CASE HISTORY OF INTEGRITY MANAGEMENT ON A CORRODED PIPELINE

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March 1999

ABSTRACT

The evolution of the integrity management process, philosophy and techniques employed on a corroding pipeline over the past 24 years are described. Knowledge gained in terms of the problem and mechanism of corrosion as determined by research, field examinations and inspection data analysis has been used to formulate a probabilistic risk based approach. Economics and hazard exposure have been used to evaluate the effectiveness of different maintenance options.

1. INTRODUCTION

The main objective of this paper is to present a case history of a 500 km long pipeline in northern Alberta. One desire, many years ago, was to determine the growth rate of every corrosion feature on the pipeline using in-line inspection (ILI) tools. This objective has been accomplished. Once corrosion features can be matched between inspections it is possible to examine many aspects of both the growth modelling and the ILI tools themselves. It is also possible to optimize the inspection frequency of pipelines.

In this paper a review of over two decades of work relating to the history of the pipeline, the growth modelling, and some of the studies that have been performed based on the growth modelling, is presented.

2. HISTORY

The pipeline is part of a system of 37,000 km of natural gas transmission pipelines that TransCanada PipeLines owns and operates in Canada. In 1997 the total throughput of the system was 4.5 trillion ft^3.

The 500 km long NPS 20 Peace River Mainline moves gas from northwestern Alberta, south to the western mainlines of the system. It was constructed in the winter of 1968/69 as an oil pipeline. Its 5.56 mm and 7.14 mm thick pipe was coated with over-the-ditch applied polyvinylchloride tape. The pipeline was purchased from the original operator and converted to gas service in 1971. Following a series of ruptures and leaks in 1975, an intensive program was established to restore the integrity of the pipeline.

The initial goals of the program were:

- to identify and repair locations where the pipe strength had been reduced to unacceptable levels, and
- to develop procedural or operational changes to prevent the re-occurrence of the corrosion problem.

2.1. In-Line Inspection

The first goal was approached by using a combination of hydrostatic retesting and in-line inspection with associated repairs. At the time, the ILI technology available was what is now referred to in industry as "low resolution." An extensive program of site specific pipe repairs and replacement sections was carried out with key portions being validated with hydrostatic testing. The maximum operating pressure of the line was reduced from 911 psi to 820 psi, and has remained so since due to the severity of the external corrosion.

2.2. The Cathodic Protection System

The second goal involved closely examining the effectiveness of the cathodic protection system. Reliability of the system was seen as a problem due to the remote location of the pipeline. Where power was available, rectifiers were difficult to access and rectifier malfunctions were not identified quickly. The situation was even more difficult where power was not available. Gas fired thermo-electric generators (TEG) were used to power the anode beds at these sites. Difficult access and design problems resulted in reduced reliability. The result of these problems meant portions of the line were without cathodic protection for several months throughout the year. A concerted effort to visit all rectifier and TEG sites each month to insure the consistent operation of the CP system was undertaken. Design changes to the TEG's were made to eliminate environmental factors which were seen to impede their reliability (eg. insect screens etc.).

2.3. Identification of Sulphate Reducing Bacteria

Study of the failure sites suggested sulphate reducing bacteria in the soil were involved in the corrosion process. Literature of the day suggested 100 mV of additional polarization was required to mitigate the effect of the soil bacteria. Consequently, the CP criteria for the pipeline was raised to 1000 mV "on." Additional ground beds were installed to insure the new criteria of protection was achieved along the entire line.

2.4. Results of the Initial Program

By 1981, the cathodic protection system was virtually 100% reliable and the 1000 mV criteria was achieved. A re-inspection of the line was performed and the data compared visually to previous inspections from 1975 and 1978. The comparison clearly showed that in spite of the improvements in the CP system, reliability and level of protection, corrosion was continuing to progress on the pipeline. Figure 1 shows the low resolution ILI trace for a typical location. On the left are records from 1978 and on the right are records from 1982. Note the changes in signal amplitude and extent at locations C and D while locations A and B show no change. Note also that upstream of A on the 1982 inspection there appears to be new corrosion.

Research (Jack et. al., (1996)), into the corrosion mechanism over the next three years revealed:

- Corrosion damage was caused by the mechanism of anaerobic microbial corrosion (a mixed population containing sulphate reducing bacteria).

- The bacteria were sustained by metabolizing components from the tape adhesive/primer.
- Corrosion was occurring under disbonded coating that shielded CP currents.
- Cathodic protection was able to stop bacterial corrosion, however, the presence of sulphide in the corrosion products significantly increased the current density required to achieve protection.

2.5. Modification of the Goals of the Program

The goal, at this point in 1984, was to use in-line inspection as a replacement for hydrostatic testing by accurately determining the size of corrosion features on the pipeline and repairing those which would not survive a hydrostatic test.

It was also clear by this time, that low resolution ILI was incapable of providing the level of detail necessary to allow accurate remaining strength calculations for identifying locations requiring repair. An agreement was reached with PII (formerly British Gas) to construct an NPS 20 high-resolution tool for use in this pipeline. The tool, however, would not be ready until 1986. Based upon minimum average corrosion rates calculated from corrosion, excavations and previous hydrostatic test ruptures, a hydrostatic test of the line was performed in 1984 to again prove the integrity of the line (8 failures occurred during the hydrostatic test in locations of external corrosion).

Prior to the 1986 inspection, the high resolution ILI tool was used in 1984 on the NPS 36 Western Alberta System Extension pipeline and its accuracy was validated with actual corrosion geometries.

Analysis of the data from the NPS 36 pipeline showed modifications were required to the remaining strength calculations contained in CSA Z184 (now Z662) and B31G. These modifications removed some of the conservative assumptions placed in the equations to make the calculations easier to perform before personal computers became widespread. These changes were among those made to the NG-18 surface flaw equations in the development of RSTRENG. Methodologies for handling very long defects (>1 pipe diameter), adjacent defects that influence each other's remaining strength and spiral flaws along the tape overlap were developed and previously reported by Worthingham and Coulson (1990).

Reporting and representation of the complex data produced by the ILI tool became an issue. The concept of reporting individual pit geometries, clusters of pits with their average depth and groups of clusters was suggested to the ILI tool vendor who successfully implemented the approach and modifications to the remaining strength calculations. Expected failure pressures were calculated for each corrosion pit, cluster of interacting pits and group of interacting clusters. The lowest failure pressure (pit, cluster, group) assigned to the region of corrosion was the expected behaviour of that particular feature.

Using the ILI tool vendor's automated sizing algorithms on the 1986 inspection of the Peace River Mainline (with manual sizing of significant features) along with a computer calculated expected failure pressure for any corrosion pit on the pipeline, it was possible to successfully and effectively size and assess the significance of over 100,000 features in 500 km of pipeline. This was a considerable feat owing to the state of computer technology in 1986. Of the 100,000 features examined, 8 were identified as requiring repair.

2.6. Identification of Growth Modelling from Repeated Inspections as a Possible Goal

The next goal was to use this high-resolution data to study corrosion rates on the pipeline and changes in the severity of the population of corrosion features. This had the potential to be a very powerful tool for developing cost effective maintenance plans. By knowing how and where a population of corrosion features was changing with time, inspections could be scheduled at the optimum time to insure failure would not occur before repairs could be made. Preemptive repairs would allow optimizing of the economics and timing of the inspection/repair cycle. Locations with growing corrosion could be repaired in a non-invasive manner (coating repair) before the features had damaged the pipe to the point that pipe reinforcement or replacement was required. The overall life cycle cost of maintenance could be considered. For example it would be possible to identify locations where it would be more cost effective to replace or recoat an entire section of line rather than perform an ever increasing number of short site specific repairs.

With the completion of the second high-resolution inspection of the Peace River Mainline in 1990, work toward the goal of determining corrosion rates for every pit on the pipeline had begun. Twenty five repairs were identified from this latter inspection.

Initial attempts at manually matching corrosion pits from the inspection records proved unsuccessful, partly due to limits caused by hard copy reporting of the data initially and the reporting resolution for axial position.

Efforts to study the growth of the overall population of features as opposed to individual features fared much better.

The software package “RKNova” was developed in 1989 and was previously reported by Morrison and Worthingham (1992). This software allowed modelling of the behaviour of the pipeline as a system and could estimate when the next inspection would be required. Unfortunately it could not identify which specific features were driving the need for reinspection or their location. The input to RKNova was the histogram of severity obtained from a single inspection. The data were analyzed to model the growth as a stochastic process.

By 1994 and the third high resolution inspection of Peace River Mainline (54 repairs identified), data storage capabilities had improved to the point where the ILI tool vendor was requested to provide a record for every pit detected in the inspection. Original data tapes from the previous inspections in 1986 and 1990 were reprocessed by the ILI tool vendor and reported in the same format to allow pit by pit matching for the corrosion growth analysis. Every corrosion feature was analyzed, interior and exterior, with minimum penetrations of 1% wall thickness.

This endeavour was one that was much more difficult than it would first seem. However the obstacles were overcome and the goal achieved.

3. CORROSION GROWTH MODELLING

Two major goals have driven the corrosion growth modelling program:

1. Make integrity decisions based upon the *actual* deterioration rate of the pipeline, including site specific rates.

2. Gain the most benefit from the data available.

Other minor goals were to fully comprehend *how* the ILI tools report the corrosion data, and to validate the tools. The NPS 20 Peace River Mainline was the primary target for analysis with inspections in 1986, 1990 and 1994. A second target for study was the NPS 36 Western Alberta System Extension, with three high-resolution inspections from 1984, 1989 and 1994.

Several questions were formulated with respect to the determination of the reinspection frequency.

- The inspection frequency for Peace River had been set at 4 years based on a *single* "reasonable" minimum average corrosion rate—could the 4 year frequency be modified to longer than once every 4 years?
- How would one go about optimizing the reinspection frequency?
- When will the remaining flaws, left growing on the pipeline but not repaired, have deteriorated sufficiently to be in danger of rupture or leak?
- How do we spend the ILI resources wisely to inspect as many lines as are required to insure system integrity and then to perform the inspections at an appropriate time?

3.1. The Dream

"your old men will dream dreams,
your young men will see visions."
(Joel 2:28)

The first assumption was that high-resolution ILI data could be used to identify where corrosion features were growing, and how quickly they were growing. All that was required was to determine the characteristics of each pit, cluster and group on each inspection, match them from one inspection to another, analyze the severity as a function of time, and estimate the severity to any time in the future.

Given success in this, the results would allow for *just in time* inspection, repair of the most severe features and those that were expected to be the most severe at any time in the future. Where features were not currently severe enough to warrant removal or reinforcement of a joint of pipe, a coating repair could be performed *before* reinforcement or removal was required.

3.2. The Reality

With both trepidation and enthusiasm the project began after the 1990 inspection by analyzing a short section of the 1986 and 1990 inspections, mostly manually at the beginning, to determine the feasibility of the matching process. It quickly became apparent that the project was "easier said than done!" The desire was to construct a mathematical model that could be used to automatically match the features, accounting for a wide variety of variability that was observed in the data. For short sections, such as a joint or two, even the manual analysis proved prohibitive because some joints had densities of several hundred features in 15 m of pipe. For a while these features were flagged "because the software overloaded and crashed the computer." Obviously more study was required to solve this non-trivial problem.

Matching from three inspections is illustrated in Figure 2. The horizontal axis is the odometer reading in a particular joint of pipe, and the vertical axis is the orientation of the features in hours. The top set of corrosion is from the 1986 inspection; the middle set of data is from 1990 and the bottom set is from 1994. The features are from the NPS 20 pipe. Note that the number of corrosion features on this one metre section of pipe has increased from 3 in 1986 to 9 in 1994. Each feature is assigned an index number, shown to the left of each box, and centred on the box is its depth in percentage of wall penetration. Dashed lines represent features less than 15% penetration for ease of checking the matches. The notation at the upper right hand corner is for debugging purposes and shows the matches by index number.

Based on the matches, it is possible to obtain information about the ILI tool reporting by examining the groups of corrosion features as a function of time. Note also, the advantage of reporting all corrosion down to the minimum level possible. A truncation of the reporting at 20% wall thickness would reduce the number of corrosion features significantly.

Some of the variability included:

- Tool settings for a particular run.
- The tool reported the corrosion differently between runs—while the general shape remained the same, the reporting of the individual "boxes" was different between inspections, and their individual sizes could be different.
- Odometer slippage between runs.
- Orientation uncertainty in the location of the features.

- Technology changes in the ILI tool (better discrimination and resolution for the more recent inspections).
- ILI tool repeatability, and ability to accurately size features.

The research program began with a first-order simple analysis in 1993, and ended with a second-order complicated process that has undergone development since 1995. The objective of being able to repeatedly identify the same corrosion feature on a pipeline, and grow the feature, was accomplished.

The software includes routines that analyze the data for certain problems recognized in the past, and indicates where a problem is suspected. Manual analysis and checking can begin immediately. Some of the aspects studied for each set of matches are; "What did all the deep features get matched to, and what were the matches for all the highest growth rate features." Statistical analyses of the comparison of data between inspections can also be undertaken.

In full, the accomplishment of the objective means that any question that can be asked of the data, the growth rates, and location (by putting the results into a geographical information system), can be answered.

Instead of the statistical modelling of the overall behaviour of the corrosion rates using RKNova, changes on a feature-by-feature basis could be determined. The key was that each feature had an associated individual rate, and site specific questions and decisions could be made.

By matching each and every corrosion feature a site specific risk of severity for each feature can be determined. The size of each feature could be projected into the future (accounting for pits, clusters and groups).

A monte-carlo analysis of each feature can be used to determine the probability of failure of each feature (including defect interaction) for any point in time in the future. The distributions used in the analysis include tool variability and repeatability. A critical sub-feature analysis is used on all ILI data collected since 1994 (these methodologies are synonymous with RSTRENG and LAPA).

After removal of a joint, the ILI vendor reporting and actual size of the features is examined and statistical analyses are performed.

4. THE ILI TOOLS

The corrosion growth modelling has formed a foundation for aiding in the determination and understanding of the ILI tool repeatability and variability. The statistical analyses include

- Determination of any systematic misreporting.
- Error bars on the reported size of features (for comparison with the vendor's specifications).
- Error bars on the field measurement methods of determining the severity of corrosion features.

For every inspection there is a continuing need to understand the limitations of the ILI tool because—and this may perhaps be a subtle point—as the pipelines become older, the corrosion can become more complicated and the ILI tools have to be able to report accurately *all* of the phenomena on the pipeline to maintain the ability of the ILI tools to replace hydrostatic testing. By understanding the limitations of a given tool, the operator is then able to account for the limitations in formulating the appropriate maintenance response.

5. FAILDATE

There are many different questions a pipeline operator can ask with respect to planning maintenance and predicting severity in the future. One of the questions is "When do we expect features to fail?" This information can be used to determine if repairs of more than one feature in a location should be conducted rather than simply repairing the single most severe feature in a location, (i.e. Are there nearby features which will require repair in a few years time?). As an operator one only wants to go into a specific location once.

The output analyses used in this type of maintenance planning is called FailDate. FailDate determines the expected date of failure of each feature on the pipeline. The predictive capability of this mathematical analysis was validated by growing matched features from the 1986 and 1990 inspections to 1994 and comparing the results to those obtained by the ILI tool in the 1994 inspection. The output, in general, was slightly conservative compared to the results of the inspection.

An example of output from FailDate is shown in Figure 3. The horizontal axis is the year and the vertical axis is the expected frequency per year of ruptures or leaks. The frequency rises gradually, peaks, and then falls to a lower value again. In this example all of the features expected to fail before 2040 are growing, and those expected to fail after 2040 have shown little evidence of growing.

Over 800 km of pipe from the Peace River Mainline and Western Alberta System Extension, for three inspections of each pipeline, were processed. In 1997 this process, including checking, running software, and so on, required 9 months to complete. The same process can be performed now in 1 month due to improvements in the software.

6. RESULTS OF THE PEACE RIVER VALIDATION OF THE GROWTH MODEL

A maintenance program was developed for the Peace River Mainline during 1997. Repair locations were determined based on the projected defect size for 2000—recall that the three inspections were in 1986, 1990 and 1994.

Site specific corrosion rates for all 160,000 features were used in the analysis. Interaction of features, RSTRENG and monte carlo analysis was included (the monte carlo analysis is a method of including tool reporting variability in a severity estimate).

The repair decisions determined from the growth modelling were compared with those that would have been made without using the growth modelling, and they were found to be different.

The conventional analysis applied a single growth rate to all features. With the new analysis, individual corrosion rates were applied to each corrosion feature, resulting in the identification those features that were actually growing in excess of the assumed rate. These features, which would not have been previously identified, were now included as part of the new repair program. There were also features identified for repair using the old methodology, which did not require repair because the features were either not growing, or were growing at very low rates.

Validation of FailDate and the ILI tool was obtained by comparing growth estimates and severity estimates as part of a 1998 removal program for Peace River.

The severity estimates from the growth analysis were expected to be slightly conservative, and were found to be so based on comparisons between the growth calculation and measurements taken from 300 pits on several joints of pipe removed from the field and examined in a laboratory.

Based on this validation, a total of 8 locations were identified as requiring maintenance in 1999. Clocksprings were to be used where applicable and 529 m of pipe were slated for replacement. This work was completed in February 1999.

7. COST COMPARISON

The objective of the cost analysis was to compare the net present cost of various maintenance options to the probability of failure (exceedance) of the remaining features, to optimize expenditure versus the likelihood of failure. Several different options were examined. The optimal scenario provided a net present cost savings of up to $ 10 million over the next 30 years using the growth modelling when compared to the status quo methodology of maintenance. This was achieved while not compromising the probability of exceedance for the most significant remaining features in the pipeline. This level of maintenance optimization was achieved for only one pipeline. Further significant overall optimization is possible by applying this type of approach to other pipelines in the system.

8. OUTPUT OF DATA TO A GIS AND COMPARISON WITH SOILS MODELS

By displaying the corrosion rate and occurrence data on a geographical information system platform, more explanation as to the "why" of corrosion can be obtained. The corrosion data has also been compared with a soils model and NOVAProbe data to enable as complete and detailed an understanding as possible of the corrosion and its relationship to the local environment. See Wilmott et. al (1995) for a description of the NOVAProbe. For example, active corrosion on slopes and pipeline CP system problems not previously identified were discovered. Figure 4 shows an example of corrosion on a hillside. Soil creep on the hill has damaged the coating and resulted in the formation of a corrosion scenario.

The downward vertical lines are the expected penetration at some time in the future and the upward vertical lines are the penetration at the time of the last inspection. The horizontal lines are the penetration rate. In this example the maximum penetration rate on the slope is 0.33 mm/year.

9. FAILURE PREVENTION

Over the past 15 years, after the use of high-resolution ILI began on Peace

River, the tool, in the three inspections, has identified 87 features of high severity which were repaired. The removal program for 1999 includes another 371 severe features, some of which were within 1 metre of each other. Thus, another 250 potential ruptures or leaks on the pipeline have been prevented due to the growth modelling, for a total of 337.

10. SUMMARY

The analysis procedures for matching and severity prediction are a mature, tested product. The following has been achieved:

1. Growth estimates over a five-year period since the last inspection of Peace River have been conducted, and compared with results from the nearly 1000 m of pipe removed in 1998.

2. The corrosion rate of every feature on Peace River and Western Alberta System Extension has been estimated.

3. The failure date of every feature on Peace River and Western Alberta System Extension has been estimated.

4. The probability of failure of every feature at given times in the future has been estimated.

5. Complete snapshots of the expected state of the pipelines at given intervals into the future have been calculated.

6. Maintenance plans based on actual pipe deterioration rates and life cycle modelling of alternative approaches has been accomplished.

7. The approach has been validated with field data and found to be accurate but yet conservative.

The major objective of spending the right amount of money at the right time for the right reason has been accomplished and an optimized maintenance program for Peace River and Western Alberta System Extension has been developed.

This paper has summarized developments in pipeline integrity monitoring and planning on the former NOVA Gas Transmission system. As the merger with TransCanada PipeLines progresses many opportunities will develop to merge the methodologies and approaches of both companies to provide ever increasing levels of pipeline safety and stewardship of the resources required to achieve these goals.

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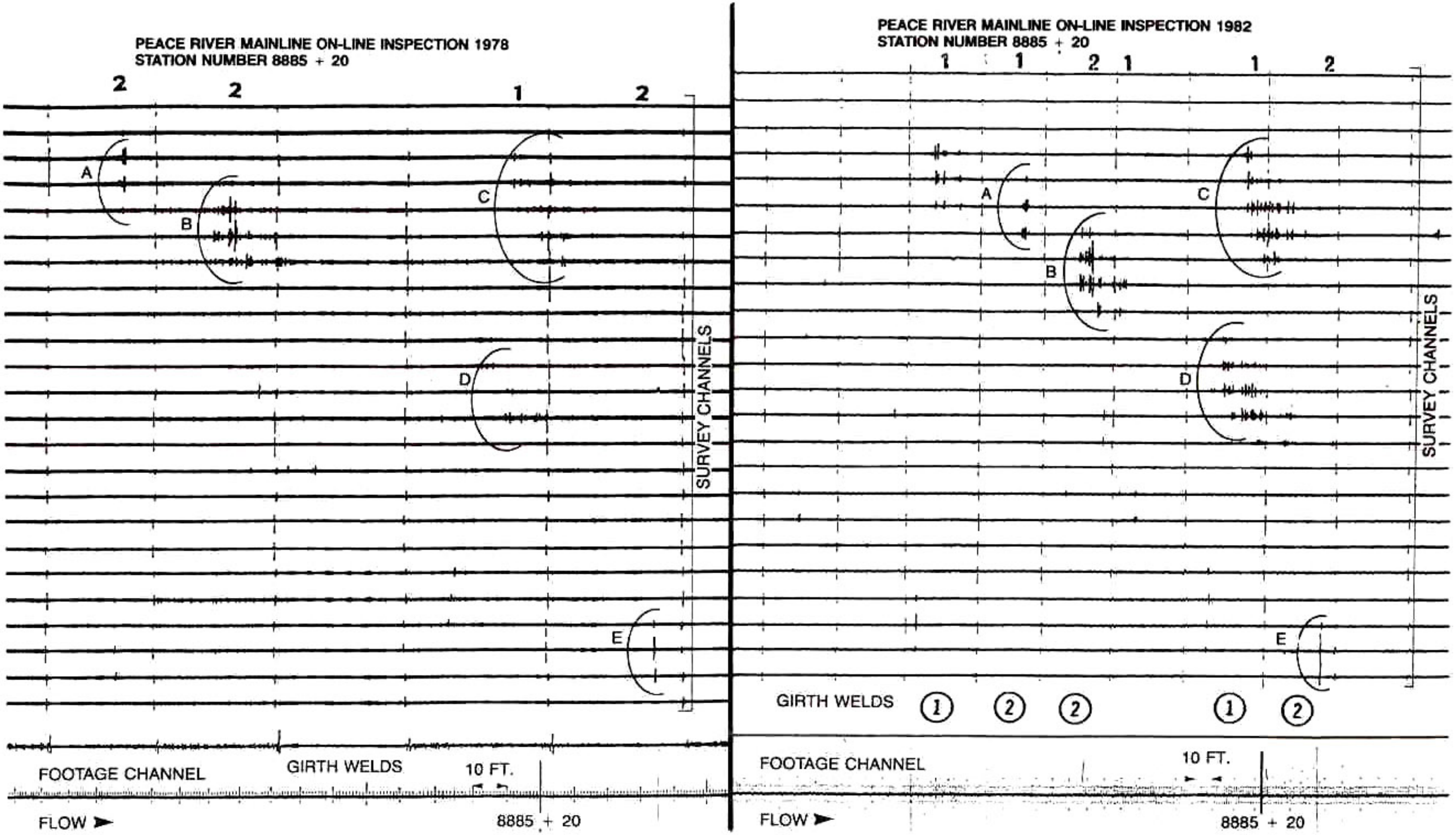

Figure 1: Illustration of Low Resolution ILI Data, on the Left from 1978 and on the Right from 1982

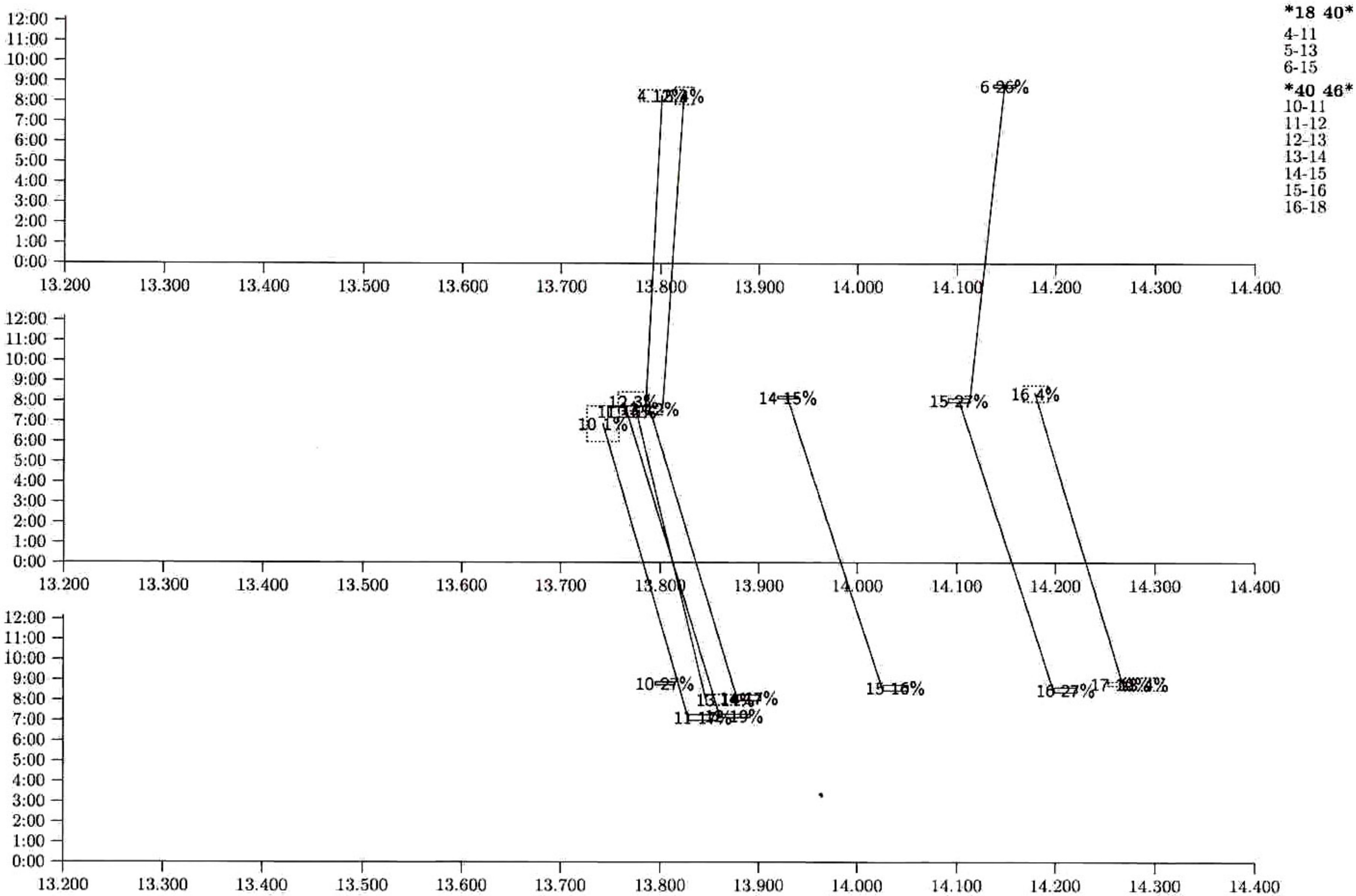

Figure 2: Example of Growth Using 1986, 1990 and 1994 ILI Data

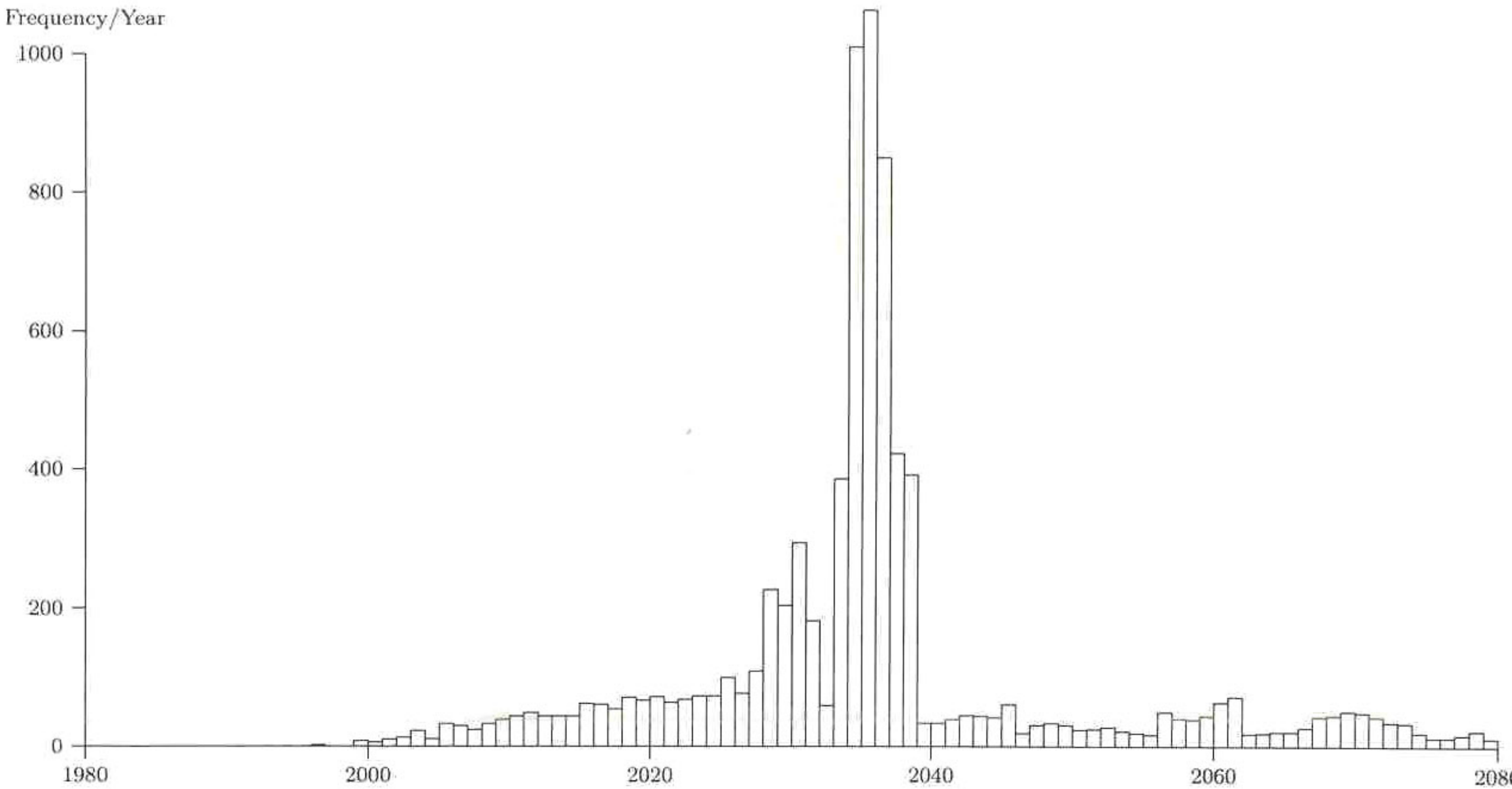

Figure 3: Histogram of Failure and Leak Dates

Corrosion Rates on a Slope

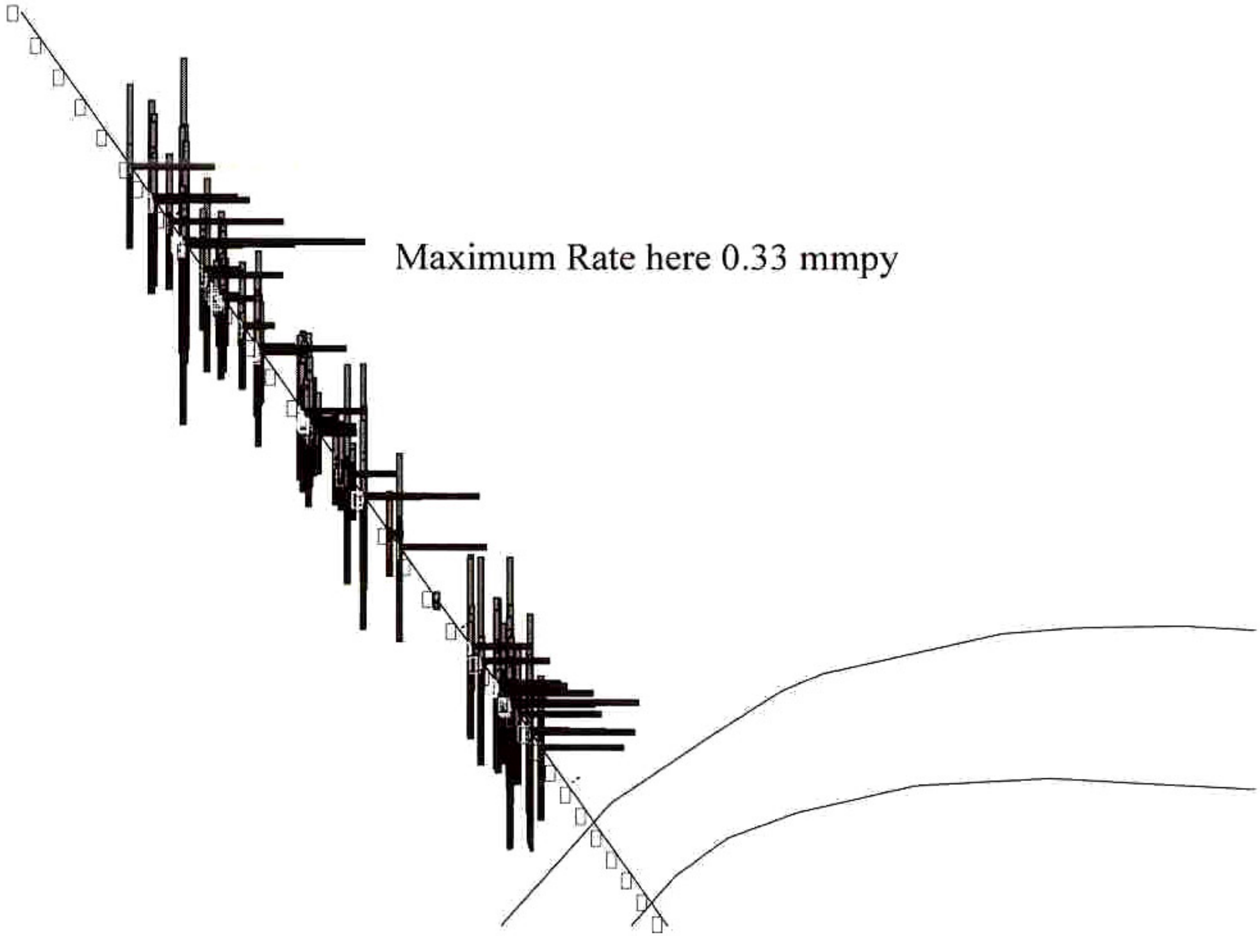

Figure 4: Illustration of Growth on a Slope by a River