Pipeline Risk Assessment

For

Cook Inlet Subarea

Prepared for

Cook Inlet Regional Citizens Advisory Council, Inc.

910 Highland Avenue
Kenai, Alaska 99611-8033

By

Gerald K. Brown, P.E. (CA)

Brown Corrosion Services Inc.
2305 Highway 6 South (77077)
P. O. Box 94638
Houston, TX, 77094-7638

Ph: (832) 327-0965
Fax: (832) 327-0968
Email: sales@browncorrosion.com

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EXECUTIVE SUMMARY

Brown Corrosion Services, Inc. was contracted by the Cook Inlet Regional Citizens Advisory Council (CIRCAC) to give a third-party review of the Cook Inlet Pipeline Operators annual voluntary reports on the status of their sub-sea pipelines as part of their overall pipeline integrity management plans.

It was agreed that this report would be done by reviewing the data submitted, telephone interviews with the operators, other published data.

After reviewing the data provided by the operators, conducting the interviews, and then comparing this data to the industry and governmental standards and practices, it is clear that the operators are using their sub-sea pipelines in a safe and compliant manner.

The three areas of concern for sub-sea pipelines are external corrosion, internal corrosion, and physical damage. All of the original assets were designed for larger volumes, higher pressures, and higher velocities than for which they are presently being used. Due to the depletion of the reservoirs, and the resulting decrease in volume, pressure, and velocity, these designs properly done for the originally anticipate production parameters - are proving to be very effective in meeting governmental and industry safety standards. Based upon present production data as reported the assets are over-designed for today's rates and thus safety margins are increased substantially.

With few exceptions, noted in the body of this report, the operators are using the most advanced data management, inspection, monitoring, testing and reporting technology currently available. It should be noted that within the industry there is still some debate on exactly what constitutes Pipeline Integrity Management. One would expect further changes, redefinitions and additions to the practices now followed and these changes will most likely be mandated by the governmental bodies involved.

The operators were very cooperative during the interviews and their knowledge and willingness to openly review the data on their sub-sea pipelines provided the substance and details for this report.

In more detail throughout this report, I have tried to define the assets, discuss the areas of concern, report on the interviews, give an overall summary of each operator's efforts, note a few small areas of concern and draw a conclusion.

One should keep in mind that there is always a remote possibility that events can occur that can cause problems (earthquakes, sabotage, or other catastrophic events) that are beyond the control of the operators.

In summary, I feel that CIRCAC had done due diligence in conducting this audit, and I can report that the operators are handling their sub-sea pipelines in the safest way possible based upon the information I reviewed and the telephone interviews.

August 23, 2005

Comments from Operators on the Cook Inlet Subsea Pipeline Report

Cook Inlet Pipeline

- Cook Inlet Pipeline operates the Christy Lee Platform and the Drift River facility

- The pipeline transports "pipeline" grade oil, containing less than .005% water entrained in the crude oil.

- Their pipelines are not regulated under DOT; there fore they are not required to have a Pipeline Integrity Plan.

Forest Oil

- Main office is located at 707 Broadway, Suite 3600, Denver, Colorado.

- Mr. Brown interviewed Mr. Ted Kramer.

- Mr. Kramer's email address is tekramer@forestoil.com .

- Added information concerning operating pressures: 4000 psi on the water injection line and down to 250 psi on the gas pipeline.

- Divers have taken direct current measurements of the cathodic protection.

- Annual third party inspections are performed.

- Changed running pigs from every 7-10 days to regular intervals as needed.

- Clarified that ice and hydrates occur in the winter months.

- Updated information to show that an anode ribbon will be applied to protect against further damage.

Unocal

- Provided onshore gas operations for Cook Inlet.

- Unocal does have a Pipeline integrity plan in place.

- Clarified that Unocal does have a dedicated pipeline engineer and a DOT Pipeline Coordinator.

- Provided further information regarding their high/low pressure alarms.

- Valves are tested every 6 months and test results are on record with DOT.

- Pointed out the negative buoyancy for stabilization of the pipelines.

- Clarified visual inspection only occurs onshore during excavations.

- Provided more detail on tidal zone damage causes.

- Updated the percentage of lines that have had smart pigging from 75 to 88.

- Added information concerning Bruce platform geometry pigging.

- Corrected corrosion inhibitors and biocide injected into the dry lines.

XTO

- Changed the number of wells operating.

- XTO operates two Subsea pipelines. (One was recently converted to gas only)

- The coating that was damaged during installation was not repaired. XTO is conducting wall thickness measurements and to date no active corrosion has taken place.

- Clarified that paraffin inhibitor is use din the winter.

- Provided an up date stating: XTO has implemented the Pipeline Integrity Management plan as of late June of 2005.

Cook Inlet Subsea Pipelines Reviewed in this Report
Summary of Cook Inlet Subsea Pipelines

Operator	*Pipeline*	*Appx. Length*	*Size*	*Sch.*	*O. D.*	*Wall*	*Yr. Install*
Cook Inlet Pipeline	Drift river Loading	3.6	30"	?	30	?	1966
	Drift river Loading	3.6	42"	?	32	?	1966
Forrest Oil	Osprey to Kustatan	1.3	8"	?	8.625	?	1993
	W. McArthur - Trading Bay	1.3	8"	?	8.625	?	1993
	Decommissioned	1.3	6"	?	6.625	?	1993
UNOCAL	Grayling to shore	6.0	10"	100	10.75	0.750	1967
	King Salmon to shore	7.0	8"	120	8.625	0.719	1967
	Dolly Varden to shore	5.7	8"	120	8.625	0.719	1967
	Steelhead to shore	6.5	8"	80	8.625	0.500	1986
	Monopod to shore	9.0	8"	120	8.625	0.719	1966
	Anna to Bruce	1.6	8"	100	8.625	0.594	1966
	Bruce to shore	1.6	6"	40/XXH	6.625	0.280/0.864	1974
	Granite Point to shore	6.0	8"	80/120	8.625	0.500/0.719	1966
XTO	A to shore	7.0	8"	100	8.625	0.594	1965
	B to shore	7.0	8"	100	8.625	0.594	1965
	C to A	2.2	8"	100	8.625	0.594	1967
	Dillon to C (abandoned)	2.1	8"	100	8.625	0.594	1967

BACKGROUND

Cook Inlet regional Citizens Advisory Council Inc. (CIRCAC) contacted Brown Corrosion Services, Inc. in July of 2004, to offer a proposal to perform a study of the risk assessment of pipelines in the Cook Inlet.

On January 11, 2005 a contract was signed (Contract Number 04-050P) to commence this study.

The purposes of the study, as outlined in your Attachment A to the contract, are as follows:

- Third party review of the reports submitted by the oil pipeline operators in the Cook Inlet of Alaska.
- Summary of inspection and maintenance practices to remedy actual and potential corrosion problems.
- Summary of chemical optimization activities.
- Summary of internal inspection activities.
- Summary of external inspection activities.
- Summary of structural concerns.
- Review of operator actions regarding corrosion trends exceeding expectations.
- Review of operator actions regarding structural trends exceeding expectations.
- Summary of programs to improve or enhance integrity.

For the purpose of this report the operators' design, production, and maintenance data and assets were not physically inspected, therefore all of the opinions in this report are based upon the interviews and reports as filed by the operators. Some of the purposes of the study were not able to be fully explored; instead the report relies upon the operators' open discussions.

It is envisioned that after review of this report and as further reports are issued by the operators over the next few years, a more concise report will emerge based upon further data being received.

As an example, I found that my inquiries into which chemical vendors are presently being used and any data from them was not obtainable. As this data is confidential between the operator and his vendor - and this is as it should be - it is impossible to fully understand or even define the chemical optimization activities. Chemical optimization is the term used to define the proper use of chemical additives added to the produced liquids and gases. These additives may be corrosion inhibitors, scale inhibitors, biocides, hydrate inhibitors, and scavengers. All of these products may or not be used. In addition, they may be used periodically, all of the time or occasionally.

The amount, the chemical formulation, and the method of placement of the additives, either used alone or mixed in a cocktail, constitute corrosion protection for the inside of the pipelines. Optimization means using the proper amount to get the desired protection, but not over-dosage which is costly, wasteful, and can be harmful. Over-dosage can cause clogging, deterioration of elastomers (seals), contamination of the oil and gas, but most of all run the budgets greatly over what they should be. Please keep in mind that, for older production, the chemical program can be the largest maintenance and/or operations cost after personnel.

BACKGROUND of OIL PRODUCTION in the COOK INLET

The first offshore platform was installed in the Cook Inlet, Alaska in 1964. To date, there are 16 platforms in this body of water. These platforms are connected to each other and to shore by a number of sub-sea (underwater) gathering lines that transport the crude oil and gas from place to place. In addition, there are docks and oil loading facilities in the Cook Inlet as well. Onshore there are a number of facilities related to the offshore assets.

The oil reservoirs in the Cook Inlet are as follows:

- Granite Point
- North Trading Bay
- Trading Bay
- McArthur River
- Middle Ground Shoal

The gas reservoirs in and around the Cook Inlet are as follows:

- Ivan River
- Beluga River
- North Cook Inlet
- Moquawkie
- Nicolai
- North Middle Ground Shoal
- West Foreland
- Redoubt Shoal
- Birch Hill
- Beaver Creek
- West Fork
- Sterling
- Kenai
- Falls Creek

The 16 offshore platforms in the Cook Inlet are as follows:

- "A" Tyonek
- Bruce
- Anna
- Granite Point
- Spark
- Spur
- Monopod
- King Salmon
- Baker

- Steelhead
- Dolly Varden
- Grayling
- Middle Ground Shoal "A"
- Middle Ground Shoal "B"
- Dillon
- Osprey

The sub-sea pipelines (Operators of Interest) in the Cook Inlet are as follows:

- Cook Inlet Pipeline Company
    1. 30" line – installed 1967
    2. 42" line - installed 1967

- Forest Oil
    1. 8" water line -
    2. 8" oil line - installed 1994
    3. 6" gas / spare line

- Unocal
    1. 10" wet oil Grayling to shore
    2. 8" wet oil King Salmon to shore
    3. 8" wet oil Dolly Varden to shore
    4. 8" wet oil Steelhead to shore
    5. 8" wet oil Monopod to shore
    6. 6" dry oil Anna to Bruce
    7. 6" dry oil Bruce to shore
    8. 8" wet oil Granite Point to shore

- XTO
    1. 8" A to shore (A line)
    2. 8" B to shore (B line)
    3. 8" C to A
    4. 8" Dillon to C (abandoned)

It should be noted that there are other sub-sea pipelines in the Cook Inlet presently being operated out of the scope of this report and most probably some abandoned lines.

The operators of the sub-sea pipelines for these facilities have changed over time with the current pipeline facilities included in this report being operated by the following companies:

- Cook Inlet Pipeline Company
- Forest Oil

- Unocal
- XTO

In many ways, all offshore structures offer a challenge. The structures in the Cook Inlet have all of these challenges plus the fact that the Cook Inlet has some distinct conditions as well due to its geographic location. Usual offshore challenges are related to the structure itself, the production and process modules on the structure, the wells and wellheads, and the risers. In these areas we look for internal and external corrosion, internal and external erosion, and mechanical weak points and/or failures. In the Cook Inlet these same areas can be even more vulnerable to failure due to localized conditions such as cold weather, strong water currents, ice flow, earth quakes, age, and declining production chemistry.

It should also be noted that this study is of the sub-sea pipelines only.

As the pipeline is an integral part of the whole system including the wells, production facilities, risers to the sea bottom, receiving facilities, and onshore facilities, failure of any of these assets could have ramifications to the pipelines themselves. In most cases the pipelines are isolated from the other structures. This isolation may be by means of physical isolation, such as shut-down valves or electrical isolation for the cathodic protection system. In both cases, if the isolation fails or does not work, failures on other structures could affect the pipelines themselves.

Examples would be if a well over-pressurized and the pressure somehow got into the pipelines, there could be damage. Another example could be if an acidizing project is performed offshore and the valves are out of phase, some of the acid could get into the pipeline causing damage.

DISCUSSION of PIPELINE INTEGRITY

In The Pipeline Safety Improvement Act of 2002, the United States Congress mandated pipeline integrity management programs to be put in place by pipeline operators. The programs were to include baseline integrity assessments of the pipelines and periodic reviews of the pipeline in areas of high consequences. These regulations are included in the Department of Transportation (DOT) Code of Federal Regulations – Title 49 Part 192 Transportation of Natural Gas by Pipeline: Minimum Federal Safety Standards and the DOT Code of Federal Regulations – Title 49 Part 195 – Transportation of Hazardous Liquids by Pipeline: Minimum Federal Safety Standards.

Basically these regulations instructed pipeline operators to have plans for the integrity of their pipelines. As our pipeline infrastructure ages in the United States, the probability of damage increases. In addition, several high profile failures occurred that brought to every ones attention the fact that there can be a danger to the environment and personnel if pipelines fail. These issues and others brought about pipeline integrity.

Portions of the pipeline integrity issue were further defined by the National Association of Corrosion Engineers (NACE International) or (NACE) in several of their documents namely ANSI/NACE RP0502-2002 Item No. 21097 Pipeline External Corrosion Direct Assessment Methodology (ECDA) and NACE TG-293 Internal Corrosion Direct Assessment Methodology for Transmission Pipelines Carrying Normally Dry Natural Gas (ICDA).

Many conferences and meetings have been held to help define exactly what is required in Pipeline Integrity Management and how to go about creating a Pipeline Integrity Plan. At one such conference (NACE External Corrosion Direct Assessment Seminar; Wyndham Greenspoint Hotel; Houston, Texas; November 5 -7, 2003), such topics were covered:

Pipeline Integrity Regulations

Step 1 Pre-Assessment

Indirect Examination

Direct Examination

Post Assessment

As there are so many variables that go into the determination of the safety of a pipeline, it is still not clear exactly what should go into these programs, and one would expect changes to come about in the near future to the requirements of a Pipeline Integrity Plan by regulators, technical societies, and end user companies. The specifications all generally state that any new technology can be used and incorporated without rewriting the specifications and should be used if it contributes to the safety of the pipeline or pipeline integrity.

The author of this report is of the opinion that the larger influence on these standards, specifications, and pipeline integrity plans, looks to external corrosion and internal inspection with important areas having less importance such as internal corrosion monitoring, sampling, chemical programs and others issues. This seems to be in conflict with data gathered over the last several years that internal corrosion, and indeed many of the recent high profile failures, have been caused by internal corrosion. However, the release of the standards and the operators willingness to comply and develop integrity management plans attest to the ideas toward showing that the pipeline operators are concerned about their assets and want to be in compliance with standards and regulations as well as operating a safe, efficient, environmentally friendly operation.

DISCUSSION of CORROSION

Corrosion is the electrochemical reaction of a material with its environment. When corrosion occurs, material goes into a liquid state and leaves the surface of the material.

This flow of material from the surface can appear in several forms, with the most common in oil and gas operations as follows:

General corrosion (corrosion fairly even over the whole surface)
Pitting or localized corrosion (an extreme attack in one isolated area)
Cracking corrosion

In oil and gas field operations, the main culprits that cause corrosion are hydrogen sulfide (H_2S), carbon dioxide (CO_2), oxygen (O_2), bacteria, and chlorides.

Control of corrosion can only be accomplished using one or more of the following categories:

1. Material selection
2. Proper design
3. Coatings
4. Cathodic Protection
5. Alteration of the Environment
6. Chemical Inhibition
7. Repair and replace

Regardless of the cause of corrosion, the above are the only methods that can be used to control corrosion.

MATERIAL SELECTION

Material selection involves selecting the best material for each application that will offer corrosion protection. In addition to corrosion protection, strength and cost play a role in material selection. During the design phase of a project, the most cost effective material is generally selected based upon the given environmental parameters. Since the best material is often a very expensive material, other less costly materials are used along with other corrosion control techniques to protect the asset. For instance, a material can be protected by coatings, cathodic protection, or the use of chemical inhibitors to coat the wall of the pipe thus separating the material from the environment.

Often the environment in contact with the pipe changes over time as well and therefore, the original material selected is not the best. An example of this would be the rising percentage of water produced with oil as the reservoir depletes. In cases such as this, other corrosion control methods must be used. Examples of further corrosion control methods brought into action after the start-up would be in-situ coatings, alteration of the environment (de-watering) or the use of inhibitors.

PROPER DESIGN

Proper mechanical design of the structures (pipelines) is essential. The size must be correct to include the diameter as well as the wall thickness. Welds and weld procedures must be proper and the configuration of the pipeline must be done correctly: tees or flow cushions, long or short radius elbows, buried or on the seafloor.

COATINGS

Coatings and/or paints provide a protective barrier between the metal wall of the pipe and the corrosive environment. Coatings are usually applied to the external surfaces and not the internal surfaces. Although technically there is no reason that internal coatings can not perform, they usually have not been successful in the past. Flow characteristics often damage internal coatings making problems worse than a pipe with no coating at all.

There is an ongoing maintenance issue with coatings as they must be periodically inspected and repaired. Probably the worst case for coating maintenance is aboard ships where this is an ongoing "chipping" and "painting" procedure.

Modern coatings such at fusion bonded epoxy (FBE) have made great strides and lowered maintenance costs substantially. The industry also has used metal coatings (fusion sprayed aluminum FSA) in many applications.

Original equipment can be coated in shop conditions but field applications are more difficult and costly. Damaged coatings can be field repaired after the determination that they have failed or have localized damage.

Coatings are often used in conjunction with other corrosion control techniques such as cathodic protection. Coatings and cathodic protection are usually used together for protection of pipelines both buried and sub-sea. Basically - as no coating is perfect - the cathodic protection "protects" the flaws (also called holidays) in the coating as well as protecting damaged areas of the coating where the base metal of the pipeline may become exposed.

CATHODIC PROTECTION

Since corrosion is electrochemical in nature, it depends upon a potential difference between the corroding structure and the soil or water surrounding the structure. By placing a current in the surrounding medium a "balance" can be achieved whereas the flow of electrons will not take place away from the pipe as the potential is "balanced". This balance can be achieved by either a sacrificial technique or an impressed current technique. In the sacrificial technique an anode is installed on the structure that allows the escaping current to flow from the structure through the anode thus allowing the anode to deplete and not the structure itself. In the case of impressed current, a ground bed is installed that allows a rectifier to induce current into the surrounding area, "balancing" the potential so that there is no flow off of the structure.

As mentioned above, cathodic protection and coatings are usually used together to offer the optimum corrosion protection to the outside (external) surface of buried and submerged structures.

ALTERATION of the ENVIRONMENT

One can say that without water there can be no corrosion. Therefore the removal of water on the inside of a pipe will stop corrosion. If oxygen is causing the corrosion oxygen can also be removed. All of the corrosion causing constituents (H_2S, CO_2, oxygen, bacteria and chlorides) can be removed. However, the removal is often costly so these removal techniques are used along with other compatible techniques to control corrosion.

As an example, water removal from oil and gas is difficult and expensive. The two common alternatives are to use a "non-corrosive" material for the pipeline that is very expensive or to use a less expensive material for the pipeline and depend upon inhibitors injected into the product in the pipeline to protect the material from which the pipeline is fabricated.

Some chemicals are used to alter the environment such as scavengers and other chemicals that change the chemistry so that the corrosive environment is no longer corrosive or at least less corrosive.

CHEMICAL INHIBITION

Chemical inhibition can alter the environment as explained above but, by far the greatest use of inhibitors is to allow them to adhere to the wall of a structure thus creating a barrier between the metal structure and the environment. One of the most common methods for internal protection of pipelines is to use chemical corrosion inhibitors. Over time, as the chemistry changes, new chemicals can be used for continued corrosion protection. Chemical inhibition is primarily used for the internal surfaces of pipelines.

As mentioned above the use of chemicals for corrosion inhibitors is probably the most used method of internal corrosion protection. Many projects can not be implemented if the corrosion control method is material selection because the material costs would be so high that the whole project could not be justified. In addition, the environment changes over time, so that the initial material selection may not be the best one when conditions change. Therefore a less expensive material is usually used along with corrosion inhibitors. An example would be using standard low carbon steel for a pipeline with inhibitors rather than stainless steel or Inconel. Stainless steel or Inconel can increase the pipeline cost by a substantial factor often making the project not viable economically.

REPAIR & REPLACE

The most common type of corrosion control is to simply let the structure or item corrode and then replace it. For household items like pans, clothes-lines, or automobiles this is an acceptable method of corrosion control. However, when pipes carry products that can be harmful to the air, sea, land, or people if they are released, this is not a realistic alternative to the 6 previous methods of corrosion control used to prevent failures.

Regardless of the method of corrosion control used, there must be some sort of monitoring in place as well as inspection to both determine the condition of the structure and to verify that the corrosion control steps taken are working to control corrosion.

All of the corrosion control methods above are used worldwide to control corrosion. Variables due to location do come into the methodology used in selecting the corrosion control method and the variables can also affect the root cause of the corrosion. In cold climates, such as in Alaska, we find that corrosion and corrosion control are the same but the intensity, effects and impacts of corrosion are different and often more intense. The weather often plays a role in the monitoring and maintenance of both the structures and the corrosion control used. Freezing and thawing, scouring and other factors exacerbate the corrosion issues.

DISCUSSION of INTERNAL CORROSION

Internal corrosion is the corrosion that takes place on the inside of pipes and vessels. Unlike external corrosion that is often visible to the eye, one can not see the inside of pipes and vessels making the detection of internal corrosion all the more difficult.

The inside of pipes offers an ideal place for corrosion to take place as well, as it is usually dark, warm and the environment often includes H_2S, CO_2, oxygen, bacteria and chlorides. Unlike external surfaces, it can not be easily cleaned or dried.

Since one can not see the inside of the pipes, we must depend upon monitoring and inspection to tell us the condition of the inside of the pipes.

Monitoring, on a near real-time basis, tells the operator what is happening in a very short window of time. Monitoring can also tell the operator if his method of corrosion control is working. For instance, if chemical corrosion inhibitor is used, the operator can gauge if it is working and if the concentration and volume are adequate to control the corrosion. Monitoring gives the operator time-stamped data as to the corrosivity of his pipeline.

Inspection, on the other hand gives the operator "snapshots" as to the condition of his pipeline. As an example if an operator runs thickness measurement surveys every year the survey will tell the net change in thickness over the yearly period. The survey will not tell when and at what rate the corrosion occurred, only that it did occur and produced the result.

Monitoring and inspection should both be used together

Since the main methods of corrosion control for the I.D. of pipes is the use of chemical corrosion inhibitors, biocides, and alteration of the environment – and the environment is continually changing -- the methods must also change over time. These changes can be determined by the results of monitoring, sampling, and inspection.

Recent data confirms that the incidences of internal corrosion failures are increasing as an overall percentage of pipeline failures. This fact attests to the excellent job that has been done in lowering failures caused by external corrosion (primarily advanced coating and cathodic protection) thus allowing these structures to last longer. By allowing the assets (pipelines) to last longer the weakest point often becomes the internal surfaces where corrosion can take place over longer time intervals and with more intensity.

DISCUSSION on EXTERNAL CORROSION

External corrosion is the corrosion that takes place on the external surfaces of the pipeline.

External corrosion is often visible. However, in the Cook Inlet, several factors greatly affect the visibility to the point where, for all intents and purposes, the pipeline is invisible. The pipelines are sub-sea, they are coated and cement coated in most cases, the water is not clear for visual inspection by divers, and many of the lines are buried in the sea bed or silted over. In addition, the changing sea-bottom adds to the problems as erosion and bottom conditions change. Another issue (covered later) is external abrasion due to tides and currents which can damage the coating and lining of the pipe.

External corrosion is most often mitigated by the use of coatings and cathodic protection working hand in hand. Since all coatings are not perfect, the cathodic protection protects the pin-holes (holidays) in the coating and other flaws. In the calculation for the amount of cathodic protection current needed, the condition of the coating must be taken into consideration.

Monitoring of the cathodic protection systems is a must to be sure the cathodic protection is working. Generally speaking, monitoring includes checking the rectifiers on impressed current systems and checking the potential between the structure being protected and the surrounding environment (sea or soil). There are standards for all of these methods usually by NACE or DNV (Den Norske Veritas, the European standards group).

All of the lines in the Cook Inlet are protected by coatings, cathodic protection, and concrete coating. In addition, some of the lines are buried either intentionally or unintentionally.

DISCUSSION of STRUCTURAL ISSUES

External structural issues regarding sub-sea pipelines fall into several categories. Generally a submerged pipeline that does not move and has stable bottom conditions will last without external structural issues. The other most common external structural damage to sub-sea pipelines involves interference from other vessels with anchors, nets, or dredges that can make contact with the submerged pipeline.

With changing sea-bottoms "spanning" may be an issue. Spanning is the length of unsupported pipe between supports or where the bottom has erodes out beneath the pipeline. Without support any structure can "bend and break." One must determine the maximum allowable length of a span before damage can occur.

In high current areas, like the Cook Inlet, vortex induced vibration (VIV) may also play a role. VIV occurs when the water current flowing around the pipeline exposed and supported between tow fulcrums starts to vibrate and in these cases the maximum safe spanning distance may have to be shortened.

Internal structural issues usually involve over-pressurization of the pipeline beyond maximum allowable working pressure (MAWP).

Often structural damage occurs in sub-sea pipelines during the laying of the pipeline. Improper calculations of pipe bends can result in "wrinkles" that add residual stresses to the pipe. Welds are critical. The weld must be good and proper procedures followed and documented. Expansion and contraction due to temperature changes must be addressed as well. Buoyancy can be a problem if the pipe is not properly weighted. Stresses on the pipeline due to sea bottom changes can take place as well. Additionally damage can occur due to rocks, boulders, submerged logs and other debris striking the pipeline.

Any of these external issues can lead to structural issues.

PIPELINE INTEGRITY – Cook Inlet Pipeline

On Friday the 11th of February, I interviewed Mr. Jim Shew, Manager / VP of Cook Inlet Pipelines by telephone. Mr. Shew's contact information is telephone (907) 263-7992, email jshew@Unocal.com. Mr. Shew is a UNOCAL employee and has had a lot of experience both with UNOCAL and in the Cook Inlet, Alaska.

Mr. Shew acts as the Corrosion Engineer along with his other responsibilities. Cook Inlet Pipeline has a Pipeline Integrity Management Plan in place and feels they are in 100% compliance with DOT 49CFR Part 195 and the State of Alaska Department of Environmental Conservation regulations.

Cook Inlet Pipeline has 2 pipelines running from the Christy Lee Platform to their Drift River Facility on the west bank of the Cook Inlet. The lines are 30" and 42". The pipelines are approximately 2 miles long. There is little boat traffic in the area, so there is little danger from that aspect.

They have an approved State of Alaska Oil Discharge, Prevention and Contingency plan in place and are a member of CISPRI.

Cook Inlet Pipeline ran a Close Interval Potential Survey (CIPS) in 2003. This survey showed their Cathodic Protection (CP) to be working well. This data is also included with the pigging data. They carry out annual cathodic protection surveys and all cathodic protection equipment is functioning properly. The survey and maintenance of the cathodic protection system is done in-house by their electrical department. To date they have had no interference issues to deal with.

Whenever a dig is scheduled, the coating is inspected, and no problems have been found to date. Erosion of the coating from external forces can be a problem, but because of the poor water conditions, the divers can not see it as most of it is buried. If erosion has occurred and damaged the coating, the cathodic protection system should protect it. Mr. Shew mentioned that sea-floor erosion is an issue in the north of the Cook Inlet but not a problem in the south as the sea-floor is solid.

Internally, they run cleaning pigs every 7 to 10 days. No samples are taken as no chemicals are added. They have no internal corrosion monitoring in place, however, the pipeline transports "pipeline" grade oil that typically contains less than .005% water entrained in the crude.

It was stated that in 37 years they have had no problems.

One fact that leads to a very safe system for Cook Inlet Pipeline, and the others as well, is that the facilities were designed for larger capacities, higher pressures, and higher velocities. The pipelines are running under capacity. In addition, the walls of the pipes are thicker than necessary for today's flow thus giving added strength and corrosion allowance. (Corrosion allowance is the amount of material on a pipe wall over strength requirements to allow for metal loss corrosion and still be within safe operating parameters).

Three recommendations for improvement that Cook Inlet Pipeline could implement in order to have even more data in which to assess their assets: First is the use of internal corrosion monitoring on their lines. The use of corrosion coupons on the receiving end of the pipelines would verify that they do not have internal corrosion (although typically containing .005% entrained water in the line the use of corrosion coupons would ensure early detection of internal corrosion). Second would be to take at least one sample, every few months and send it to a laboratory for analysis. Third would be to institute a formal Pipeline Integrity Management (PIM) Plan. These steps would further ensure that Cook Inlet Pipeline is operating in a safe and efficient manner and documenting the results. While these offshore lines are not regulated by DOT, rather USCG and thus are not required to have a formal plan in place, the practice would ensure the protection of Unocal's assets.

Overall, from the data given in the telephone interview, Cook Inlet Pipeline is conducting its operations and assets in a manner consistent with today's regulations and industry practices with the three exceptions outlined above. Cook Inlet Pipeline is operating their pipelines within regulations.

PIPELINE INTEGRITY – Forest Oil

Forest Oil Corporation is headquartered at 707 Broadway, Suite 3600, Denver Colorado 80202, (303) 812-1400. They have operations in Louisiana, Oklahoma, Texas, Utah, Wyoming, the Gulf of Mexico, Canada, South Africa, and Alaska. Their office in Alaska is at 310 K Street, Suite 700, Anchorage, Alaska 99051 (907) 258-8600.

Forest Oil Corporation operates onshore and offshore assets in Alaska and has one platform, Osprey, in the Cook Inlet.

On Friday, the 11th of February, I interviewed Mr. Ted Kramer, Production Manager, and Paula Inman, Production Engineer, by telephone. Mr. Kramer and Ms. Inman were very well informed. Mr. Kramer's contact information is telephone (907) 258-8600, email tekramer@forestoil.com.

Forest does not have a staff Corrosion Engineer and depends upon their chemical company for the internal corrosion and contractors for inspection and external corrosion needs. The chemical company reports to Ms. Paula Inman. Forest does not have a Pipeline Integrity Management Plan (PIM) in place at this time.

Forest produces offshore and sends everything onshore where it is processed. They have 3 pipelines with 2 being in service. Their pipelines are relatively straight with about one half of the length onshore and with no tie-ins or branches.

The operating pressure fluctuates in their facilities, but in all cases, less than designed pressure. Often they operate at approximately 1,000 psi on the oil pipeline. 4000 psi on the water injection pipeline and possible down to 250 psi for the gas pipeline when in service.

They do have emergency shut-down valves in place at both ends of all of their pipelines. They have an approved State of Alaska Oil Discharge, Prevention and Contingency plan in place and are a member of CISPRI.

Externally they have both coatings and cathodic protection as corrosion control methods in place. They have not conducted any close interval potential surveys but have used divers to take direct current measurements of their cathodic protection effectiveness.

Forest Oil has had no apparent external erosion problems but did have one place where the pipeline rubbed against a rock and the coating was damaged. It has since been repaired. Their pipelines are not equipped with concrete coating. However, divers verified the integrity of the pipeline and that the cathodic protection is adequately protecting the pipeline in these areas.

Forest Oil has a cathodic protection system in place, and it is operated and maintained by their employees. Annual 3[rd] party inspections are also performed. As they have no other structures crossing their pipelines, they have no interference issues to deal with.

Internally, Forest Oil runs cleaning pigs every at regular intervals as needed. Samples are not taken routinely but on an as-needed basis. Some ice and hydrates form in front of the pig during the winter months. Water analysis is taken by the chemical vendor.

Chemicals are injected into all active pipelines. Corrosion coupons are in place at specified points on lines, and the chemical vendor supplies the analyses. If corrosion coupons show that corrosion is occurring outside specified limits, the chemical program is adjusted accordingly. No sand has been detected in the pipelines or in the vessel bottoms.

Forest Oil does not have a formalized Pipeline Integrity Management Plan in place but takes all of the manual readings and enters them into a data management file.

Hydro testing has been performed in the past with all tests successful.

Forest Oil runs yearly surveys to determine if spanning occurs and exceeds specified limits. Corrective action, where necessary, is implemented by stabilization methods. They have not encountered seabed erosion that would cause spanning.

The results of a recent smart pig run demonstrated some external corrosion in one riser. This corrosion was looked into. One would expect that once the amount of corrosion is determined, and if it is slight, a coating or tape will be applied to protect this riser against any further damage. An anode ribbon will be applied to protect this riser from any further damage.

From the data provided, Forest Oil appears to be operating and monitoring their assets in a way consistent with today's regulations and industry practice. It should be strongly suggested, while their pipelines are not DOT regulated that Forest Oil move towards a Pipeline Integrity Management Plan (PIM) as soon as possible. This plan would focus the attention on the integrity of their assets and provide documentation for further evaluations or investigations.

PIPELINE INTEGRITY - UNOCAL

Unocal is a Multi-national Oil Company with assets throughout the world.

Unocal discovered gas onshore in Alaska in 1959 and acquired offshore drilling rights in the Cook Inlet in 1962. Unocal presently operates 10 platforms in the Cook Inlet and 6 of 14 gas fields. Of the 30 established fields or units in the Cook Inlet, Unocal has an interest in 16 and is the designated operator for 15. Unocal has approximately 329 employees in Alaska.

In addition to the 10 platforms that Unocal operates, they have the Granite Point tank farm, and the Trading Bay, Swanson River and Granite Point production facilities. Unocal also operates the onshore Swanson River oil and gas field, Westside gas fields at Ivan River, Lewis River and Pretty Creek, and Happy Valley gas field.

To date CIRCAC has received very comprehensive reports from Unocal as to the status of their sub-sea pipelines for 2004 and 2003, as well Unocal provided CIRCAC's Props committee with a presentation of their Pipeline Integrity Program.

On Monday the 14th of February, I interviewed Mr. Lew Dennis, Engineering & Construction Manager (formerly Pipeline Engineer). Mr. Dennis's contact information is telephone (907) 276-7600, email dennisl@Unocal.com.

Unocal has a Pipeline Integrity Management Plan in place and feels they are in compliance with DOT 49 CFR Parts 195 (oil) and 192 (gas) and the State of Alaska Department of Environmental Conservation regulations, as well as their own company standards.

UNOCAL has a dedicated Pipeline Engineer and a DOT Pipeline Coordinator who is also Unocal's Cathodic Protection Technician. Both of these individuals are part of the Pipeline Integrity Team which includes the Sub-Sea Projects Technician and 2 to 3 full time contractors. All issues are reported to the Pipeline Engineer who in turn reports to Mr. Lew Dennis.

Data is stored in a data base as an overall integrity plan using Arc View GIS software.

Unocal has 8 sub-sea pipelines as listed above. There are no major tie-ins or branch connections. All of the lines are operating far below Maximum Operating Pressure (MOP) thus giving Unocal more than adequate wall thickness for present operating conditions.

Unocal has emergency shut-down valves on both the platforms and onshore activated by high and low pressure sensors (alarms). The values are tested every 6 months in accordance with DOT regulations and test records are on file. The pressure sensor alarms are tested quarterly in accordance with the Unocal maintenance program. These are tested annually and test records are on file. They have an approved State of Alaska Oil Discharge, Prevention and Contingency plan in place and are a member of a local oils spill response cooperative organizations CISPRI (Cook Inlet Spill Prevention and Response Inc.).

Unocal pipelines have an external coating and cathodic protection as corrosion prevention measures. Many of the sub-sea pipelines have a concrete weight coating that helps to maintain negative buoyancy and stabilize the pipelines.

During excavations, onshore or in the tidal zone, the coating is always visually inspected at the site, and repaired as required. There have been no problems with the coating except in the tidal zone where there has been some occasional damage to the coating caused by wave action in conjunction with ice, rocks and sand. The location of the pipelines in the tidal zone can make coating repairs from difficult to impossible, but the high amperage output cathodic protection systems have proven to be extremely effective at preventing corrosion. There has been no significant external corrosion found in the onshore tidal zone. Onshore tidal zone repairs and maintenance are performed on an as needed basis, and all active pipelines have had some amount of maintenance work over the past few years.

The cathodic protection systems were installed during initial construction of the platforms and onshore facilities. Rectifier and anode readings are recorded monthly. Cathodic protection surveys are performed annually on both the onshore and offshore pipeline segments by third party corrosion engineering firms. Based on measured CP levels from the annual surveys, mitigative actions are taken, such as retrofitting anode sleds or installing deep anode beds onshore. A close internal cathodic protection survey (CIS) is performed every five years on the entire length of each pipeline; no problems have been detected on the offshore pipelines requiring mitigative actions. With routine maintenance, the cathodic protection systems function as designed and are providing adequate cathodic protection as shown by Unocal's data and their pipeline inspection results.

Ultrasonic wall thickness testing is carried out on an as needed basis on the exposed portions of the pipelines. 88% of the active oil pipelines have had intelligent (smart) pigs run in them as their baseline assessments, with no anomalies requiring repairs. Cleaning pigs are run 1 or 2 times per week on each pipeline to clean out any accumulations of paraffin or sludge. Any "non-typical" deposits pushed in front of the cleaning pig are analyzed.

The internal diameter of the 6 inch heavy wall pipeline from the Bruce Platform to shore is too small to run an intelligent pig so it has had a geometry pig run and hydro-test for its baseline assessment. Although pipelines under 6 inches have not been able to have intelligent pigs run through them, the technology may be available within the next few years. However, at this time the only alternative pipeline assessment has been hydro testing which is the industry and regulatory accepted alternative.

Chemical corrosion inhibitor and biocides are injected into the wet (oil and water) pipelines lines and biocide only is injected into the dry pipelines. The injection system is checked daily and the chemical vendor evaluates the system for corrosion, scale, sulfate, reducing bacteria and paraffin. Proper maintenance of these programs has helped to prevent pipeline failures.

Annual side-scanning sonar surveys are conducted on the sub sea pipelines to locate pipeline spans or possible physical features near the pipeline such as rocks, ect. When a pipeline span over 50 feet in length is found it is stabilized with sand-cement bags on an as needed basis.

In 2003 Unocal underwent a DOT Audit on their Integrity Management Program for hazardous liquid pipelines in high-consequence areas without any notable exceptions. DOT routinely (annually) audits Unocal's pipeline operations and maintenance programs with no notable exceptions recorded.

From the data provided, Unocal appears to be operating and monitoring their assets in a way consistent with today's regulations and industry practice.

PIPELINE INTEGRITY – XTO

XTO is a public company headquartered at 810 Houston Street, Fort Worth, Texas 76102-6298 (817) 870-2800. XTO's Alaska office is at 52260 Shell Road, Kenai, Alaska 99611 (907) 776-2511.

In 1998, XTO purchased the Middle Ground Shoal Field in the Cook Inlet. This highly complex field has yielded 130 million barrels of oil to date. The company operates 2 platforms in about 70 feet of water. A successful program is underway to further develop the complex reservoir and extend the waterflood.

CIRCAC has received a report from XTO on the status of their sub-sea pipelines.

On Tuesday the 15th of February, I interviewed Mr. Shane C. Alexander, Manager- Natural Gas Facilities. Mr. Alexander was very knowledgeable and experienced. Mr. Alexander's contact information is telephone (817) 885-2572, fax (817) 870-8441.

Mr. Alexander is the Project Engineer based in Fort Worth, Texas and is responsible for corrosion and corrosion control along with his other responsibilities. XTO has a Pipeline Integrity Management Plan in place complying with DOT regulations and feel they are in 100% compliance with DOT 49CFR Part 195, XTO's own manual, and the State of Alaska Department of Environmental Conservation regulations.

XTO operates 2 subsea oil pipelines. They are 8" lines from Platform A (B line) to shore and Platform C to Platform A. They have one abandoned line that previously ran from Platform Dillon to Platform C. Recently the 8" line that ran from Platform A to shore (A line) was converted to a gas only line.

These lines are 8" schedule 100 pipe which has a wall thickness of 0.594" and operates at lower pressure than their Maximum Allowable Working Pressure (MAWP) of 600 psig. The line was pressure tested to 750 psig. XTO operates in the 160 to 280 psig range. There have been no reports of previous leaks in any of their lines. All of their lines are coated and have a concrete coating as well.

XTO has Shut-down Valves on the platforms. They have a leak detection system in place and do daily fly-overs to look for any traces of leaks. They have an approved State of Alaska Oil Discharge, Prevention and Contingency plan in place and are a member of CISPRI.

Externally XTO has coating and concrete cover. They do yearly diver inspections in selected areas. Some of the coating was damaged during installation. The coating has not been repaired, however, XTO conducts wall thickness measurements and to date no active corrosion has taken place. The coating has not been applied due to possible damage to the pipe.

Cathodic protection is in place and is handled by contractors. Their rectifiers are checked monthly by an on staff electrician. A Close Interval Potential Survey (CIPS) is performed once every five years. There are permanent test points near the beach, and they are monitored yearly.

Internally XTO runs cleaning pigs (spheres and foam pigs). The lines are not designed for intelligent pigging and therefore the lines have never been intelligent pigged (ILI). Ultrasonic inspections for wall thickness have only been done on exposed areas of the pipe. Pigging is done once or twice a week. When cleaning pigs are run, samples are taken and analyzed. Samples are also taken offshore. There was some bacteria discovered in a water tank, but biocide injection killed it and there have been no further other indications of bacteria. NALCO is the chemical vendor and, as such, issues monthly reports.

Corrosion coupons are used offshore and onshore and have shown no high rates of metal loss internal corrosion.

Internal erosion in not a problem as the velocities are low. There has been some sand production but the low velocities have not moved the solids at a rate to cause internal erosion.

Paraffin build-up has been a problem; a paraffin inhibitor is used year round with an increase during the winter months.

There has been some movement of the sea bed and spanning has been an issue. Annual side scanning sonar is used and in the last year 5 sites have been discovered and sand-bagged to prevent any damage. A few boulders were discovered lodged against the pipeline, they have either been removed or the line was sand bagged to prevent damage.

At the beach there are metal covers in place over the pipeline to prevent any third party damage to the pipelines. There are inspection ports, and although they have not been used, they will be in the future.

From the data provided, XTO appears to be operating, monitoring and inspecting their assets in a manner consistent with today's regulations and industry practices. XTO has implemented the Pipeline Integrity Management Plan (PIM). These plans focus attention on the integrity of their assets and provide documentation for further evaluations or investigations.

OVERALL INTEGRITY of SUBSEA PIPELINES in the COOK INLET

Based upon the data provided from the 4 operators, Cook Inlet Pipeline, Forest Oil, Unocal and XTO, it appears that the issue of sub-sea pipeline integrity is being managed well.

It should be noted that the information used is writing this report is incomplete and with voluntary reporting over time, an even more complete picture can be obtained. In addition, it is envisioned that further details as to standards and practices on Pipeline Integrity Management will be issued. More complete information and more detailed standards will allow CIRCAC to further define the study conducted herein.

CONCLUSIONS

In general there are Pipeline Integrity Management plans in effect for the 4 operators studied in this report. All of these plans appear to be compliant with governmental and industry standards.

The assets, as reported, all appear to be operated in a safe manner consistent with company, industry, and governmental procedures.

It should be noted that the Cook Inlet, due to its geographic location, is subject to harsh conditions including earth quakes, tides, currents, ice flows, and shifting sea bottoms. Also other outside influences such as timber, rock, fishing boats, and other vessels could cause interference with the sub-sea pipelines. All of these issues could cause problems for the sub-sea pipelines under abnormal conditions and circumstances.

Overall, the operators appear to be operating, monitoring and inspecting their assets in a manner consistent with today's regulations and industry practices.

Based upon the data provided the following areas of concern are noted:

Cook Inlet Pipeline

1. Pipeline Integrity Management Plan (PIM) should be implemented.
2. Obtain liquid samples to lab for analysis to check for iron, bacteria, etc.
3. Begin internal corrosion monitoring - *coupons at a minimum.*

Forest Oil

1. Provide voluntary pipeline report to CIRCAC.
2. A Pipeline Integrity Management Plan (PIM) should be implemented.
3. Continue to obtain liquid samples to lab for analysis to check for iron, bacteria, etc
4. Continue the monitoring for corrosion on top of riser -- wax tape etc.
5. Re-check spanning calculations as they relate to sea-floor erosion..

Unocal

1. Re-check spanning calculations as they relate to sea-floor erosion.

   Comment -- Unocal is currently conducting an engineering study that involves a bottom current survey and engineering calculations regarding sub-sea pipeline stabilization. The allowable pipeline span vs. bottom current speed calculations will be updated and Unocal's Pipeline Integrity maintenance practices will be adjusted accordingly if so indicated.

XTO

1. Re-check spanning calculations as they relate to sea-floor erosion.
2. Pipeline Integrity Management Plan (PIM) should be implemented.

REFERENCES

1. Cold Climate Corrosion - Special Topics ISBN 0-8281-1280-0 NACE Perrigo, Byars, Divine.
2. DOT Code of Federal Regulations – Title 49 part 192 - Transportation of Natural Gas by Pipeline: Minimum Federal Safety Standards.
3. DOT Code of Federal Regulations – Title 49 part 195 – Transportation of Hazardous Liquids by Pipeline: Minimum Federal Safety Standards.
4. NACE Standard RP0176-2003 Item No. 21018
5. NACE Proposed Standard for Pipeline Internal Direct Assessment.
6. DNV
7. ANSI/NACE standard RP0502-2002 Item No. 21097 Pipeline External Corrosion Direct Assessment Methodology

ATTACHMENTS, MAPS & CHARTS

1. Map of Cook Inlet Alaska Oil and Gas Activities (01/2005)
2. Map of Alaska.
3. UNOCAL September 2004 PowerPoint Presentation.
4. UNOCAL undated report.
5. UNOCAL November 2003 PowerPoint Presentation.
6. XTO Presentation, undated.
7. XTO Presentation, undated.
8. Chart A - Summary of Pipelines in Cook Inlet.
9. Chart B - Summary of Inspection by Operator in Cook Inlet.
10. Risk of Continued Operation Chart.
11. Paper 3.9 Underwater Maintenance and Inspection of Offshore Structures in Cook Inlet, Alaska; John C. Daley, Don Ingraham; NACE Cold Climate Corrosion
12. Major Pipeline Outlines Its Compliance Plan for Integrity Management; Drew Hevle; Pipeline & Gas Journal, March 2004.
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14. Assessing External Corrosion, D. A. Ersoy, K. G. Lewis, Pipeline and Gas Technology, March 2004.
15. Integrated Data approach to Pipeline Integrity Management, Perich, van Oostendorp, Puente, Strike; Pipeline & Gas Journal, October 2003.
16. Interpretation is Key to Direct Assessment Success; Perich, van Oostendorp, Dauzat, Earle; Pipeline & Gas Journal, March 2005.
17. Benchmarking for Integrity; Healy, Jones, Clyne, Cazenave; Pipeline and Gas Technology, January/February 2005.
18. Pipeline Integrity Assessment and Management; Manian, Hodgdon; Materials Performance, February 2005.