a formal process that monitors inspection results and corrective actions to ensure closure and tracking		• Inspection results were collected in MIMIR. • Critical inspection that result in a PMP were tracked to closure by CIC. *(Operations Lead – Applications Team, Business Information Manager, review of MIMIR data base, review of PMP tracking spreadsheet)*	• Non critical inspection results were not tracked to closure. *(Operations Lead – Applications Team, Business Information Manager, review of MIMIR data base, review of PMP tracking spreadsheet)*	◑	API Recommended Practice 580, Risk Based Inspection	
2.22	There is a program in place that periodically reviews the inspection process to ensure its effectiveness		• The Annual Corrosion Monitoring report provided an analysis of the corrosion trends and the methods of inspections. • Coffman Engineering provided an annual review of the BPXA Commitment to Corrosion Monitoring report. *(Annual Corrosion Monitoring report to ADEC, Coffman reports)*	• The Baxter audit recommended that the CMS strategy be revised and that the new inspection technology be evaluated. • Annual CMS updates to ADEC and the Coffman reports allowed BPXA to review the effectiveness of its corrosion inspection program. *(Baxter report, Annual Corrosion Monitoring reports to ADEC)*	◑	API Recommended Practice 580, Risk Based Inspection	The new CMS strategy in development will explicitly incorporate risk based inspections.
2.23	There is an appropriate assurance and enforcement regime in place		• Critical inspections might have resulted in the issuance of a PMP, which required corrective actions. *(Section 3 GPB PMP Process – Agreed)*	• The PMP process tracked modifications execution that are past due. • There was little evidence of an escalation / enforcement process for non-compliance. *(BPXA Technical Director, BPXA Engineering Authority, CIC Strategy & Planning Manager, GPB, Area Managers)*	◑	RMPS I.5	Engineering authority now has enforcement and assurance powers. *(BPXA Technical Director, BPXA Engineering Authority)*

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
INCIDENT/ACCIDENT REPORTING AND INVESTIGATION							
2.24	There is a formal process for identifying, reporting, and investigating accidents and incidents (not just "reportable")	GP 43-49 5.13.a.	• There was a formal process for identifying, reporting, and investigating all incidents. *(Sept. 2001 Incident Investigation Manual)*	• The manual emphasized that all incidents were to be investigated with root cause analysis. • There was a formal process—through an incident notification table that defined how incidents were to be reported and to whom. • The investigation work flow procedures covered all incidents, beyond just reportable. There was also a program to report near misses. *(Sept. 2001 Incident Investigation Manual, Injury Incident Reporting Sequence, GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report)*	●	49 CFR 195.55	
2.25	The incident investigation process includes causal analysis and risk assessment	GP 43-49 5.13.e.	• The investigation process included causal analysis. There was a "Comprehensive List of Causes" that serves as a checklist for investigators. *(Sept. 2001 Incident Investigation Manual, Injury Incident Reporting Sequence, GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report)*	• GC2 incident investigation included extensive root cause analyses, but not risk assessment. *(Sept. 2001 Incident Investigation Manual, Injury Incident Reporting Sequence, GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report)*	◕	49 CFR 195.55	

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.26	Incident investigation recommendations include pre-emptive, preventative and corrective actions		• Investigation report included risk ranked action items that translated into corrective action priorities. *(Sept. 2001 Incident Investigation Manual, Injury Incident Reporting Sequence)*	• Neither the GC-2 nor the FS-2 incident investigation reports made recommendations. *(GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report; FS-2 Oil Transit Line Spill Prudhoe Bay Eastern Operating Area, August 6, 2006 Incident Investigation Report)*	◕	49 CFR 195.56	
2.27	Incident investigation teams are appropriately trained		• Incidents investigations were led by either a BPXA HSE team or an HSE team external to BPXA. • Teams included root cause failure analysis experts from both HSE and Operations. *(Sept. 2001 Incident Investigation Manual, Injury Incident Reporting Sequence)*	• Root Cause Failure Analysis was part of the current BPXA training curriculum and was attended by both HSE and Ops staff. *(2006 Training Snapshot, HSE training matrix)*	●	No Available Standard	
2.28	Incident results are tracked and trended and incorporated into risk assessments	GP 43-49 5.13.e.	• Individual incident reports (IRs) were used to track corrective actions to closure. All IRs were entered into the TRACTION database, which is then used to track incident data. *(Review of TRACTION data base, HSE Program Manager)*	• Neither the GC-2 nor the FS-2 incidents results were fed back into a formal risk assessment process. *(GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2, 2006 Incident Investigation Report; FS-2 Oil Transit Line Spill Prudhoe Bay Eastern Operating Area, August 6, 2006 Incident Investigation Report)*	◔	RMPS IV.1	

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
EMERGENCY RESPONSE							
2.29	There is a formal and documented emergency response plan	GP 43-49 5.12.a	• The GPB Oil Discharge Prevention and Contingency Plan (ODPCP) was the emergency response (oil spill) plan for the Greater Prudhoe Bay Area.	• The plan was in compliance with the ODPCP regulations of the ADEC (18 AAC 75.425) and the federal regulations of USEPA, MMS, U.S. DOT, and USCG. • GPB Emergency Response Plan (ERP) provided guidance on specific emergency procedures to personnel with the goal of protecting life, minimizing danger to personnel, preventing harm to the environment and damage or loss of property, and applied to all BPXA employees, contractors and visitors within Greater Prudhoe Bay. *(HSE Crisis Manager, GPB Emergency Response Plan)*	●	PHMSA- 49 CFR 194 ADEC- 18 AAC 75.425 EPA- 40 CFR 112 MMS_ 30 CFR 254, USCG - 33 CFR 154	
2.30	Validations of the emergency response plan through exercises and drills	GP 43-49 5.12.b	• BPXA has fully adopted the National Preparedness for Response Exercise Program (NPREP).	• Common practice in the industry was to adopt the PREP guidelines for exercises. The NPREP based BPXA program complies with federal and State requirements. *(HSE Crisis Manager interview, GPB ODPCP)*	●	PHMSA- 49 CFR 194 ADEC- 18 AAC 75.425 EPA- 40 CFR 112 MMS_ 30 CFR 254, USCG - 33 CFR 154	

Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.0 RISK MANAGEMENT							
2.32	Staff are trained on the emergency response procedures (spill related training)	GB 43-48 9.2.3. GB 43-06 6.8.4	• Alaska Consolidated Services provided Incident Management Team (IMT) training for its own personnel and for the BPXA North Slope IMT personnel.	• IMT included Incident Command System (ICS), ICS position specific training, tabletop exercises and deployment drills. • North Slope Spill Response Team consisted of 115 emergency responders shared between BP and Conoco Phillips. They conducted weekly spill response training on areas of responsibility. *(GPB ODPCP, HSE Crisis Manager, ACS Technical Manual)*	●	PHMSA- 49 CFR 194 ADEC- 18 AAC 75.425 EPA- 40 CFR 112 MMS_ 30 CFR 254, USCG - 33 CFR 154	
SPILL PREVENTION							
2.33	There is a formal and documented Spill Prevention plan (including clear organizational responsibilities)	GP 43-49 5.12.a GP 43-06 6.8.1.	• The GPB ODPCP contained general guidance on prevention, inspections, and maintenance programs.	• GPB ODPCP did not contain information required by 49 CFR 195.402 (e) for emergencies. • Ownership of the prevention program was not clear. • Leak detection information in the ODPCP did not match some of the findings uncovered in the GC-2 Incident Investigation Report. *(GPB ODCPC, GC-2 Transit Line Spill Prudhoe Bay Western Operating Area March 2 2006 Incident Investigation Report)*	◐	49 CFR 195.402 (a) EPA- 40 CFR 112 18 AAC 75.425(e) (2)(A)	GPB now has a DOT approved Spill Response Plan for the OTL per part 195.

2.0 RISK MANAGEMENT							
Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
2.33	Validation through drills and exercises of the prevention plan and procedures	GP 43-06 6.8.4 GP 43-49 5.12.b	• The GPB ODPCP contained general guidance on spill response drills and exercises.	• Drills and exercises did not specifically address discharge prevention exercises or drills. • Emergency shut-down drills were conducted periodically but did not always reflect realistic conditions. *(GPB Area Manager, BPXA Operating Procedures Coordinator, Traccess Training)*	◐	49 CFR 195.403 (b) (1) EPA- 40 CFR 112 18 AAC 75.425(e)(2)(A)	
2.34	Staff are trained on the spill prevention procedures	Not found	• Oil-handling staff were trained in BPXA, state and federal pollution prevention measures, North Slope Training Center (NSTC) training in pollution prevention, and EPA SPCC-required topics for pollution prevention.	• All GPB personnel received training that included general North Slope procedures, spill prevention, environmental awareness, safety training pertinent to their jobs, site specific orientation, and Hazardous Waste Operations and Emergency Response safety. *(GPB ODPCP)*	●	CFR 195.403 (a) EPA- 40 CFR 112 18 AAC 75.007(d)07	HSE and Operations are working to continuously update the training program and designate ownership of the discharge prevention program.

3.0 COMMUNICATION

Item	Protocol/Element	Global BP Standard	GPB Procedure and practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
3.1	There is a process in place that communicates key risk data horizontally across organization		• Information flowed between the BPXA field organizations and BPXA Anchorage organizations through a series of formal and informal reports and meetings. *(BPXA Commercial Director, GPB Commercial Manager, BPXA QPRs 2004-2005)*	• CIC slope and town met weekly to discuss the scheduled inspection information from MIMIR. • GPB Field Management team met weekly. • A monthly report with details about the status of PMPs and inspection details was sent to Area Managers. • A report with details about overdue PMPs was sent to BP Group in London. *(CIC S&P Engineer, GPB CIC Team Lead, CIC S&P Engineer, GPB Area Managers, Former GPB Technical Services Director)*	◐	RMPS II.1	
3.2	There are processes in place to communicate key risk data vertically between frontline staff to senior decision makers		• The primary path for communicating corrosion risk was through the reporting of PMP status. • QPR brought management together to discuss various business issues (including risk).	• CIC was four levels below BPXA President, limiting and filtering its communications with senior management. • Vertical information flow was limited to inspection results and did not include information such as risk assessment. • Integrity and risk management issues were not formally reported to the ALT. Other key information related to corrosion such as the pigging statistics, inspection statistics and summary, status of MOCs were reported to management on an ad hoc basis. *(GPB CIC Team Lead; HSE Analyst, CIC S&P Engineer, BPXA organization charts, GPB Area Managers, GPB BUL, GPB Field Manager, 2006 QPR reports)*	◐	RMPS 3.2	Risk Register will formally capture and communicate risk assessments to management. *(BPXA Engineering Authority, BPXA, Technical Director)*

3.0 COMMUNICATION							
Item	Protocol/Element	Global BP Standard	GPB Procedure and practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
3.3	There is a formal process that communicates key inspection results to management for review and action (including causal analysis of high risk issues)		• A report with details about active, overdue and new PMPs was sent to the Area Managers every month. *(GPB CIC Team Lead; HSE Analyst)*	• All communications and follow ups were done through an email system manually. • There was no formal report of non critical inspection results or process to communicate them to senior management. *(CIC S&P Engineer, GPB Area Managers, CIC Head)*	◑	No Available Standard	.
3.4	Key risk data are appropriately rolled-up and presented in a comprehensible way to senior management		• Risk data had to go through three organizational levels to reach the GPB Field Manager. • Lists of all overdue PMPs were sent to the BP group in London in a monthly report. *(Strategy & Planning Manager; CIC S&P Engineer, GPB Field Manager, GPB Organization chart))*	• Integrity and risk management issues were not formally reported to the ALT. • Activities were reported to ALT but did not necessarily include risk impact information. *(ADEC Commitment to Corrosion Monitoring report, GPB BUL, GPB Field Manager, BPXA Commercial Director, former BPXA President, various QPRs, CIC S&P Engineer)*	◔	RMPS III.2	

4.0 CULTURE

Item	Protocol/Element	Global BP Standard	GPB Procedure and Practices (Source Cited)	Fact-Based Findings (Sources Cited)	Ranking	Regulatory Approach/ Practice (CFR or PHMSA)	Post-Incident Changes
4.1	There is an open-reporting policy for safety and risk issues		• BPXA policy was to encourage a safe work environment and support reporting to resolve issues. *(Alaska 2006 Safety Manual; 2005 North Slope Environmental Field Handbook)*	• There was an open reporting policy for safety and risk items. Employees can raise risk and safety concerns to their managers. *(Alaska 2006 Safety Manual; Alaska Incident Investigation 9/01; Vinson & Elkins report 10/04).*		No Available Standard	
4.2	No sanction is assigned to those who report accidents, incidents or near misses		• BPXA employees and contractors have an obligation, without fear or reprisal, to notify management of apparent hazards. *(Alaska 2006 Safety Manual)*	• There was an open reporting policy for safety and risk items. • Managed service contracts incorporated requirements to report all HSE concerns, with assurances against reprisal. *(Alaska 2006 Safety Manual; Alaska Incident Investigation 9/01; Vinson & Elkins report 10/04, NALCO Contract Attachment 7)*		No Available Standard	
4.3	There are mechanisms in place for senior management to communicate risk priorities to staff		• Formal mechanisms for BPXA to communicate risk priorities came through employee outreach programs (training, poster, communication). *(BPXA Talent Manager, HSE Manager)*	• There were robust workplace safety programs throughout GPB. • No evidence was found that senior management communication to staff focused on the risk associated with corrosion. *(BPXA Talent Manager, HSE Manager)*		No Available Standard	
4.5	There is a mechanism in place for sharing internal corporate BP leading practices (both inside and outside of Alaska operations)		• Sharing practices across SPUs and business units was encouraged by BP leadership. *(2004 BP Management Framework)*	• There was no formal mechanism to share best practices associated with corrosion management. *(BPXA Strategy and Planning Manager)*		No Available Standard	

RMPS:

Risk Management Program Standard produced by The Joint Risk Management Program Standard Team
January 17, 1997
http://www.cycla.com/opsiswc/docs/s8/p0005/RMProgramStandard.pdf

Note: this document was used as a framework to develop Appendix C to CFR Part 195.45 Implementation of an Integrity Management Program, while this document is targeted for gas transmission line, the fundamental risk management practices represent common practices across multiple industries

Also see: Risk Management Framework for Hazardous Materials Transportation prepared by ICF Consulting, sponsored by US DOT Research and Special Programs Administration (RSPA)
November 1, 2000
http://hazmat.dot.gov/riskmgmt/rmsef/risk_framework.pdf

Other risk management guidelines: OSHA, API, ISO…